U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.:	50-293
Report No.:	92-23
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Location:	Plymouth, Massachusetts
Dates:	October 20 - November 23, 1992
Inspectors:	J. Macdonald, Senior Resident Inspector A. Cerne, Resident Inspector D. Kern, Resident Inspector E. King, Physical Security Inspector

Approved by: Eugene M. Kelly 12/29/92
E. Kelly, Chief, Reactor Projects Section 3A   Date

Scope: Resident safety inspections during the midcycle outage in 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 a walkdown and functional evaluation of the salt service water (SSW) system, motor-operated valve maintenance, reactor vessel level instrumentation performance, and the continued implementation of the SSW system piping replacement.

Inspections were performed on backshifts during October 22, 27-29 and November 2, 4, 5, 12, 16-19, and 23. "Deep" backshift inspections were performed on October 24 from 7:00 am - 8:00 pm and on November 5-6 from 11:00 pm to 2:30 am.

Findings: Inspection results are summarized in the Executive Summary.

EXECUTIVE SUMMARY

Pilgrim Inspection Report 50-293/92-23

Plant Operations

The overall control of plant operations was good, and operators were cognizant of maintenance and modifications in progress during the midcycle outage. Excellent lineup and tagging activities for salt service water system train separation maintained the plant in a safe configuration.

Radiological Controls

Radiological protection support for outage maintenance, particularly the use of the optical disk surrogate plant tour, was outstanding. Reviews of outage maintenance work packages were unsuccessful in identifying the high radiation levels in the radwaste demineralizer room, but detailed corrective actions were promptly implemented.

Maintenance and Surveillance

A heat exchanger repair to stop a small coolant leak in the reactor water cleanup system was well planned and executed in accordance with ASME Code requirements. Other field activities were observed to be properly controlled and implemented by knowledgeable personnel. An aggressive motor-operated valve (MOV) maintenance schedule was accomplished during the midcycle maintenance outage. Several generic issues were appropriately addressed, which further improved valve reliability. An overall implementation schedule for MOV preventive maintenance remained under development due to pending revisions to the program's scope.

Emergency Preparedness

Annual testing of the Prompt Alert and Notification System on November 19 successfully demonstrated the licensee's capability to notify occupants of the ten mile emergency planning zone in the event of an emergency.

Security

Effective security measures were taken to compensate for any degraded conditions resulting from the midcycle outage work. BECo promptly responded to potential problems identified by the NRC with access controls for equipment undergoing modification. The Fitness-for-Duty Program was found to be effectively implemented.

EXECUTIVE SUMMARY (CONTINUED)

Safety Assessment and Quality Verification

Sound safety perspectives were demonstrated in the development of the midcycle outage schedule. The "system window" approach was effective in maximizing decay heat removal capability and electrical distribution system flexibility. Quality Assurance Department verification of operator tours has been effective, utilizing objective criteria to independently assess Operation Section self-monitoring.

Engineering and Technical Support

BECo's Issue Team continues to evaluate the reactor vessel level instrumentation performance in a deliberate and technical fashion. External consultant expertise has been effectively utilized. The presence of noncondensible gases in the reference legs was confirmed. The Issue Team appropriately factored-in Pilgrim-specific experience with respect to BECo's response to Generic Letter 92-04, as well as to the generic considerations of the Boiling Water Reactor Owner's Group. Salt service water piping replacement activities continued, and were found to be well planned and conservatively executed.

TABLE OF CONTENTS

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 October 23, 1992, operations personnel began the process of deinerting the drywell in preparation for the start of the scheduled 30 day midcycle surveillance testing and maintenance outage. At 8:00 pm on October 23, control room operators initiated the reactor power reduction. A thermal backwash of the main condenser was conducted at approximately 50% of rated power. On October 24, 1992 at 5:40 am, the turbine generator was disconnected from the offsite distribution system. All control rods were fully inserted at 10:06 am on October 24 and shortly after at 10:45 am the reactor mode select switch was placed in the SHUTDOWN position.

At 11:10 am on October 24, a spurious spike of two intermediate range monitors caused an automatic reactor protection system actuation. No control rod motion resulted, as all rods had previously been inserted. Reactor vessel water level instrumentation "spiking" was experienced during reactor depressurization. The spiking began at approximately 350 psig and was similar to that experienced during previous reactor shutdown and depressurization evolutions.

At 10:28 pm on October 24, an unplanned automatic primary containment isolation system Group I actuation occurred as the result of a spike in the reactor vessel water level instrumentation associated with the "B" reference leg. At the time of the event, the reactor was essentially depressurized at about 2 psig and the reactor coolant system temperature was about 165 degrees fahrenheit. The main steam isolation valves had previously been closed during the normal course of reactor depressurization and cooldown, and were unaffected by the actuation. The appropriate main steam drain line and reactor sample line isolation valves repositioned to the closed position as designed.

Limiting outage testing and maintenance was completed on "A" train systems on October 30, 1992. Restoration of "A" train systems was completed and "B" train system outage testing and maintenance was initiated on November 1, 1992. Limiting "B" train activities were completed and the systems were restored to service on November 20, 1992. Additional "A" train activities were conducted on November 20-22, 1992. Non-train limiting activities were completed on November 23, 1992.

The reactor mode select switch was placed in the STARTUP position at 4:00 pm on November 23, 1992, following completion of final valve lineups and startup prerequisites. At the conclusion of the report period, the reactor was in the initial phase of power ascension.

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 (Protected Area)
Reactor Building	Turbine Building
Diesel Generator Building	Screen House
Switchgear Rooms	
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 to be appropriate. 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, lifted lead and jumper logs, and were found to be satisfactorily maintained.

2.2 Drywell Inspection

On October 24, 1992, the inspector accompanied the operations section manager and members of the maintenance and technical staff on an initial drywell inspection with the reactor at rated pressure and prior to placement of the reactor mode select switch to shutdown. Radiological section personnel properly established the drywell control point. The radiation work permit briefing was thorough and accurately reflected survey data and permit precautions and requirements. Station security established the drywell access control point and maintained positive control of personnel entering the drywell. The drywell inspection was comprehensive. Each drywell level was observed for system leakage; recirculation pumps were inspected for seal package leakage, oil levels, and general condition; and the undervessel area was inspected for potential control rod drive leakage. All areas were observed to be in good material condition with no abnormal leakage noted. However, minor leakage from the "B" recirculation loop discharge isolation valve, MO-202-5B, valve body drain line was identified. The drain line is 0.75 inches in diameter and drains to the clean radwaste system via two 0.75 inch hand operated

series globe valves (HO-202-113B and HO 202-114B). During the outage, the hand operated valves were replaced. The inspector reviewed the work package and discussed the valve replacement with involved maintenance personnel and identified no concerns.

2.3 Salt Service Water (SSW) System Walkdown (71710)

In conjunction with the inspection of SSW piping replacement and system modification activities (see section 8.2), the inspector conducted a walkdown of the SSW system to include a review of component status, an examination of equipment condition and configuration, and an evaluation of the overall system lineup for the current PNPS operating mode. This inspection was conducted with the plant shutdown, the "B" SSW train of equipment undergoing modification, and the "A" SSW train operating in accordance with the Technical Specifications (TS). The inspector verified train isolation and proper valve lineup and control switch positioning (e.g., swing pump P-208C aligned for loss of power contigency) in the control room and spot-checked the associated component tagging in the field.

