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REGION I

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Report No. 50-293/84-39

Docket No. 50-293

License No. DPR-35 Priority -- Category C

Licensee: Boston Edison Company M/C Nuclear
800 Boylston Street
Boston, Massachusetts 02199

Facility Name: Pilgrim Nuclear Power Station

Inspection At: Plymouth, Massachusetts

Inspection Conducted November 21, 1984 - December 31, 1984

Inspectors: for J. E. Tripp 1/28/85
J. Johnson, Sr. Resident Inspector Date

for J. E. Tripp 1/28/85
M. McBride, Resident Inspector Date

G. W. Meyer 1/28/85
G. Meyer, Project Engineer Date

for J. E. Tripp 1/28/85
H. Eichenholz, Sr. Resident Inspector, Yankee Rowe Date

Approved By: J. E. Tripp 1/28/85
E. Tripp, Chief, Reactor Projects Section Date
3A, Projects Branch No. 3

Inspection Summary: Inspection on November 21, 1984 to December 31, 1984 (Report No. 50-293/84-39)

Areas Inspected: Routine unannounced safety inspection of plant operations including: Followup on previous findings, operational safety verification, ESF system walkdowns, events, startup from refueling outage, surveillance and testing,

maintenance and modifications, health physics, and housekeeping activities. The inspection involved 402 inspector-hours by three resident and one region-based inspectors.

Results: One violation was identified (failure to promptly identify conditions adverse to quality, paragraph 3 and 5). Concerns regarding a failure to add post accident sampling system primary containment isolation valves to Technical Specification Table 3.7.1 (paragraph 3.b), a lack of preventative maintenance on accumulator alarm lights on the full core display in the control room (paragraph 3.b), a lack of preplanning for reactor startup as reflected by last minute reviews and changes to system valve line up procedures (paragraph 4.b), the effect of poor housekeeping and area contamination levels on operator access to the "A" RHR quadrant (paragraph 10), and significant time delays in posting license amendments to the control room Technical Specifications (paragraph 3.b) were also identified.

DETAILS

1. Persons Contacted

Within this report period, interviews and discussions were conducted with members of the licensee and contractor staff and management to obtain the necessary information pertinent to the subjects being inspected.

2. Followup on Previous Inspection Findings

a. (Closed) Unresolved Item (80-30-01). Review testing and modifications to nitrogen supply system prior to return to service. The licensee had committed to maintain the nitrogen supply to the drywell instrumentation out of service until modifications were made to prevent inadvertent safety-relief valve operations. This commitment was documented in a letter from the NRC:Region I to the licensee dated October 31, 1980 (IAL 80-45). The licensee has made these modifications, completed testing, and provided the results of these actions in a letter to NRC:Region I dated December 4, 1984.

The inspector reviewed test records, procedure changes, and drawings and inspected the installed equipment to verify completion of these actions. A pressure switch was installed which will alarm in the control room upon low or high pressure. A check valve was installed to prevent the drywell nitrogen line from being overpressurized by a delivery truck. And, a relief valve has been installed to prevent overpressurization.

The inspector reviewed drawing M227, Rev. E5, pre-operational test procedure No. TP83-25, alarm response procedure No. 2.3.2 12, and QC Inspection Report No. I-81-9-28.

No problems were identified other than a question of the setpoint for the alarm in the control room. The licensee stated that the setpoint would be reviewed and procedure No. 2.3.2.12 revised if required.

The inspector informed the licensee of NRC:Region I concurrence with returning the nitrogen supply system to normal service. This item is closed.

b. (Closed) Circular (81-CI-02). Performance of NRC licensed individuals while on duty. The licensee has incorporated the guidance contained in this IE Circular in administrative station Procedure 1.3.34, Conduct of Operations, Rev. 4. In addition, the inspector noted that the Chief Operating Engineer disseminated (on August 22, 1984) the Circular, IE Information Notice 79-20, Regulatory Guide 1.114, and Procedure 1.3.34 to licensed personnel. The licensee maintained records of the receipt and review of the information by the licensed personnel.

This Circular is considered closed.

c. (Closed) Deviation (83-09-09) Failure to implement procedure 3.M.3-6, Inspection and Overhaul of 480V Load Center Breakers, during the refueling outage that ended March, 1982. The licensee's response to this item, dated July 6, 1983, stipulated that an optimum lubricant and appropriate frequency of lubrication was being developed with the assistance of the manufacturer. Review and revision of Procedure 3.M.3-6 was to be accomplished by December 31, 1983.

The inspector reviewed Procedure 3.M.3-6, Rev. 4 dated December 30, 1983, and determined that it reflected detailed instructions related to lubricating material and techniques.

Regarding the schedule of implementation, the inspector reviewed the licensee's Master Surveillance Tracking Program, determined that Procedure 3.M.3-6 is specified to be performed on 480V load center breakers once per refueling cycle, and noted that the licensee has documented the completion during the last outage on October 24-25, 1984 for the subject breakers.

This item is considered closed.

