U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.	50-293
Report No.	95-15
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Location:	Plymouth, Massachusetts
Dates:	July 6, 1995 - August 18, 1995
Inspectors:	R. Laura, Senior Resident Inspector A. Cerne, Resident Inspector T. Shedlosky, Project Engineer

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Scope: Resident Inspector safety inspections were conducted in the areas of plant operations, maintenance and surveillance, engineering, plant support and safety assessment and quality verification. Reactive inspections were conducted for the unplanned downpower event involving the "B" sea water pump, the identification of several wiring discrepancies and a missed technical specification surveillance test. A planned review of the reactor vessel water level indication was done using temporary instruction 2515/128. The quality of five licensee event reports was reviewed. Two operations review committee and one offsite review committee meetings were attended by the inspector.

Findings: No violations were identified. One unresolved item was identified involving wiring discrepancies. An unresolved item concerning the reactor core isolation cooling turbine oil system and governor valve was closed. A licensee identified violation involving a missed automatic depressurization system surveillance test was treated as a non-cited violation. Performance during this five week period is further summarized in the Executive Summary.

EXECUTIVE SUMMARY

Pilgrim Inspection Report 95-15

Safety Assessment/Quality Verification: The onsite and offsite review committees were effective in evaluating potentially safety significant issues. For example, the operations review committee identified an opportunity to further reduce the uncertainty involving an operability evaluation for SBM control switches. Also, the nuclear safety review and audit committee stressed with plant management the need for increased teamwork and communication between departments to significantly lower the maintenance request backlog. Five licensee event reports were reviewed that met the intent of 10 CFR 50.73.

Plant Operations: Overall good performance by operators was evident during routine and emergent operational activities. BECo is making an adequate effort to achieve an alarm free main control board. Swift and effective operator response averted a reactor trip during an unplanned downpower event involving the "B" sea water pump. The unplanned downpower resulted from human performance related issues involving painters working in the screenhouse and also mechanics who were not aware of the details of the design of the "B" sea water pump motor lower bearing oil sightglass that loosened and allowed the oil reservoir to drain. The OMNI guard temperature panel response procedure was enhanced to provide operators with more detailed guidance on the significance of temperature alarms relative to the upper component temperature limits.

Maintenance and Surveillance: Maintenance workers completed work activities on the station blackout emergency diesel generator, pressure transmitter 5021 and replacement of two residual heat removal system SBM switches in a deliberate and competent manner. Effective self-checking was observed during an undervoltage and degraded voltage technical specification surveillance test of electrical emergency bus A5. Management has implemented many changes to streamline and enhance the work control and planning processes and reduce the maintenance request backlog. Operations management identified a missed automatic depressurization system surveillance test that resulted from a personnel error made when changing periodicity codes in the master surveillance tracking program.

Engineering: Weaknesses in electrical wiring configuration control were evident when questions raised during a quality assurance audit led to the identification of two safety related motor operated valves that stopped travelling shut on the close limit switch rather than the close torque switch. One valve was miswired due to inconsistencies between electrical prints and incorrect advice from an engineer, while the other valve was miswired due to a maintenance worker mislanding leads. Plant management initiated an issue team to evaluate the causes and develop corrective actions for the electrical configuration control deficiencies. A review of the reactor vessel level

(EXECUTIVE SUMMARY CONTINUED)

indications for NRC Temporary Instruction 2515/128 identified no significant concerns with the keep fill modification made to the reactor vessel water level transmitter reference leg lines.

Plant Support: Good performance of the radiological control staff was evident. Progress was made in reducing the amount of contaminated area in the reactor building allowing easier access for plant workers and managers. For example, the east and west hydraulic control unit banks were decontaminated. The turbine end of the high pressure coolant injection room was also decontaminated. Effective radiological controls were maintained during the dewatering of the dryer/separator pit. A radiation protection technician also promptly stopped a calibration activity in the TIP room when an unrelated barrel connected to the condensate demineralizer vent header overflowed. A past violation involving fire doors was closed out.

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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 July 19, operators lowered reactor power to 60% power to secure the "B" sea water pump due to an overheated lower motor bearing. After the maintenance staff repaired the damaged bearing, operators returned the unit to 100% power on July 21, 1995. The unit operated at or near 100% power during the remainder of this inspection period.

2.0 PLANT OPERATIONS (71707, 92901, 93702, 40500)

2.1 Plant Operations Review

The inspector observed the safe conduct of plant operations (during regular and back shift hours) in the following areas:

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

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. Workers complied with radiation work permits and appropriately used required personnel monitoring devices. Modification and testing of switchyard breakers was carefully coordinated with weather and grid loading conditions and other ongoing work to minimize risk.

Special emphasis was placed on monitoring the control room environment including the timeliness of equipment problem resolution. Operators were observed using the new recirculation pump motor generator set digital controllers. The digital controllers, which were installed as a major modification during refueling outage no. 10 (RFO10), allow operators more precise control of recirculation flow adjustments for routine reactor power control. Although an upgraded main control board annunciator system was installed during RFO10, the operations section has not yet achieved an alarm free main control board. Typically, three or four annunciator windows remained lit during the period. The inspector discussed the status of lit annunciators with operators including the possibility of disabling lit annunciator windows associated with longer term deficiencies. Examples of this included switchgear (i.e., B17 and B18) high temperature alarms due to faulty temperature switches.

