OFFICE OF INSPECTION AND ENFORCEMENT
DIVISION OF INSPECTION PROGRAMS

Report No.: 50-293/85-30

Licensee: Boston Edison Company
800 Boylston Street
Boston, MA C2199

Docket No.: 50-293 License No.: DPR-35

Facility Name: Pilgrim Nuclear Power Station

Inspection Conducted: October 23 - November 22, 1985

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SCOPE: This special announced team inspection involved 674 inspection hours assessing in depth the operational readiness of the high pressure coolant injection system. A partial review was also conducted of other safety-related systems such as core spray, standby gas treatment, and residual heat removal.

RESULTS: The licensee's operational readiness and management controls as they relate to selected safety systems were reviewed in five functional areas. The functional areas reviewed were:

- Maintenance
- Operations
- Surveillance
- Training
- Design Changes and Modification

Additionally, nine potential enforcement findings were presented to the NRC Region I Office as Unresolved Items for followup.

I. INSPECTION OBJECTIVE

The objective of the team inspection at Pilgrim Nuclear Power Station was to assess the operational readiness of the high pressure coolant injection (HPCI) system. This assessment included a determination of the following:

- o capability of the system to perform the safety functions required by its design basis;
- o adequacy of testing to demonstrate that the system would perform all of the safety functions required;
- o adequacy of system maintenance (with emphasis on pumps and valves) to ensure system operability under postulated accident conditions;
- o adequacy of operator and maintenance technician training to ensure proper operations and maintenance of the system;
- o adequacy of human factors considerations relative to the HPCI system (e.g., accessibility and labelling of valves) and the system's supporting procedures to ensure proper system operation under normal and accident conditions.

II. SUMMARY OF SIGNIFICANT INSPECTION FINDINGS

Section III of this report provides the detailed inspection findings pertaining to each functional area evaluated. The more significant findings discussed in Section III are summarized below.

A. Hydrodynamic transients (commonly referred to as water hammer) associated with the high pressure coolant injection (HPCI) turbine exhaust line have been occurring since the beginning of the plant operation in 1972. The team considers the occurrence of hydrodynamic transients over this thirteen year period of operation a design deficiency and a significant safety issue. The team recognized that this deficiency was known by Boston Edison, that recent engineering activity has focused on reducing the likelihood of events that lead to hydrodynamic transients in this system, and that additional engineering activity is planned. Nevertheless, the team believes the history of hydrodynamic occurrences and the modifications made to the system have not addressed the root cause and, instead, have addressed symptoms. The licensee informed the inspection team that additional HPCI system modifications were planned for the next refueling outage that would effectively mitigate future hydrodynamic transients.

B. Problems were noted in the Pilgrim design change process. Programmatic weakness identified by the team that had the potential to affect the adequacy of the design changes and modifications to safety-related systems include:

1. The design criteria and design basis for the HPCI system existed in various controlled and uncontrolled documents and were not easily retrievable. The lack of a design reference document, such as a system description, was considered a weakness. The

team is concerned that engineers preparing modification packages or conducting reviews of modification packages may not have a clear understanding of how the system, as installed, is expected to operate to perform its safety functions. This concern was amplified by the inaccuracies found in the HPCI system training materials.

2. The team found a lack of traceability to original design bases for establishing the setpoints of safety-related instruments and the sizing of some components.

3. The team found instances where design analyses were not performed; instead, undocumented engineering judgments were apparently used to conclude that a design analysis did not have to be performed.

The team concluded that the above programmatic weaknesses in the design change process potentially contributed to the following examples of inadequate design analysis and design change implementation:

- o A design analysis did not exist to document the determination of the duration of the nitrogen purge for the HPCI turbine steam exhaust line.

- o No safety analysis was performed when the HPCI turbine exhaust stop check valve was replaced.

- o The sizing for DC motor-operated valve overload alarms was not consistent. In many cases similar motors were protected with different size overload alarms. Additionally, most motor-operated valve overloads were found to be oversized for their design purpose.

- o The level setpoints for HPCI level switches LS2351A and B were not in accordance with the plant's original design basis although they appeared to be conservatively set.

- o No design analysis existed to confirm that a modification associated with the HPCI gland seal condenser and lube oil cooler was sufficient to prevent potential overpressure conditions from exceeding design pressures of piping and equipment.

- o Inadequate justification was provided for determining the acceptability of removing insulation from the residual heat removal heat exchanger.

- o Design analyses did not exist to substantiate ECCS room cooler allowable out of service time.

C. A weakness was identified regarding the control of plant instrumentation. The team discovered two instrument isolation valves associated with the HPCI system that were shut. One of these valves isolated the local steam supply pressure gage and the other valve isolated the local and control room indication of HPCI pump suction pressure. Plant operations personnel were not aware that these indications were isolated nor was there any administrative system in effect to alert operators to this condition. This apparently deficient control over instrument isolation valves could lead to plant operating decisions based on inaccurate indications.

D. Problems were identified with respect to the way the licensee handled vendor information and recommendations which affected the adequacy of the design and operation of safety-related systems. Examples identified include:

1. For several safety significant General Electric Service Information Letters (SILs), the available documentation did not provide the basis for concluding that sufficient plant specific action had been taken or that plant design features existed such that the review could be considered complete.

2. A vendor manual for the emergency lighting system was not available.

E. The licensee's program for approving and validating procedures used to support the symptom-based emergency operating procedures (EOPs) appeared to be weak. This conclusion was based on a review of a procedure used, in conjunction with the EOPs, to bypass safety-related interlocks to permit operations of various systems in an abnormal manner. The team identified errors in two attachments to the procedure, and the licensee later identified similar errors in three additional attachments. These errors, if left uncorrected, could have adversely affected the operators' ability to handle accident conditions in the plant.

F. The team identified concerns regarding the licensee's ability to conduct a plant shutdown and cooldown from outside the control room in the event of certain fire scenarios. The team found weaknesses in operator knowledge, in the amount of training provided operators, in hardware availability, and in the procedure to be used to carry out this activity.

G. Problems were noted in the Pilgrim maintenance program for motor-operated valves. Weaknesses identified included:

1. maintenance technician work practices for setting limit switches that were not consistent with the way maintenance supervision intended these limit switches to be set;

2. a lack of maintenance procedures for motor-operated valve operators, placing sole reliance on the vendor technical manual for maintenance instructions;

3. inadequacies in motor-operated valve training materials;

4. undocumented and apparently weak root cause determination for motor-operated valve failures;

5. and a significant number of motor-operated valve operator problems during the last year.

III. DETAILED INSPECTION FINDINGS

A. Operations and Surveillance

1. The procedures and drawings related to the normal and abnormal operations of the high pressure coolant injection, core spray, and standby gas treatment systems were reviewed in detail. The inspection team identified several weaknesses involving information that was contained in these procedures and drawings which could impact operations or maintenance of these systems. For example:

   a. Procedure 2.3.2.2, "Panel 903 Center Control Room," Rev. 7, listed the HPCI system low flow alarm setpoint as 800 gpm, and Procedure 2.2.21 "High Pressure Coolant Injection System," Section VI.E, stated that valve MO-2301-14 will automatically open if an initiation signal is present and flow is less than 800 gpm. However, a review of drawings MIJ-16-10, MIJ-71-12, and MIJ-32 and surveillance data sheets for FS-2354 revealed that both the valve automatic open signal and the alarm actuate at 400 gpm.

   b. The current procedural requirement for the operators to perform a 3 minute nitrogen purge of the HPCI turbine exhaust line after turbine shutdown did not appear in the system shutdown section of Procedure 2.2.21, "High Pressure Coolant Injection System." A requirement for a 2 minute purge did appear in the section of the procedure which dealt with overspeed trip testing of the turbine. However, the team determined that a Standing Order had been issued to the operators which required a 3 minute purge daily and after each HPCI system use. The operators appeared to be following this Standing Order.

   c. Procedure 2.2.47, "HPCI Compartment Cooling and Ventilation System," allowed redundant HPCI compartment unit coolers to be out of service simultaneously for up to 30 days. Similarly, Procedure 2.2.48, "Reactor Building Corner Compartment Cooling and Ventilation System," allowed redundant unit coolers to be out of service for up to 30 days. The procedurally allowed outage time of 30 days for redundant unit coolers exceeded the outage times prescribed by Technical Specifications (TS) for the systems served by the various coolers, such as the HPCI, core spray, residual heat removal, and reactor coolant isolation cooling (RCIC) systems. The team requested the results of an analysis that would justify an outage time beyond the seven day outage allowed by TS for the HPCI system. This analysis was not available although it was referenced in Section 10.18 of the USAR. In response to the inspection team's concerns in this area, the licensee agreed to revise Procedures 2.2.47 and 2.2.48 to limit the allowed unit cooler outage time to that required by TS for the system it serves.