3. Operational Safety Verification

a. Scope and Acceptance Criteria

The inspector observed control room operations, reviewed selected logs and records, and held discussions with control room operators. The inspector reviewed the operability of safety-related and radiation monitoring systems. Tours of the reactor building, turbine building, drywell, station yard, switchgear rooms, SAS, RCIC room, "A" RHR quadrant, HPCI quadrant, and control room were conducted.

Observations included a review of equipment condition, security, housekeeping, radiological controls, and equipment control (tagging).

These reviews were performed in order to verify conformance with the facility Technical Specifications and the licensee's procedures.

b. Findings

(1) On November 30, 1984, a hydrostatic test was conducted on the ASME Class I section of the reactor coolant system boundary in accordance with Section XI 1980 Edition, Winter 1980 Addenda. The test was controlled by an approved procedure, TP-84-259, "Class I Hydrostatic Test Following Recirculation Piping Replacement Program".

The reactor vessel and portions of the recirculation, core spray, residual heat removal, reactor water cleanup, and feedwater systems were pressurized to a test pressure of 1141 psig. Temporary one-inch lines were installed to hydraulically connect the systems during the test and to equalize pressure around system check valves.

The reactor vessel was filled with water and pressurized at 1:23 a.m. on November 30, 1984, with test pressure attained at 5:36 p.m. on November 30, 1984. Reactor pressure was varied during the test by changing the control rod drive flow into the vessel (through scrammed drives) and by varying vessel letdown flow through the reactor water cleanup system. Moderator temperature was maintained below 212 deg. F during the test, but above the minimum required for brittle fracture prevention.

The inspector observed the initial heatup and pressurization portions of the test and verified that the reactor vessel temperature and primary coolant pressure were appropriately controlled and logged. The inspector also verified that the two, redundant test pressure guages were recently calibrated (November 26, 1984) and indicated the same pressure during the test.

A small, pinhole leak in a socket weld in the flange of a spool piece in the reactor vessel head vent line was detected during the test. The spool piece was located in a section of the line that cannot be isolated from the primary coolant system. The spool piece is a part of original plant construction and was not modified during the recirculation replacement outage.

No Failure and Malfunction Report (F&M Report) was initiated following discovery of the defective weld. An F&M Report was completed and the NRC was notified via the ENS line on December 17, 1984, following the inspector's request for an evaluation of the reportability of the defect.

Procedure 1.3.24, "Failure and Malfunction Reports", Revision 10, April 11, 1984 states that one objective of the F&M Reports is to provide information for determination of event notification and reportability to the NRC. The procedure requires that an F&M Report be initiated whenever failures or malfunctions are identified in a system which could prevent the system from fulfilling its function in the intended manner. The defective socket weld could have prevented the head vent line from fulfilling its intended function as a primary coolant system boundary. Failure to initiate an F&M Report report is a violation of station Procedure No. 1.3.24 (84-39-01).

Subsequently, the licensee stated that the spool piece socket weld was repaired and hydrostatically retested. No evidence of steam cutting was found on the inner surface of the spool piece near the leaking weld.

The "A" recirculation pump could not be inspected for weld leakage due to the presence of leakage from a mechanical seal on the outside of the pump during the hydrostatic test. The licensee stated that the pump seal was repaired and was retested and no leakage was observed. The inspector had no further questions.

(2) On November 30, 1984, the inspector noted that 25 control rod drive (CRD) accumulator alarm lights were not lit on the full core display in the control room during the hydrostatic test. These alarms activate upon high accumulator water level or low gas pressure and should have alarmed during the initial part of the test when the accumulators were discharged by a scram.

Licensee form OPER9 states that the full core display accumulator trouble lights are used to satisfy a once-per-shift surveillance requirement in Technical Specification 4.3.D. Checks of local accumulator trouble alarms are typically done each shift and could satisfy this requirement. However, these local checks are only required by procedure to be done on a daily basis. A redundant alarm signal is generated by the control room accumulator trouble annunciator. However, this annunciator will not sequentially alarm unless each accumulator failure is cleared prior to the next failure.

The licensee investigated the problem and replaced 50 bulbs (2 per alarm light) that had burned out. The bulbs likely burned out during the recent piping replacement outage when a scram was maintained for an extended period of time. The only way to verify the bulbs are functional while the accumulators are charged is to remove the bulbs from the display and individually test them.

The inspector expressed concern to the licensee about the lack of appropriate preventative maintenance on full core display lights. The inspector was also concerned that the control room staff did not investigate the problem with the accumulator lights during the hydrostatic test prior to the inspector's questions (a period of several hours). The status of the accumulator lights will be reviewed during subsequent scrams for evidence of bulb problems. No violations were identified.

(3) During the recent refueling outage the licensee identified cracking in several SRM and IRM dry tubes. The inspector reviewed the licensee's basis for concluding that no action was needed or planned until the next refueling outage. Items reviewed included the following:

- Letter for General Electric Co. (G-HK-4-238) dated 10/16/84.

