U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.:	50-293
Report No.:	92-28
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Location:	Plymouth, Massachusetts
Dates:	November 24 - December 31, 1992
Inspectors:	J. Macdonald, Senior Resident Inspector A. Cerne, Resident Inspector D. Kern, Resident Inspector

Approved by: Eugene M. Kelly 1/28/93
E. Kelly, Chief, Reactor Projects Section 3A Date

Scope: Resident inspection addressed the areas of plant operations, radiological controls, maintenance and surveillance, emergency preparedness, security, safety assessment and quality verification, and engineering and technical support. Initiatives selected for inspection included: restoration from an electrical backfeed lineup; observation of an inplant emergency preparedness drill; control and testing of certain containment isolation valves; and, plant design changes associated with the reactor vessel head spray lines.

Inspections were performed on backshifts during November 30 and December 1-4, 7, 11, 13-18, and 21-31, 1992. "Deep" backshift inspections were performed on December 13 from 10:00 to 12:00 p.m. and December 14 from 00:01 to 05:45 a.m.

Findings: Inspection results are summarized in the Executive Summary.

Procedure 3.M.2-7.6, "NUMAC Log Radiation Monitor Setpoint Change Procedure" was not properly performed. Technicians established incorrect RPS protective setpoints and management reviews failed to identify the associated discrepancies (Violation 92-28-01, see Section 4.4).

The technical basis for the deactivation of a head spray line remains unresolved (Unresolved Item 92-28-02, see Section 8.2).

EXECUTIVE SUMMARY

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Plant Operations Operations Section preparation for and response to the effects of a northeaster storm were comprehensive. Decisions to maintain reduced reactor power at the 80% rod pattern line and to separate the safety-related buses from the distribution system demonstrated a strong safety perspective.

The immediate response by operators to two automatic reactor trips was appropriate. Communications, use of procedures, and supervisory oversight of control room operations were excellent during post-trip recovery activities and subsequent reactor startups. Also, the identification of loose or missing bolts on motor operated valve actuator limit switch covers during routine rounds indicated good questioning attitudes and attention to detail by plant operators.

Maintenance and Surveillance Actions taken to verify the presence of and trend the effect of steam leakage past safety relief valve (SRV) RV 203-3A were thorough. Although not required by Technical Specifications (TS), the decision to establish cold shutdown and replace the leaking SRV pilot valve following an unrelated plant shutdown demonstrated sound safety judgement. In addition, coordination between the materials & component engineering section, maintenance personnel, and system engineers to complete the repair during this unscheduled maintenance period was outstanding. Restoration from the backfeed electrical lineup following post trip corrective maintenance was performed. Maintenance and operations personnel demonstrated excellent procedural knowledge and communications.

An automatic reactor trip on December 20 was caused by procedural weaknesses and poor work practices by technicians changing the main steam line (MSL) high radiation protective setpoints. Also, the technicians failed to lower the MSL high radiation alarm setpoints following the reactor trip. As a result, the MSL high radiation alarm was not available to control room operators upon the subsequent plant restart. Failure to properly reestablish the MSL high radiation protective setpoints and associated failure of the management review process on two occasions indicates a need for greater management attention.

Emergency Preparedness The capability to draw, analyze, and provide real time post-accident sampling system data under simulated emergency conditions was successfully demonstrated in a December drill.

Safety Assessment and Quality Verification Implementation of Phase II of a planned three phase structural reorganization, to become effective January 1, 1993, was announced on December 16, 1992. Licensee event reports (LERs) were of good detail, accurate, and clearly identified root cause and corrective action, detailed and properly addressed the required reporting criteria.

(EXECUTIVE SUMMARY CONTINUED)

Engineering and Technical Support Deactivated head spray line containment isolation valves remain to be removed from the Type C local leak rate test program. Several questions regarding American Society of Mechanical Engineers (ASME) Code criteria and the technical basis of certain aspects of the head spray line deactivation plant design change remain unresolved.

Continuing NRC review of the licensee reactor vessel water level instrumentation spiking status determined the operability assessment was consistent with the guidance of NRC generic documentation for degraded or nonconforming conditions on operability.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

At the start of the report period Pilgrim Nuclear Power Station was in the initial phase of power ascension following the completion of a midcycle maintenance outage.

On November 24, 1992, packing leakage from the reactor core isolation cooling (RCIC) system steam supply valve (1301-16) was identified during the drywell inspection with the reactor vessel pressurized. Post-work testing of the RCIC system was completed and the system was returned to service on November 25.

Elevated tailpipe temperatures downstream of safety relief valve (SRV) RV-203-3A were observed on November 24 following reactor startup. Reactor pressure remained stable and operators commenced trending of tailpipe temperature on an increased frequency. Tailpipe temperature stabilized at approximately 218 degrees F.

Full power operation began on November 30 until December 11 when reactor power was reduced to approximately 75 percent to allow for rapid power reduction in the event of condenser fouling as a result of a severe Northeaster storm. Power was periodically reduced further to support backwash of the main condenser. On December 13, the station experienced a load rejection and resultant automatic reactor trip from approximately 50% of rated power. All systems responded to the trip as designed and the reactor was quickly stabilized in a hot shutdown condition. On December 14, the "A" reactor protective system (RPS) bus was momentarily deenergized due to personnel error while attempting to shift power supplies. This resulted in multiple engineered safety feature actuations. Systems were properly restored to their intended lineup and notification to the NRC was appropriately made. Reactor startup was performed on December 17 and the main generator was synchronized to the offsite distribution grid on December 18. Post-work testing of RV-203-3A, which was replaced during the plant outage, was completed satisfactorily.