Implementation of these procedure revisions and USAR justification will remain an inspector followup item pending confirmation of the licensee's corrective actions (50-293/85-30-01). Conversations with licensee management and with licensed operators revealed that both unit coolers in each corner compartment have apparently never been simultaneously out of service.

d. Comparison of the valve position requirements contained in Procedure 2.2.20, "Core Spray System," to those shown on the system Piping and Instrumentation Diagram (P&ID) M-242 identified several disagreements.

   1) The P&ID indicated the pipe downstream of valves HO-203A and B should be capped; the procedure did not reflect this requirement.

   2) The procedure required HO-101A and HO-16B to be locked in position; the P&ID did not reflect this requirement.

   3) The procedure required the pipe stub downstream of HO-63B to be capped. The P&ID showed that another valve, HO-64B, was located immediately downstream of HO-63B; therefore capping the pipe stub from HO-63B would not be possible.

   4) An additional discrepancy involved the required positions of HO 27A and B. These valves are the A and B core spray leak detection instrument root valves. The core spray leak detection instruments are required to be operable by Technical Specifications. Although the procedure required HO 27A and B to be open, the P&ID did not clearly show the required positions for these valves. The site aperture cards and the controlled P&ID drawing in the control room appeared to indicate that these valves should be closed. The team determined that the system was lined up per the procedure; the problems with the drawings were attributed to weaknesses in drawing clarity.

e. A review of the drawings related to the standby gas treatment system identified two minor discrepancies.

   1) Drawing E-244 indicated that contacts 42-1526 and 42-1426, shown in the control logic circuits for schemes SAU 28 and SBU 29, related to fans VEX 204A

and B, respectively. A review of drawing E-241 indicated these contacts were the interlock contacts associated with the standby gas treatment system fans, VEX 210A and B.

2) Drawing M-294 indicated that damper AON-100 was a normally open/fails open damper whose position was controlled by normally energized solenoid valve SVL-79. Drawing E-244 indicated that SVL-79 was a normally deenergized solenoid.

The inspection team concluded that the weaknesses described above regarding incorrect information in safety system procedures and drawings did not reflect an overall programmatic weakness in the licensee's control of procedures and drawings. Each of the specific weaknesses identified was discussed with the licensee who agreed to evaluate the team's concern and take corrective actions as appropriate.

2. The team reviewed Abnormal Operating Procedure 5.3.21, "Bypassing of Selected Interlocks and Isolation Signals and Inhibit of Auto ADS." This procedure would be used in conjunction with various symptom-based emergency operating procedures (EOPs) to implement circuit modifications to allow operations of plant systems, such as HPCI, in abnormal modes. The team noted specific caution statements in EOPs 01, 03, 04, 05, 06, 07, and 08 that indicated bypassing interlocks on various system valves might be required to depressurize the reactor under certain conditions. The team was concerned that the licensee's program for review, approval and validation of procedures which support the EOP's may have been weak as indicated by the following findings:

   a. Attachment D to Procedure 5.3.21 provided a method of altering the control logic for low reactor steam pressure isolation of the HPCI system. This attachment required the lifting of leads at terminals BB-11 and BB-36 to drop out relay 23A-K12, as shown on drawing M1J 16-10. However, review of the drawing indicated that lifting of these two leads would not be sufficient to drop out the relay under all circumstances.

   b. Attachment J to Abnormal Operating Procedure 5.3.21 discussed the method to be used to defeat the HPCI high reactor vessel water level trip features by lifting a lead at terminal BB-34 in Panel 939, thus dropping out relay 23A-K5. However, a review of drawing M1J 16-10 showed that lifting the one lead would be insufficient to assure the relay would deenergize. Relay 23A-K5 would seal-in if a high reactor vessel water level has been sensed by the logic circuitry and a subsequent low reactor vessel water level has not been reached. Therefore, this seal-in feature must also be defeated to guarantee 23A-K5 would deenergize under all circumstances.

c. After the NRC identified the problems discussed above, the licensee reviewed each of the 14 attachments to the procedure and identified three similar errors in Attachments G, E and I.

d. The team also determined that Procedure 5.3.21 was not specifically referenced in the EOPs in which it would be required to be implemented. Apparently, operator training was relied upon to inform the licensed operators of the existence of this procedure. Discussions with a small sample of operators confirmed that they were aware of the procedure and the need to implement it in connection with the EOP's.

The licensee, in response to NRC concerns regarding Procedure 5.3.21, agreed to revise this procedure to correct the errors identified. However, the existence of errors in an approved procedure used in connection with the EOPs calls into question the adequacy of the EOP implementation process. The adequacy of this process will remain unresolved pending NRC review of licensee corrective actions (50-293/85-30-02).

3. The safety evaluation (SE) written to support Temporary Modification 85-22 for the removal of the demister sections from each of the two redundant standby gas treatment system (SGTS) filter trains was determined to be incomplete in that it did not address the effects of this modification on all accident scenarios in which the SGTS would function. Specifically, the SE addressed only the design basis LOCA and indicated that, because all saturated steam would be contained in the primary containment during this accident, there would be no need for demisters to remove water entrained in the air being processed through the SGTS filters. The team determined that the SE did not analyze the effects of the assumed primary containment leak rate during the accident of 0.5%/day Further, the team noted that the SE did not specifically address the effects on SGTS operability of other events such as tota loss of spent fuel pool cooling and HPCI system operation during a small break LOCA.

In response to NRC concerns, the licensee indicated that the SE only addressed accidents for which credit is given to the SGTS in the radiological analyses. The licensee indicated that SGTS would not be required to contain the radiological effects of loss of spent fuel pool cooling and HPCI system operations to below previously analyzed levels. The licensee further stated that the effects of the design basis LOCA containment leak rate on SGTS performance would be small due to the large dilution volume available in the reactor building. However, because the SE did not contain the detail necessary to demonstrate that the licensee's conclusions were valid, the adequacy of the SE is considered unresolved pending a more rigorous analysis by the licensee to verify the SE's conclusions (50-293/85-30-03).

4. The team identified weaknesses in the licensee's ability to shut down the plant from outside the control room in the event of a fire in the cable spreading room or the control room. These

weaknesses existed in operator training, in hardware, and in the procedure used to perform the shutdown. For example:

a. Operator knowledge regarding Emergency Operating Procedure 2.4.143, "Shutdown From Outside Control Room Due to Fire in C.S.R. or Inhabitability of Control Room," appeared weak as indicated during discussions with operators. Knowledge weaknesses appeared to exist regarding the methods to be used to gain local control of systems, the methods to be used to operate valves at local motor control centers (MCC), and the method to be used to coordinate actions at the local control station to effect a safe shutdown of the plant.

b. Training of operators in Procedure 2.4.143 appeared to be inadequate. Formal training in this procedure had been given to only one group, a senior reactor operator license candidate class in 1983. The remaining licensed operators and senior operators reviewed this procedure as part of a reading package during requalification training. Apparently, no drills/exercises in the use of this procedure had been conducted and no organized walkdowns of this procedure occurred.

c. The level of detail provided in Procedure 2.4.143 for local operation of equipment appeared weak when viewed in the context of the training which had been given. Attachment E to the procedure described those steps to be taken at local switchgear and MCCs to prevent or counteract spurious operation of equipment. The attachment required manual manipulation of motor-operated valve motor starter contactors using an insulating device. The procedure did not specifically identify the appropriate pushbuttons, nor were these pushbuttons adequately labeled in the MCCs examined by the team. Also, some MCCs were in areas not served by emergency lighting. Operation of these starter contactors would be further complicated if plant lighting were lost.

d. Procedure 2.4.143 discussed the use of various portable equipment, including 2-way radios, insulated tools, MCC breaker control power fuses, and a 12 VDC battery for diesel generator field flashing. A review of actions described in Attachment E indicated that flashlights may also be required. The portable equipment needed to implement the procedure had not been specifically delineated, segregated, or otherwise dedicated for this purpose.

e. Attachment G to Procedure 2.4.143 was intended to provide operators with a plot of pressure versus temperature for saturated steam. The attachment would be used by operators to control reactor coolant system temperature as they conducted a cooldown from hot shutdown to cold shutdown. The team noted that Attachment G was incomplete in that although the axes of the plot were provided, the actual plot of data points was omitted.

f. The team identified problems with the emergency lighting installed to serve various system local control stations. For the HPCI and RCIC local control stations, the team determined that the emergency lighting battery packs were not located such that their lights could be aimed at the system control switches. For the case of the automatic depressurization system local control station, a battery pack was available such that it would be capable of illuminating the controls, but the pack's lights were not aimed at the panel (see Operations Observation 5, below, for further details regarding emergency lighting).