The plant manager informed the inspector that establishing an alarm free main control board is an item included on the plant manager's top 10 items report. The inspector reviewed the report which contained a list of 11 disabled annunciators with the cause and scheduled corrective action. Additionally, near the end of this inspection period, operations section management issued a new three page morning report. The new report consolidates several turnover and various status reports to reduce the administrative burden on the operators. Included on the new morning report is a listing of lit alarms due to valid problems and also a list of alarms that have been disabled. The new report format provides a greater level of detail to all site personnel. Periodically, at the morning plant manager's meeting, the inspector observed plant management discuss the reason for lit alarms and the actions necessary to clear the condition. In conclusion, BECo is making a reasonable effort to achieve an alarm free main control board.

2.2 Human Performance Forced Power Reduction

On July 19, 1995, operators lowered reactor power from 100% to 70% to secure the "B" sea water pump due to an overheated lower motor bearing as evidenced by a main control room alarm. Licensee investigation found that a bearing oil sightglass located on the "B" sea water pump motor had loosened and rotated 180 degrees down from the normal vertical position. This configuration allowed the lower motor bearing oil to drain from the sightglass onto the floor of the sea water pump room, which is located in the screenhouse building. Operators initiated problem report 95.9403 to document the event, evaluate the root cause and develop corrective actions. The inspector reviewed the event by direct observation of operator actions to stabilize plant conditions, review of a time history plot of key parameters, visual inspection of the sightglass, and interviews with operators and operations and maintenance section managers.

The time history plot showed that approximately 12 minutes elapsed after the "B" sea water pump motor lower bearing high temperature alarm (setpoint is greater than 174 degrees) sounded to when the pump was tripped. The bearing temperature reached a maximum reading of 340 degrees Fahrenheit. During the 12 minute period, operators took the following actions: respond to the OMNI guard temperature panel (located on a control room back panel) and identify which component initiated the high temperature alarm, review the alarm response procedure guidance to identify which component was in alarm, inspect the pump motor locally in the screenhouse building to determine the cause of the increasing bearing temperature, decrease reactor power using control rods and recirculation flow changes to avoid a reactor scram when tripping the "B" sea water pump. Due consideration was given to the caution zone region of the power-to-flow map. The inspector determined that operators responded appropriately to the event by lowering reactor power and securing the "B" sea water pump.

Chemical analysis of a lubricating oil sample and discussions with the pump motor vendor confirmed that the lower motor bearing was wiped. After rebabbitting the bearing at a vendor facility offsite, the maintenance staff reinstalled the bearing and the pump was restarted. Pump vibrations and bearing temperatures trended normal. Operators returned the unit to full power. Additionally, anti-rotation devices were added to both sea water pump motor lubricating oil sightglasses to prevent movement and possible loss of lubricating oil in the future. The repair of the wiped bearing and installation of the anti-rotation devices on the lubricating oil sightglasses represented the short term corrective actions necessary to restart the "B" sea water pump and return the unit to full power.

The BECo root cause analysis identified human performance as the most likely root cause from two aspects. First, as part of the plant material condition upgrade initiative, workers were working in the "B" sea water pump room preparing surfaces and applying preservation coatings. On July 13, 1995, a nuclear watch engineer (NWE) noticed that workers tied a rope to the sea water pump motor lower bearing lubricating oil sightglass as a support for staging. After the NWE had the rope removed, he noticed the sightglass was tilted from the vertical position. The NWE returned the sightglass to the vertical position and notified mechanical maintenance to verify that the mechanical joints were tight. The mechanics determined that the mechanical joints appeared tight and noted that no lubricating oil was leaking from the sightglass mechanical joints by maintenance technicians. The sightglass had straight threads and was locked in position by the friction created between the flats on the fitting and the body of the sightglass and the crushing of a teflon gasket where the two surfaces met. Hence, unknown to the mechanics, when the NWE repositioned the sightglass to the vertical position, the movement actually loosened the mechanical joints leaving the joints vulnerable to become loose during normal pump vibration. The lack of knowledge of the internal design of the sightglass mechanical joints represents the second human performance related aspect of the root cause. The inspector determined that BECo conducted a thorough root cause investigation of this downpower event.

In addition to the short term corrective actions described above, the workers applying the preservation coatings were thoroughly briefed by operations section management not to interfere with operating plant equipment. Longer term corrective actions included the discussion of this event as part of the continuing training program and a review for other plant pumps with a similar design. Lastly, the alarm response procedure (ARP) for the OMNI guard temperature alarm panel was enhanced to provide operators with more guidance concerning the significance of alarm setpoints relative to the upper component temperature limits and recommended actions. The corrective actions taken to preclude repetition were comprehensive.

The inspector concluded that operators acted swiftly and effectively in response to the high bearing temperature on the "B" sea water pump motor. These actions precluded a reactor scram and catastrophic damage to the bearing shell and pump shaft. BECo correctly identified human performance as the root cause of the downpower event. This included the workers who tied a line to the pump motor lubricating oil sightglass as part of the plant material condition upgrade process and also the maintenance training deficiency that contributed to the mechanics not understanding the details of the sightglass mechanical joints. The NWE who initially identified the loose sightglass on July 13, 1995 and notified mechanical maintenance exhibited a questioning attitude. The alarm response procedure enhancements provided operators more meaningful information to respond more effectively to plant equipment high temperature alarms in the future. The root cause analysis and corrective actions were comprehensive; however, operators were unnecessarily challenged by the event and its underlying two root causes.

3.0 MAINTENANCE AND SURVEILLANCE (61726, 62703, 92902)

3.1 Routine Maintenance and Surveillance Observations

The inspector observed portions of selected surveillance and maintenance activities to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to limiting conditions for operations, and correct system restoration following testing. Instrumentation and control (I&C) technicians were observed calibrating pressure transmitter 5021, which is a Foxboro brand transmitter that measures the drywell-to-torus differential pressure. The as-found readings were outside the acceptance limits requiring the I&C technicians to make span and zero adjustments. The as-left readings were within the prescribed limits. The technicians completed the calibration process and returned the transmitter to service. The technicians used good self-checking techniques during the calibration process.

