U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-293/88-13

Docket No. 50-293

License No. DPR-35

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

Facility Name: Pilgrim Nuclear Power Station

Inspection At: Plymouth, Massachusetts

Inspection Conducted: April 11-15, 1988

Inspectors: H. J. Kaplan 5/10/88
H. J. Kaplan, Senior Reactor Engineer date

E. H. Gray 5/10/88
E. H. Gray, Senior Reactor Engineer date

Approved by: Jack Strosnider 5/10/88
J. Strosnider, Chief, Materials and Processes Section date

Inspection Summary: Inspection on April 11-15, 1988 (Report No. 50-293/88-13)

Areas Inspected: A routine announced inspection was conducted to review the licensee's followup and corrective actions related to several previously identified open items in the area of materials and component integrity, plant modifications and test procedures.

Results: The open items were satisfactorily resolved by appropriate licensee action. No violations were identified.

DETAILS

1.0 Persons Contacted (Boston Edison Co.)

*K. Highfill, Station Director
*C. Stephenson, Senior Compliance Engineer
*R. Hamilton, Comp. Div. Manager
*N. Desmond, QC Div. Manager
*W. Clancy, System Gr. Leader
*R. Grazio, Field Engineer Section Manager
G. Mileris, Nuclear Engineering
R. Mattos, Nuclear Opertions, Sr. System Specialist
J. Perkis, Engineer

Other NRC Personnel

T. Kim, Resident Engineer
J. Lyash, Resident Engineer

*In attendance at 13/88 meeting on April 15, 1988.

2.0 Followup on Outstanding

(Closed) - Followup Item (50-293/86-34-06) - Safety Related Pipe Supports

The inspector determined that, as the result of finding two damaged hydraulic snubbers and loose fasteners on pipe supports in 1986, the licensee had instituted a comprehensive program to assess the condition of safety related pipe supports. This was done in order to determine if a generic problem existed and to take appropriate corrective actions. The inspector reviewed Report No. 198 7XC-ER-NCE, dated March 1987 in which the licensee reported the results of an initial evaluation of 92 nonconformance reports (NCRs) involving safety related pipe supports. The NCRs were generated in refueling outage (RFO) No. 7. The licensee concluded that the 92 NCR's covering 144 discrepancies fell into five categories: (1) Workmanship (44%), Drawing Discrepancies (22%), Loose Parts (17%), Damage (14%) and No Defects (3%). The latter involved items in which the inspectors' findings were found to be incorrect. In addition, the report reviewed the NCRs generated in RFO 6 to determine if RFO discrepancies occurred during the past operating cycle and if they were repeat failures. Each of the categories were thoroughly analyzed and recommendations involving twelve long term and short term corrective actions were initiated.

Except for the lack of features to prevent loosening of fasteners in the original hardware, no generic problem was identified in the licensee's study. The report indicated that only 14 of 59 pipe supports cited in RFO No. 7 with discrepancies had been identified in RFO 6 as having discrepancies. The 14 supports found discrepant in RFO 6 had been previously corrected. The report suggested that the criteria and level of detail of the

ISI examination may have been inconsistent even though 7 of 14 discrepancies involved loose fasteners which may have loosened during operation. This issue is being studied by the licensee for possible corrective action in preparation for RFO No. 8.

The inspector visually inspected nine supports which had been dispositioned to correct certain discrepancies. These were H-29-1-26, H-29-1-25, H-29-1-36, H23-1-27, H-23-1-35, H-23-1-28S, H23-1-28, H23-1-30 and H-30-1-52. The inspector verified that the repair work required by these NCRs was accomplished and had been reinspected by QC. It is noted that loose bolts were retightened and staked by filing a portion of the exposed threads. In RFO-8 (scheduled for 1990) 190 supports will be inspected including 93 supports repaired in RFO No. 7 to determine if a design problem exists (e.g., vibration). The inspector also reviewed the licensee's corrective action status covering 12 recommendations generated from Report No. 1987XC-ER-NQE. Four of these recommendations have been completed. The remaining corrective actions are long term actions such as NCR trending and drawing updates. The status memo establishes responsibility and response dates. In summary, the inspector concluded that the licensee initiated an effective program, along with a computerized system, to assure that safety related supports conform to nuclear quality standards.

(Closed) Followup Item (50-293/86-17-03) Main Steam Isolation Valve Failure.

The inspector reviewed the history of the problem involving the Main Steam Isolation Valves (MSIV) in which seven of eight valves failed to open after closure following an isolation reactor scram in April 1986. The licensee subsequently determined that the cause of the problem was due to the pilot poppet assemblies becoming partially or completely disengaged from the stems because of a faulty locking design involving the retaining nuts and the stems. The set screws that secured the nuts to the poppet became loose because they did not have an adequate surface to bear on when screwed into the poppet. The corrective action consisted of increasing the set screws from one to two and increasing their length to assure engagement of the poppet. The inspector's review of the work package indicated that the work had been performed and verified by QC. It is also noted that the machining in progress involving the design change was found to be satisfactory as reported in Inspection Report 86-11.