The team considered it inadequate for the licensee to establish and issue a procedure without providing a reasonable assurance that the procedure could be effectively used. The adequacy of Procedure 2.4.143 is thus considered unresolved pending NRC review of licensee corrective actions (50-293/85-30-04).

5. During a walkdown of the HPCI system on November 5, 1985, two out of a sample of three battery operated emergency lighting units were found inoperable. Specifically, emergency lighting unit 14 (near stair No. 2 on the west wall of the "B" residual heat removal pump quadrant) was missing its battery pack, and unit 38 (on the east wall of the HPCI room) had a depleted battery according to the individual emergency lighting unit voltmeter. As a consequence of these observations, the team conducted a more extensive review of the battery operated emergency lighting system. This review revealed the following:

a. A backlog of approximately 55 outstanding maintenance requests (MRs) was identified for the battery operated emergency lighting system at the time of the inspection. The licensee stated that approximately 50 of the outstanding MRs were attributable to failure of the amber "ready" indicating light on the front of the battery pack and did not reflect an inoperable condition. However, licensee maintenance and operations personnel noted that they have had difficulty in maintaining an adequate charge on the emergency lighting battery packs, but there was disagreement among the personnel interviewed regarding the root cause for the battery depletion. Attempts by the NRC inspection team to determine independently the exact nature of the emergency lighting problem were hampered by the lack of supporting technical information (e.g., vendor manual) both on-site and at the off-site engineering offices.

b. The results of the licensee's most recent monthly emergency lighting unit test (Procedure 8.B.21, "Emergency Lighting Units," Rev. 1) completed on November 17, 1985, were inconsistent with observations made by the inspection team three days later. Fourteen battery operated emergency lighting units, approximately 22 percent of the total number, were checked by the team. Thirteen out of the 14 emergency lighting units did not have illuminated "amber" ready indicating lights (an illuminated amber "ready" light indicates a fully charged battery for the emergency lighting unit). In contrast, the licensee's documented observations in step VII.A.1 of the monthly test procedure indicated that virtually all of the emergency lighting unit amber "ready" indicating bulbs were lighted. The team noted, however, that for each of the 13 emergency lighting units that did not have a lighted amber "ready" light, installed voltmeters on the battery units indicated that the batteries were fully charged. Discussions with licensee personnel involved with the November 17, 1985, test revealed that the discrepancies between the recorded test results and the NRC team's observations were attributable to confusion on the part of the technicians performing the test regarding the test requirements.

c. Thirteen safe shutdown panels were identified as having been installed in 1980 and 1981 in response to Branch Technical Position 9.5-1 relative to fire protection. Discussions with the licensee's licensing personnel revealed that at the time of this inspection, five of these safe shutdown panels (C-154, 155, 158, 159, and 163) were currently required to conform with the eight hour emergency lighting requirements of 10 CFR 50, Appendix R, Section III.J. An inspection of the panels listed above revealed that in four of five cases the present installation and orientation of emergency lighting was not adequate to illuminate the shutdown panel. For example, the lighting unit (No. 15) for safe shutdown panels C-155/158 was located behind the panel. Similarly, it was physically impossible to see inside safe shutdown panels C-154/159 because of the location of lighting units numbers 16 and 17 (operational problems stemming from these emergency lighting discrepancies are discussed in Operations Observation 4.f, above).

The failure to provide adequate emergency lighting for the four safe shutdown panels discussed above appears to be contrary to the requirements of 10 CFR 50 Appendix R, Section III.J. This matter was discussed with the licensee and will remain unresolved pending review by the NRC Region I Office (50-293/85-85-30-05).

The licensee noted that a temporary test procedure, TP 85-44, will be implemented to perform an indepth walkdown and test of the emergency lighting system so that all problems can be identified and corrected. The licensee did not provide a specific time for the performance of temporary procedure TP 85-44, but indicated that it would be accomplished in the next several weeks.

6. The inspection team reviewed HPCI and core spray logic circuitry against surveillance procedures to verify that all circuits and components were tested during Technical Specification (TS)

surveillances. The team found one component in the core spray pump start circuitry which was not identified in surveillance procedures. This component was the core spray pump start timer specified in Table 3.2.B of the TS. As specified in the USAR, this time delay relay operates to delay closing of the core spray pump breaker for 0.33 seconds when the bus is energized from the diesel generator. Table 3.2.B specifies a setting between 0 and 1 second for this device, and TS Table 4.2.B.4 requires calibration once each operating cycle. The team found no procedure or document which specifically addressed calibration or surveillance of this component. The team noted that Surveillance Procedure 8.M.3-1A, "Automatic ECCS Load Sequencing of Diesels and Shutdown Transformer with Simulated Loss of Off-Site Power," provided a functional test of the operation of the relay, and its setting could be inferred from the recorded test data (strip recorder trace). However, Procedure 8.M.3-1A did not reference this relay as part of the test, it did not contain any acceptance values for the performance of this relay, and it did not provide a place to record the as-found or as-left trip time values for this relay.

ANSI N18.7-1976, Section 5.3.10, requires in part that test procedures contain acceptance criteria and a record of as-found and as-left condition. The apparent failure to provide an adequate surveillance procedure for the core spray pump start timer and to accomplish the required calibration was discussed with the licensee and will remain unresolved pending follow-up by the NRC Region I Office (50-293/85-30-06).

7. The team noted an additional weakness in the overall surveillance program. The licensee had no cross-reference of Technical Specifications (TS) surveillance requirements with the corresponding implementing procedures to ensure that all requirements were being met. If such a cross-reference check had existed, the absence of a surveillance and calibration procedure for the core spray pump start timer could have been identified by the licensee. Licensee Event Reports 83-057, 85-002, and 85-028 describe related examples of inadequate TS implementing procedures that also could have been identified by such a cross-reference check.

8. The team determined that portions of the training material for the HPCI system were technically inaccurate in their description of system design and operating characteristics. The following HPCI system training documents were reviewed:

   o HPCI System Training Module, MM-27, which was approved July 15, 1983, and utilized for systems training of non-operators. Discussions with Training Department personnel revealed that MM-27 was developed from existing operator training documents on the HPCI system.

   o HPCI System Operator Requalification Fact Sheets, which were approved January 24, 1985, and used to refresh operator knowledge during requalification training periods.

- o Draft HPCI Systems Training Document, which was being used for the first time in a reactor operator/senior reactor operator (RO/SRO) training class at the time of this inspection. This document was developed by a vendor and reviewed twice by station and vendor training personnel before being used in the classroom.

The inspectors validated these training documents by walkdowns of the HPCI system, reviews of piping and instrumentation drawings (P&IDs) and operating procedures, and through discussions with operators. Examples of deficiencies identified as a result of this validation process include:

a. MM-27 and the Requalification Fact Sheet incorrectly showed the HPCI system connected to feedwater header "A" instead of the actual header, "B."

b. MM-27 and the Requalification Fact Sheet improperly numbered some HPCI system valves and showed the wrong valve positions for the standby alignment of the HPCI system. Both documents identified the HPCI turbine stop and control valves as HO-2301-23, and HO-2301-24 instead of HO-2301-01 and HO-2301-02. MM-27 also identified the HPCI injection valve as MO-2301-5 instead of MO-2301-8 as identified in HPCI system operating procedures. Additionally, both documents showed the downstream pump suction valve, MO-2301-35, as being open when the HPCI system was in a normal standby alignment. The HPCI system operating procedure requires this valve to be shut in the normal standby alignment.

c. MM-27 incorrectly stated that all but one of the HPCI system motor-operated valves (MOVs) were supplied with 250 VDC power. In fact, however, four system MOVs were supplied from 125 VDC power.

d. The draft RO/SRO training document described HPCI system operations that were inconsistent with station operating procedures and practices. In discussing manual initiation of the HPCI system, the training document stated that the HPCI pump discharge valve, MO-2301-8, should be opened before the pump is started. This is contrary to Procedure 2.2.21 which requires that MO-2301-8 not be opened until HPCI pump discharge pressure equals reactor pressure. Additionally, the training document described a daily routine of starting the auxiliary oil pump to cycle the HPCI turbine stop and control valves without admitting steam to the turbine. There was, however, no procedure for this activity, and interviews with operators revealed that this practice did not occur.

e. MM-27 had not been updated to reflect changes to the HPCI system. The modifications for installation of a nitrogen purge subsystem, addition of a turbine control valve hydraulic bypass line, addition of a ramp startup signal, and deletion of the air operator feature on the HPCI pump discharge check valve (2301-7) were among those changes not covered by MM-27.