- General Electric Co. Report AE-96-1084 Rev. 0, dated October, 1984

- Licensee safety evaluation No. 1748 dated 10/12/84

These documents took into consideration possible problems with structural damage to fuel, pressure boundary integrity, loose pieces, channel wear, fuel loading, and instrumentation insertion. No safety concerns were identified. The inspector had no further questions.

(4) The inspector discussed the processing of two other NRC:Region I inspectors onto the site on December 12, 1984. Items discussed included issuance of an incorrect badge and use of personal identification during processing. The licensee acknowledged the inspector's comments. No violations were identified.

(5) On December 21, 1984, during a tour of the control room, the inspector noted that the control room copy of the Technical Specifications did not have the last two license amendments issued by NRR (Nos. 83 and 84 dated November 7, and November 27, 1984, respectively). Amendment No. 83 included new requirements for monitoring torus temperatures and certain post-accident parameters, applicable to the upcoming plant startup, and Amendment No. 84 pertained to the new Halon system.

No violations regarding equipment operability were identified, and the licensee has subsequently updated the controlled Technical Specifications. However, the inspector expressed concern that new Technical Specifications be more expeditiously processed and entered into controlled volumes. The licensee acknowledged the inspector's concerns and stated that this area would be reviewed for possible future improvements.

(6) In a letter dated December 4, 1984, the NRC:NRR informed the licensee that they had satisfactorily completed actions stated in the NRC's August 26, 1983 "IGSCC Inspection Order Confirming Shutdown", and that the plant may be returned to full power. Until Technical Specifications are revised, NRR recommended that the licensee follow the guidance in Attachment 1 to NRR Generic Letter No. 84-11 regarding leak detection limits. On December 17, 1984, the inspector questioned the licensee how these guidelines would be met. The licensee stated that they would be incorporated into station procedures.

Following plant startup on December 24, 1984, the inspector verified that the licensee had implemented these more restrictive guidelines (calculate drywell sump leakage rate each 4 hours, shutdown following an increase of 2 gpm in 24 hours, and a visual inspection of piping during each plant outage with the drywell inerted).

The inspector had no further questions.

4. ESF System Walkdown

a. Scope and Acceptance Criteria

The inspector verified the operability of selected engineered safety feature (ESF) systems by performing a walkdown of accessible portions of the systems. The walkdowns included a review of valve lineup procedures and plant drawings to ensure that they reflected the as-built configuration. Valves were verified to 1) be in the appropriate position, 2) have power available, and 3) be locked as appropriate. Selected pipe supports and hangers were visually inspected for signs of degradation. General housekeeping was reviewed during the walkdowns and is discussed in Section 10 of this report. The following ESF systems were walked down during the inspection period:

-- The "A" loop of the Core Spray System,

-- The Standby Liquid Control system, and

-- The Reactor Core Isolation Cooling system.

b. Findings

(1) On December 17, 1984, the "A" loop of the Core Spray system was walked down.

The inspector noted that procedure 8.5.1.3, "Core Spray Motor Operated Valve Operability Test", Revision 9, December 7, 1983 requires that stroking times for the Core Spray pump discharge valves be less than 12.5 sec and FSAR section 7.4 requires times less than 10 sec. The acceptability of the stroke time requirement in procedure 8.5.1.3 is unresolved, pending licensee review (84-39-02).

The position of valves HO-1400-200A and B and 201A and B which isolate the high point vents on the Core Spray system loops were incorrectly shown as locked closed in procedure No. 8.C.13, "Lock Open, Lock Close Valve Lineup Surveillance", Revision 11, July 13, 1984. A walk down of locked open and locked closed valves using procedure 8.C.13 was completed on December 14, 1984 and the four valves were signed off as being in the locked closed position, when they were actually open. The vent lines were extended past the 200 and 201 valves during the recent outage and four new isolation valves (HO-1400-202A and B and 203A and B) were installed. The new valves were not labeled at the time of the walk down and were apparently mistaken for the 200 and 201 valves, which were also unlabeled.

The correct positions for the valves were shown in the Core Spray system valve lineup, Procedure No. 2.2.20. The licensee walkdown using this procedure had not been completed at the time of the inspector walk down on December 17, 1984. The licensee stated that procedure No. 8.C.13 would be reviewed and suitably revised and that the locked open and locked closed valves would be walked down again using the revised procedure prior to reactor startup. The inspector had no further questions at this time. Revision of Procedure 8.C.13 as well as proper valve labeling and valve positioning per this procedure remains an open item (84-39-05). No violations were identified.

(2) On December 18, 1984, the inspector walked down the Standby Liquid Control (SBLC) system using Procedure No. 2.2.24, Revision 14 and drawing M249, Revision E6. All valves were in the correct position. However, the inspector found that the high point vent off the SBLC system, valve 1101-21, was entered twice on the drawing in two different positions (one correct and one incorrect). The licensee agreed to revise the drawing to correct this error. Later, the inspector reviewed P&ID drawing M249, Revision E7, December 21, 1984, and found the drawing to be correct (incorrect position of valve 1101-21 removed). No violations were identified.