On December 20, the reactor tripped from 75 percent power in response to a main steam line (MSL) high radiation signal to the reactor protective system (RPS). The reactor plant responded as designed to the automatic trip signal. Control room personnel verified that MSL radiation levels were normal prior to and after the reactor trip. The trip resulted from incorrectly established protective trip setpoints. Reactor startup was performed on December 22 and full power was achieved at 3:55 a.m. on December 24, and maintained through the end of the reporting period.

2.0 PLANT OPERATIONS (71707, 40500, 90712)

2.1 Plant Operations Review

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

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

Control room instruments were 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 contamination and high radiation areas were appropriate. Use of and compliance with radiation work permits and use of required personnel monitoring devices were confirmed.

Plant housekeeping controls, including control of flammable and other hazardous materials, were observed. During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, tagout, and lifted lead and jumper logs. The inspectors monitored control room operations during reactor startup and synchronization of the main generator to the electrical distribution grid. Communications, use of procedures and supervisory oversight were excellent.

2.2 Load Rejection and Automatic Reactor Trip

On December 13, 1992, at 5:23 p.m., the station experienced a load rejection and resultant automatic reactor trip from approximately 50% of rated thermal power. All systems responded to the trip as designed and the reactor was quickly stabilized in a hot shutdown condition. Anticipated Group II and VI primary containment isolation system and reactor building isolation system actuations were experienced in response to normally low reactor vessel water level following the trip. Reactor pressure increased from 960 psig to 990 psig after the load rejection and remained below safety relief valve setpoints.

Following the trip, the licensee initiated a reactor cooldown and depressurization. A cooldown rate of 50-70 F/hr was maintained. On December 14, 1992, at 20 psig reactor pressure and 240 F reactor coolant temperature, the plant initiated the shutdown cooling system mode of decay heat removal.

Since December 11, 1992, Southeastern Massachusetts had been battered by a severe winter northeaster storm accompanied by sustained winds in excess of 50 mph, torrential rains, and extremely high tides (+9ft to +12 ft). The extreme weather and sea conditions necessitated the licensee to continuously operate the intake structure travelling screens and to conduct several main condenser backwashes to remove debris and marine life. As precautionary measures during the storm, the licensee reduced reactor power to approximately 75% (with further reductions to conduct condenser backwashing and per load dispatcher direction) and maintained the core configuration at the 80% rod pattern line. Additionally, on December 12, 1992, for approximately seven hours (1:30 p.m. - 8:15 p.m.) during a period that included temporary loss of one of the two 345 KV lines (i.e., Bridgewater line) the licensee transferred the source of power to the two 4.16 KV safety related buses, (A-5 and A-6), from the unit auxiliary transformer to the associated emergency diesel generator (EDG). After the "A" EDG was secured (8:15 p.m.), the licensee identified that the belt had broken on the engine driven fuel pump. The belt was replaced, post-maintenance testing was completed and the "A" EDG was returned to normal standby service within 11 hours, at 7:13 p.m. on December 13, 1992. Additionally, on December 14, 1992 at 4:50 a.m., power to the A-5 and A-6 buses was again transferred to the EDGs following further switchyard electrical instability.

Operations Section preparation for and mitigation of the potential effects of the storm were comprehensive. Backwash evolutions were well controlled. Sound safety perspectives were evidenced by the decision to maintain reduced reactor power at the 80% rod pattern line. Appropriate actions were taken to separate the safety-related buses from the distribution system during periods of high winds and distribution system instability.

Control room operator oversight of post reactor trip recovery activities was good. Reactor cooldown and depressurization were well controlled. The nuclear watch engineer (NWE) maintained clear communications with the offsite distribution system dispatcher. Additionally, after assessing preparations for washdown of switchyard equipment, the NWE concluded the continuing severe winds precluded safe conduct of the washdown and the activity was postponed and the safety related 4.16 KV buses were transferred to the EDGs.

The licensee conducted a post-trip review to determine the root cause of the load rejection and reactor trip. The trip report, 92-01, dated December 17, 1992, appropriately documented the event, root causes, and corrective actions. The report was supported by design and event data. The report concluded the load rejection was caused by flashover in the switchyard due to salt spray buildup.

After the storm passed and the winds subsided, the licensee conducted a sequential freshwater washdown of the switchyard to remove salt spray deposits. Visual inspection confirmed evidence of one of the two 345 KV lines (355 line) flashover on three bushings on the C phase between the air circuit breakers ACB 102 and ACB 105. Calibration setpoints for directional distance relay (21/MT), directional ground overcurrent relay (67N/MT), and overcurrent fault detector relay (50/MT) were verified to be correct. Additionally the main transformer secondary relay wiring configuration was verified to be accurate. Continued licensee troubleshooting identified damaged insulation on one of the conductors for the "C" phase current transformer supply to the 21/MT relay. It was questioned whether this condition could have caused the relay to actuate for a fault outside of its protective zone. Licensee electrical laboratory experts determined the damaged insulation would not have had any significant impact on the function of the 21/MT relay and therefore, similarly concluded the load rejection was caused by two near simultaneous switchyard flashovers between ring bus air circuit breakers ACB 102 and ACB 105 as well as between ACB 104 and ACB 105 and the main transformer. Finally, during reactor startup the licensee verified the proper polarity of the 21/MT relay.