During the examination of SSW equipment in the intake structure, plant auxiliary bays, newly constructed piping vault and the excavated SSW piping areas, the inspector checked material conditions and the impact of scaffolding and other outage work control items on the operation of the "A" SSW train. The inspector also reviewed the accuracy of the current revision (E44) of the SSW piping and instrumentation drawing (P&ID) no. M212, noting that the relevant plant design change (PDC) information that was outstanding to this P&ID had been posted by document control personnel. Included among the outstanding PDC's were the ongoing modifications to the hypo-chlorination system and SSW piping replacement activities, which the inspector confirmed to be in progress during the walkdown inspection.

The inspector identified a minor P&ID discrepancy relative to the in-line positioning of two thermowell, dual temperature elements (TE-6240/TE-3890 and TE-6241/TE-3891). In each case, the TE's were incorrectly represented to be upstream of the backwash piping connection to the reactor building closed cooling water (RBCCW) heat exchanger. However, the inspector determined that the "A" and "B" train piping isometric drawings accurately reflected the TE locations and that the P&ID error was insignificant from an operational standpoint. The licensee initiated a request to correct the minor discrepancies when P&ID M212 is next revised. The inspector also identified a missing condulet cover for the wiring of one TE. The licensee issued a work request, reference tag no. 027613, to correct this deficiency.

Additionally, the inspector examined the design and as-built configuration of certain SSW system pipe hangers in the intake structure. The inspector reviewed specific hanger drawing details, as well as isometric drawing no. JF-29-15, and noted that certain discrepancies between the isometric drawing and the field location of a few hangers, had already been identified by the licensee and were documented in problem report 92.0541. With respect to hanger H29-1-23, the inspector questioned the orientation of a load carrying plate and its attachment welds and requested the design calculation set for this hanger. The inspector reviewed calculation no. SK-C-924(Q), as augmented by a licensee weld check verification to confirm the structural adequacy

of the specific welds questioned by the inspector. These licensee calculations verified the load carrying capacity of the support welds with a substantial safety margin. The inspector also examined the sampled SSW piping supports for workmanship, material, member sizes, dimensions, tolerances and bolting practices. No nonconforming conditions were identified and the inspector had no further questions regarding hanger design or construction.

Overall, the inspector determined that the SSW system was built and was being maintained substantially in accordance with design and quality requirements. System operation during the current midcycle outage, was found to be in compliance with the Technical Specifications. Acceptable work controls (e.g., safety and work request tagging, scaffolding use, maintenance work packages) in accord with procedural requirements, were noted. The inspector observed good knowledge of system status and component availability and good interdepartmental communications in practice by the plant operators during inspection visits to the control room on several shifts. Except as noted above as minor discrepancies which are being corrected by the licensee, no additional concerns were identified during this inspection walkdown of the SSW system.

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 control area (RCA) continued to be thorough and directed toward minimizing personnel exposure. Survey postings, radiological conditions and controls were appropriate, with no discrepancies noted. Various maintenance in contaminated and high radiation areas was observed during the maintenance outage. The inspector witnessed use of the optical disk surrogate tour in preparation for drywell and reactor building inspection activities. Use of the surrogate tour by inspectors and maintenance personnel was effective in reducing personnel radiation exposure. Radiological briefings and support during maintenance were outstanding.

3.1 Unanticipated High Radiation Levels in Radwaste Demineralizer Room

On October 29, 1992, two personnel reported that their self indicating dosimetry, set to alarm at a dose rate of 50 millirem per hour (mR/hr), had alarmed when entering the radwaste demineralizer room. This was unexpected since previous radiological surveys had indicated that typical dose rates in this area were 10 to 20 mR/hr. The room was posted as a high radiation area. A radiological protection (RP) technician immediately performed a survey and confirmed that the dose rates in the radwaste demineralizer room were significantly higher than normal. The area dose rate at the room entrance step-off-pad was 1200 mR/hr while the highest on contact dose was 70 R/hr at the radwaste demineralizer. A door guard was immediately stationed and the room was then controlled as a locked high radiation area. Dosimetry was processed for the two workers who had initially reported the high dose rate condition. Their individual exposures (1 mR and 3 mR respectively) were well below 10 CFR 20 regulatory limits. The Radiological Section Manager was informed, and a door locking device was installed. All personnel involved responded promptly and took appropriate corrective actions.

A critique was initiated to determine the cause of the higher than expected radiation levels in the radwaste demineralizer room. The inspector noted licensee discussion to be detailed and pursuant to a logical conclusion. The critique identified the most likely cause of the high radiation levels to be the direct processing of unfiltered reactor water by the radwaste demineralizer. The reactor water cleanup (RWCU) system demineralizer is normally used to filter reactor water during both power and shutdown conditions. Continued direct treatment of reactor water through the radwaste demineralizer (during a period when the RWCU demineralizer and the condensate demineralizer were unavailable) resulted in higher than normal radiation levels in the radwaste demineralizer room.

The inspector reviewed the RWCU system maintenance work package and noted that the potential of higher radiation levels in the radwaste demineralizer room had not been considered during the RP review. It appeared to the inspector that the RP review should have identified this potential condition. Review of maintenance records, operations logs, and RP survey records for the current operating cycle identified no previous occurrence of this same condition. Recommendations to preclude recurrence included revision of operating procedure 2.2.19, "Residual Heat Removal System", to inform RP and radwaste personnel prior to transferring reactor water to radwaste. In addition, Radiological Section standing order 92-30 was issued to specify radiological posting and control of the area when the radwaste demineralizer is used as a reactor water letdown path. The inspector reviewed the revision to procedure 2.2.19 and standing order 92-30 and determined that the new instructions were clear, concise, and correctly addressed the causal condition. The critique was effective and corrective actions were promptly implemented.

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

4.1 Motor Operated Valve Maintenance

The licensee undertook an aggressive motor operated valve (MOV) workload during the midcycle outage encompassing maintenance and surveillance on 52 MOVs. Inspections and corrective maintenance to resolve generic issues were performed in addition to several MOV actuator overhauls.

Eleven MOV torque switches were inspected for the presence of fiber spacers as initially discussed in Limitorque Corporation 10 CFR 21 notification dated September 29, 1989. Two of these torque switches contained fiber spacers and were replaced with torque switches of a newer design containing a metallic contact bridge in place of the fiber spacers. The last MOV remaining to be inspected for this issue (MOV 4060B) has been scheduled for inspection during planned valve maintenance in January 1993. NRC Inspection Report 50-293/92-80 previously concluded that the licensee had not taken action to resolve the fiber spacer issue in a timely manner. Additional licensee inspection activities and resultant torque switch replacements during the March 1992 maintenance outage and during the current outage have appropriately addressed this issue.

Thirty additional inspections for generic concerns were completed, addressing a Limitorque 10 CFR 21 notification dated December 11, 1990 regarding undersized torque switch roll pins and NRC Notice 88-84 concerning deficient motor pinion keys. The inspector concluded that the MOV corrective maintenance program is appropriately addressing generic industry concerns.