In one instance, it appeared that some of the incorrect training information may have been used in the station. Maintenance Request (MR) 85-506 and Temporary Procedure (TP) 85-72 were issued for work on the HPCI system and incorrectly identified the HPCI turbine stop and control valves as HO-2301-23 and HO-2301-24, respectively. This TP with the improper valve identification was approved by the Operations Review Committee (ORC) and was consistent with the HPCI system training materials (see item b. above). However, the stop and control valves should have been identified as HO-2301-01 and HO-2301-02 in accordance with the station valve lineup sheets and HPCI system operating procedures. Valve 2301-24 was actually a one inch manually operated isolation valve in the HPCI System. There was apparently no confusion or problems caused by this error; however, it does demonstrate the potential for improper training information to affect station operations.

The cause of these errors in training documents was considered to be the inadequate validation of these materials by station and vendor personnel. Contributing to this inadequate validation was the poor design documentation for the HPCI system as currently built. Personnel performing the validation were hampered by the lack of documents describing the design characteristics of the HPCI system, including changes made to the HPCI system since initial construction. For example, the valve numbers for the HPCI turbine stop and control valves were not identified on the P&ID (M-244, Rev. E7), but were identified on the valve lineup sheets in the system operating procedure. The inspection team was concerned that the training program at Pilgrim Nuclear Station did not accurately reflect inplant configuration and practice.

B. Maintenance

1. Weaknesses were noted in the licensee's program for conducting maintenance on Limitorque motor-operated valves. Weaknesses identified included:

   o maintenance technician work practices for setting limit switches that were not consistent with the way maintenance supervision intended these limit switches to be set;

   o a lack of maintenance procedures for motor-operated valve operators; instead, sole reliance was placed on the vendor technical manual for maintenance instructions;

   o inadequacies in motor-operated valve training materials provided to maintenance technicians in 1985;

   o inconsistent sizing and apparent over-sizing of motor overloads (described in Design Changes and Modifications Observation 10).

- o undocumented and apparently weak root cause determination for motor-operated valve failures;

- o and a significant number of motor-operated valve operator problems during the last year.

Details regarding these weaknesses are provided below:

a. Interviews with licensee personnel revealed that maintenance technicians were not setting motor-operated valve limit switches as intended by maintenance supervision. Specifically, limit switches that actuate when the valve is shut were described by maintenance technicians as being set with the valve shut or just at the point of contact where the valve disc meets the valve seat. Maintenance supervision, on the other hand, intended that the limit switches be set with the valve a few turns off the shut seat. This inconsistency is considered significant for two reasons. First, as described in observation 1.b below, there were no procedures available at Pilgrim that specified the exact position of the valve when setting the shut limit switch. Secondly, during certain automatic closures of motor-operated valves, a limit switch, LS 8, is put in parallel with the torque switch, TS 17, that normally stops valve motion in the shut direction. LS 8 must then trip to stop the valve motor operator. Setting LS 8 with the valve fully shut could lead to a motor overload or overtorquing the valve on its shut seat in an accident situation. Interviews with maintenance technicians also revealed a lack of awareness that actuation of LS 8 is required to stop valve motion in certain situations.

b. No maintenance procedures or instructions were available other than the vendor technical manual to describe how to perform maintenance activities (e.g., MOV overhaul and torque switch and limit switch setting and adjustment) on Limitorque valve operators. This is considered significant because the vendor technical manual does not, in all cases, provide sufficiently detailed work instructions to ensure proper job completion. For example, the vendor technical manual procedure for setting the shut valve limit switches is unclear as to the exact position of the valve when these switches are set. In addition, no approved procedures were available to describe preventive maintenance activities on motor-operated valve operators. However, at the time of the inspection, the licensee had draft motor-operated valve maintenance procedures that were intended for future issue covering MOV overhaul and limit switch and torque switch setting and adjustment. The failure to provide more detailed maintenance instructions for work on Limitorque valve operators has apparently led to the improper setting of limit switches as discussed in observation 1.a, above. This issue was discussed with the licensee and will remain an inspector followup item pending review of the new motor-operated valve maintenance procedures (50-293/85-30-07).

c. The team reviewed motor-operated valve operator training materials that were used to train maintenance technicians in 1985. The training guidance for limit switch adjustment was found to be inconsistent with the vendor technical manual because the training guidance stated that the limit switches were normally set to operate at the end of travel of the valve stem with no mention of backing off the valve to set either the open or shut limit switches. Additionally, the training materials reviewed discussed limit switches in terms of providing only valve position indication. At Pilgrim these limit switches are also used to stop the valve motor under certain conditions. It appeared that the incomplete training for motor-operated valve maintenance may have contributed to the improper maintenance practices discussed in observation 1.a. above. (See Operations Observation 8 for further examples of incomplete and inaccurate training.)

d. A review of equipment history records revealed a significant number of motor-operated valve operator corrective maintenance problems in the last 12 months at Pilgrim. These events are listed below.

Date	Valve Number	Valve Description	Problem
12/07/84	MO-1001-63	RHR head spray isolation	Torque switch adjustment
12/20/84	MO-1001-28A	RHR outboard injection	Worn gear teeth
12/25/84	MO-1001-28B	RHR outboard injection	Torque switch malfunction
01/07/85	MO-1001-43C	RHR pump suction	Motor burnout
01/11/85	MO-2301-3	HPCI steam supply	Limit switch adjustment
02/08/85	MO-220-1	Steam drain isolation	Motor burnout
02/11/85	MO-4009A	RBCCW suction isolation	Torque switch adjustment
03/07/85	MO-1001-36A	RHR spray isolation	Broken gear
03/16/85	MO-220-1	Steam drain isolation	Motor burnout
03/25/85	MO-1400-4A	CS test isolation	Motor overload

Date	Valve Number	Valve Description	Problem
05/17/85	MO-1001-37A	RHR spray isolation	One phase of wiring burned
05/30/85	MO-1001-34A	RHR spray isolation	Motor burnout
06/06/85	MO-1001-34A	RHR spray isolation	Motor overload
07/23/85	MO-2301-6	HPCI pump suction	Worn gear
07/29/85	MO-1400-25B	CS injection valve	Stem nut interference
08/02/85	MO-1400-4A	CS test isolation	Motor burnout
09/03/85	MO-4085A	RBCCW supply isolation	Clutch mechanism malfunction
09/19/85	MO-1001-29B	RHR injection	Motor burnout

The team conducted a detailed review of the documentation relating to the above motor-operated valve failures and concluded that, in many cases, the analysis of the cause of component failure did not appear to be adequate. Additionally, documentation relating to the cause determination for the failures was found to be spread out over a wide range of licensee records such as Maintenance Requests, Failure and Malfunction Reports, Operations Review Committee meeting minutes, and licensee event reports. Of the motor-operated valve failures described above, failure analysis appeared to be particularly weak in the following cases:

(1) On 12/7/84, MO-1001-63 would not open electrically. The torque switch was adjusted to a higher value. No record was found providing consideration for why the previous torque switch setting became inadequate.

(2) On 1/7/85, MO-1001-43C valve operator motor burned out. The torque switch and motor were replaced. No record was found indicating how or why the torque switch failed.

(3) On 1/11/85, MO-2301-3 would not close electrically because it was stuck on its backseat. The valve limit switch was adjusted to prevent the valve from back-seating. No record was found providing consideration for why the previous limit switch setting became inadequate.

(4) On 2/11/85, MO-4009A would not open electrically. The torque switch was adjusted to a higher value. No record was found providing consideration for why the previous torque switch setting became inadequate.