2.3 Reactor Protective System Automatic Reactor Trip

On December 20, 1992 at 2:33 a.m., the reactor tripped from 75 percent power in response to a main steam line (MSL) high radiation signal to the reactor protective system (RPS). The reactor plant responded as designed to the automatic trip signal. The Group I primary containment isolation system (PCIS) actuated in response to the high radiation signal. Group II and VI PCIS and reactor building isolation systems actuated as expected in response to the transitory low reactor water level immediately following the trip. Control room personnel reviewed MSL radiation level recorders and verified that normal MSL radiation levels existed prior to and after the reactor trip. No high MSL radiation condition had actually occurred. The licensee initiated an event critique to determine the root cause of the trip and corresponding corrective actions as described in further detail in Section 4.4.

2.4 Loose Motor Operated Valve Limit Switch Cover Bolts Noted During Operator Tour

Operators identified loose or missing closure bolts on four motor operated valve (MOV) limit switch compartment covers during the reactor building tour on December 29, 1992. The covers remained inplace, held firmly by the remaining bolts which were tight. The loose bolts were tightened and problem report (PR) 92-9296 was initiated to determine the cause and appropriate corrective actions. The Nuclear Engineering Department performed an engineering evaluation that concluded that the MOVs in question were operable for the period during which the bolts were not correctly installed. The inspector reviewed the engineering evaluation and determined that it was technically sound.

The four MOVs on which loose bolts were identified had each been worked on during the recent midcycle maintenance outage. The licensee therefore initiated an inspection of the remaining 48 MOVs on which maintenance had been performed during the recent outage. This inspection identified four additional MOVs with loose limit switch cover bolts which were promptly tightened. Eight of the 48 MOVs were not accessible for inspection in the present plant operating condition; however, inspections have been properly scheduled for when plant conditions are appropriate. Identification of the loose or missing bolts was indicative of detailed and questioning tours by plant operators. The inspector concluded that initial corrective actions were appropriate and that the plant report process was properly initiated to address root cause.

3.0 RADIOLOGICAL CONTROLS (71707)

The inspector reviewed radiological controls in place as well as the radiological conditions of selected areas of the plant. Management tours of the radiological controlled area continued to be thorough and directed toward minimizing total personnel radiation exposure. Survey postings, radiological conditions and controls were appropriate with no discrepancies noted.

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

4.1 Replacement of Defective Safety Relief Pilot Valve

On November 24, 1992, control room operators observed elevated tailpipe temperatures downstream of safety relieve valve (SRV) RV-203-3A. Reactor pressure remained stable and operators commenced trending of tailpipe temperature on an increased frequency. The SRV is designed to relieve reactor vessel pressure directly to the suppression pool in the event of a high pressure transient, an automatic signal from the automatic depressurization system (ADS), or a manual actuation of ADS. The elevated temperature was characteristic of steam leakage past the normally closed SRV or SRV pilot valve. Excessive SRV leakage can result in SRV actuation setpoint drift and response time degradation. While the drywell was open, Operations personnel locally verified the elevated tailpipe temperature.

As required by Technical Specifications, an engineering evaluation was performed to determine whether continued power operation with elevated SRV tailpipe temperature (above 212 degrees F) was acceptable. The completed evaluation concluded that the SRV was operable as it would still open upon demand to perform its intended safety function and that continued operation was justified with elevated SRV tailpipe temperatures up to 255 degrees F. The inspector noted the engineering evaluation to be detailed and technically sound. Operations response to the elevated RV 203-3A tailpipe temperature was appropriate. During a control room inspection, the inspector noted and discussed with operations personnel the alarm status for the continuing elevated tailpipe temperature. In order to prevent this condition from masking elevated tailpipe temperature alarms from the other SRVs, the alarm for RV-203-3A was disabled and the temperature recorder for this point checked hourly to establish a temperature trend and ensure the 255 degrees F limit was not exceeded. The inspector considered this operator action to be prudent and responsive to the existing plant conditions.

Maintenance work packages were prepared and replacement of the RV-203-3A pilot valve was scheduled for the next refueling outage. Operators continued to trend RV-203-3A tailpipe temperature, which remained below 220 degrees F. The reactor trip on December 13, 1992, provided an unscheduled opportunity to replace the leaking pilot valve. Maintenance work plans were ready and contained an appropriate level of instruction for the intended work. Although not required by Technical Specifications (TS), the licensee decided to place the plant in a cold shutdown condition following the trip and to replace the SRV pilot valve. This decision demonstrated a conservative safety perspective. In addition, the inspector noted effective coordination between the Materials & Component Engineering Section, maintenance personnel, and system engineers to complete the repair during this unscheduled maintenance period.

The inspector observed the licensee drywell closeout inspection prior to reactor startup at the conclusion of SRV pilot valve replacement. In addition to inspection of RV-203-3A, the air isolation supply valve to the RV-203-3A pilot valve was verified open. The drywell inspection was thorough and properly addressed the minor material discrepancies noted. Post maintenance testing (PMT) was successfully completed in accordance with procedure 8.5.6.2, "ADS System

Manual Opening of Relief Valves" following reactor startup and pressurization. The inspector witnessed the conduct of the PMT of RV-203-3A in the control room on December 18 with the reactor mode select switch in the STARTUP position and the reactor at approximately 10% power. A thorough pre-evolution briefing was observed and contingency actions for a stuck open SRV, (i.e., procedure 2.4.29), were available for ready reference. The inspector noted good coordination of test activities among the operators stationed at control room panels 903, 905, C10 and C171. In accordance with procedures RV-203-3A was opened and immediately closed upon receipt of the acoustic monitor alarm and verification of partial bypass valve closure.

Preliminary licensee inspection of the failed SRV pilot valve concluded that the failure mechanism was unrelated to the failure of RV-203-3D which occurred in August 1991. The licensee intends to ship the defective SRV pilot valve to an off-site test facility for detailed root cause failure analysis and testing. The inspector determined that the licensee's response to the elevated tailpipe temperature of RV-203-3A was in compliance with TS 3.6.D, including plans for testing the as-found condition of the pilot valve.