The inspector observed electricians replace the SBM control switches for reactor core isolation cooling (RCIC) system shutdown cooling isolation valves 1001-47 and 1001-50. The switches were replaced as a result of concerns involving the switch cam followers which were made of impure lexan and were vulnerable to cracking primarily due to a manufacturing defect. The manufacturing defect involved a drilled hole in the lexan cam follower where a roll pin was inserted. The hole was too small and when the roll pin was inserted, stress concentrations remained leading to degradation of the lexan and cracking. The inspector verified that the upgraded replacement switch cam followers were made from an upgraded material of valox. The electricians carefully followed the work package instructions. The electricians took precautions not to interfere with any energized circuits in the vicinity of the control switches being replaced in the control panels. Also, the inspector observed electricians measure the insulation resistance of the station blackout diesel generator. Overall, electricians performed well and no problems were observed.

Electricians performed a channel functional test of the loss of voltage and degraded voltage relay surveillance on electrical bus A5, which is the 4160 volt emergency power bus. The inspector observed this activity and verified that the procedure 8.M.2-2.1.10 met the intent of technical specification table 4.2.B. The pre-job briefing covered expected alarms, procedural adherence, and self-checking. Electricians wore protective clothing when working near energized circuits. The electricians were experienced and completed the activity in a competent and professional manner. In summary, the maintenance staff performed well during the completion of routine maintenance and surveillance activities.

3.2 Maintenance Request Backlog

The inspector reviewed the maintenance request backlog to determine the effectiveness of the maintenance organization and plant management in repairing equipment deficiencies in a timely manner. A total of 1009 maintenance requests existed including both outage related and running repairs, which can be worked with the plant on-line. The breakdown of the

1009 maintenance requests includes 238 outage related activities and 714 running repairs with the remaining requests being miscellaneous in nature. Approximately 150 maintenance requests of the 1009 total involved safety-related equipment. Previously, the inspector reviewed the safety related maintenance requests determining that an adverse trend did not exist for any single system as documented in NRC Inspection Report 50-293/95-09.

The work control manager indicated that the maintenance request backlog goal was to reduce the backlog to 575 items by the end of 1995. This goal was the lowest equilibrium value achieved at PNPS. The plant manager established a longer term goal of less than 100 maintenance requests. BECo has initiated several changes to make the maintenance work process more effective including: streamlining the work control procedure, using a work-it-now (WIN) team to expeditiously make minor repairs within skills of the trade and creating a new work control department to implement a rolling 12 week system schedule using work week managers to plan and execute on-line maintenance. The WIN team manager has been frequently observed in the plant preplanning and providing guidance to WIN team workers during maintenance activities. BECo has made substantial changes and set challenging backlog reduction goals indicating strong management support.

3.3 Missed ADS Technical Specification Surveillance

As a result of questions asked following the identification of the wiring deficiencies described in Section 4.1 of this report, operations management identified a technical specification (TS) violation for a missed surveillance test. Specifically, TS surveillance 3.5.E.1.a to simulate an automatic test of the automatic depressurization system (ADS) prior to startup from refueling outage no. 10 was missed. Upon discovery, operators declared the ADS inoperable. Instrumentation and controls technicians performed the missed ADS surveillance with satisfactory results. The ADS system was declared operable again.

Licensee review determined that the root cause of the missed TS surveillance test was personnel error. The initial data entry into the master surveillance test program (MSTP), in the 1985 time period, was entered incorrectly as semi-annual in lieu of once per refueling outage prior to startup. The error was perpetuated in June of 1994, when the MSTP for this surveillance, was changed from semi-annual to a 24 month periodicity rather than prior to startup following each refueling outage. The missed surveillance also occurred prior to start-up from RF09. Since the ADS system successfully passed the surveillance test, the safety significance of this violation was low. All similar TS surveillance required to be done prior to restart following a refueling outage were verified to be coded correctly and within periodicity. In accordance with 10 CFR 50.73 (a)(2)(i)(B), BECo submitted licensee event report 95-07 to report the missed TS surveillance requirement. The inspector evaluated this violation in accordance with the enforcement policy (60FR34381, June 30, 1995) as licensee identified and concluded that effective corrective actions had been implemented in a timely manner and that minor safety consequences were observed. This licensee identified and corrected violation is being treated as a Non-Cited Violation consistent with Section VII of the Enforcement Policy.

4.0 ENGINEERING (37551, 92903)

4.1 Valve Wiring Discrepancies

As documented in NRC Inspection Report 50-293/93-15, several cases of field wiring that was inconsistent with the electrical drawing details were identified by the licensee and individually analyzed and corrected. While the inspector expressed concern over the lack of a more collective analysis of the wiring discrepancies, it was noted that in the identified cases, any component operability problems would have been flagged by post-work testing or surveillance requirements. During the current inspection period, the licensee found additional cases of wiring deficiencies. These have been documented in BECo problem reports, PR 95.9403, 95.9427, 95.9435 and 95.9439.

The inspector reviewed these problem reports and evaluated the licensee follow-up activities, noting that in two cases (PR 95.9403 and 95.9435) the as-found field wiring was electrically equivalent to the functional requirements. Thus, the affected equipment performed as designed. However, for PR 95.9427, a quality assurance audit (95-07) of the core spray (CS) system revealed a number of wiring discrepancies, one of which appeared to affect the safety function of CS valve MO-1400-4A. This valve is a normally closed, motor-operated gate valve in the "A" train CS full flow test line to the suppression pool. By design, this valve will automatically close when a CS system initiation signal is generated.