Eight MOVs were overhauled as part of the MOV preventive maintenance program. The inspector reviewed completed work packages for maintenance performed on the outboard containment spray isolation valve (MOV 1001-23B) and the reactor core isolation cooling (RCIC) injection valve (MOV 1301-48). During overhaul of the MOV 1001-23B actuator, the spring pack was replaced, a torque switch limiter plate was installed, and minor physical discrepancies were properly corrected in accordance with approved procedures. Post maintenance diagnostic testing was performed in accordance with procedure 3.M.3-24.12, "VOTES 100 Operating Procedure" with satisfactory results. Preventive maintenance was performed on the MOV 1301-48 limit switch assembly and the motor pinion key was replaced (reference: Notice 88-84). One isolated case of incorrect maintenance status resulted in operation of MOV 1301-48 prior to adjustment and testing of the limit switch, which in turn caused motor damage. The motor was promptly replaced and post-work testing was satisfactorily accomplished. The cause of the miscommunication was identified and appropriate corrective actions were initiated. The inspector reviewed substitution equivalency evaluations for the motor and the motor pinion key (SSE-530 and SSE-548 respectively) and determined that the bases for equivalency were appropriate. Overall coordination of MOV maintenance was excellent, supporting completion of a significant amount of corrective and preventive maintenance during the outage.

The inspector observed an MOV program team critique of outage maintenance activities. The critique was detailed and produced good recommendations to further enhance work productivity. Recommendations included prestaging of spare overhauled MOV actuators for in-kind substitution; use of local vice remote MOV control during post-work testing; implementation of a consolidated MOV bolting specification; elimination of redundant operations and maintenance operability testing; and, MOV technician training enhancements. The MOV Program Manager plans to further develop and present recommendations to licensee management for disposition and implementation. During the outage, the licensee implemented an aggressive schedule and completed a noteworthy amount of MOV maintenance, accomplishing improved valve reliability. A comprehensive preventive maintenance scheudle remained under development due to pending revisions to the MOV program scope.

4.2 Reactor Water Cleanup System Leakage

As documented in NRC inspection reports 50-293/92-14 and 92-16, a small coolant leak on the shell of regenerative heat exchanger E-208B in the reactor water cleanup (RWCU) system has been monitored by the licensee since its discovery in June 1992. Continued safe operation of the facility was not adversely affected by the identified leakage conditions and repair operations were scheduled to be conducted during the outage.

During this inspection period, which encompassed outage maintenance and repair activities, the inspector reviewed the maintenance request, governing the repair of RWCU heat exchanger E-208B. While this second stage component to the RWCU regenerative heat exchanger is a nonsafety-related piece of equipment, it was originally procured as an ASME Section III, Class C vessel and is a code stamped item. Therefore, ASME Section XI repair/replacement rules governed the repair plans without need for additional section III code certification. A code reconciliation to a later version of the ASME Section III code (i.e., 1980 edition through winter 1980 addenda) was performed and the 1980 edition of the ASME Section IX code was invoked for welding activities.

The inspector reviewed the maintenance work plans, controlling heat exchanger disassembly and diaphragm inspection, and the governing the leaking diaphragm weld repair. One MWP that discussed an option to replace, rather than repair, the existing diaphragm was not used. As was discussed in IR 50-293/92-14, a defect in the stainless steel diaphragm, serving as the non-load carrying pressure boundary, was suspected and subsequently confirmed, to be the source of the identified leakage. The inspector also reviewed the MR log sheet, the weld repair data sheet and traveler no. 3432.03. These records, along with the ASME XI repair forms, were evaluated for consistency with the technical criteria delineated in the ASME Code and ESR Response Memorandum, ERM 89-1171 (Revision 1) documenting the engineering repair recommendations.

The inspector questioned some informational data (e.g., diaphragm material type) on certain of the supporting documents to the weld repair records and concluded that repair activities were adequately controlled. The source of the leak was found to be a pinhole defect in the stainless steel diaphragm, which was excavated and liquid penetrant tested (LPT) in accordance with ERM and code provisions. The inspector examined the welding procedure specification procedures and verified acceptable LPT of the final weld, along with QC coverage of the required NDE and specific welding variables, e.g., preheat and interpass temperatures. Since ERM 89-1171 (Revision 1) was written to address any future repairs to any of the three stages to regenerative heat exchanger E-208, the inspector also examined the GE specification sheet in the Heat Transfer Products vendor manual, and MR document packages to confirm appropriate consideration of the currently installed diaphragm material type. The inspector noted that ASME/ASTM SA 240, TP-304 stainless steel was originally provided as heat exchanger diaphragm material and subsequently changed to TP-304L low carbon material to address integranular stress corrosion cracking (IGSCC) concerns. As documented in the governing ERM, the option for replacement of the diaphragm, if required for future heat exchanger repairs, involves a material substitution to SA 240, TP-316L stainless steel, representing the best option to prevent corrosion pitting and the propagation of IGSCC defects.

The inspector assessed the engineering direction, sequence of work and QC coverage, and overall control of heat exchanger E-208B heat exchanger repair operations and identified no unresolved safety issues. Prior to startup from the outage, the RWCU system was placed back in service with no evidence of a continuing leakage problem. The inspector has no additional questions regarding either the acceptability of the repair work or the documentation package completeness.

4.3 Maintenance and Modification Field Work

The inspector conducted several plant inspection-tours during the outage, checking the status of plant equipment and the conduct of maintenance and modification activities in progress. The following components, work and documentation were spot-checked by the inspector to ensure adequate planning and control of the observed activities:

-- Machine tooling of the collector ring on the exciter end of the "B" recirculation pump motor-generator (M-G) set (X-204B) in accordance with maintenance work plan, MWP 19201023-1,

-- Installation of concrete expansion anchors and conduit supports as part of the plant design change, PDC 91-59A, for the replacement of transformer X56, providing 120V vital AC power to distribution panel Y4, in accordance with maintenance request, MR 19104143,

-- QC initiation of a problem report, PR 92-9189, and the nuclear engineering department (NED) conduct of an operability evaluation for certain reactor building closed cooling water (RBCCW) pipe supports identified with structural configuration deficiencies (reference work request tags 027809 thru 027812), and

-- Operations control (tagout T92-002-015) of the 'B" loop recirculation M-G set lockout relay testing in accordance with procedure 3.M.3-37.

The inspector interviewed craftsmen, operators, field engineers and QC personnel, as appropriate, to evaluate the acceptability of implementation of the above work activities. Field documentation and records were spot-checked and procedures examined, as necessary, to confirm applicability to the relevant quality criteria. Where work remained to be completed, the inspector noted the provision for the conduct of the appropriate post-work testing. Continuing open items were documented (e.g., PR 92.9189) and evaluated for operability. The inspector identified no unresolved safety concerns and had no additional question regarding the conduct or status of the observed field work. The MR/MWP documents examined appeared to be well organized, written clearly and capable of providing both effective direction to work crews and acceptable recorded evidence of the quality work performed.

5.0 EMERGENCY PREPAREDNESS (40500)

On November 19, 1992, the licensee conducted an annual test of the Prompt Alert and Notification System (PANS) for the ten mile emergency planning zone (EPZ) surrounding Pilgrim Station. The PANS system consists of remote activation consoles located at the five EPZ town fire department dispatch centers and 112 notification sirens. The test was conducted to verify the PANS capability to notify occupants of the EPZ in the event of an emergency.

Procedure EP-AD-417, "Annual Siren Test Program", requires at least 90 percent of the PANS sirens (or 101 sirens) to operate properly for the test to be successful. If this acceptance criterion is not met, the system has failed and the licensee would be required to notify the NRC in accordance with 10 CFR 50.72. The inspector questioned the clarity of the wording of test acceptance criterion specified in EP-AD-417, noting that it could result in unnecessary town, state and NRC notifications. The licensee initiated appropriate actions to clarify the test acceptance criterion. The inspector reviewed siren feedback system records and observer log sheets from the test and noted that all but one of the 112 sirens had properly sounded. An observer in the vicinity of the single failed siren reported that the warning tone could be heard. However, the peak decibel level recorded by the automated siren feedback system was outside of normal parameters. Therefore, the licensee conservatively categorized that single siren as a failure and initiated corrective action to repair the siren. The inspector concluded that the test was successful and that the licensee personnel demonstrated a high level of knowledge regarding the design of PANS and test performance.