(5) On 5/17/85, MO-1001-37A would not operate electrically because one phase of power supply wiring was found burned off its terminal. No record of consideration was found for why this wire had burned through.

(6) On 9/3/85, MO-4085A would not open electrically and the handwheel operator turned when the valve was shut electrically. No record of consideration was found for the cause of this problem.

2. The team identified a weakness regarding the control of instrument isolation valve status. During a tour of the HPCI equipment area on November 5, 1985, with the plant operating at approximately 71% power, an inspector discovered two normally open instrument isolation valves that were shut. These valve positions were later verified shut by a licensee instrument and control technician. One instrument valve isolated the local HPCI steam supply pressure gage, PI 2363, and the other instrument valve isolated PI 2381 and PI 2340-7, the local and control room indication of HPCI pump suction pressure. Discussions with control room personnel that same day revealed that the operators were unaware that these pressure indications were unavailable. There were also no tags on the valves or instruments to indicate an abnormality. The two instrument valves were opened later in the day, and licensee personnel were unable to determine how long they had been shut.

   Further discussion with plant supervisory personnel revealed an informal policy of temporarily isolating selected pressure gages for the purpose of protecting them during pressure surges. It was believed by operations personnel that the instrument valves mentioned above were shut for this purpose. Discussions with the Instrument and Control Supervisor revealed that instrument isolation valve positions were not routinely checked, such as when coming out of an outage, but were verified to be in the proper position only after maintenance or calibration is performed on associated instruments.

   The lack of instrument isolation valve labeling was also considered a weakness. Most of the instrument valves on the HPCI instrument control panel, including those found out of position, were not labeled. These unlabeled valves included the isolation valves closest to the instrument and the next upstream valve.

The plant manager stated that the policy of isolating selected pressure gages would be reviewed with consideration given to providing more positive control over instrument isolation. The issue of control over instrument isolation valves will remain an inspector followup item pending resolution by the licensee and followup by the NRC Region I Office (50-293/85-03-08).

3. The inspection team conducted a detailed walkdown of the HPCI system which included a comparison of system drawings with the actual equipment layout, a review of the adequacy of the system valve lineup, and an inspection of the material condition and cleanliness. Several weaknesses were noted:

   a. The team observed that the licensee had expended considerable effort in maintaining the general cleanliness of the HPCI room, particularly the floor and walls; however, the housekeeping effort expended to maintain the cleanliness of the system components was found to be lacking. Specifically, numerous pieces of stray debris, including rags, paint stirring sticks, broken light bulbs, tape, rope, poly, nuts and bolts, as well as some graffitti were located on the HPCI turbine/pump pedestal and on motor operated valves. Accumulated oil and water, leaking from various sources, covered a considerable portion of the turbine/pump pedestal surfaces.

   b. An approved drawing of the HPCI turbine control oil system was not available. However, a cross check of the valve line-up with the actual installed system revealed no discrepancies.

   c. Three valves, 2301-D7, 2301-22, and 2301-125, were missing their handwheels. Four temperature instruments associated with the turbine control oil system did not have either a cover plate, a temperature indicating faceplate, or an indicating needle.

   d. The HPCI turbine stop and turbine control valves were not labeled with a valve number or other identification. Additionally, many small manual valves, located in process lines that were two inches or less in diameter, were similarly unlabeled.

C. <u>Design Changes and Modifications</u>

1. In reviewing plant design changes to the high pressure coolant injection (HPCI) system, the team noted that a significant number of modifications had been performed, in part, to eliminate or mitigate the consequences of hydrodynamic events in the turbine exhaust steam line. During interviews with Boston Edison personnel and reviews of engineering files, the team determined that hydrodynamic transients have been occurring since the beginning of plant operation. The most recent instance occurred on May 18, 1985, and resulted in damage to safety-related snubbers.

These hydrodynamic transients have been described by Boston Edison personnel as "water hammer events" and as "anomalous events".

The team considers the occurrence of hydrodynamic transients on the HPCI exhaust line over the thirteen year period of operation a design deficiency and a significant safety issue. The team recognized that this deficiency was known by Boston Edison, that recent engineering activity has focused on reducing the likelihood of events that lead to hydrodynamic transients, and that additional engineering activity is planned; the team believes the history of hydrodynamic occurrences and the modifications installed have not addressed the root cause and, instead, have addressed symptoms. For example, the team found instances where the size of broken snubbers were increased or replaced without a clear understanding or determination of the cause of failure.

With respect to the design of the HPCI turbine exhaust line and the modifications made since the plant commenced commercial operation, the following observations were made.

a. A 1973 General Electric recommendation to incorporate vacuum breakers between the torus and the piping downstream of the last 20-inch stop check valve was not incorporated. The team considers the siphoning of water from the torus into the exhaust line a significant contributor to the hydrodynamic transients experienced.

   In a General Electric letter received by Boston Edison on January 3, 1973, the licensee was informed that "there are generic problems associated with exhausting steam from the HPCI and RCIC turbines into the suppression pool." The letter further indicated that the problem varies from plant to plant and appears dependent on exhaust line arrangement and selection of valves. One of the recommendations from this letter was to install a vacuum breaker on the exhaust lines to prevent suppression pool water from being siphoned into the turbine exhaust line each time the turbine/system is shutdown. As the exhaust line cools, a vacuum condition occurs within 2 or 3 seconds. In addition, a vacuum condition may occur more rapidly when the steam exhaust line is cold and a turbine initiation is followed by a trip. The piping arrangement for the Pilgrim high pressure coolant injection turbine exhaust line contains a 4 foot drop and a 20 foot horizontal run from the torus penetration to the first check valve which further aggravates the potential for significant hydrodynamic transients.

   In an October 31, 1973 Services Information Letter (SIL), General Electric informed all boiling water reactor owners that surveillance testing of the HPCI/RCIC systems had disclosed an undesirable exhaust line vacuum condition causing one or more of the following adverse effects: pressure instability in the exhaust line; cycling and slamming of the exhaust line check valves; pipe and torus vibration; water slug carryover; and post shutdown vibration caused by steam collapse. This SIL provided a recommended arrangement for vacuum breakers including sizing, pressure drop, and isolation requirements. Contrary to this recommendation, and despite the continued occurrence of hydrodynamic transient events at Pilgrim, vacuum breakers were not installed.

The team was informed that General Electric's recommendation was not installed because General Electric accepted Boston Edison's installed arrangement consisting of a vacuum breaker between the turbine exhaust and valves 2301-45 and 2301-74 (turbine exhaust to torus check and stop check valves, respectively) and a non-safety-related nitrogen purge capability of the exhaust line. With Boston Edison assistance, the team determined that the extent of documentation of General Electric's acceptance is a March, 1974, Bechtel memo of a telephone conversation with Boston Edison personnel. This memo indicated that a Boston Edison engineer had spoken to General Electric concerning the recommended vacuum breaker arrangement and that General Electric was drafting a letter stating the change was not necessary at this time. Subsequent investigation by Boston Edison indicated that a followup letter from General Electric was never received.

b. No design analysis existed for sizing of the vacuum relief valve currently installed upstream of two 20-inch check valves. The team found that this safety-related vacuum relief valve, VRV-9066, had never been tested after installation. In addition, the team found documentation to indicate that Boston Edison knew in March, 1972, that the existing design of the vacuum breaker arrangement would not perform its intended function.

An internal Boston Edison memorandum, describing the installation of the vacuum relief valve on the HPCI exhaust line, stated that the vacuum breaker would be prevented from performing its intended function because it was not at the high point of the exhaust line and was located behind two 20-inch check valves. The team was informed that Boston Edison recognized that the vacuum breaker was not sufficient and modified the steam exhaust line in May of 1973 to have a nitrogen purge capability, thus eliminating the need for a vacuum relief capability.

c. Although the addition of a nitrogen purge capability to the HPCI exhaust line was the primary basis for not incorporating the General Electric recommendation concerning vacuum breakers and, apparently, for not taking action to correct the known deficient location of the existing vacuum breaker, no design analysis existed to substantiate the duration of the nitrogen purge. In addition, no evidence existed to conclude that engineering personnel recognized the potential need for a nitrogen purge to mitigate the consequences of a hydrodynamic event during an accident (i.e., a HPCI system actuation and subsequent turbine trip followed by an automatic restart) because the nitrogen purge system was not designed to be safety-related.