(3) On December 19, 1984, the inspector walked down the Reactor Core Isolation Cooling (RCIC) system using the valve checkoff list (COL) in Procedure No. 2.2.22, Rev. 22. The inspector found all valves to be in the correct position. However, the inspector had the following comments:

-- 2" Valve 1301-60 appears in the COL in 2 places, as the minimum flow line valve and as the vacuum pump discharge valve. It appears the vacuum pump discharge valve number may be incorrect.

-- Valve PCV-17 was mislabelled as PCV-7.

-- More than half of the Valves were unlabelled.

-- There appeared to be no orderly sequence to the listing of valves on the COL. For example, Valves 58A and 58C, located adjacent to each other, are listed on page 4 and page 7, respectively.

-- The locations listed for valves 1301-51, -52, -58A, -58C, and -71 were incorrect.

On December 19, 1984, the inspector observed two licensee personnel completing RCIC COL, Revision 21. [illegible]evision 22 of the COL had been approved on December 14. The p[illegible] ceased using the Revision 21 and obtained the correct re[illegible]e inspector compared the two COLs and found the only dif[illegible] be the addition of valve 1301-50, a testable check valve. [illegible]see representive stated that COLs were being frequently u[illegible]ue to modifications and revision to the drawings. Further[illegible]olume of these procedure changes had bogged down the documen[illegible]rol process. Accordingly, the licensee representative stated t[illegible]o ensure that proper revisions of COLs had been used and tha[illegible]he information on the most recent COLs was taken into account, p[illegible]or to reactor startup, all completed COLs for safety related systems would be reviewed against the most recently approved COL.

The inspector discussed concerns about the valve lineup checklists with licensee management on December 20, 1984. The licensee stated that the procedures and checklists for safety related systems would be reviewed prior to reactor startup and inconsistencies with as built configurations corrected. The licensee also indicated that in the future, control room personnel would pick up procedure revisions directly from the document control center, instead of waiting for them to be delivered. No violations were identified in this area.

5. Followup on Events, Trips, and Nonroutine Reports

a. On November 19, 1984, the licensee made an ENS report to the NRC stating that routine visual examinations (performed as required by ASME Section XI) of piping supports on the Residual Heat Removal (RHR) and Core Spray Systems identified deficiencies from design drawings.

The inspector reviewed copies of Failure and Malfunction Reports (F&M Reports) which indicated that these inspections had been performed between September 15, 1984 and October 7, 1984 and included problems such as a loose pipe clamp, bent bolts and clamps, inadequate hanger rod thread engagement, a locknut missing, improper cold setting of hanger, interference cut outs for a hanger rod not shown on the appropriate drawing, and a clamp out of alignment.

The licensee stated that personnel error was the cause of these deficiencies not being immediately evaluated and F&M Reports initiated. Since core refueling had taken place these hanger deficiencies should have been evaluated earlier for effect on system operability. The licensee stated that a vendor (Magnaflux) had performed the inspections and the licensee's supervisor had not promptly forwarded the reports.

The licensee's Quality Assurance Operations QC Group Leader stated 1) that in addition to counselling personnel, part of his followup actions was to go through all the vendor inspection notification reports and 2) that he did not find any more similar problems. This licensee representative stated that additional corrective actions would be to review appropriate procedures and ensure that there is a definite time to evaluate these findings.

On November 21, 1984 the inspector questioned the Nuclear Engineering Department Structural Group Leader regarding the evaluation of these deficiencies. He stated that the licensee review (including inputs from Bechtel) indicated that the Core Spray and RHR systems were operable.

The licensee continued the hanger inspection program and identified additional similar hanger deficiencies. The inspector verified in these subsequent cases, that an evaluation and the associated F&M Reports were appropriately initiated. The licensee's actions included immediately correcting the hanger deficiencies as well as conducting an evaluation of system operability. The inspector also verified that the licensee's review included an evaluation of increased sample size based upon the findings to date. The licensee stated that (following a review of ASME Section XI IWF 2140-2500) all hangers in the Core Spray, RHR, and HPCI systems would be inspected. The licensee stated that the system operability review was expected to be complete by the end of January, 1985.

The failure to promptly identify and correct these conditions adverse to quality and initiate the appropriate Failure and Malfunction Report(s) is another example of a violation (84-39-01) described above.

b. On November 21, 1984 at approximately 12:30 p.m., a small portion of an alleged controlled substance was detected on an individual about to enter the site. The individual was detained and arrested by a local law enforcement agency. The individual's authorization for site access was withdrawn at the time of the incident. No violations were identified.

c. On December 4, 1984, the licensee notified Region I by telephone that through-wall cracks had been detected in a one-inch stainless steel primary containment atmospheric sampling line. The cracks were detected in horizontal sections of a drywell atmospheric sample line at locations outside containment during a hydrostatic test. The licensee subsequently walked down all containment atmospheric sample lines and cut out and metallographically analyzed sections of pipe from 16 locations in the system.