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.

6.1 Modification Compensatory Measures

During inspection of certain piping replacement activities, the inspector evaluated the adequacy of compensatory measures where security areas had been breached by the construction work. Augmented access controls were in place, and the inspector confirmed that compensatory controls would continue to be implemented until a more permanent measure was installed to prevent area ingress.

The inspector questioned whether the suspension of full access compensatory measures met the intent of NRC Regulatory Guide (RG) 5.65 for barriers at water sources. The inspector discussed both the regulatory guidance and the planned licensee security controls for accessible

piping with the PNPS Security Section Manager and Region I security specialists. It was noted that at the time of this inspection, the system was not required to be operable and was in fact out of service to implement the planned piping replacement modifications. However, after return to service, a portion of the piping would remain accessible from outside the area barriers. Therefore, the licensee committed not only to reinstitute acceptable compensatory access controls, but also to continue implementing those security measures necessary to safeguard the piping appropriately.

The inspector determined that the overall licensee security controls and compensatory measures for the piping replacement activities provided adequate safeguards protection. BECo's licensee responsiveness to NRC concerns was timely and well directed. The inspector verified that the licensee has plans for continued security coverage of the piping replacement activities, in accord with the guidance of RG 5.65 and the provisions of the Pilgrim Security Plan, until the modification is completed during the next refueling outage (RFO 9).

6.2 Fitness For Duty Program Review

During the week of November 2-7, 1992, a regional-based security inspector conducted a selective review of the licensees fitness-for-duty (FFD) program implementation. The review consisted of an examination of the licensee collection facility, collection and chain of custody procedures, and records. Additionally, the inspector interviewed licensee medical staff members concerning specimen collection and chain of custody procedures. The inspector determined that the individuals were very knowledgeable of their specific duties and responsibilities. Based on the foregoing review, the inspector determined the program was being effectively implemented and was in accordance with the requirements of 10 CFR Part 26.

7.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

7.1 Assessment of Midcycle Outage Activity Controls

Prior to the midcycle outage, the licensee established a system "window" approach to maintain maximum decay heat removal capability, reactor coolant system inventory control, electrical distribution availability, and primary and secondary containment control during outage related maintenance and testing. The two major phases or windows to the outage were "A" train and "B" train system outages. The window approach during the last refueling outage was very effective in providing maximum configuration flexibility of available fluid and electrical systems. Additionally, the process clearly established system configurations which met or exceeded technical specification requirements.

The licensee outage safety review team, chaired by the onsite review committee chairman, independently reviewed the outage schedule to assess safety perspective and license compliance. The team also reviewed the midcycle outage compensatory measures procedure (TP 92-067) established to provide operations personnel with an overview of the outage schedule, system unavailability, established compensatory measures, and mitigation capabilities. The team

identified ten enhancements to the outage operations. Significant team contributions included maximization of reactor vessel inventory to improve loss of shutdown cooling mitigation capability, maximizing power source availability, several contingencies to address potential system misalignments due to valve mispositioning, and awareness of contingencies during electrical bus maintenance outages.

The licensee also established an emergent issues team (EIT). This team coordinated the response to outage issues on a real time basis in order to minimize overall outage management impact. To a lesser extent, the EIT projected potential concerns and contingencies to ongoing outage activities. The approach to reactor startup was well controlled. Completion of post-modification and maintenance testing was verified. Train and system restoration and valve lineups were accomplished in an orderly fashion. Additionally, the ORC reviewed the status of the reactor vessel water level instrumentation prior to startup. Overall, licensee control of outage activities with respect to plant safety was concluded to be excellent.

7.2 **Verification of Plant Records (TI 2515/115, RI-TI 92-01)**

On April 23, the NRC issued Information Notice IN 92-30, "Falsification of Plant Records," that documented instances of falsified plant logs at several nuclear power plants. The inspector documented initial licensee response to this issue in section 7.3 of NRC Inspection Report 50-293/92-08.

The NRC's resident inspector staff have accompanied plant operators on selected portions of plant tours, including a complete deep backshift accompaniment of the turbine building rounds. Throughout all direct inspection observations, operators were noted to be knowledgeable of tour procedure (procedure 2.1.16) requirements, inoperable equipment was properly identified, changing system parameters were appropriately documented, and general housekeeping such as component wipe-downs and loose debris collection was good. Additionally, the operators were noted to have made excellent use of the closed circuit television (CCTV) tours of the condenser bay, reactor water clean up system (including heat exchanger leak assessment), and the turbine deck. The value of the CCTV tour with respect to comprehensive area inspections in low radiological dose rate environments was clearly evident.

Throughout this period of time, BECo Quality Assurance Department (QAD) continued to conduct surveillance of operator tours. A QAD surveillance of operator tours from September 13-26 was conducted as documented by QAD surveillance number 92-1.1-12. The surveillance reviewed operator entries into the reactor building, diesel generator rooms, vital MG set room, "A" and "B" switchgear rooms, salt service water pump rooms, main stack, and several other plant areas as described by tour log data entry and by plant security computer printout.

Two inconsistencies were identified during the surveillance by issuance of deficiency report (DR) No. 2004. The first inconsistency involved operator documentation of the main stack tour. One logged entry into the main stack facility was not recorded by the security computer. The

security computer recorded the operator exiting the main gate, as would be required to accomplish the remote location tour at a time consistent with travel to the main stack. At the time in question, maintenance was being performed at the stack and the facility roll-up door was open. The operator stated that entry to the facility was accomplished directly through the open door, and that the security card reader was inadvertently bypassed. The QAD independently verified that the door was open and that operator exit and return to the main gate were consistent with the times in question. Therefore, the first inconsistency documented in DR 2004 was determined to have an acceptable explanation.

The second inconsistency involved a single entry into a switchgear room during a September 21, 1992, turbine building tour. The security computer did not record the operator's entry or exit from the area during the time that the tour was conducted. The remainder of the tour was verified to be consistent with security computer records. Operations Section management responded to the deficiency by conducting a full review of the subject operator's tours for calendar year 1992. The review indicated 100% compliance with log entry and security computer records, except for the one noted discrepancy. Additionally, the individual in question (who holds a reactor operator license) maintains having completed entry into the switchgear room during the tour in question. Further review indicated that security controls for entry to the switchgear room had been verified to be functioning properly, consistent with normal periodicities. The switchgear room check did not involve any surveillances required by Technical Specifications.

The QAD surveillance also identified certain weaknesses in the Operations Department self-monitoring program of operator tour entries. Specifically, the monthly nuclear watch engineer (NWE) assessment of tours for July, August and October were properly completed, but the September 1992 NWE assessment had not been performed. The quarterly Chief Operating Engineer assessment for the same period had also not been performed. Additionally, the monitoring of operator tours and turnovers were being performed weekly, vice three times per week, as instructed by Procedure 1.2.4, "Operations Performance Assessment Program." The QAD issued a second deficiency report (DR No. 2005) to document these self monitoring weaknesses.

Independent assessment of record verification by the QAD has been effective. Initial response to NRC IN 92-30 was comprehensive and confirmed that operators are properly completing required plant tours. The surveillance process has maintained objective criteria such that any noted observations, weaknesses and deficiencies have been appropriately communicated to the Operations Section.