The QA audit found that a lifted lead in the field circuitry for valve MO-1400-4A resulted in valve closure up to its limit switch setting (versus the torque switch control) upon receipt of a CS initiation signal. Since manual closure of this valve is correctly wired to cut out on torque, surveillance and other MOV testing (e.g., Generic Letter 89-10), which utilize manual manipulations, did not identify the discrepant condition. The inspector reviewed CS Logic System Functional Text (LSFT) procedure no. 8.M.2-2.10.1-4 and confirmed that the MO-1400-4A valve testing is performed using the manual control switch in the control room. The inspector discussed with operations management personnel the adequacy of the LSFT in validating both design and technical specification requirements.

With regard to specific licensee actions for the MO-1400-4A wiring error, the licensee ensured that both the "A" and "B" train CS full flow test valves were fully closed, disabled the electric power supplies, caution tagged the switches and initiated a tracking limiting condition for operation (LCO T95-180) to address further controls, if necessary should the valves have to be opened prior to resolution of additional operability concerns. The "B" train valve was treated similar to the "A" train as a conservative measure. Subsequently, the licensee determined that MO-1400-4A, a gate valve, closed sufficiently into its seat to cut off all flow upon reaching its limit switch setting. Thus, no unacceptable CS bypass flow conditions potentially existed as a result of this problem. The licensee corrected all the wiring discrepancies identified by the QA audit, closed LCO 95-T180 and restored both CS full flow test valves to an operable status.

The inspector discussed the generic implications of PR 95.9427 with both operations section and QA department personnel, verifying that additional reviews were being conducted to evaluate the impact of similar wiring problems on other systems. The licensee performed further circuit analyses and initiated additional wiring inspections to check whether other safety-related motor operated valves might be affected by conditions related to the PR 95.9427 problems.

On August 14, 1995, the licensee identified a similar miswired condition on valve MO-1201-80, the containment isolation valve on the discharge side of the reactor water cleanup (RWCU) system. MO-1201-80 was closed. The RWCU system was isolated, and the wiring deficiency was repaired on August 15, 1995. The licensee confirmed that this was the only other safety-related MOV with such a discrepant condition. However, since valve MO-1201-80 is a globe valve (versus the MO-1400-4A gate valve), the licensee had no assurance that valve closure on an automatic signal would meet the containment isolation functional criteria. Furthermore, unlike the lifted-lead conditions on the CS valve, this RWCU valve wiring discrepancy appeared to involve a permanent electrically landed connection, raising the question of when the deficiency was introduced into the circuitry.

The licensee issued a problem report, PR 95.9439, to document the RWCU valve MO-1201-80 wiring discrepancy for further review and action. Since the problem was corrected shortly after discovery, the remaining concerns relate to the adequacy of containment integrity from a historical perspective and the reportability requirements of 10 CFR 50.73. Also, the generic issue of LSFT acceptability is in question since valve indication of closure (i.e., the limit switch) was not a true representation of valve position. The licensee confirmed that overall concerns regarding wiring deficiencies, while verified by test and inspection to no longer be a problem with safety-related valves, were still being reviewed from a more generic standpoint for impact upon other plant systems and equipment.

The licensee has formed an issue team to evaluate these further concerns raised incident to PR 95.9439. The inspector reviewed the BECo memorandum providing direction to the Issue Manager and, in accordance with Pilgrim procedure 1.3.109, assigning responsibilities for root cause analysis, design evaluation and future organizational and action planning to resolve any further concerns related to the identified wiring discrepancies. The tasks delineated in this issue memorandum appear to be comprehensive. Pending NRC review of the additional licensee analysis, results and additional corrective actions, this issue remains unresolved. **(UNR 50-293/95-15-01).**

4.2 Plant Hardware Modifications to Reactor Vessel Water Level Instrumentation (TI 2515/128), Closed

This inspection was to verify and evaluate certain aspects of the modification to the reactor vessel water level instrumentation that was made by Boston Edison Company (BECo) in response to NRC Bulletin 93-03. Various aspects of the modification had previously been reviewed by the NRC, details of this review are in inspection reports 50-293/93-14, section 4.1 and 93-20, section 2.2. The focus of this inspection included BECo's actions concerning a postulated transient initiated by closing one of the manual valves in the instrument system that would isolate the instrumentation reference leg from the reactor vessel. This issue was discussed within NRC Information Notice (IN) 93-89, Potential Problems with BWR Level Instrumentation Backfill Modifications, dated November 26, 1993.

The inspector based the review upon plant design change (PDC) 93-24, its 10 CFR 50.59 safety evaluation and supporting documents, plant procedures and records. Specifically, the inspector verified that BECo had established a backfill flow rate that was based on engineering calculations. Those calculations (N138 and M585) established a flow rate range sufficient to prevent the migration of non-condensable gas down the reference leg piping but would not create a thermal stress gradient at the reactor vessel nozzle weld, nor would result in a pressure drop sufficient to effect the reactor vessel level instrumentation. Plant procedure 2.2.80, Reactor Vessel Level, Temperature and Internal Pressure Instrumentation requires a normal flow range for back fill of 0.006 to 0.010 gallons per minute (or if reference leg leak rate has been identified and quantified, the flow rate is established at 0.006 to 0.010 gpm greater than the leakage rate). These flow rates are verified each shift as part of the nuclear plant operator tour. Flow rates are recorded in a database to allow analysis of trends. The inspector examined flow rate data plots and also observed during this inspection that both flow instruments were indicating within the required range. In addition to observing reference leg backfill flowrates, the control room operators daily surveillance log includes once per shift comparison checks of reactor vessel level indication.