The nitrogen purge capability was added to the HPCI system in May 1973 by modification package DCREG 89. This modification package narrative indicated the change was required to add nitrogen into the HPCI turbine steam exhaust line to break a siphon when the turbine stops and to prevent unnecessary water drainage from the torus to the reactor building sumps. Operating Procedure No. 2.2.21, "High Pressure Coolant Injection System," required that the steam exhaust line be purged with nitrogen for 2 minutes after a turbine trip. However, no design calculations existed to establish the necessary duration of the nitrogen purge. The team was informed that 2 minutes was established based upon field experience. Although the team concurs that field results in the form of post-modification testing can substantiate the results of design analyses, establishment of operating requirements should be based upon design analyses which consider various operating modes expected of the system. The team found no testing results documenting that a purge duration of 2 minutes was sufficient to break the siphon effect from the torus caused by condensing steam in the exhaust line under the most adverse design conditions. Likewise, the team found no documented basis for the current purge duration of 3 minutes which was committed to in Licensing Event Report (LER) 85-08, dated April 26, 1985.

The lack of a design analysis to support establishment of the purge duration appears to be contrary to ANSI N45.2.11, Sections 4.1 and 4.2, which require that design analyses be performed in a planned, controlled and correct manner and that there exist traceability from design input through to design output. This item will remain unresolved pending followup by the NRC Region I Office (50-293/85-30-09).

d. The team identified a concern regarding the control room operators' ability to use the nitrogen purge feature during or following a design basis event. Nitrogen is added to the steam exhaust line by a remote manual pushbutton located in the control room. However, in an accident situation the HPCI turbine will restart automatically without a time delay once a trip signal has cleared (if an initiation signal is present). As a consequence, the operators may not have the time or ability to purge the steam exhaust line following a trip of the turbine after HPCI system actuation.

e. An inadequate design analysis was performed when the HPCI turbine exhaust stop check valve was replaced during the licensee's "valve betterment" program. The new valve had a disc cracking pressure approximately three times higher than that of the original valve. This higher cracking pressure appears to lessen the ability of the installed vacuum breaker to function. The team was shown vendor information which indicated that the cracking pressure of the new valve ranges between 0.55 to 0.90 psi and that the replaced valve cracking pressure ranged between 0.22 to 0.30 psi.

Plant Design Change (PDC) 83-28 replaced the HPCI turbine exhaust swing stop-check valve, 2301-74, and the air-operated testable tilting-disc check valve, AO-2301-7, in the HPCI pump discharge line with resilient seat stop-check valves. Because of the hydrodynamic transients experienced with the HPCI pump turbine exhaust line, the team examined the replacement of valve 2301-74 in detail. Because the existing 20-inch valve was being replaced with a similar but upgraded valve, the modification package narrative indicated that no safety analysis was required. Contrary to this conclusion, the team believes that the new valve reduced the ability of the installed vacuum breaker to function and increased the potential for hydrodynamic transients. As stated previously, the installed vacuum breaker is located between the high pressure turbine and valve 2301-74. As a consequence, the check valve must open to break vacuum conditions between the check valve and the suppression pool and prevent siphoning of water from the torus into the exhaust line.

The lack of an adequate design analysis to support the replacement of valve 2301-74 appears to be another example of design analysis weaknesses discussed in Observation 1.c, above. This lack of an adequate design analysis contributed to the apparently erroneous decision not to perform a safety analysis as required by 10 CFR 50.59. This item will remain unresolved pending followup by the NRC Region I Office (50-293/85-30-10).

The team was informed that the long term corrective action included a plan to develop a modification to install additional vacuum breakers to preclude water hammers. This long term corrective action was documented in LER 85-012-01, and is intended to be implemented during the next refueling outage.

2. Plant Design Change (PDC) 84-59 was reviewed. This modification was initially prepared to replace the existing HPCI suppression chamber level switches, LS-2351A and LS-2351B, with an environmentally qualified Robertshaw Model No. SL 302-A2-S21-C21-1. The purpose of these switches is to initiate switchover of the HPCI system suction from the condensate storage tank to the suppression pool upon sensing suppression pool high water level. The original switches were Robertshaw Model No. 83035-A. On December 21, 1984, field revision notice FRN-84-59-01 to this PDC revised the modification package to replace only LS-2351A because it was the only level switch broken. To assess the environmental qualification of LS-2351B the team examined the equipment qualification data files.

Based on a review of the available documentation, the team noted that the completed equipment qualification package for LS-2351B erroneously assumed that the level switch was a Robertshaw SL-702A1. During the inspection, it was determined that LS-2351B was in fact a Robertshaw 83035-A2. The licensee acknowledged that the wrong model number for LS-2351B was qualified, and corrective action was initiated to qualify the correct model. After departing the site, the team was presented with a qualification verification report prepared by a contractor which indicated that LS-2351B was now properly qualified. This error was attributed to two inadequate walkdown verifications, the lack of instrument tag numbers, and a less than thorough investigation when model numbers were not available.

3. The team noted that the original setpoint calculations for safety-related instrumentation and control devices were not readily available, and that recovery of the basis for a setpoint was difficult. The team is concerned that difficulty in retrieving the bases for setpoints could result in a less than thorough investigation by design engineers that prepare design modifications.

   This concern was reinforced when the team determined that modification package PDC 84-59 contained an instrument data sheet for LS 2351A which incorrectly described the trip setpoint. Specifically, Boston Edison Level Switch Data Sheet, Rev. 0, dated July 31, 1984, for LS 2351A stated that the trip level is 5 inches above the nominal water level. The team, however, determined that the high level water trip setpoint was actually at (-) 2 feet 2.5 inches which is approximately 8 inches above the nominal water level. The maximum nominal water level was lowered in order to reduce containment dynamic loads during the pool swell phase of a design basis loss-of-coolant accident. This reduction occurred in plant modification PDCR 77-66. It appears that information for the instrumentation data sheet was obtained from an old General Electric data sheet which was not revised as a result of completed modification PDCR 77-66.

4. Plant Design Change 81-38 was reviewed. This modification to the HPCI system involved the replacement of a 4-inch pressure reducing valve, PCV 2301-46, upstream of the gland seal condenser and lube oil cooler. In the HPCI system, cooling water is supplied to the gland seal condenser and the turbine lube oil cooler by discharge from the HPCI system booster pump. In the original design, a pneumatic-operated pressure control valve was used to reduce the booster pump discharge pressure. Restricting orifices were located downstream of the lube oil cooler and the gland seal condenser to provide the additional system resistances to meet flow requirements. The pressure control valve was designed to fail open upon loss of pneumatic control and a relief valve was provided between the pressure control valve and subsystem heat loads.

   The modification file contained information indicating that frequent gland seal condenser gasket failures had been experienced and resulted from excessive pressure surges. The modification file also stated that the these failures would continue if the modification were not performed and that the lube oil cooler could be subjected to pressures exceeding its design pressure.

To remedy these concerns and eliminate continued gasket failures, the PDC did the following:

a. Replaced the air-operated pressure control valve with a Marotta self-regulating valve,

b. Relocated the downstream restricting orifices to piping upstream of the components served,

c. Implemented recommendations of General Electric SIL No. 129, dated March 31, 1975, concerning enhancements to gasket/ joint (e.g., installation of metal band around joint).

Since the replacement Marotta self-regulating valve was also designed to fail open, the team expected to see design calculations as part of the modification file or referenced in the modification file to substantiate that design pressures of piping and equipment served would not be exceeded on failure of the Marotta pressure regulating valve to the full open position. However, the team found no such documentation. Further, there were no calculations to substantiate an evaluation of the relief valve size to assure that the valve, PSV-53, would prevent over-pressurization as recommended by General Electric SIL No. 129.

The team noted that General Electric's System Description 257HA324, Rev. 1, stated that relief valve PSV 2301-53 should be sized "to prevent over-pressurizing piping, valves, and equipment in the coolant loop in the event of failure of pressure control valve 2301-46." Further, ANSI B31.1, the governing piping standard for this system, states that "relieving capacity provided shall be such that design pressure of the low pressure system will not be exceeded if the reducing valve fails to open."

Although the team was advised that no further gasket failures have been experienced, the team was concerned that the same potential for system overpressurization appeared to exist for the modified system incorporating the self-regulating pressure reducing valve as had previously existed prior to the modification. When starting the HPCI pump against the normally closed discharge valve, pressures in excess of the 280 psig could exist at the inlet to an assumed failed open pressure regulating valve resulting in exceeding downstream component design pressures of 150 psig.