4.2 Repair of Minor RCIC Valve Packing leakage

During the drywell inspection (with the reactor pressurized), a minor packing leak was identified on RCIC steam supply containment isolation valve RCIC-16. The licensee initiated maintenance request (MR) 19200103 to document the repair. On November 24, 1992, maintenance personnel applied five turns to the packing gland nut to isolate the leak. Because the RCIC-16 valve constitutes a primary containment isolation system boundary, motor operated valve diagnostic testing was included as a portion of the post maintenance testing requirements. The valve was time tested for the open and closed stroke travel, with maximum motor current recorded. The valve opened in 6.7 seconds with a maximum current of 1.3 amperes. Both values met the acceptance criteria of open stroke not to exceed 12 seconds at a running current of 1.4 amperes. The valve closed in 8.2 seconds with a maximum current of 1.4 amperes. Both values met the acceptance criteria of closed stroke not to exceed 12.5 seconds at a running current of 1.4 amperes. Voltages recorded for the 480V power supply were recorded to be between 481-484V and remained below the overvoltage limit of 486V. Post maintenance testing was completed satisfactorily and the RCIC system was declared operable and the plant startup continued.

During conduct of the post maintenance testing, two electrical technicians appeared to suffer from the effects of heat exhaustion and required medical assistance. The reactor was at approximately 900 psig and drywell temperatures at the 41 ft. elevation in the vicinity of the RCIC-16 valve were recorded at approximately 100 degrees F at the time the testing was conducted and the testing was considered to be of medium metabolic physical demand. Station safety personnel established a 60 minute stay time and the individuals involved wore personnel heat stress monitors. The work crew entered the drywell at approximately 11:00 a.m. (on November 24, 1992). Approximately 15 minutes later the crew exited the drywell because an A.C. cable for the test equipment was missing. The cable was located and the crew returned to the drywell at approximately 11:40 a.m. Approximately 35-40 minutes later, the cognizant test engineer stopped the work effort upon the feeling of fatigue. The test engineer exited the drywell without need for assistance. One of two electrical technicians reported becoming weak and lightheaded and required assistance exiting the drywell work area. At approximately 12:20 p.m., station emergency medical technicians (EMTs) responded to the drywell control point and administered to the technician. The technician was helped from his protective clothing and the EMTs assisted him onto a stretcher. Oxygen at 6 liters was applied via the nasal passage and wet towels were applied to the technician's chest. The technician was frisked by radiological protection personnel and was determined to be free of contamination and was then transported to the licensee medical facility. At approximately 12:32 p.m., the technician arrived at the medical facility and additional treatment was initiated but the technician declined the treatment and requested that an ambulance be dispatched so that he could seek further evaluation and treatment at the Jordan Hospital. A Town of Plymouth ambulance responded and transported the technician to Jordan Hospital where he was treated and released later in the day. The second technician apparently traveled to Jordan Hospital via a private vehicle where he was similarly treated and released.

Immediately following the event, the licensee convened an event critique in accordance with station procedure 1.3.63, "Conduct of Critiques and Incident Investigations," to determine what factors contributed to the technicians' heat exhaustion. The critique included statements from involved individuals and event timeliness reconstructed from security computer records and radiation protection control logs. Initial critique findings documented by memorandum (ISD 92-62) dated December 4, 1992, indicated that due to the emerging nature of the maintenance activity, normal practices prescribed by procedure 1.4.43, "Heat Stress Management," such as planning and communications and technician preparations such as pre-job heat stress briefing were expedited and may have contributed to the event. The practice of self-determination of physical condition during the work activity was determined to be partially effective and due to work area equipment noise levels, the work crew could not hear the personal heat stress monitor alarms. Additionally, the report identified some ambiguity regarding what constitutes a recovery period as it relates to stay time. The inspector reviewed the critique report and all submitted reference material, including statements of record from involved individuals. The critique was very detailed and effectively developed potentially contributing factors to the event. The inspector found the initial report findings and conclusions acceptable. No violations were identified.

4.3 Restoration of Normal Shutdown Electrical Lineup from Backfeed Lineup

The plant tripped on December 13, 1992, due to an electrical transient and turbine load reject signal as discussed in Section 2.2. A contributing factor to the electrical transient had been excessive salt buildup on electrical components in the switchyard during a severe storm. Corrective action prior to reactor restart included washdown of switchyard components with clear water to remove the excessive salt residue. The station was placed in an alternate electrical backfeed lineup to support isolation and washdown of the start-up transformer (the preferred power source while shutdown). In the backfeed lineup, station electrical busses are supplied with offsite power via the main and auxiliary transformers. In this lineup the main generator flexible links are removed to prevent damage to the generator. Proficiency at safely establishing and restoring from a backfeed electrical lineup is important with regard to maximizing availability of off-site power sources during varied shutdown conditions.

The inspector observed restoration from the backfeed electrical lineup in accordance with procedure 3.M.3-9, "Main Generator or Main Transformer Flexible Connectors Removal and Restoration/Main and Unit Auxiliary Transformer Back Scuttling", following completion of the startup transformer washdown. Proper verification while posting and clearing tagouts was demonstrated throughout the evolution. The procedure was well written to an appropriate level of detail and clearly understood by both operations and maintenance personnel. However, the inspector noted that the procedure did not direct the removal of the control key following repositioning of the Turbine Auxiliary Trip Relay Cutoff Switch. This was discussed with the Chief Operating Engineer and properly addressed.