Plant procedure 2.2.80 also establishes procedural requirements for placing the backfill system in service, removing the backfill system from service, administrative limitation for the system out of service, changeout of the backfill supply water filter elements and valve alignment requirements. Compensatory actions to be taken in the event that the backfill system is removed from service are stated in Attachment 8 to 2.2.80. These include requirements for verifying the readiness for process computer trends if the backfill system is out of service for greater than fourteen days and also establishes a process for enhanced reactor water level monitoring if out of service for greater than fourteen days when the reactor is depressurized. The procedure provides guidance to the control room operators for appropriate defaults to the Emergency Operating Procedures, EOP-01, on the assumption that there has been a loss of indicated reactor vessel level if both channels of wide range and narrow range instruments and the shutdown level instrument will not trend with changing level or if level channels can not be trended.

Procedure 2.2.80 is used in conjunction with 2.2.87, Control Rod Drive System, which supports the operation of the high pressure water source for the reference leg backfill. It provides procedural guidance for interfacing evolutions such as removal and restoration from service of the CRD system, changeover of inservice pumps and filters, drive system venting and alignment requirements for connecting supply valves.

The information within NRC IN 93-89 was evaluated by BECo who endorsed the position of the BWR Owners' Group in a letter (BWROG-94018) to the NRC, dated

February 11, 1994. The results were documented in operating experience form OEAI 93.0201. The Owners' Group had taken the position that administratively controlling the position of the manual isolation valves within the reference leg piping was acceptable. Additionally, the Owners' Group evaluated the IN 93-89 scenario of a relay failure in addition to an operator error in closing a reference leg isolation valve as beyond the licensing basis for most BWR plants.

BECo representatives stated the intention to include the reference leg isolation valves in the plant locked valve program after the inspector pointed out that the Owners' Group stated that administrative controls include mechanical devices to 'seal' or lock a valve. The Owners' Group position was developed from NUREG 0800, Section 6.2.4-5, Standard Review Plan - Containment Isolation System and NRC Generic Letter 89-10, Safety Related Motor Operated Valve Testing and Surveillance, in its discussion of requirements for blocking motor operated valves against inadvertent mispositioning. In the evaluation of IN 93-89, BECo agreed with the Owner's Group evaluation for administrative controls and pre-startup valve alignment checks. The inspector observed that the isolation valves for each safeguards reference leg, 2-HO-126A and -126B, are clearly labeled and unique in their appearance and location. The inspector did not consider that these valves were exceptionally susceptible to misidentification.

The BECo operating experience evaluation, OEAI 93.0201, also stated that the Pilgrim Plant design does not include automatic opening of the safety relief valves on sensed high reactor pressure at the safeguards instrument racks. The design of the backfill system includes supply relief valves set at 1130 $\pm$30 psig to prevent overpressurizing the instrumentation.

The backfill modification safety evaluation (SE), SE No. 2769, included the evaluation of various systems and components including failure of the control rod drive system and a failure of non-safety class piping. The evaluation also addressed failure of the flow control needle valve to result in a high flow condition and the potential for either overpressurizing the instrument rack or for isolating back fill flow to the rack. Neither failure was determined to be beyond the bounds of previous analyses.

The backfill modification was applied to two of the four reference legs. BECO did not include the control channel reference legs. This feature allows the control room operators to compare indication from the modified safeguards channels with the unmodified control channels. These unmodified control channels are manually back filled as required by procedures, 2.1.1 and 2.1.5, Startup from Shutdown and Controlled Shutdown from Power, respectively. The manual backfill process is contained in procedures 3.M.2-12.3 and -12.4.

The inspector found BECo had failed to meet several internal commitments stated in the plant design change, PDC 93-24, narrative concerning injection flow meter calibration and check valve seat leakage measurement. Both were identified as refueling outage frequency items within the design change.

Section 6 of the PDC 93-24 Narrative, Section C Plant Impact, Maintenance stated that flow meters must be calibrated every refueling outage. At the time of the inspection, there was no such procedure. In response to this observation, BECo began developing a functional test procedure for the EG&G Model FC-70A Flow Computer and the associated turbine flowmeter.

The same section of the PDC Narrative required that the four injection flow check valves, CK-C2205A-1, -2, CK-C2206A-1, and -2, be seat leak tested in series for zero seat leakage every refueling outage. This test was not made during the previous refueling outage. BECo elected to replace all four check valves during the last refueling outage because of the difficult nature of seat leak testing two in series valves. The installed design for reference leg backfill provides flow to the reference leg piping through two in series valves at each of the two instrument racks. There are not enough test connections to allow seat leak rate tests of the individual check valves. If tested while installed, the seat leakage test would be through two in series valves.

These valves also provide the seismic class break between the reference leg and the new backfill supply system. Each of the instrument lines was originally equipped with a restricting orifice located in the containment portion of the piping to provide the piping class break. There is also an excess flow check valve at each line's containment isolation valve.

The Pilgrim Station Inservice Pump and Valve Testing Program is contained in Procedure 8.I.1.1. Within that procedure, the table for valve testing referencing P&ID M-253, Nuclear Boiler Vessel Instrumentation, included all four injection check valves. However, the referenced seat leakage test procedure, 8.3.3.3, has not yet been written. BECo has implemented the alternate position verification tests of the check valves within procedure 8.I.31, sections 8.9 and 8.10. Because these check valves are not code-class components, BECo's actions are acceptable.

The inspector found that BECo had effectively evaluated the issues concerning the reactor vessel level instrumentation design modification, including those that were stated in NRC IN 93-89, with the exception of applying locked valve controls to the reference leg isolation valves. BECo had not yet met the internal commitments to calibrate the system flow meters or seat leakage test the check valves.