8.0 ENGINEERING AND TECHNICAL SUPPORT (71707)

8.1 Reactor Vessel Water Level Instrumentation Spiking

8.1.1 Background

As documented in NRC inspection report 50-293/92-04, the licensee has experienced reactor vessel water level instrumentation "spiking" during reactor depressurization following plant shutdowns. Typically, the level instrumentation spiking has been observed to begin at reactor pressures below 470 psig during depressurizations. The spiking initially occurs on the level instrumentation associated with the reactor vessel "B" reference leg. The spikes are typically of 20-30 seconds in duration, four to six inches in amplitude, and are similar to a square wave recorder trace. As reactor pressure decreases, the amplitude of the spiking increases. At reactor pressures below approximately 60 psig the recorder trace of the spiking becomes less regular. Instrumentation associated with the "A" reference leg initially exhibits the spiking phenomenon at approximately 65 psig and is typically one to two inches in amplitude. Maximum spiking observed at very low pressures (i.e. less than 60 psig) has been approximately 22 inches on the "B" reference leg instrumentation and 17 inches on the "A" reference leg instrumentation.

Licensee corrective actions for the spiking phenomenon have been primarily focused on the improved thermodynamic performance of the condensing chambers and steam drain lines associated with the level instrumentation system. However, throughout the evaluation of the spiking phenomenon, the presence and accumulation of noncondensible gases within the reactor instrumentation system has been recognized as a potential contributing factor. Temporary temperature instrumentation was installed on the "A" and "B" reference leg condensing chambers and associated steam drain lines in order to monitor and trend condensing chamber performance. The instrumentation also monitors the potential effects of the buildup of noncondensible gases within the reactor instrumentation system during power operations, as well as during ensuing plant shutdowns. Additionally, the licensee management team (or "Issue Team") assembled to investigate this issue remained active and contracted with an instrumentation engineering consultant with expertise specific to boiling water reactor (BWR) level instrumentation system design and operation.

8.1.2 Generic Applicability

Subsequent to the April 12, 1992 station startup, generic concern for potential inaccuracies in boiling water reactor vessel water level indication during and after rapid depressurization events was identified. Specifically, the concern addressed the evolution of noncondensible gases, accumulated in the reference legs, during reactor depressurization in sufficient volume to cause errors in indicated reactor vessel water level. This concern is documented in NRC Information Notice 92-54, "Level Instrumentation Inaccuracies Caused by Rapid Depressurization," dated July 24, 1992 and NRC Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," dated August 19, 1992.

Continuing engineering analysis by BECo (and their consultant) preliminarily concluded that the potential exists for noncondensible gases to accumulate in the reference legs. Independent NRC review of the available Pilgrim-specific and generic data and analyses, as documented in inspection report 50-293/92-17, concluded that noncondensible gas accumulation in the reference legs significantly contributed to the recent reactor vessel water level instrument spiking events. The NRC also determined that current station data strongly suggest a potential problem may still exist, especially in the "B" reference leg.

The noncondensible gas accumulation phenomenon appears to be dependent upon three basic contributing effects including: 1) the presence of noncondensible gas in the condensing chambers; 2) a mechanism for transporting the gas into the reference leg, such as small leaks in reference leg fittings and components; and 3) an instrumentation piping geometry that supports gas accumulation (e.g., horizontal sections). Licensee consultant and generic evaluations indicate that the elimination of any one of these effects can ameliorate the spiking.

In response to this information, BECo took action to identify all external leakage paths on reference leg piping located outside the drywell. An approved developer material, that reveals leaking component interfaces, was applied to approximately 400 joints on the reference legs and instrumentation racks. Joints that exhibited leakage were bagged and the water leaks were quantified. Results indicated the "B" reference leg external leakage to be approximately 100 milliliters per day and "A" reference leg external leakage to be approximately 0.14 milliliters per day. A temporary procedure to be conducted during the midcycle outage was developed to quantify leakage internal to the instrumentation system (i.e., past the individual instrument bypass valves). Additionally, BECo installed ultrasonic equipment on the reference legs with the intent to detect potential gas bubble travel during reactor depressurization after plant shutdown for entry into the recent midcycle outage.

8.1.3 Midcycle Outage Reactor Shutdown and Depressurization

On October 23-24, 1992, the licensee performed a routine reactor shutdown and depressurization for the purposes of conducting a scheduled 30 day surveillance testing and maintenance outage. The reactor had been at power operation for 190 days prior to the shutdown. Reactor vessel water level instrumentation was monitored closely during reactor depressurization. At 10:45 am on October 24, the reactor mode select switch was placed in the SHUTDOWN position. From approximately 10:58 am to 11:14 am the reactor was depressurized from 750 psig to 350 psig with no water level instrumentation spiking observed. However, at approximately 350 psig, small spikes of two to four inches in amplitude were observed on the "B" reference leg level instrumentation. Similar amplitude spikes continued to occur over the next five hours as reactor pressure was decreased to 65 psig. The amplitude of the spikes increased to 8-17 inches as reactor pressure was reduced to 30 psig over the next two hours.

At 10:28 pm on October 24, with the reactor essentially depressurized at 2 psig and reactor coolant temperature at 165 degrees F, reactor vessel water level as indicated on "B" reference leg instrumentation spiked 29 inches (from +21 inches to +50 inches), resulting in an automatic primary containment isolation system Group I isolation signal. Spiking of two inch amplitude was first observed on "A" reference leg level instrumentation at approximately 63 psig reactor pressure. Several spikes of 17 inches were observed on "A" reference leg level instrumentation at less than 5 psig reactor pressure.

The reactor vessel water level instrumentation spiking observed during the October 24 depressurization was similar to that experienced during recent reactor shutdowns. Although the spiking began at lower pressures and was initially of lesser amplitude, the signature of the spiking recorder traces was essentially identical to the previous occurrences. Past corrective actions to improve condensate chamber and steam drain line performance by addressing thermodynamic performance appeared to have been minimally effective. Additionally, the ultrasonic equipment confirmed the travel of gas bubbles in the "B" reference leg. Following completion of the reactor cooldown and final analysis of level instrumentation data, the licensee concluded that the primary cause of level spiking was noncondensible gases coming out of solution during reactor depressurization.

8.1.4 **Corrective Actions**

As was discussed previously, the volume of noncondensible gases present within the reference legs is significantly influenced by reference leg configuration and by the presence of very small leaks in reference leg fittings and components. These relatively minor reference leg fitting leaks provide a slow and persistent flow which causes the gases to migrate down the reference legs.

BECo corrective actions during the midcycle outage were directed toward minimization of both "external" and "internal" reference leg leakage paths. External leakage paths identified during plant operations were repaired primarily by tightening fitting interfaces.

Internal leakage (from the reference leg past instrument bypass valves to the variable leg) was quantified by performance of a leak rate test. Temporary procedure TP 92-047 sequentially established instrument rack electrical and mechanical isolations and applied a demineralized water pressure test source of 20 psig to the low side head tank of a selected instrument on the instrument racks (RK 2205, 2206) associated with the "A" and "B" reference legs. Testing of the "B" reference leg instrument racks was initiated on November 9. Test pressure and head tank level stabilization were established and test parameters were monitored for approximately 8 hours, with no quantifiable internal leakage observed.