Sound personnel safety practices were utilized when removing electrical fuses and "racking out" circuit breakers. Operations and electrical maintenance personnel demonstrated excellent knowledge of the procedure and equipment being operated. Minor discrepancies, such as improperly terminated electrical connectors and relay covers adrift inside electrical cabinets, were noted and correctly addressed by technicians performing this procedure. The evolution was performed in a controlled manner, with excellent communications between maintenance and operations personnel. The licensee demonstrated the capability to effectively establish the electrical backfeed lineup and to restore the normal shutdown electrical lineup.

4.4 Reactor Trip Resulting from Incorrectly Adjusted Protective Setpoints

Technical Specifications require the MSL high radiation trip setpoints to be set at a value less than or equal to seven times the normal full power background radiation level. As described in Section 2.3, the reactor tripped on December 20, 1992, in response to a main steam line (MSL) high radiation signal to the reactor protective system (RPS). Control room recorders indicated normal MSL radiation levels and no MSL high radiation alarm occurred prior to the RPS trip. The licensee promptly initiated an event critique to determine the root cause of the trip. Inspector review of radiological monitor data confirmed that MSL radiation levels were normal at the time of the trip.

Procedure 3.M.2-7.6, "NUMAC Log Radiation Monitor Setpoint Change Procedure" was performed following reactor startup on December 19, 1992 in order to raise both the MSL high radiation alarm and MSL high radiation trip setpoints. The setpoints were changed to correspond to the increase in normal background MSL radiation levels that exist when hydrogen water chemistry injection is in service. The event critique team determined that the trip occurred as a result of Instrumentation and Control (I&C) technicians adjusting trip setpoints to an incorrect value during performance of procedure 3.M.2-7.6. It was noted that the procedure documented the required setpoints in decimal notation while the NUMAC instrument screen displayed the setpoints in scientific notation. Despite second person verification of the setpoint adjustment, the trip setpoints of all four instrument channels were erroneously adjusted (lowered) to values which were a factor of ten below the intended setpoints. Inspector review of the completed procedure noted that in addition to the incorrect trip setpoints, the "C" MSL high radiation trip reset point, which clears the trip signal, was documented as being a factor of one thousand too high. Although the reset value error had no safety consequence, this was also a setting requiring verification by a second person, and provided further indication that technicians did not afford appropriate attention to the work being performed. Personnel error was identified as the root cause of the trip, with human factors and procedural weaknesses noted as contributing factors. Initial corrective actions included counseling of the technicians and revision of procedure 3.M.2-7.6 (revision 3) to address the procedural weaknesses which most directly contributed to the trip. Significant procedure improvements were implemented prior to the subsequent reactor startup.

After reactor startup and performance of revised procedure 3.M.2-7.6 on December 23, 1992, the inspector verified that the existing MSL high radiation alarm and trip setpoints were correct. However, the inspector noted that the instrument downscale trip reset points were not set in accordance with the revised procedure. The error was not of safety concern, but indicated that the revised procedure may not have been thoroughly reviewed by personnel performing the maintenance or by I&C supervisory review of the completed maintenance documentation. In addition, the inspector identified several further inconsistencies in procedure 3.M.2-7.6 which the I&C division manager planned to address as part of the ongoing critique team review of the event.

The MSL high radiation alarm setpoint is established well below the MSL high radiation trip setpoint to provide control room personnel with advance indication to initiate operator action to mitigate the cause or effect of the increasing radiation condition and eliminate unnecessary safety system challenges. The incorrect setpoint adjustment on December 19, lowered the MSL trip setpoints to a value below the MSL high radiation alarm setpoint. Therefore control room personnel had no advance warning of the reactor trip. Inspector review of additional maintenance documents determined that the MSL high radiation alarm setpoints were not lowered following the reactor trip on December 20 as required by procedure. As a result, the MSL high radiation alarm was not available upon plant restart until after the MSL high radiation trip setpoints were raised to support hydrogen water chemistry injection. These discrepancies were not identified by the technicians performing the maintenance nor by required management review of the completed procedure. The inspector reviewed documentation of procedure 3.M.2-7.6 performance for the past 18 months and identified no other similar discrepancies.

Technical Specification 6.8.A requires the proper implementation of procedures recommended in Appendix A of USNRC Regulatory Guide 1.33. Appendix A, Section 4 recommends establishment of procedures for startup, operation, and shutdown of safety-related systems including the RPS system. The licensee failed to properly implement procedure 3.M.2-7.6, in that technicians established incorrect RPS protective setpoints and management reviews failed to identify associated discrepancies. This failure to follow procedural instruction directly resulted in the December 20, 1992, reactor trip and challenged several safety-related systems. In addition, as identified by NRC inspection upon review of completed procedure records, MSL high radiation alarms were unavailable to operators on two occasions. Failure to properly implement procedure 3.M.2-7.6 adversely affected the establishment of the correct RPS protective setpoints and is a violation of Technical Specification 6.8.A (VIO 50-293/92-28-01).

5.0 EMERGENCY PREPAREDNESS (40500)

The licensee conducted a post accident sampling system (PASS) drill on December 3, 1992, to evaluate the capability of station personnel to draw, analyze, and provide real time PASS data under simulated emergency conditions. The inspector reviewed the drill scenario prior to the evolution and concluded that the scenario was appropriate to support assessment of the stated objectives. Nuclear Watch Engineer verification that the scenario did not conflict with existing plant conditions prior to authorizing drill commencement was thorough. The inspector observed initial staffing and deployment of response personnel from the Operations Support Center. No discrepancies were identified. Licensee assessment of this drill concluded that areas of concern noted during the previous PASS drill (92-01) had been effectively addressed.