4.3 (CLOSED) UNR 94-18-02: RCIC Oil System and Governor Valve

BECo actions concerning RCIC lubricating oil problems that manifested themselves as turbine speed oscillations and oil loss through bearing caps was addressed in report 50-293/94-18, section 3.1 and in report 95-02. The associated system isolation was addressed by BECo within LER 94-004-01, dated December 20, 1994. BECo has completed the remaining item within this issue, a root cause analysis of binding of the RCIC turbine steam governor control valve. The findings included an inadequate maintenance procedure that allowed misalignment of control valve fulcrum pins and that the pins are not properly identified on vendor drawings. BECo issued a drawing change notice to revise 2059-12-6 to include the pins. The RCIC Turbine 5 Year preventive Maintenance Procedure, 3.M.4-78, has not yet been changed, however its completion is being tracked within BECo commitment tracking systems and has an expected completion date of September 22, 1995. This item is closed.

5.0 PLANT SUPPORT (71750)

5.1 Radiological Controls

During tours of the radiologically controlled area (RCA), the inspector verified worker adherence to radiation work permits and postings. Progress was made in the reduction of contaminated areas to allow plant workers and managers on tour easier access and minimize the potential for personnel contamination. The east and west hydraulic control unit banks were decontaminated. Some other examples of areas decontaminated included: the residual heat removal valve room, the high pressure coolant injection turbine room and the reactor core isolation cooling turbine room. The inspector also observed dewatering activities of the dryer/separator pit on the refueling floor. As a precautionary measure, the pit was treated as a hot particle area. Remote reading dosimetry was worn by workers in the bottom of the pit. The remote dosimetry readings were closely monitored by radiation protection (RP) technicians. Lastly, the inspector observed a HP technician quickly secure the tip room area and stop an I&C calibration activity, located in the same area, when an unrelated barrel connected to the condensate demineralizer vent header overflowed with water. Operations management initiated a problem report to evaluate the cause and implement corrective actions to prevent the barrel from overflowing again. Overall, the inspector noted good performance exhibited by the HP staff.

5.2 (CLOSED) VIO 94-09-02: Control Of Fire Doors

A violation issued with report 50-293/94-09 identified that BECo had failed on separate occasions to control fire doors and combustible material at the Pilgrim Station. The BECo response, dated June 30, 1994, identified two contributing factors; human performance and the lack of procedure clarity detailing the required implementation of compensatory measures. Corrective actions included staff notification of the issue through a nuclear organization newsletter, discussion during a May 1994 safety meeting, and placing new signs concerning combustible material controls at the reactor and turbine building trucklock entrances. In addition, procedures 8.B.14, Fire Protection LCO and Compensatory Measure Fire Watches and 1.4.3, Combustible Controls, were revised to better define management expectations and required compensatory measures.

The inspector reviewed these procedures and fire door postings found at various plant locations. No discrepancies were noted concerning fire doors or combustible materials. The circumstances of each of the issues detailed in the above referenced violation were discussed with licensee personnel. Corrective actions implemented by BECo were considered appropriate and this violation is considered closed.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 92700)

6.1 Onsite and Offsite Review Committee Meetings

The inspector attended the nuclear safety review and audit committee (NSRAC) meeting held on August 16, 1995. Messrs Ted Amundson and Ronald Eytchison were introduced as new members by the NSRAC chairman. The meeting was attended by plant and executive level managers. The inspector reviewed technical specifications section 6.5 before the meeting to understand the NSRAC charter.

Various safety related topics were discussed at the meeting. The plant manager briefed the NSRAC members on the problem report backlog reduction effort and proposed changes to the system. In essence, the problem reporting threshold remains very low capturing many events of lower significance, but a few potentially significant problems were discussed that were not resolved in a timely and effective manner. The examples cited were the inadequate corrective actions associated with (1) the control board SBM switches and the emergency diesel generator (EDG) building roof leakage onto the "A" EDG as documented in NRC Inspection Report No. 50-293/95-14 and (2) the loose stator laminations on the "A" emergency diesel generator as discussed in NRC Inspection Report Nos. 50-293/95-09 and 16. The proposed changes will still capture minor issues but allow for closure of minor issues with little or no review or corrective action. The purpose of issuing problem reports for these minor issues would be primarily for tracking purposes. This would allow more thorough and timely analysis of potentially significant issues.

The operations and maintenance section managers explained the unplanned downpower event that involved the "B" sea water pump, which is discussed further in section 2.2 of this report. The NSRAC members exhibited a questioning attitude and an effective exchange of information occurred between the plant staff and the NSRAC members. The inspector attributes the effective information exchange due to the experience and apparent credibility of the NSRAC members as well as the open and self-critical nature of the plant and executive level managers. Discussions focused on reactor safety and opportunities for improvement. The general theme of the NSRAC comments centered around the need for increased teamwork and communications between the plant departments. This was most apparent during the discussions involving the new work control and scheduling processes that are being implemented. Although the processes seem sound, the NSRAC members noted that extensive teamwork and coordination is necessary to significantly lower the maintenance request backlog.

During this period, the inspector also attended two operations review committee (ORC) meetings that reviewed an engineering evaluation concerning the SBM control switches. As a result of NRC concerns raised during the week of June 19, 1995 (reference NRC Inspection Report 50-293/95-14), BECo performed an inspection of all accessible safety-related switches. Approximately 85 safety-related, lexan switches, including 28 inaccessible switches, exist based on a visual inspection. Only three switches exhibited signs of significant degradation. These three switches were replaced immediately as part of online maintenance. The remaining switches are scheduled for replacement during the respective rolling 12 week system outage windows. Plant management intends to finish replacing these safety related switches, which are at the end of service life, by the end of the first calendar quarter of 1996.