The analyses indicated the presence of transgranular chloride stress corrosion in horizontal sections of two sampling lines, one line from the drywell (penetration X-50A-D) and one line from the torus (penetration X-228C). The drywell sample line supplies the post accident sampling system, the containment monitoring system (hydrogen and oxygen), and a drywell leak detection atmospheric radiation monitor (the C19 monitor). The torus line supplies the post accident sampling system and the containment monitoring system.

Through-wall cracks were detected at several locations in the drywell sample line. Oxide buildup and pitting but no through-wall cracks were detected in horizontal sections of the torus sample line. Additional atmospheric sample lines from the drywell and torus were clear, with no evidence of corrosion or cracking.

The licensee examined samples of piping which had not been installed and were stored onsite but found no evidence of corrosion or degradation. The affected piping was installed in the sampling system several years ago and was flushed and tested during the 1984 outage. These findings were discussed with the resident inspector, regional specialist inspectors, and NRR representatives during a conference telephone call on December 12, 1984.

The licensee believes that heat trace temperature control problems during 1984 preoperational testing may have caused sections of the sample lines to reach temperatures of 500 deg.F over a period of several weeks. Residual water remaining in horizontal sections of the pipes after flushing, would have then evaporated and concentrated impurities at those locations. The licensee reviewed preoperational testing, but could find no evidence that low purity water or equipment contaminated with chloride residues had been used during the tests. The licensee stated that even demineralized water (at 0.1 ppm chloride) could have been concentrated by the heat to the point that chloride attack was possible.

The licensee subsequently replaced sections of the drywell and torus sample lines. The replacement piping was flushed and dried prior to installation and installed with socket welds (to minimize piping contamination from welding). The lines were then pressure tested with air. All other containment atmospheric sample lines were previously hydrostatically tested.

An NRC Order, dated June 15, 1984, required that the licensee have a post accident sampling system and a containment monitoring system installed by the completion of the 1984 refueling outage. The licensee submitted a request for relief from this requirement in a letter to NRR, dated December 12, 1984, because the sample lines might not be repaired until several months past the projected December 1984 reactor start up. On December 17, 1984, the NRC issued Amendment No. 85 to the Facility Operating License, DPR-35, extending the completion date for the post accident sampling system and containment atmospheric monitoring system until June 30, 1985.

The inspector expressed concern that the T.S table of containment isolation valves (3.7.1) was not yet revised by the licensee. The licensee stated that all new containment isolation valves associated with these new modifications (H2O2 and PASS) would be tested and maintained in a similar manner as other containment isolation valves. The licensee further stated (in a letter to NRR dated October 5, 1984) that revised Technical Specifications regarding manual and automatic containment isolation valves would be submitted within 120 days after startup. The inspector had no further questions at this time.

d. At 1:10 pm on December 17, 1984, the power supply breaker to the 'B' 120 volt ac safeguards bus (Y4) was inadvertently opened by workers in the area. The plant had been shutdown and in the cold conditions (90 deg.F), and, other than a reactor water cleanup system isolation, there was no effect on the plant. Ten minutes later conditions were restored to normal.

No inadequacies were identified. The licensee submitted LER No. 84-16 describing this event.

e. At 6:05 pm on December 19, 1984, the two normal offsite power lines (345 kv) were lost because operators did not reset the breaker protection relays in the switchyard prior to returning two breakers to service. The diesel generators operated properly and the other offsite power source (23 kv) was available.

The reactor was shutdown with final preparations being made for plant restart following the outage. The switchyard was returned to normal at 6:20 pm.

The inspectors toured portions of the plant during this event and observed the status of emergency lighting on the 23 foot elevation of the reactor building. Control room operations were also observed and discussions with licensee personnel were held. A problem with improper transfer of a 480V bus was attributed to a slightly misaligned breaker. This was repaired and satisfactorily retested.

No violations were identified during this review.

6. Plant Startup from Refueling

a. Scope and Acceptance Criteria

The inspector observed startup activities during December, 1984 to verify that they were conducted safely and verified that the activities complied with Technical Specification and federal regulatory requirements. The inspector verified that the control rod withdrawal sequence and withdrawal authorization were available in the control room, reviewed the startup testing program, and reviewed startup procedures. The inspector also reviewed all outstanding Nonconformance Reports and Watch Engineer tags to verify no adverse impact on plant startup.

b. Startup, Chronology (Times from Control Room Log)

Date	Time	Event
12/24/84	12:48 pm	Mode switch was placed in the startup position
	8:43 pm	Initial criticality was established
12/25/84	10:58 am	Reactor head vents were closed and the reactor was pressurized
	12:20 pm	Group I (MSIV) isolation occurred from false high reactor water level signal (Yarway problem)