6.0 SECURITY (71707)

Selected aspects of plant physical security were reviewed during regular and backshift hours to verify that controls were in accordance with the security plan and approved procedures. This review included the following security measures; security force staffing, vital and protected areas barrier integrity, maintenance of isolation zones, behavioral observation, and implementation of access control including access authorization and badge issue, searches of personnel, packages and vehicles and escorting of visitors. Security force personnel continued to perform their duties in an alert manner.

7.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (92701)

7.1 Licensee Event Report (LER) Review

7.1.1 LER 92-11

LER 92-11, "Unplanned Actuation of a Portion of the Residual Heat Removal (RHR) System Logic Circuitry During Surveillance Testing," describes the August 21, 1992, inadvertent initiation of portions of the RHR system due to personnel error while the reactor was at power. The actuation occurred when a technician inadvertently operated an incorrect relay during a planned surveillance. An immediate result was the trip of the "A" recirculation pump and entry into single loop operation. Operator response to the event was appropriate and in accordance with Technical Specifications. Further discussion of licensee response to the event and corrective actions are documented in NRC Inspection Report 50-293/92-16. The LER accurately detailed the event and addressed the reporting criteria.

7.1.2 **LER 92-12**

LER 92-12, "Failure to Perform Calibration Test of Neutron Monitoring System Recirculation Flow Converters," describes the licensee determination that they did not have documentation to verify that an instrument calibration was performed within the Technical Specification required periodicity. On September 16, 1992, during a review of documentation, an engineer could not locate the calibration results from a surveillance which was signed off in the Master Surveillance Tracking Program (MSTP) as having been completed on February 12, 1992. Immediate corrective actions included initiation of a search for the missing data, and reperformance of the calibration test.

Problem Report 92.9170 was initiated to determine whether or not the instrument calibration had been performed as documented on the MSTP. The licensee determined that the instrument functional test had been performed on February 12, 1992, but that the calibration was not performed. The supervisor who signed-off the MSTP for completion of the calibration had incorrectly believed that completion of the functional test would also satisfy testing requirements for the calibration. A contributing factor was the inclusion of both the functional test and the calibration test within the same procedure. The calibration test was reperformed on September 16, 1992 with satisfactory results, the supervisor was counselled regarding calibration test requirements, and a procedure revision was initiated to more clearly differentiate between functional test and instrument calibration requirements. Corrective actions were appropriate. The LER effectively developed the causal contributors and documented licensee corrective actions.

7.2 **Phase II Organizational Restructuring**

On December 3, 1992, Mr. Roy A. Anderson, Senior Vice President Nuclear (SVP,N) announced his resignation from BECo to accept a similar position with the Carolina Power and Light Company at the Brunswick Facility. Dr. E. Thomas Boulette, Vice President of Nuclear Operations and Station Director was appointed to act as SVP,N upon Mr. Anderson's departure.

On December 16, 1992, the licensee officially announced the selection of various managerial positions to be effective January 1, 1993 consistent with Phase II of the three phase structural reorganization. Phase I was initiated on June 29, 1992 and is documented in NRC Inspection Report 50-293/92-14, Section 7.1. Initially, as previously announced, Mr. E. Thomas Boulette will continue to serve as Acting Senior Vice President, Nuclear and Mr. Edward Kraft will serve as Acting Vice President of Nuclear Operations and Station Director. Mr. Les Schmeling was selected as Plant Manager, with the plant department remaining unchanged. Mr. William Rothert was selected as General Manager, Technical, with the Nuclear Engineering Department managed by Mr. Robert Fairbanks and the new Regulatory Affairs and Emergency Planning Department managed by Mr. Vern Oheim as direct reports. Mr. Frank Famulari remains the Quality Assurance Manager and continues to report to the Senior Vice President, Nuclear. Mr. Leon Olivier was selected as Nuclear Services Manager. The Nuclear Services Department maintains the radiological, radwaste and chemistry sections and will gain most plant support functions in Phase III. Finally, Mr. Jack Alexander remains the Nuclear Training Manager. The Nuclear Training Department remains unchanged in Phase II but will gain most management support functions in Phase III. Phase III is planned to be implemented in the summer of 1993 following completion of the next refueling outage.

Two significant reorganization highlights are the elimination of the Vice President, Technical position and the merge of Emergency Planning (EP) into one department with Regulatory Affairs. Prior to Phase I, EP reported as a department directly to the Senior Vice President. In Phase I, EP remained a separate department but was realigned to report to the Vice President, Technical.

7.3 Staff Qualifications

Technical Specification (TS) 6.3 requires that station staff meet the educational and experience requirements described in ANSI N18.1-1971, "Selection and Training of Personnel for Nuclear Power Plants," at the time of appointment to an active position. The licensee implements the requirements of TS 6.3 through station procedure 1.3.78, "Procedure to Qualify BECo Employee to ANSI Requirements," in conjunction with a position description manual for every position requiring ANSI certifications. A qualification matrix is established that delineates the requirements of the job description, ANSI N18.1-1971, ANSI/ANS 3.1-1987 and the educational experience background of the candidate. ANSI/ANS 3.1-1987, "American National Standard for Selection, Qualification and training of Personnel for Nuclear Power Plants," was issued to reflect the improvement in the selection and training practices in the industry. Candidates for ANSI certified positions must be verified to fulfill the matrix requirements before being appointed to the respective positions.

The inspector reviewed the job description manual and verified that ANSI certified positions were properly identified with appropriate requirements identified. The inspector also reviewed the qualification matrixes for various department, section, and division managers. The matrices were well maintained and reflected the current organizational structure. Additionally, the inspector determined that the qualifications of the managers who matrices were reviewed were consistent with the ANSI requirements. The inspector had no questions in this area.