The ORC commented that the management commitment to replace all of the safety related SBM, impure lexan switches represents a conservative and comprehensive approach. The visual inspection process of the switches provided valuable data on general switch conditions. However, the ORC raised concern about the need to minimize the uncertainty of the operability evaluation by further circuit analysis or inspection of the condition of the 28 inaccessible switches. Also, it was evident to the inspector at the meeting, that engineering had not adequately communicated with operations and work control to develop a mutually agreed upon completion date for the 85 switches. Specifically, engineering erroneously assumed that the switches would be replaced during the first available 12 week outage system window. Operations management expressed concern that the net safety gain of entering a limiting condition for operation would have to be evaluated along with other necessary work for a particular system. This would ensure that a net safety gain occurs from the safety system unavailability time. Subsequently, two of the 28 inaccessible switches were visually inspected. For the remaining 26 that could not be visually inspected, engineering conducted circuit analyses to determine the potential safety consequence of each switch failure. Any switch that could affect the capability of a component is being scheduled for replacement during the first available 12 week rolling system window.

In summary, the NSRAC and ORC were effective in evaluating potential safety significant issues. Meaningful discussions occurred that focused on reactor safety. Although a conservative approach was taken to replace all safety related, impure lexan, SBM switches, engineering could have provided a more integrated approach in the scheduling of switch replacements.

6.2 Licensee Event Report Review

The inspectors reviewed Licensee Event Reports (LERs) submitted to the NRC to verify accuracy, causal analysis, occurrence commonality, and the effectiveness of corrective actions. The inspectors evaluated the need for additional information, possible generic implications, and whether any specific inspection followup was warranted. The LERs were also reviewed with regard to the requirements of 10 CFR 50.73.

- **LER 93-04 & 93-22**

LER's 93-04 and 93-22 involve automatic reactor scrams and the loss of preferred offsite power.

Both of these LERs are discussed in NRC Inspection Report (IR) 50-293/93-23. Inspection followup of the operational impact of the storms leading to these events is documented in IRs 50-293/05 and 93-15, respectively. As a result of further inspection followup, the NRC issued a Notice of Violation in IR 50-293/93-06 with regard to plant conditions relating to unexpected component failures subsequent to the LER 93-04 load rejection and scram. The violation was subsequently closed in IR 50-293/94-14.

During this inspection period, the inspector reviewed the commonality between these two events from the standpoint of the 345 KV switchyard performance. In one case, switchyard insulator flashovers were caused by blizzard conditions; while in the other case, lighting strikes caused the opening of the switchyard breakers, creating the loss of preferred offsite power conditions in both situations. Licensee corrective actions since that time have resulted in significant physical improvements to the plant electrical switchyard.

As documented in IR 50-293/95-03, switchyard performance improvements included the planned replacement of all four 345 KV air-blast circuit breakers (ACBs) with new dead-tank, type SF6 (gas insulated) breakers, as well as other insulator replacement and recoating activities. One ACB was replaced during the mid-cycle outage in 1994, another during the recent refueling outage (RFO 10), and the last two ACBs were replaced during the June-August period in 1995. The inspector noted during this inspection period the good coordination between the licensee and the grid/load dispatchers for the final testing and restoration of new ACB 102, representing the last major component replaced as part of the switchyard improvement activities.

Overall, the switchyard modifications have been well controlled and appropriately directed toward minimizing storm-related, loss of preferred offsite power challenges to the plant, as were in evidence and documented in LERs 93-04 and 93-22. The major improvements completed in the 345 KV switchyard represent significant corrective actions to address the types of weather-related events identified in both of these LERs. In conjunction with the inspection activities conducted in the inspection reports documented above, the confirmation during this inspection period that all four ACBs have now been replaced indicates an improved capability at Pilgrim to withstand storm induced electrical disturbances to the preferred 345 KV power sources. Therefore, LERs 93-04 and 93-22 are closed.

- **LERs 93-03 (Supplement I) and 93-05**

LERs 93-03 (Supplement I) and 93-05 relate to isolation signals for the reactor water cleanup (RWCU) system, which represent a primary containment isolation system (PCIS) Group 6 actuation.

The conditions and corrective actions involved with LER 93-03 were inspected and documented in IR 50-293/93-09. On April 10, 1995, the licensee submitted Supplement I to LER 93-03 to submit the results of additional calculations of the trip settings for the RWCU system high flow switches. The inspector reviewed the supplement, which indicated that even considering instrument inaccuracies, none of the originally reported as-found trip setpoints exceeded the limits allowed by the Technical Specifications (TS). Therefore, the RWCU high flow switches would have functioned as designed, and in accordance with TS requirements, when the instruments were originally identified to be set out of their tolerance range in 1993.

With respect to LER 93-05, which was examined by the inspector and documented in IR 50-293/93-23, the inspector reviewed the latest revision (Rev 43) to Reactor Water Cleanup System procedure no. 2.2.83. A "Caution" exists in this RWCU procedure relative to jogging the cleanup system suction valve, MO-1201-85, slowly open to prevent a high flow isolation signal. LER 93-05 documents that despite the fact that this cautionary measure was followed by operators, a Group 6 isolation of the RWCU system occurred in March 1993.

The inspector questioned whether Supplement I to LER 93-03, which calculated that the RWCU high flow setpoints were more conservative than allowed, had been considered in any additional corrective actions to preclude further unnecessary RWCU isolations, as reported in LER 93-05. This issue was discussed with the RWCU system engineer. An original consideration to replace the gate valve MO-1201-85 with a globe valve, which would be more amenable to throttling, was determined to not be practical based on ALARA and other considerations. The inspector determined that relaxing the RWCU high flow setpoints would not have significant impact upon the system capability to prevent an unwarranted Group 6 isolation, should the cleanup system suction valve be misthrottled.