Date	Time	Event
	1:58 pm	Reactor shutdown* initiated because of a reactor water level instrumentation (Yarway) problem. Shutdown was terminated at 3:10 pm and startup resumed following a purge of the Yarway instrument lines, which corrected the instrument problem.
	3:54 pm	Criticality was reestablished.
	7:05 pm	Group I (MSIV) isolation* occurred from a high reactor water level due to a previous reactor water cleanup (RWCU) system isolation which stopped letdown flow. The RWCU system isolation (Group 2 isolation) was caused by a false high RWCU system flow signal. Two additional RWCU isolations* from false high flow signals occurred on 12/26/84.
12/26/84	---	Reactor pressure was maintained at 95 psig on 12/26 and 12/27 while startup testing continued.
	8:05 am	Voluntary reactor shutdown* was initiated due to control problems with low pressure coolant injection (LPCI) valve MO 1001-29A. LPCI declared operable and shutdown terminated at 5:00 pm on 12/26/84.
	5:50 pm	Voluntary reactor shutdown* was initiated due to control problems with LPCI MO 1001-28B valve. Shutdown was terminated at 6:45 am on 12/27/84, although the valve was not declared operable until 8:30 am on 12/28/84.
12/27/84	---	Startup tests continued and included HPCI and RCIC turbine overspeed trip tests.

Date	Time	Event
12/28/84	---	Reactor pressure was raised to 150 psig for HPCI and RCIC full flow tests. The licensee intentionally entered a 24-hr reactor shutdown LCO* following the tests when both HPCI and RCIC systems were made inoperable with reactor pressure greater than 104 psig. The systems were inoperable for about five hours while reducing orifices were installed in the HPCI and RCIC test lines. The orifices had been removed so that the full flow tests could be conducted. The reactor shutdown was terminated at 10:46 pm on 12/28/84 and heatup resumed.
12/29/84	2:06 am	Reactor pressure was increased to about 370 psig and the safety relief valves (SRV) were cycled. Heatup resumed after the SRV test.
	4:07 pm	Mode switch was placed in run position.
12/30/84	12:03 pm	Main generator was placed on line and station output breakers closed. Reactor power was increased to 25%.
	4:03 pm	Reactor shutdown* initiated because the drywell was not nitrogen inerted 24 hours after placing mode switch in run position (24-hr reactor shutdown LCO).
12/31/84	12:15 am	The shutdown was terminated when drywell inerting was completed and a drywell-to-torus differential pressure was established.
	4:00 am	Drywell-to-torus leakage test was conducted.

*The NRC was notified of these events via the ENS telephone line.

c. Findings

(1) Findings regarding surveillance testing are described in Paragraph 7.b below.

(2) On December 24, 2984 at 9:26 pm an shortly after the reactor had been taken critical, the inspector noted on a back panel that the 'A' channel Intermediate Range Monitor (IRM) had a red Hi Hi alarm

light lit (seal in). The on-watch operators were questioned as to the cause of this signal. The licensed operators and Shift Technical Advisor reviewed the alarm printer and noted that at 8:57 pm the Hi alarm had come in but no scram channel had tripped.

In order to verify proper operation of the IRM and RPS systems, the licensee immediately performed two functional tests (down ranging the IRM until into alarm) with satisfactory results. Following a review of electrical drawings, the licensee concluded that a short duration transient on one (of eight) channels was insufficient to trip the RPS system, and that all equipment was fully operable.

No violations were identified. Proper operation of the IRM detector systems will be reviewed during routine inspections.

(3) On December 29, 1984, during steam plant heatup the licensee identified two anomalies. One was that the main condenser vacuum and off gas flow were fluctuating. The cause was eventually determined to be a faulty steam jet air ejector pressure regulator and was corrected by using the manual bypass. The other was identified to be a "stinging" sensation to the eyes by personnel making a drywell inspection for steam leaks. This was attributed to an initial small amount of fumes from newly painted structural supports and other equipment following reactor coolant system heatup to normal operating temperatures. The licensee purged this drywell atmosphere through the Standby Gas Treatment System (SGTS) and it quickly cleared up. The licensee stated that it was aware of the requirement to sample the SGTS charcoal following exposure to paint fumes.

No violations were identified.

7. Surveillance Testing

a. The inspector reviewed the licensee's actions associated with surveillance testing in order to verify that the testing was performed in accordance with approved station procedures and the facility Technical Specifications.

A list of items reviewed is included at the end of this report in Attachment 1.

b. Findings

(1) On December 17 1984 the inspector reviewed the results of testing performed in accordance with procedure No. 8.M.3-1, Revision 5, Automatic ECCS Load Sequencing of Diesels and Shutdown Transformer with a Simulated Loss of Off Site Power. Included in this review was a check of the calibration of the brush recorder used for measuring event times, a review of the completed procedure check list, and an independent estimate of event times for the loading of the

'A' and 'B' diesel generators and the core spray and RHR pumps. The inspector estimated that the time to load the 'B' diesel was slightly greater than the procedure acceptance criteria of 10.5 seconds (10.52 seconds). The licensee's Nuclear Engineering Department personnel performed a safety evaluation which provided the basis for allowing the diesel loading time to be extended to 10.6 seconds. The inspector reviewed this safety evaluation and had no further questions. The licensee is considering adjustment of a time delay relay to decrease the diesel loading time. No violations were identified.

(2) On December 30, 1984 the inspector independently performed a calculation of reactor power via a heat balance using the licensee's procedure No. 9.3, installed instrumentation, and steam tables (CE Power Systems ninth printing). This was completed upon first reaching about 20% power and performed to verify proper operation of the process computer program OD-3.