8.0 ENGINEERING AND TECHNICAL SUPPORT (71707)

8.1 Containment Isolation Valves

The inspector checked the testing and handling of specific containment isolation valves (CIVs) whose status had either been modified by a plant design change (PDC) or was defined by a unique system categorization. Specifically, the inspector reviewed the status of motor operated valves, MO-1001-60 & 63, whose function as CIVs in the reactor head spray system piping was eliminated by field revision notice FRN 196 to PDC 86-52B (see section 8.2 of this report for additional inspection of this plant modification); and also checked the status of air operated valve, AO-5025, a normally sealed-closed isolation valve in the direct torus vent system. These valves are currently listed in Table II of procedure 8.7.1.5 as requiring Type C local leak rate testing in accordance with 10 CFR 50, Appendix J requirements.

Based upon the nonfunctionality of valves, MO-1001-60 & 63, the inspector verified that cognizant licensee personnel are aware of the need to revise procedure 8.7.1.5 to eliminate the categorization of these reactor head spray valves as CIVs. Additionally, the inspector confirmed that the containment penetration, X-17, for the reactor head spray system would still be appropriately Type B tested, in accordance with 10 CFR 50, Appendix J, because the expansion bellows original design was required to accommodate the thermal movement of the piping (reference: PNPS FSAR section 5.2.3.4.2).

For valve AO-5025, the inspector also verified acceptable local leak rate testing provisions, and noted a position indication test requirement in accordance with the ASME Code Section XI in-service testing program. Since procedure 8.7.1.5 specifies cycling of the valve for the position indication test prior to the conduct of the Type C leakage test, periodic stroking of valve AO-5025 is assured by the PNPS CIV testing program. However, since the opening of the direct torus vent valve is not stroke timed and done only coincidentally to the Type C testing, the inspector questioned whether the other safety function of the valve, i.e., venting versus containment isolation, has been appropriately addressed by the PNPS in-service testing program.

In response to the inspector's question, the licensee initiated an integrated action data base (IADB) item, GM 93-0002, to evaluate the need for a procedural requirement to conduct and document the stroke time testing of valve AO-5025. The inspector reviewed the IADB data entry form for this item and determined that this issue was being tracked to an appropriate technical resolution. Since the normal direct torus vent system configuration maintains valve AO-5025 as a sealed closed CIV, representing its fail-safe position, the inspector had no additional questions regarding the current status or isolation capability of the valve. The licensee resolution of item GM 93-0002 is due prior to the start of the next refueling outage (RFO 9), when valve AO-5025 is again scheduled for testing.

8.2 Plant Design Change Review - Removal of Reactor Head Spray System

Previous NRC review (Report 50-293/90-25) of plant design change (PDC) 86-20 evaluated cutting and capping of the reactor head spray line from the standpoint of continued protection of the primary containment boundary. During the last (August 1991) refueling outage (RFO 8), new design change PDC 86-52B was implemented which involved the removal of piping which included an inboard containment isolation valve (CIV); the capping of containment penetration X-17; and, the abandonment of piping and another CIV outside of the containment. While the abandoned piping remained seismically qualified and in accordance with safety-related Class "II over I" criteria, the safety class of the components was downgraded and no provision for continued maintenance and testing of the valves was required. During this inspection, the inspector reviewed field revision notice (FRN) 196 to PDC 86-52B to determine the existing status of the systems, components and material affected by the head spray design change, as implemented.

The inspector also checked the compatibility of the Residual Heat Removal (RHR) system configuration, as-left after implementation of PDC 86-20 with the design intent of PDC 86-52B-196 and, in this regard, additionally reviewed drawings M100BC-282-1, M100-38-7, MIN 40-12, M241 and an earlier FRN 191 to PDC 86-52B. During a plant inspection tour, the inspector noted that the electrical supply breaker (B20B3) for the head spray valve (MO-1001-63) which had been removed during RFO 8 was still danger-tagged open. The inspector reviewed the PNPS tagout sheet T90-10-21 and determined that this open tag status was inconsistent with the handling of the electrical supply to the other head spray CIV (MO-1001-60), where the breaker had been left open, but the tagout cleared. The inspector discussed this inconsistency with cognizant plant personnel who initiated action to query the nuclear engineering department as to whether the entire tagout T90-10-21 could be closed and cleared.

In review of PDC 86-52B-196 design change criteria, the inspector identified a statement which implied that the abandoned piping in the reactor head spray system outside containment would remain vented. However, since PDC 86-20 installed a pipe cap on one side of this piping and PDC 86-52B-196 capped the piping at penetration X-17 on the other side, the reviewed licensee documentation provided no indication how such venting was implemented in that the valves identified in the PDC relating to this piping appeared to have been left in the closed position. Furthermore, since valve MO-1001-60, as identified in tagout T90-10-21 was chained closed, two vent paths, one on either side of the closed valve, would have to have been provided for the as-left piping to be consistent with the PDC design criteria.

Additionally, the inspector confirmed that the pipe cap for the penetration X-17 piping had been procured to ASME Code, Section III, Class 2 criteria as "impact-tested material." However, it appeared that an impact-tested weld procedure had not been used to install the pipe cap as would be required by the ASME Code, Section IX, unless certain conditions of exemption allowed by Section III of the code were satisfied. Given that the PNPS FSAR documents the containment drywell shell material to be fabricated of impact tested plate and forgings, the licensee issued problem report 93-9005 to resolve this question regarding the weld procedure qualification.