Testing of the "A" reference leg instrumentation racks was initiated on November 15. Test conditions were established and test parameters were monitored for approximately 15.5 hours. The "A" reference leg high side isolation valve (2-HO-126A), which established a test boundary, appeared to be not fully seated. The inability to fully isolate this valve created a leakage path

for the test demineralized water source from the reference leg to the reactor vessel. This leakage was not directly relevant to the test objectives but, if quantifiable, could be used to estimate bypass leakage. Initial "A" reference leg instrument rack leakage was quantified as 21.6 ml/day, which included instrument bypass valve leakage as well as leakage past the 2-HO-126A valve to the reactor vessel. In order to more accurately quantify bypass valve leakage, the licensee isolated each level instrument and calculated any leakage rate change. With all instruments isolated, leakage rate was calculated to be approximately 14 ml/day. Therefore, bypass valve leakage on "A" reference leg instrument racks was assumed to be approximately 7 ml/day.

Following subsequent plant startup and pressurization, the licensee intends to inspect for the presence of external leaks and quantify any observed leakage.

8.1.5 **Issue Status**

On November 20, the BECo reactor vessel water level instrumentation spiking Issue Management Team presented a status report to the onsite review committee (ORC). The report (attached to this inspection report) summarized data from the October 24 shutdown. The Issue Team found that instrumentation response during reactor depressurization was consistent with recent shutdowns, and that the characteristic spiking signature was repeatable. Spiking observed during the October 24, 1992 shutdown was bounded by previous operability analyses which assumed the presence of noncondensible gases in the reference legs. Therefore, the licensee concluded that the level instrumentation remained operable throughout the October 24th shutdown.

The status report addressed corrective actions completed during the midcycle outage including; repair of reference leg external leakage paths, quantification of internal instrument bypass valve leakage, and reinstallation of steam drain line insulation. The insulation had been previously removed in order to improve condensing chamber performance by increasing heat transfer across the steam drain line and condensing chamber on the "B" reference leg. However, instrumentation performance did not demonstrate any significant improvement during the October 24 shutdown; therefore, the insulation was reinstalled.

The status report provided a detailed review of Pilgrim specific experience relative to the generic concern for level instrumentation inaccuracies due to noncondensible gases as described in NRC Generic Letter 92-04. The BECo Issue Team concluded that the level instrumentation response during recent Pilgrim shutdowns was consistent with the noncondensible gas theories presented to the NRC staff by the Regulatory Response Group of the Boiling Water Reactor Owner's Group (BWROG), and was similarly consistent with the theories developed by the licensee-contracted specialist with expertise in this discipline. The Issue Team also concluded that the instrumentation spiking observed at Pilgrim would not affect either the limiting FSAR transient and accident analysis or the operability evaluations and conclusions of the plant-specific safety assessment (as well as the BWROG generic safety assessment) in response to NRC Generic Letter 92-04.

The ORC discussion of the level instrumentation concern with the Issue Team was observed by the NRC resident staff to be well focused. Extensive technical detail from NRC Generic Letter 92-04 was requested by the ORC Chairman, and discussion regarding NRC staff acceptance of interim operation with the noncondensible gas phenomenon as described in Generic Letter 92-04, such that the committee was enabled to independently establish generic applicability. The committee also reviewed level instrumentation response to design bases transients and accidents with the Issue Team. Following additional description of Pilgrim experience, and plant-specific safety assessment, the ORC independently concluded that the safety function of the level instrumentation would be fulfilled and that the Issue Team continues to effectively manage station response to the phenomenon. Following ORC recommendation, the Plant Manager approved the Issue Team reactor water level spiking status report.

NRC inspection, evaluation and assessment of license performance with respect to the spiking occurrences, to date, have identified no violations of Pilgrim license conditions. The NRC staff also independently reviewed the bases for BECo's operability determination, and agreed with its conclusions. The NRC has determined that the plant-specific assessment for Pilgrim has acceptably addressed regulatory requirements (and the points raised in Generic Letter 92-04), and has verified the continued safe operation of the plant while the spiking phenomena is investigated further as a generic issue.

8.2 **Salt Service Water Piping Replacement**

As documented in inspection reports 50-293/92-08, 92-10, and 92-14, salt service water (SSW) piping replacement activities commenced in May 1992 and have continued in several stages to the present. During the outage, the licensee installed the first pieces of titanium piping as "B" train penetration spools in the intake structure and auxiliary bay walls. As governed by plant design change (PDC) 91-10C, this phase of work involved removing existing rubber-lined, carbon steel sections of piping and replacing each penetration spool with titanium pipe, an expansion joint member and a new rubber-lined, carbon steel pipe piece to reconnect to the existing SSW supply headers. The inspector witnessed the modification activities, noting that the "B" SSW train was returned to service during the outage with the titanium penetration spools installed and that the corresponding "A" train work is scheduled during RFO 9. During the period of time between the outage and RFO 9, new titanium piping will be installed in excavations in proximity to the existing SSW headers in accordance with controls established by PDC 91-10D. The final tie-in of the titanium piping to existing SSW piping in both the intake structure and auxiliary bays is planned for completion during RFO 9.

The inspector reviewed PDC 91-10C-02 and related portions of PDC 91-10D. The inspector also reviewed the current revisions of the original piping specifications, M-300 and M-301, and the titanium piping specification, M-100E, along with the commercial grade item (CGI) engineering evaluation No. 596 for the titanium pipe and fittings. As required by specifications, the inspector verified that the installed titanium piping penetration spools had been procured to American Society for Testing of Materials (ASTM) B337-83 standards. However, both the FSAR change associated with safety evaluation 2693 and the acceptance criteria for pipe

chemical properties listed in CGI 596 indicated that the 1987 edition of the ASTM standard was the correct reference. The inspector discussed this discrepancy with licensee compliance personnel who initiated Problem Report 92-0536 to resolve the noted document conflicts. From a technical standpoint, the titanium spool pieces were fabricated and supplied to the correct design standards. The inspector reviewed the "A" SSW supply header drawing, SKM-91-10C-001C, for the intake structure spool/expansion joint assemblies and compared the listed material requirements with the referenced specifications. No hardware deficiencies were identified and the inspector has no further questions regarding component fabrication details.

The inspector also evaluated the ongoing SSW pipe replacement activities with respect to PDC 91-10C details, governing hydrostatic pressure testing to ANSI B31.1 and ASME Section XI code requirements, protection of the titanium piping from galvanic corrosion, and verification that the unlined carbon steel spool pieces remaining in service meet code minimum wall requirements. With regard to the latter inspection point, the inspector reviewed the BECo response to NRC Generic Letter (GL) 89-13; NED memorandum 91-145, revision 1, outlining routine SSW piping inspection plans; and BECo quality control inspection report 92-60, documenting the results of the ultrasonic thickness examinations of the SSW pipe spools installed without rubber lining. The inspector verified that actions to address the concerns documented in GL 89-13 were consistent with licensee commitments, program controls and the phased sequence of SSW piping replacement activities.

Additionally, the inspector witnessed the re-installation of a hanger, H29-1-12SG, for the "B" SSW train piping. The inspector confirmed adequate work controls were specified in the maintenance work package, MWP 19200471-1, and observed craft compliance with engineering criteria (e.g., torque requirements) and adequate QC coverage of the job. Ongoing SSW "B" train pipe replacement and restoration activities were evaluated for impact on the "A" train SSW system and components required to be operable and operating. The inspector identified no adverse consequences on the function of the SSW system to provide decay heat transfer to the ultimate heat sink during the outage.