As identified in Power Ascension Plan 2, the MSIVs are scheduled for testing during start up to ensure operability of the pilot valve lifting assembly in accordance with Procedure TPS7-219.

(Closed) Followup Item (50-293/86-07-1)

The licensee was committed to inspect RHR B loop valve MO-1001-36B in light of the problems identified with MO-1001-36A in April 1986. The failure of 36A was found to be due to seat ring failure and valve body erosion. The inspector verified that inspection was not required since both 36A and 36B valves had been replaced with improved design valves as indicated in memo FS & MC87-339 dated August 31, 1987.

(Closed) Followup Item (50-293/87-26-01) Containment Spray Header Rusting

The inspector reviewed the problem and corrective actions associated with the rust found in the carbon steel spray header piping of loop A during replacement of the spray nozzle in June 1987. The inspector reviewed the details of the problem in licensee report SG87-234 "Root Cause Analysis and Corrective Measure Evaluation." The inspector agreed with the licensee's conclusion that the most likely cause of the rusting was due to entrapped coolant which collected in the system during surveillance cycling of two sub-system valves located outside containment. The water eventually leaked past these valves into the containment and corroded the headers. The presence of rust in the carbon steel system is not unexpected considering that the system is generally exposed to stagnant conditions. The presence of rust was also found in the B loop header. The corrective actions included (1) removal of the rust in the Loop A and B headers in accordance with Procedure TP87-118 rev 3 using a Hydrolazer (high pressure water hose) until rust did not accumulate in a collection bag; and, (2) installation of continuous drains inside the containment and low point drains between the two sub systems valves located outside the containment. The inspector verified that these actions were performed by a review of appropriate documentation (TP 87-1181, PDC 86-52A10 and PDC 86-52. In addition the licensee initiated a procedure change notice to Procedure 8.5.3.4 - "Drywell and Torus Header and Nozzle Air Test" to require a boroscope examination prior to performing the five year air test. The licensee also agreed to inspect the newly installed continuous drain inside containment for operability during the next refueling outage. In addition to the above the inspector noted that the licensee had performed ultrasonic testing to determine wall thickness in both loop A & B found no areas that fell below the required minimum wall of .084". The measured wall thicknesses varied between .880 and .910. Ultrasonic examination, however, did reveal two similar indications in the loop B header which were subsequently investigated by cutting a section of the header for metallographic examination. The indications were reported to be non-metallic inclusions and judged to be of a minor significance. The licensee also reported that corrosion (rust) was apparently restricted to the header and spray nozzle inside containment since visual examination of the inside diameter (ID) of the pipe between the two sub-assembly valve outside of containment did not reveal any rust or wastage. Inspection of the ID of the pipe was made possible when the pipe was cut to accomodate the Hydrolaze.

(Closed) Inspector Followup Item (293/85-08-01) HPCI turbine steam exhaust line damaged pipe snubber.

Repair of this damaged pipe snubber is documented in NRC inspection report 50-293/85-08. Root cause analysis, corrective actions and testing of the modified high pressure coolant injection (HPCI) steam exhaust and turbine speed control are discussed in item 293/85-18-01, below.

(Closed) Unresolved Item (293/85-18-01). HPCI steam driven turbine pump trips, water hammer in steam exhaust line, pipe snubber repair and correction of root causes. Licensee Event reports LER 85-008-00 and LER 85-012-02 describe the HPCI steam piping and related pump startup problem and identify corrective actions including the following:

1) Provide an oil bypass in the Electric Governor (EG/R) to reduce startup turbine speed transients. This is to prevent turbine trip on overspeed during startup. An overspeed trip and restart shortly after the trip were found to cause water hammer by drawing water from the suppression pool (Torus) into the steam exhaust line prior to restart.

2) Provide for vacuum breakers in the steam exhaust line to prevent steam condensation from causing water to be drawn into the steam line with a subsequent water hammer on HPCI turbine restart.

3) Provide for snubber and pipe support baseplate repair.

LER 85-012 describes the pipe snubber and base plate repairs. The EG/R oil bypass was installed under permanent design change (PDC) 85-35 with completion on June 6, 1985. The HPCI system was subsequently tested and declared operable on June 10, 1985. While this change reduced the possiblity of a HPCI steam exhaust water hammer event, the prevention of a vacuum in this line further reduces this possibility. The installation of vacuum breakers on the HPCI turbine steam exhaust line was first recommended by GE SIL No. 30 dated October 31, 1973 to minimize conditions that could cause water hammer in this line. PDC 85-59 provides the BECo safety evaluation for installation of these vacuum breakers and related components which were installed in 1987. PDC 85-59 includes consideration of the effects of the change on plant procedures and portions of other plant equipment.

Following installation of the steam exhaust line vacuum breakers, the HPCI steam driven turbine and pump system was tested to establish pump capacity at 150 psig steam pressure using temporary steam per procedure TP 87-199. This testing of the HPCI systems was completed on December 31, 1987. HPCI vacuum breaker preoperational testing is provided by procedure No. TP 87-88. An operability test of the HPCI system at 1000 psig input steam is covered in procedure No. 8.5.4.1 and is a part of the plant power ascension test program. Procedure No. 2.2.21 provides detailed instruction for HPCI operation under various conditions. This procedure in paragraph VI, F indicates the proper position of vacuum breaker isolation valves to avoid a water hammer caused by trapped water.