Hence, licensee actions to emphasize the procedural cautions, as well as operator training, were most appropriate to preclude future similar events. The isolation of the RWCU system during power operation had no significant safety impact as reactor water chemistry is monitored, in accordance with TS requirements, to prevent the degradation over longer periods of time than the 10 minute system isolation documented in LER 93-05.

Overall, the inspector reviewed LERs 93-03 (Supplement I) and 93-05 in conjunction with the facts related to the documented RWCU high flow conditions and determined that each event was handled acceptably. The inspector concluded that the existing RWCU high flow setpoints maybe conservative, but that unnecessary system isolations would be best prevented by continued emphasis upon proper operator actions in accordance with the existing procedural controls. Both of these LERs are closed.

- LER 93-23

This LER involves the lack of timely action for one two-by-two control rod array that exceeded the 10% scram insertion time criteria.

In this case, the average scram insertion times for the problematic two-by-two control rod array were acceptable at the 30%, 50% and 90% insertion points, as specified in TS 3.3.C.1. The problem with meeting the 10% insertion criteria was affected by the fact that it is an average of the three fastest rods in the array; with the timing of all rods not necessarily done at the same time. Therefore, the average time value may not be current. This was the case with LER 93-23, compounded by a deficiency in procedure 9.9, "Control Rod Scram Insertion Time Evaluation," which did not provide specific guidance on the actions to be taken if the 10% scram insertion time exceeded its acceptance criteria. The licensee was able to confirm that on two automatic scrams of the reactor in December 1992, subsequent to receipt of the test data of concern, the subject two-by-two control rod array exhibited satisfactory scram times, including those for 10% insertion.

As corrective action, the licensee revised the procedure for control rod scram insertion time evaluation and implemented a design change to the scram pilot valve air (SPVAH) system. The plant design change, PDC 94-27, resulted in an operating pressure reduction in the control rod drive (CRD) air header. Since increased air header pressure results in increased scram insertion times, ensuring a lower pressure through the installation of safety-related pressure regulators will also increase the safety margin between measured surveillance times and the TS limits.

The inspector reviewed Pilgrim procedure no. 9.9 and verified that the latest edition (Revision 30) directs appropriate action should any two-by-two array exceed the average scram insertion time limits. The inspector also confirmed that the current procedure takes into account the SPVAH modification and resulting air header pressure reduction. The new instrument rack (C3002) in the reactor building, installed in accordance with PDC 94-27, was examined by the inspector. The safety-related pressure regulators and associated nonsafety air piping were inspected to verify consistency with approved PDC field revision notices, as well as the SPVAH valve schematic included in an attachment to procedure 9.9. The inspector also evaluated the procurement requirements for the SPVAH modification materials, the seismic test report for the pressure regulators, and the installation criteria for the C3002 instrument rack. One question regarding seismic interaction between one regulator and C3002 was raised with the cognizant design engineer and satisfactorily resolved with a field inspection.

Overall, the licensee corrective actions to LER 93-23 have been comprehensive in not only enhancing the procedure handling of control rod scram insertion time test results, but also improving the overall design of the SPVAH system. The modifications have been completed and the inspector verified control of the system air header pressure within its desired range. A walkdown of the new system design and review of the existing procedural controls identified no significant questions or concerns. This LER is closed.

7.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (71707)

7.1 Routine Meetings

Two resident inspectors were assigned to the Pilgrim Nuclear Power Station throughout the period. Back shift inspections were performed on August 17 and deep back shift inspections on August 3 and 5. Additionally, on August 17 and 18, Mr. L. (Tad) Marsh, the Director of NRR Project Directorate I-1, visited the site to tour the plant, interview senior and plant level managers, and hold discussions with the resident inspectors. On August 25, Ms. Beth Korona supplanted Mr. Tony Cerne as the NRC resident inspector assigned at PNPS. Mr. Cerne completed his five year assignment at PNPS and has been reassigned to the Division of Reactor Safety (DRS) in the NRC Region I office.

Throughout the inspection, the resident inspectors held periodic meetings and toured portions of the plant with plant management to discuss inspection findings. On August 25, 1995, the inspector held an exit meeting to present the findings and assessments to plant management. No proprietary information was covered within the scope of the inspection. No written material regarding the inspection findings was given to the licensee during this inspection period.

7.2 Other NRC Activities

On July 17 and 18, Messrs Hal Ornstien and Sada Pulani from NRC headquarters visited the site, along with two contractors, to collect data concerning the anticipated transient without scram (ATWS) systems. The data collection is part of an NRC industry audit to determine the level of compliance in meeting the intent of the ATWS rule. After visiting several other sites, an audit report will be issued discussing the findings. Additionally, Messrs James Wiggins, Eugene Kelly, and Fred Bower, all from DRS in the NRC Region I office, conducted a public exit meeting on July 19 to discuss the findings of the NRC review of the BECo service water system operational performance inspection (SWOPI) self-assessment. The findings and assessments associated with the SWOPI review are documented in NRC Inspection Report 50-293/95-01. Also, Mr. George Morris performed an inspection from August 7 to August 11, 1995 concerning four open items on station blackout components. The results of this inspection are documented in NRC Inspection Report 50-293/95-16. Lastly, a management meeting was held in NRC Region I office on August 14, 1995 with Messrs E. Boulette, R. Fairbanks and D. Horan from BECo to discuss the electric utility industry deregulation and restructuring, and BECo restructuring plans.