The overall SSW piping replacement project, to date, has been well planned and conservatively executed. The inspector reviewed a sample of nonconformance reports, written against vendor materials supplied to support PDC 91-10 work. Adequate QC inspection of safety-related material and appropriate engineering evaluation of the sampled NCRs were found to have been implemented. The inspector interviewed craft, QC, engineering, and project management personnel involved with PDC 91-10 activities and identified no unresolved safety concerns. At the conclusion of this inspection, ongoing excavation work governed by PDC 91-10D continued. Future NRC inspections by regional and resident personnel will monitor the progress of this major modification.

9.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (30702)

9.1 Routine Meetings

At periodic intervals during this inspection, meetings were held with 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 December 11 with BECo management, summarizing the preliminary inspection findings for this report period. No proprietary information was identified as being included in the report.

9.2 Other NRC Activities

On November 2-6, two NRC Region I radiological specialists conducted an inspection to evaluate licensee radiological controls practices during outage conditions. Inspection results will be documented in Inspection Report 50-293/92-24.

On November 2-6, an NRC Region I security specialist conducted a programmatic security inspection. Inspection results are documented in Inspection Report 50-293/92-25.

On November 5, NRC resident inspectors attended a meeting of the Plymouth Nuclear Matters Committee. The committee discussed issues which had been raised by the Citizen's Radiological Monitoring Network, Inc. (CRMN) in a letter to the NRC regarding events which occurred during the October 24 Pilgrim shutdown. The NRC responded to the CRMN letter on November 20.

On November 16-20, NRC Region I operator licensing specialists administered initial license examinations and requalification examinations. Results of the examinations will be documented in Inspection Report 50-293/92-22.

On November 16-20, an NRC Region I fire protection specialist conducted an inspection of the Pilgrim fire protection program. Inspection results will be documented in Inspection Report 50-293/92-27.

On November 19, two NRC Headquarters officials accompanied the NRC resident inspectors on a safety inspection of the drywell and selected portions of the reactor building.

Office Memorandum

Boston Edison Company

To: E.S. Kraft, Jr. From: S.D. Hudson Record type A4.08

Date: November 20, 1992 Dept. Doc. ESED92-167 Non-Safety Related

Subject: **REACTOR WATER LEVEL SPIKING STATUS REPORT**

Distribution:

R.A. Anderson	E.T. Boulette	W.S. Clancy
J. Bellefeuille	W.C. Rothert	R.V. Fairbank
H.V. Oheim	T. Sullivan	D. Tarantino
J. Rogers-BT	S. Dasgupta-BT	R. Cannon
T. Trepanier	R. Kelley-BT	K. Kampschneider
E. Almeida	P.D. Smith	L. Francis

Approval For Release Outside Plant Dept. ____________________
E.S. Kraft, Jr.

BACKGROUND:
During the shutdown and cooldown on 10/24/92, reactor water level was continuously monitored with the EPIC Computer. Close communication was maintained with the Control Room. Spiking was observed to begin at approximately 350# on the "B" ECCS instruments. The characteristic signature which had been observed in the past was present during depressurization. The overall performance of the water level instrumentation was similar to past performance.

A Group 1 Isolation occurred at approximately 160°F due to a maximum recorded spike of 29 inches (limited by instrument range). Water level was +21 inches at the time of this spike. All valves responded as designed due to the false high level signal.

Spiking began at 63# on the "A" Side instruments. The "A" Side also performed as expected. The maximum spike observed on the "A" Side was 17 inches.

OPERABILITY DETERMINATION FOLLOWING OCTOBER 24, 1992 SHUTDOWN:

Reactor water level instrumentation remained operable during the shutdown and cooldown on 10/24/92. An Operability Evaluation was performed by Engineering and Plant personnel in September 1992 which assumed the existence of non-condensible gas in the reference legs. This evaluation recommended operability criteria for the reactor water level instrumentation if notching were to occur during a plant shutdown. The ORC reviewed and concurred with the evaluation and was accepted by Plant Operations. The evaluation assumed bounding notching characteristics which were then evaluated for their impact on the ability of systems to perform their specified functions. The notching characteristics assumed in the evaluation bound the notching observed during the October shutdown. Therefore, the reactor water level instrumentation remains operable.

ACTIONS DURING MCO #9:

-Measurement of Instrument Bypass Valve Leakage

The Reactor vessel reference legs were tested under TP92-47. This pressurized the reference leg and all instrument bypass valves to 20 psi. The test was performed on the 'A' and 'B' reference legs. The 'B' side was completed first, and after stabilization, a leak rate of zero was determined after 8 hours of test.

On the 'A' side, pressure was applied between the root valve and the instrument bypass valves. The total leakage observed was approximately 22 ml/day. However, leakage continued after all level transmitters had been valved out. The amount of leakage past the instrument bypass valves and how much was leaking past the normally open root valve could not be determined.

No instrument bypass valves were replaced.

-Repair of External Leakage

The external leaks on the 'A' reference leg and 'B' reference leg were quantified prior to shutdown as approximately .14 ml/day and 97 ml/day, respectively. Additionally, seepage had been identified at mechanical joints but its too small to quantify. The identified leaks and seepage were tightened under a Maintenance Request and will be examined as part of Post-Work Testing after startup.

-Condensing Chamber Steam Drain Line Insulation

During a short outage in the spring of 1992, the insulation on the drain line (from condensing chamber to vessel) was removed from the 'B' side. It was originally postulated that this action could mitigate the water level anomolies noted during vessel depressurization. The insulation was removed to increase the surface area available for condensation in order to increase the rate of steam flow into the condensing chamber. Although it was recognized that this would increase the reate of dilute gas flow into the drain line, it was expected the corresponding increase in condensate flow returning to the vessel would sweep/scrub a disproportionately larger amount of concentrated gas. This was expected to slow the rate of gas accumulation so as to delay the onset of or prevent gas binding of the chamber. Unfortunately, the chamber temperature trends during operation and shutdown as well as the instrument performance during the shutdown indicate that little if any benefit was gained and the condensing chamber gas binding was not significantly retarded.

However, during the October 1992 shutdown, the pattern and volume of level errors on 'B' side instruments did not show any distinct improvement. Moreover, the insulation removal adds surface area for vapor condensation, potentially accelerating the inflow of dilute gas into the condensing chambers and shortening the period for gas accumulation and concentration in the chamber. Chamber temperature trends during the last operating period tend to support this possibility. Previous operation with the insulation on 'B' side did not result in more adverse level anomolies than observed in the October 1992 shutdown. Thus, the reinstallation of this insulation during MCO #9 was implemented.

EVALUATION OF ROOT CAUSE ANALYSIS:

The instrumentation response was consistent with the non-condensible gas theory developed by Saul Levy, Inc. Additionally, ultrasonic detectors installed on the reference leg piping on the back of the 'B' ECCS Rack detected gases traveling up the piping during the spiking. Detectors on the 'A' side did not detect the gas because the upper detector was not functioning.

Therefore, it is now believed that the cause of the spiking is due to non-condensible gases coming out of solution during depressurization. As the gas forms a bubble and travels up the vertical sections of piping, the weight of the water in the reference leg is reduced and the transmitter indicates a higher level than actual. When the gas bubble reaches a horizontal section of piping, it has negligible effect on the level transmitter output and indicated level returns to actual level. The characteristic "square wave" shape is a function of the geometry of the reference leg piping. At low reactor pressure, gas is being released from multiple collection points at slightly different times. Therefore, the response takes on a ragged mountain peak shape.