The inspectors estimate of 414 mwt compared favorably with the computer estimate of 395 mwt.

No violations were identified.

(3) On December 28, 1984, the inspector observed the testing of the four main steam line safety relief valves (SRV). The inspector verified that an approved procedure was used during the test and that the SRV accoustic monitors responded when each valve was cycled. The discharge pipe temperature monitor (a backup sensor) for the "A" SRV did not function during the test and was being evaluated at the end of the inspection period. The inspector had no further questions. No violations were identified.

(4) On December 29, 1984, the licensee notified the NRC via the ENS telephone line that the drywell-to-torus leakage test required by technical specification 4.7.A.4b to be conducted during each refueling outage would not be conducted until after the main generator was online and the output breakers closed. The licensee had originally scheduled the test prior to placing the generator online, but found that extra time was needed to inert the primary containment with nitrogen which would delay the leakage test. The licensee stated that the plant would be at 20 to 25% power during the test and that placing the generator on line prior to the test (as opposed to opening the bypass valves to the condenser until after the test) had no safety significance.

The test was discussed with Region I management during a telephone call on December 29, 1984. At that time, the licensee stated that the drywell-to-torus leakage test would be conducted as soon as the primary containment atmosphere had been inerted with nitrogen and had stabilized. The licensee agreed to maintain core thermal power at 20 to 25% until the test was successfully completed and also agreed to shut down and repair the vacuum breakers if leakage exceeded the one-inch orifice criteria in Technical Specification 4.7.A.4.b.

The licensee completed inerting the containment at 12:15 am on December 31, 1984 and conducted the test four hours later, after the containment atmosphere had stabilized. The licensee reported a leak rate of 3.6 lbm/hr which was well below the calculated one-inch orifice leak rate, 378.7 lbm/hr.

The inspector observed the test and noted that the drywell-to-torus differential pressure continually decreased after inerting, requiring licensee action every few minutes to ensure the appropriate differential pressure was maintained. Following the tests, the inspector discussed the implications of the drywell-to-torus leakage problem with the licensee. At the close of the inspection, the acceptability of the licensee's drywell-to-torus leakage test was unresolved, pending further licensee evaluation of the leakage problem (84-39-03).

(5) During the period December 22-24, 1984, the inspector randomly selected surveillances from the Technical Specifications that were required to be done on a once-per-cycle refueling outage basis and reviewed the licensee's actions to perform them.

Items checked included 1) testing the diesel generator while isolated from the cable spreading room, 2) performing a rated load test of the station batteries, 3) a simulated loss of off site power test, 4) a functional test of the containment atmosphere dilution system, 5) calibration of hydrogen analyzers, 6) testing of core spray valve(s) from the alternate shutdown panel, 7) inspection and testing of drywell-to-torus vacuum breakers, 8) source calibration of main steam line radiation monitors, 9) calibration of safety and safety-relief valve position indication, and 10) testing of excess flow check valves and automatic containment isolation valves.

The inspector noted that procedure No. TP84-151, "Preoperational Test of H2/O2 Analyzer", performed calibration of the hydrogen analyzers. However, the low range scale had not been included. The inspector verified that warning deficiency stickers were placed on the range switches for information until the low range scales are properly calibrated.

The inspector noted that the completed data sheet for functional testing containment isolation valves (procedure No. 8.M.2-1.5.9, Revision 6) dated December 11, 1984 did not include four newly installed valves (5065-13B, 15B, 20B, and 22B) which were tagged out at the time of the test for maintenance. Following discussions with the inspector, the licensee tagged shut these containment isolation valves until the plant conditions permitted completion of this test.

No violations were identified.

(6) During the period December 23-30, 1984, the inspector held discussions with licensee representatives regarding the acceptance criteria for timing the Main Steam Isolation Valves (MSIVs). The Technical Specifications (T.S.) (Table 3.7.1) specifies the times to be between 3 and 5 seconds. Station procedure No. 8.7.4.4, Revision 9 requires the valves to close within the range 3.5 and 5.5 seconds and adds a .5 second response time to the T.S. The inspector questioned the licensee regarding justification for adding this .5 seconds since two inboard MSIVs had times between 5 and 5.5 seconds and were timed from the instant of control room switch operation to closed light indication. The licensee stated that the one person who knew the answer was on vacation and the information would be provided to the inspection as soon as possible. Pending review of the basis for the extra .5 seconds, this item is unresolved (84-39-04).

8. <u>Maintenance and Modification Activities</u>

a. <u>Scope</u>

The inspector reviewed the licensee's actions associated with maintenance and modification activities in order to verify that they were conducted in accordance with station procedures and the facility Technical Specifications. The inspector verified for selected items that the activity was properly authorized and that appropriate radiological controls, equipment tagging, and fire protection were being implemented.