The team noted that similar modifications were made to the reactor core isolation cooling system using an identical self-regulating valve. The team was concerned that excessive pressures could also result from a failed open pressure regulating valve in this system since no calculations existed to substantiate whether such conditions had actually been alleviated by the modifications made.

In response to the team's concerns, the licensee initiated design analyses to confirm that low pressure piping and components were protected from higher booster pump discharge pressures assuming failure of the pressure reducing valve and no credit for relief valve operation. Prior to the end of the inspection, the licensee reported that the analysis indicated that the current piping and component arrangement was adequate to withstand the most severe overpressure condition expected.

5. Plant Design Change 84-75 was reviewed. The purpose of this modification was to remove insulation from the residual heat removal (RHR) heat exchanger to facilitate inspection of the heat exchanger. The modification package included a calculation summary which provided the results of the calculations performed to substantiate that the insulation was not required. The summary sheet concluded that temperatures in the RHR pump room would not exceed the 115 degrees F design temperature for the shutdown cooling and post-LOCA conditions. However, the team identified a number of deficiencies in the calculations, some which could affect the results, and thereby render the conclusions concerning the removal of the insulation questionable. The team was concerned that the calculation did not adequately demonstrate that the capacity of the safety-related heating, ventilating, and air conditioning equipment was sufficient to maintain design temperatures. The following deficiencies were identified:

   a. The calculation did not reference the original design calculations which established the equipment capacities for the residual heat removal pump room cooling equipment or design temperatures. The only heat loads identified in the calculation were those associated with the residual heat removal and core spray pump motors and the convective and radiation losses from the uninsulated heat exchanger. Heat loads associated with piping (insulated or uninsulated), electrical cable, or other equipment which might be in the room were neither identified nor accounted for in the analysis.

   b. No basis was provided for the shell side RHR heat exchanger temperatures assumed for the shutdown cooling mode (240 degrees F inlet and 215 degrees F outlet).

   c. The USAR is the referenced basis for the shell side residual heat removal heat exchanger temperatures used for the post-LOCA mode instead of a design document or calculation. Typically, USARs are summaries of design output documents reflecting how the plant was designed. The document may contain design criteria; however, it does not always contain sufficient information to be considered the source of design information. Although the USAR is updated yearly, a means did not exist to notify design engineers as to what changes are pending (i.e., not incorporated) between yearly updates.

   d. There appeared to be no documented basis for the 115 degree F design temperature used for the residual heat removal pump room.

e. Typical motor efficiencies were obtained from an engineering handbook and used to calculate pump motor heat losses rather than actual documented motor efficiencies for the specific equipment in use at its operating point. This implicit assumption was not identified as an assumption requiring confirmation at a later date. The team confirmed that the assumed motor efficiencies were consistent with vendor data for the motors.

f. The team questioned the licensee as to the availability of the original design analysis supporting the sizing and procurement of the residual heat removal pump room cooling equipment. However, the team was informed that such a design analysis was not available. The absence of an original design analysis reinforces the team's conclusion that the design analysis performed for this plant modification should have addressed design considerations comparable to an original design analysis.

The failure to perform a thorough design analysis comparable to an original design analysis and thus ensuring that the modification would not adversely affect the original design basis appears to be contrary to the requirements of ANSI N45.2.11, Sections 4.1 and 4.2. ANSI N45.2.11 requires that design analyses be performed in a planned, controlled and correct manner and that there exist traceability from design input through to design output. This item will remain unresolved pending followup by the NRC Region I Office (50-293/85-30-11).

6.. DCREG-89 was reviewed. In 1972, this modification added the capability to inject nitrogen into the high pressure coolant injection turbine exhaust line. The purpose of this modification was to provide a means to break the siphon created by steam condensing in the turbine exhaust line when the turbine stops and to prevent unnecessary water drainage from the torus to the reactor building sumps.

The associated safety evaluation, PESE-91, indicated that the change did not decrease the margin of safety as defined in the basis for any technical specification and did not increase the consequences of an accident or malfunction of equipment important to safety previously evaluated in the USAR. However, the evaluation recognized that if the operator failed to secure the nitrogen purge after two minutes the nitrogen would eventually discharge into the torus and bubble up into the free space above the normal torus water level. The safety evaluation concluded that the maximum containment pressure rise would be less than 13 psi and, therefore, would not affect primary containment integrity. This conclusion was based upon a very conservative analysis which assumed that the initiating event is simply the operator's failure to close AO 9312 or AO 9313 (nitrogen purge isolation valves) and did not take credit for operator action based upon his response to safety-related indications and alarms. The worst case pressure rise was calculated to be 6.65 psi (Reference: Calculation No. PE-73-1 (PEADC-91), dated

September 6, 1973). However, the evaluation did not recognize that the initial containment design conditions for a design basis accident would be altered and did not assess the effect that the higher initial containment pressure might have on the accident analysis and containment integrity.

In response to this concern, the licensee identified that the first safety-related indication available to the operator that an increasing pressure condition existed in the containment would be the position indication and alarms associated with the drywell to suppression chamber vacuum breakers. The licensee described the following sequence of events that would constitute a "worst case" scenario:

- o The operator places the nitrogen purge pushbutton in the locked down position for continuous purge and forgets to secure the purge after the required duration.

- o Nitrogen will flow into the exhaust header, and pressure will increase in the header and eventually open check valves 2301-45 and stop check valve 2301-74 permitting nitrogen to flow into the suppression chamber through the exhaust line sparger.

- o Over a period of time the pressure in the free volume of the containment will increase. Non-safety-related indication available to the operator includes (1) PI 5067A - drywell pressure indication, (2) PI 5076B - suppression chamber pressure indication, and (3) DPI 5021 - differential pressure drywell to suppression chamber.

- o If the operator does not observe the changing pressures, the suppression chamber pressure will continue to increase and the differential pressure will decrease. When the suppression chamber pressure increases to 0.5 psi greater than the drywell pressure, the differential pressure will be equalized by the vacuum breakers.

  Movement of the vacuum breakers is indicated in the control room by safety-related indication and alarms.

- o Based upon this indication, it is assumed that the operator will recognize his error and secure the nitrogen purge.

The licensee stated that the accident analysis for the containment assumed that the drywell pressure started at 1.29 psig and the suppression chamber started at 0.1 psig. The consequences of an undetected continuous nitrogen purge followed by a design basis accident was not analyzed.

Prior to completion of the inspection, the licensee had not confirmed that the accident analysis described in the USAR bounded the case described above. This item will remain an inspector followup item (50-293/85-30-12).

7. The team examined the supporting documentation/design analysis used to establish the Pilgrim Q-List. The licensee produced marked-up piping and instrumentation diagrams (P&IDs) which were colored to indicate the various system safety boundaries. The team noted that these P&IDs were not part of a design analysis and did not appear to be treated as controlled documents. The team also saw no indication that an independent verification had been performed on these P&IDs.

   The team concluded that the Pilgrim Q-List was essentially a system level Q-List consisting of two sections. One section defined the safety-related boundaries by system and the other section identified specific components which were safety-related. The team was informed that the component listing was not complete, and the team confirmed this by examining safety-related HPCI components. To determine if a piece of equipment was safety-related an individual referred to the component listing and if the piece of equipment was listed, then it was safety-related. However, if the component was not listed it did not mean that it was not safety-related. Instead, the individual had to refer to the system level boundaries to make a final determination. Although the Q-List stated that the system level list was the final source for determining safety category, the team was concerned that individual users may not have been trained in the use of the Q-List. The team was informed that the 1984 Combined Utility Assessment Audit identified a similar concern and recommended that training be provided on the use of the Q-List. In response to the team's concern, the licensee provided documentation that the recommended training was still in progress.

8. The following observations were made during the review of the modification package for the replacement of the Pilgrim safety-related 250 VDC station batteries:

   a. The team reviewed the manufacturer's service duty test results (Test 2504 2/2/80) performed on a selected sample of the new cells and noted that the test results contained three minor discrepancies where the specification requirements were not met. The licensee could not produce any justification for the anomalies during the inspection.