Three factors are necessary for the spiking to occur. These are: (1) a buildup of non-condensible gases in the condensing chamber; (2) horizontal sections in the reference leg piping; and (3) leakage near the transmitters which cause the gas saturated water to migrate down the reference leg. Elimination of any one of these three factors should prevent the spiking during normal reactor depressurization.

IMPACT ON GENERIC LETTER 92-04 RESPONSE:

GL 92-04 requested licensees to determine the impact of level errors caused by non-condensible gas on automatic safety system response, Operator short and long term actions, and Operator actions described in Emergency Operating Procedures. Boston Edison performed a Plant Specific Safety Assessment in addition to the Generic Safety Assessment performed by the BWR Owner's Group. This safety assessment was reviewed by the ORC and approved by the Plant Department Manager. This assessment concluded that potential errors would have no affect on limiting FSAR transient and accident analyses, and in the event Operators are unable to determine water level, EOPs provide clear direction for Operator actions. The notching caused by non-condensible gas does not affect operability as described previously, nor does it affect the conclusions of the safety assessment contained in Boston Edison's response to GL92-04.

The testing and analysis program being performed by the BWROG is predicated upon the existence of non-condensible gas in reference legs. The notching observed during this shutdown confirms non-condensible gas buildup. The observed notching was consistent with our past experience and does not invalidate our response to Generic Letter 92-04. Therefore, the proper course of action is to pursue the BWROG testing and analysis program so the causes and effects of gas buildup can be determined and fixed, if necessary.

OPERABILITY EVALUATION FOR 2/3 CORE COVERAGE PERMISSIVE:

Since 2/3 core coverage interlock is the only level device that must function after reactor pressure has dropped to the point where degassing occurs, the operability of this function has been revisited in light of data obtained during the recent shutdown and industry information. Experience from the recent shutdown and previous shutdowns provides empirical evidence that notching of 29 inches or more can occur.

The root cause of level notching is now believed to be primarily due to non-condensibles. Although previous level responses during slow depressurizations reasonably compare with theoretically predicted level system responses, no validated industry analyses, plant specific analyses have been completed that can predict responses during rapid depressurizations. Theoretical performance must be benchmarked against real test data. Such testing is actively being pursued by the industry. Therefore, the magnitude of any error can not accurately be determined by analysis.

It should be noted that over 20 linear feet of reference leg volume, including both horizontal and vertical sections, must be lost during a rapid depressurization to create 14 inches of continuous level error. This level error is already considered in establishing the set point for the 2/3 core coverage level switch.

The potential for level errors should be considered lessened because the presence of non-condensibles relies on transport into the reference legs due to leakage. External leakage is believed to be reduced from the leakage conditions that existed during past operating periods. This eliminates one of the conditions necessary for rapid depressurization level error as discussed in NRC Generic Letter 92-04. Less gas in the reference legs should decrease magnitude of the error due to rapid depressurization.

The 2/3 core coverage condition is only expected for large recirculation pipe breaks. These breaks lead to level recovery to at least 2/3 core height since this is the level of the refloodable vessel volume. The 2/3 core coverage permissive prevents operators from inadvertently diverting LPCI flow to containment cooling if reactor level is less than 2/3 core height. Also, if LPCI flow has been diverted to containment cooling and reactor level drops to 2/3 core height, the containment cooling valves automatically close to redirect all LPCI flow to the reactor. EOPs direct operators to maintain level above top of active fuel (TAF). 2/3 core coverage is 4 feet below TAF. Level errors of up to approximately 4 feet would not prevent operators from maintaining 2/3 core coverage. This level is adequate for core cooling.

Tech Spec Table 3.2.B indicates that the 2/3 core coverage interlock prevents inadvertent actuation of containment spray during accident conditions. The trip device is set at the trip setting specified in the table. Water level errors do not affect the sensed level at which the Tech Spec switches actuate and Table 3.2.B is therefore satisfied. However, Tech Spec Bases 3.2 indicates that the objective of the specification is to prescribe the trip setting required to assure adequate performance. As shown below, under rapid depressurizations, the system performance is adequate to assure the core cooling function. This condition, therefore, represents a potential nonconformance with the FSAR design criteria for the system and not a noncompliance with Tech Specs. Water level inputs to the 2/3 core coverage interlock function are expected to the extent practical and feasible, to be true measures of operational conditions and to respond correctly to the sensed condition over the expected range of magnitudes and rates of change. Level errors represent a departure from fully conforming with these criteria.

This departure does not prevent the 2/3 core coverage interlock from detecting abnormal conditions with sufficient timeliness, precision, and reliability to assure that its specified safety functions can be performed.

Flow diverson to containment spray represents roughly 25% of a single RHR pump's flow. The remaining LPCI flow to the reactor would still be well in excess of jet pump leakage (800 gpm per FSAR 3.3.6.5.2) and 2/3 core coverage would be maintained during spray diversion.

It is also important to note that for large recirculation line breaks, at least one core spray loop will be available assuming a worst single failure. Accounting for 800 gpm jet pump leakage, one core spray pump can maintain 2/3 core coverage and the effects of water level errors on the core cooling function are further diminished.

Appendix K LOCA Analyses for PNPS indicate that massive core uncovery (e.g., more than 10 feet below TAF) for approximately 60 seconds can occur without exceeding 2200°F peak clad temperatures. The LOCA analysis is done assuming the reactor has just been shutdown due to the accident when fuel sensible heat and decay heat are still high and coolant temperature is high. Worst peak clad temperatures are for the recirculation suction line break with LPCI injection valve failure. Conservative analysis indicates this peak clad temperature to be 1821°F which provides margin to 2200°F. Operator actions to divert LPCI flow would not occur until the core had been reflooded with comparatively cool water and fuel sensible and decay heats had substantially decreased. Loss of injection at this time would lead to level reduction due to boiloffs and not due to depressurization blowdown. Core spray flow and some LPCI flow will maintain 2/3 core height. Multiple failures must occur to cause a condition where no core makeup flow exists. Level errors of up to five feet under this unlikely scenario will not lead to PCTs exceeding those in current LOCA analyses.

The FSAR acknowledges some level errors occur during design basis events. In selecting reactor water level as an input parameter to initiating safety functions, it is understood that some inaccuracy is inherent in the design. Deviations between actual and sensed level are expected due to pressure and thermal density effects, reference leg flashing, coolant voiding, and flow across instrument nozzles (see FSAR 7.8.5.2). In selecting level trip settings, FSAR 7.2.4 states that the "trip point selected is not the only value of the trip point which results in acceptable results relative to the fuel or nuclear system process barrier. Trip setting selection is based on operating experience and is constrained by the safety design basis". As has been shown, trip actuations at levels different than assumed in accident analysis due to level errors do not lead to unacceptable results.

The potential for level error following a rapid depressurization is an industry-wide issue. Although the exact nature of the effects rapid depressurizations have on the 2/3 core coverage interlock has not been quantified by the industry (BWROG) or Boston Edison, the available design margins, empirical plant data and reductions in reference leg leaks provide reasonable assurance that the 2/3 core coverage interlock will remain operable.

Performed By: Thomas White Jr. 11/20/92

Reviewed By: Thomas White Jr. FOR David Long per telecon review of FAX

Recommends Approval: F.J. Olivier for RVF
Nuclear Engineering Manager

Recommends Approval: [signature]
Operations Manager

Recommends Approval: [signature]
ORC Chairman

ORC Meeting Number 92-100

Plant Manager Approval: E.A. Kraft Jr.