The inspector determined through the review of PDC 86-52B-196 and related supporting documentation that the current configuration of the reactor head spray piping was acceptable, in that the continued safe operation of PNPS had not been adversely affected by the design modification. However, as noted above, certain questions, regarding the existing pipe venting and the containment penetration weld qualification criteria, remain open. Pending the licensee presentation of evidence that the installed configuration is in compliance with the intended PDC design criteria, these issues remain unresolved (**92-28-02**).

8.3 Reactor Vessel Water Level Instrumentation Update

NRC Inspection Report 50-293/92-23, Section 8.1, provided a detailed status of licensee activities in response to reactor vessel water level instrumentation spiking experienced during recent reactor shutdown evolutions. Specifically, the issue has been addressed in terms of the generic concern for level instrumentation inaccuracies during rapid depressurization events due to the evolution of noncondensible gases from the reference legs.

The NRC conducted review of BECo operability determination of the level instrumentation, with particular attention on the instrumentation associated with the two-thirds (2/3) core height containment spray interlock. The safety function of this instrumentation is to provide level signals and indication such that adequate core cooling can be achieved for certain classes of accidents. The NRC staff independently concluded that this safety function would be satisfied at Pilgrim based upon the following:

- If flow is diverted to containment spray after 2/3 core coverage is achieved, one core spray pump alone is adequate to maintain 2/3 level and core cooling. Thus, even the diversion of all available low pressure coolant injection (LPCI) would not preclude adequate core cooling.

- It is unlikely that significant diversion of flow would occur prior to reflooding the vessel to 2/3 core height, because:

    -- the interlock does not cause any automatic actuations; that is, satisfying the interlock does not automatically divert LPCI flow to containment spray.

    -- according to the Pilgrim Reload Analysis (SAFER/GESTR Report NEDC-31852), for design basis loss of coolant accidents, the core is reflooded to 2/3 core height within approximately 60 to 150 seconds; therefore, the operator would have to immediately divert LPCI for such erroneous action to occur prior to reflooding the vessel. Moreover, operators are directed by procedure to assure adequate core cooling prior to initiation of containment spray, and operators have been sensitized to potential errors in level indication. Station Emergency Operating Procedures (ie, EOP-03, "Primary Containment Control") which govern the decision to divert LPCI flow and spray the containment would require the presence of a high drywell pressure above 2.5 psig. Also, the EOPs direct that only "those RHR pumps not required to assure adequate core cooling by continuous operation in the LPCI mode" be used for containment spray diversion.

    -- over 20 linear feet of reference leg volume, including both horizontal and vertical sections, must be voided and not recovered at Pilgrim to cause a continuous 14 inch level error, and an error of this amplitude is already considered in the interlock setpoint.

    -- it is expected that the magnitude of error in the level indication following an actual depressurization event would be significantly less than that estimated by conservative assumptions used in the calculations performed by the General Electric Company and the BECo consultants.

    -- the potential for level errors has likely been lessened by actions taken by the licensee to reduce external reference leg leakage (ie, tighten fittings and packing at the instrument racks).

- If it was postulated that LPCI flow was prematurely diverted to containment spray, the safety function of the interlock would still be fulfilled, because:

-- at Pilgrim the diversion of LPCI flow to containment spray (both drywell and torus) represents only approximately 25% of the capacity of one LPCI/RHR pump.

-- Appendix K analysis from the current Pilgrim Reload Analysis for the most limiting case for which LPCI flow is credited (ie, battery failure case), indicate a 1694 degrees F peak clad temperature (PCT), which represents a 506 degrees F margin to the 2200 degrees F PCT limit.

-- NRC staff reviewed analysis for a similar BWR/3 plant in which 100% of the flow of one RHR pump was assumed to be diverted from the core from the onset of the accident. These analysis support the staff judgement that, using Appendix K analysis assumptions, diversion of 25% of the flow of one RHR pump would not result in exceeding 2200 degrees F PCT.

Based on the above, the NRC staff concluded that any manual actuation of containment spray which is based upon an erroneous level signal to this interlock is both highly unlikely and of low safety significance, and that the safety function of the level instrumentation system at Pilgrim would therefore be fulfilled. The NRC staff also concluded that the BECo operability determination was performed consistent with the guidance of NRC Generic Letter No. 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," dated November 7, 1991.

During reactor depressurization following the two automatic trips that occurred during this inspection period, no reactor vessel water level instrumentation "spiking" was observed. The reactor tripped on December 13, 1992, after 20 days of operation and again on December 20,1992, shortly after startup from the previous trip. The NRC will continue to monitor BECo's progress in resolving the problem of noncondensible gas accumulation in the level instrumentation system at Pilgrim.

9.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (30702)

9.1 Routine Meetings

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting on January 7, 1993 with licensee management, summarizing inspection activity and preliminary findings for this report period. No proprietary information was identified as being included in the report.

9.2 Other NRC Activities

During the weeks of November 30 - December 4, 1992 and December 14-18, 1992 a Probabilistic Risk Assessment team inspection was conducted. Inspection results will be documented in NRC Inspection Report 50-293/92-81.

On December 17, 1992, Messrs. Jacque Durr, Region I, Division of Reactor Safety, Engineering Branch Chief, Eugene Keily, Region I, Division of Reactor Projects, Chief Section 3A, Ronald B. Eaton, NRR, Project Directorate 1-3, Senior Project Manager, and Jefferey Harold, NRR, Project Directorate 1-3, Project Engineer conducted a site visit. Activities during the visit included discussions with the Resident Inspector staff, observation of PRA inspection team performance, meeting with station management to discuss the Phase II reorganization, attendance a. e Town of Plymouth Nuclear Matters Committee Meeting and attendance at the PRA inspection exit meeting on December 18, 1992.