      Following the inspection, the licensee produced a summary report developed by the battery manufacturer (Report No. BT 2504, dated January 22, 1985, approved November 25, 1985) which provided sufficient justification for the acceptance of the new 250 VDC station batteries.

   b. The team reviewed the results of the periodic battery performance testing performed at the Pilgrim station and noted that the relative capacity of the battery was not calculated in accordance with the Nuclear Operations Department Procedure 8.9.8, "Battery Rated Load Discharge Test."

      The team also noted that this test procedure was deficient in that the requirement for cell voltage readings was made across the terminals of each cell instead of from the terminal of one cell to the corresponding terminal of the next cell. Therefore, the prescribed cell voltage readings did not include the intercell connector (which would detect excessive contact resistance). The test procedure also failed to specifically state that the electrolyte temperature at the start of the discharge should be used in the cell capacity calculations. The licensee's corrective actions to remedy the procedure deficiencies noted above will remain an inspector followup item (50-293/85-30-13).

c. The team reviewed the Technical Specification Limiting Condition for Operation 3.9 and noted that the Pilgrim station batteries were not considered to be inoperable until the battery voltage dropped below 105 VDC on the 125 VDC system and 210 VDC on the 250 VDC system. The Nuclear Operations Department Procedure 8.C.14 for the weekly battery check also established the same acceptance criteria. This acceptance criteria equates to 1.75 volts per cell in both batteries. The inspection team noted that during a periodic battery discharge test a battery would approach an individual voltage of 1.75 volts only at the end of the discharge. Therefore, the existing Pilgrim acceptance criteria would permit a completely discharged battery to be considered operable. This definition of battery operability does not appear to be consistent with 10 CFR 50 Appendix A, Criterion 17, which requires that the batteries have sufficient capacity to assure performance of their safety function assuming a single failure of the redundant system. The licensee agreed to review their current battery operability criteria for technical adequacy. This will remain an inspector followup item (50-293/95-30-14).

d. The team reviewed the latest DC load study calculation (PS-81-19) performed by Boston Edison after installation of the new batteries. The team noted that the calculation went into sufficient detail to establish that the load profile contained in the original battery specification contained a sizable amount of design margin when compared to the latest calculation. However, the team noted that MOV motor data used in this latest (1981) study differed from the corresponding data used in the 1975 voltage drop calculation (the data in the 1975 calculation is in better agreement with the presently installed equipment). The team attributed this discrepancy to the fact that superseded or voided MOV motor data still remained in the Boston Edison files without being identified as voided or superseded. The team was concerned, on a generic basis, that the design change control system did not require that superseded documents be so identified to avoid incorrect data being used in later analyses.

9. Plant design changes PDC 84-16B and PDC 84-16G were reviewed. These modifications replaced the motors on selected HPCI DC motor-operated valves with similar qualified Class 1E motors. The team

reviewed the overload protection design for these motors and noted that the overload relays were used only to alarm on overload. The team also noted that the overload heater elements for these relays were inconsistently selected with no apparent criteria, such that four identical HPCI motors were monitored for overload with four different heaters and the range of protection provided was between 78% and 193% of motor full load current. The team independently calculated the overload heater size for ten HPCI DC MOVs using the vendor's recommendations and found only one valve with a heater element selected that was consistent with those recommendations.

The team expressed the concern that the present settings could lead to motor insulation damage, and that this motor damage could go undetected until the valve was required to function during an accident condition. The licensee stated that they were aware that they had a problem with MOV overload heater selection and stated that this was an area presently under review. They presented for review the PNPS List of Potential Availability Improvements, dated October 8, 1985, which listed "Fuse, Breaker, Overload Heater Upgrade Program" as Item No. 39 on the list. The licensee also exhibited Design Criteria 1039E-01, "Sizing Overload Heaters for MOV's," submitted by Bechtel in 1984 in support of these subject modifications. This criteria was subjected to a detailed review by Boston Edison and found to be acceptable. This will remain an inspector followup item pending completion of the licensee's corrective actions (50-293/85-30-15).

10. Plant design change modification (PDCM) 78-28A.1 was reviewed. This change added control for selected HPCI components on remote shutdown panel C-155. The team reviewed the basis for the selection of equipment required for remote control as developed by Bechtel and Boston Edison, and the team reviewed the HPCI elementary diagrams for correct implementation of this change. As part of the inspection in this area the team also confirmed that the power supply assignments to the various HPCI components was correct and consistent with other documents and operating procedures. The team identified no significant concerns as a result of this review.

11. The team reviewed selected elementary diagrams for the core spray system. In particular, the team reviewed the control circuit for valve 1400-25A (and 1400-25B) as presented on drawing M1K-16, Rev. E2, dated 11/19/85. The team had the following observations.

    a. The circuit diagram was not revised to note the wiring change on this circuit internal to the motor control center as a result of Field Revision Notice (FRN) 79-28A.1-03, dated March 3, 1980.

    b. A normally closed contact from relay 14A-K20A was used in this circuit. The description of this relay as given on drawing M1K 4-11, Rev. E3, was incorrect and did not agree with Operating Procedure 2.2.20, "Core Spray System." The description of this relay stated that the auto signal was sealed-in, but instead it appeared to be bypassed. The first sheet of the core spray system elementary diagram references IEEE 279. IEEE 279-1971, Section 4.16, requires that once initiated, a protective action shall go to completion. Therefore, the team questioned why the valve circuit does not contain a seal-in for the automatic safety signal so that the valve would complete its safety function by going to the full open position. This item will remain unresolved pending followup by the NRC Region I Office (50-293/85-30-16).

IV. MANAGEMENT EXIT MEETING

An exit meeting was conducted on November 22, 1985, at the Boston Edison Nuclear Engineering Department offices. The licensee's representatives are identified in the Appendix. In addition, Mr. James M. Taylor, Director, NRC Office of Inspection and Enforcement; Mr. Thomas E. Murley, NRC Region I Administrator; and Mr. Gus C. Lainas, Assistant Director, Division of BWR Licensing, NRR, attended the exit meeting. The scope of the inspection was discussed, and the licensee was informed that the inspection would continue with further in-office data review and analysis by team members. The licensee was informed that some of the observations could become potential enforcement findings. The team members presented their observations for each area inspected and responded to questions from licensee's representatives.

APPENDIX

Persons Contacted

The following is a list of persons contacted during this inspection. There were other technical and administrative personnel who also were contacted.

*W. D. Harrington, Senior Vice President, Nuclear
*A. L. Oxsen, Vice President, Nuclear Operations
*J. E. Howard, Vice President, Nuclear Engineering & Quality Assurance
*C. J. Mathis, Nuclear Operations Manager
*E. J. Ziemianski, Nuclear Operations Support Department Manager
*R. N. Swanson, Nuclear Engineering Department (NED) Manager
*R. E. Grazio, Group Leader, NED
*W. Clancy, Group Leader, NED
*J. Pawlak, Group Leader, NED
*R. V. Fairbank, Nuclear Engineering Department Deputy Manager
*J. F. Crowder, Senior Compliance Engineer
*F. J. Mogolesko, Nuclear Engineering Department Engineer
*M. N. Brosee, Chief Maintenance Engineer
*P. E. Mastrangelo, Chief Operations Engineer
*E. T. Graham, Compliance Management Group Supervisor
*S. Dasgupta, Group Leader NED
*P. T. Antonopoulos, Group Leader NED
*J. Coughlin, Senior Engineer, Power Systems, NED
*R. L. Flannery, Planning Scheduling and Cost Control Department Manager
*J. D. Keyes, Group Leader, Regulatory Affairs
*J. A. Seery, Technical Group Section Head
*D. E. Sanford, Nuclear Training Manager
*H. F. Brannan, Quality Assurance Manager
*T. J. Tracy, Group Leader, NED
*J. Gosnell, Principal Engineer, NED
*S. Roberts, Engineer, NED
*G. Mileris, Engineer, NED
L. Dooley, Technical Training Supervisor
R. Cook, Operations Training Supervisor
D. Whitney, Senior Engineer, NED
S. Wollman, Lead STA/Performance Engineer
F. Giardello, Surveillance Scheduling
P. Moraites, Senior I&C Engineer
M. Maguire, Senior Electrical Engineer
J. Gaedtke, Senior Mechanical Engineer
J. Vender, Senior Mechanical Engineer
R. Sherry, Assistant Chief Maintenance Engineer
S. Brennion, Senior Systems and Safety Engineer, NED
P. Kahler, Senior Licensing Engineer

*Attended exit meeting on November 22, 1985.