During inspection 88-13 GE SIL No. 30; portions of PDC 85-35, PDC 85-59, TP 87-88, TP 87-199, procedure 2.2.21, procedure 8.5.4.1; and related documentation between the licensee and contractors relating to the HPCI system were reviewed. The present condition of the HPCI (and RCIC equipment) was observed. Attention was directed toward the status of steam exhaust rupture discs, steam inlet and outlet piping including supports and snubbers, vacuum breakers, provisions for nitrogen injection into the steam exhaust line and pump water inlet and discharge piping. The inspector concluded that the root causes of HPCI steam exhaust pipe water hammer had been found and corrected, with verification of the system status implemented by testing. Additional system tests are included as part of plant startup. This item is closed.

(Closed) Unresolved Item (293/86-40-02). Core spray system, Loops A and B Velan 6 inch size check valves 1400-35 and 1400-214. Licensee review of the problems with these valves in 1979 and 1986 identified the root causes as chatter of the valve disc extension against the valve body during periods of flow through the valve. These valves are intended for use in the horizontal position rather than the installed vertical position. The 26-CK-361 valve of this type which is installed in the horizontal position has performed satisfactorily. Engineering Service Requests (ESR) 87-062 and 87-230 include a root cause analysis and corrective measures evaluation. The options of installing check valves designed for vertical installation or pipe rerouting to use the existing type valves in the horizontal position are under consideration with completion of this corrective action scheduled for RFO #8. The 1400-35 and 1400-214 valves have been repaired and are presently in the original design condition. These valves are in the open position during monthly core spray testing and are expected to be capable of satisfactory performance beyond the number of test cycles to RFO #8. Core Spray line bypass through the test line is prevented by core spray test line motor operated valves MO-4A nd MO-4B being in the closed position except during core spray flow testing. Plant action number 03-920-09 provides tracking of the physical change to properly orient the 1400-35 and 1400-214 check valves.

(Closed) Unresolved Item (293/88-03-01). Fatigue Analysis and NDE of drain lines on the RHR lines A and B near valves 33, 68, 28 and 29. During March 1988, Non Destructive Examination (NDE) by liquid penetrant testing (PT) and visual examination (VT) was performed on the drain line attachment to valves 33 and 68 and to the welds on both sides of the first isolation valves to these lines. The drain line on the 29B valve and the drain line located between the 29B and 68B valves were PT and VT inspected at welds out to the far side of the first isolation valve. Of the 24 welds examined, no evidence of fatigue cracking was found. The inspector reviewed BECo inspection reports IR 88-10-18a/b/c/d/e for these examinations and the disposition of NCR 88-024 for removal of tool marks on one section of piping that was unrelated to the fatigue issue. BECo engineering in response to Engineering Support Request (ESR) 88-85 reviewed the factors affecting fatigue for the above drain and vent lines using GE data for fatigue vibrational loading taken during the previous plant run. This engineering analysis established that the vent and drain line geometries are not subject to fatigue using the 2% dampening value of the FSAR. The analysis did show that loading by personnel stepping on the piping would have the potential for causing a fatigue loading problem. Design of supplemental supports for those drain lines (off 1001-68A/B and 1001-33 A/B valves) that could be loaded in this manner is in progress with support installation scheduled for RFO No. 8. This work is covered by BECo scope and justification approval (SJA) 88-15.

3.0 Torus Internal Surface Condition

The internal surface of the torus shell was sandblasted and repainted during RFO No. 5 in 1982. The torus internal surface was examined on February 18, 1988 by the responsible engineer and a coatings consultant. The NRC inspector reviewed the results of this examination with the responsible engineer. Report ERM 88-123 in reference to ESR 87-396 indicated that little change had occurred on this surface between RFO No. 6 and RFO No. 7. The inspection included both the vapor phase and submerged portion of the torus. The inspection results indicated the presence of minor surface rusting and flaking. Flaking was noted to be of a fine nature on a small percentage of the surface such that there is no potential to clog the ECCS suction strainers at the bottom of the Torus.

4.0 Closed NRC IE Bulletin No. 80-13 - Cracking in Core Spray Spargers

The licensee satisfied the action required by NRC IE Bulletin 80-13 to perform a visual examination of the core spray spargers following a refuleing outage. The inspector reviewed the final Southwest Research Institute report dated March 1987 covering visual examination of core spray spargers and associated piping inside the reactor pressure vessel using remote video equipment. This examination was performed during RFO No. 7 and was a followup to the January 1980, October 1981 and December 1984 examinations. The Southwest Report indicated that the RFO No.7 inspection did not reveal any significant new indications even though previous inspections had disclosed several indications. This difference was attributed to improved equipment and personnel training.

5.0 Exit Interview

The inspectors met with licensee representatives (denoted in paragraph 1) at the conclusion of the inspection on April 15, 1988. The purpose, scope and findings of the inspection were summarized and discussed. At no time during the inspection was written material provided to the licensee by the inspectors.