A list of items reviewed is included at the end of this report in Attachment 1.

b. <u>Findings</u>

On December 29, 1984 the inspector reviewed Maintenance Request 84-611 which was initiated to troubleshoot the electrical portion of the High Pressure Coolant Injection (HPCI) control circuit. The sections entitled work performed, testing completed, quality control requirements met, and returned to service had not been completed. Since the HPCI system had been operated and returned to service the inspector questioned why the MR was not completed. The I&C supervisor and Watch Engineer immediately corrected this and completed the M.R. The inspector verified that the proper operability testing had been performed (procedure 8.5.4.1) prior to returning the HPCI system to service and provided this information to the station manager.

The inspector had no further questions. No violations were identified.

9. Health Physics Items

a. The following information is included in this report to assist NRC management personnel in following radiation exposure at the station.

The monthly site personnel radiation exposures based on TLD measurements for November and December 1984 were 195 and 141 person-rems, respectively. These exposures were considerably less than the exposures in October, 1984 (345 person-rems) and reflected decreasing amounts of outage work during preparations for plant startup. The total outage exposure through the end of December, 1984 was approximately 4,000 person-rems, including about 1,800 person-rems attributed to the recirculation pipe replacement project.

b. During the period December 18-19, 1984, the inspector reviewed the circumstances surrounding the unplanned exposure to a worker who made an unauthorized entry into an empty liquid radwaste tank (the 'C' monitor tank) on December 17, 1984 during desludging activities. This event was reviewed during a special inspection by a Region I based radiation specialist and the findings are included in Report No. 84-44.

c. On December 27, 1984 the inspector questioned the licensee regarding contamination of portions of the demineralized water (decontamination water) system with radioactive resin. The licensee stated that the extent of contamination was determined from sampling, was controlled, and had been caused by radioactive water and resin backing up a hose connection from radwaste activities while the decontamination water pump had been secured.

Although the licensee's evaluation was not complete at the end of this reporting period, the inspector had no further questions at this time. No violations were identified.

10. Housekeeping

During the month of December, 1984, the inspectors toured the station paying particular attention to safety-related areas within the reactor building. The status and condition of cleanliness, housekeeping, and contamination were reviewed.

The following observations were made and provided to the licensee's management.

- Off gas analyzer: loose welding mask on floor, six spare solenoids on floor, paper, plastic, tape, and plastic gloves on the floor.

- Drywell: water covered portions of the 9 foot elevation floor, a safety-relief valve accumulator relief valve was slightly leaking air, and the torus down comers had been cleaned and an inspection performed by QC personnel.

- 'A' core spray and RHR quadrant: double sets of anticontamination clothing and full face respirators were required due to the extensive amount of radioactive contamination; trash included empty polaroid film packages, a bag of light bulbs, spare hoses, a bucket of water, several electrical extension cords, plastic bags, vacuum cleaner hoses, rags, and loose wrenches on deck plating.

The licensee's management acknowledged the inspectors comments and stated that actions would be taken to clean the station prior to and following plant startup.

The inspector had no further questions at this time. Housekeeping conditions will continue to be reviewed during future routine inspections of the station.

11. Management Meetings

During the inspection, licensee management was periodically notified of the preliminary findings by the resident inspectors. A summary was also provided at the conclusion of the inspection on December 20, 1984 and January 21, 1985 and prior to report issuance. No written material was provided to the licensee during this inspection.

ATTACHMENT 1

The following is a list of surveillance and maintenance items reviewed during this inspection period.

Portions of the following tests were r iewed:

- LPCI pump operability test ("A" and "C" pumps) in accordance with procedure 8.5.2.1 on December 27, 1984
- Reactor building closed cooling water pump operability and flow rate tests in accordance with procedure 8.5.3.1 on December 26, 1984
- Salt Service Water pump operability and valve tests in accordance with procedure 8.5.3.2 on December 26, 1984.
- HPCI flow rate test at 150 psig in accordance with procedure 8.5.4.3 on December 28, 1984
- Manual opening of main steam line relief valves in accordance with procedure 8.5.6.2 on December 29, 1984
- Core thermal power calculations by the process computer (program OD-3 at 25% power on December 30, 1984)
- Average power range monitor calibration in accordance with procedure 9.1 on December 30 and 31, 1984
- Leak test of the drywell-to-torus vacuum breakers in accordance with procedure 8.A.2 on December 31, 1984
- Pre-operational testing on the nitrogen supply system for drywell instrumentation in accordance with procedure TP83-25
- Hydrostatic test of the ASME Class I reactor coolant system boundary in accordance with procedure TP84-259 on November 30, 1984 to December 1, 1984
- Loss of offsite power test in accordance with procedure 8.M.3.1 on December 15, 1984
- Manually start and load "A" diesel generator in accordance with procedure 8.9.1 on December 22, 26, and 27, 1984
- ATWS calibration test in accordance with procedure 8.M.1-30 on December 22, 1984
- Core spray pump operability test in accordance with procedure 8.5.1.1 on December 26 and 27, 1984
- Core spray motor operated valve operability tests in accordance with procedure 8.5.1.3 on December 27, 1984

- Reactor coolant system temperature monitoring during heatup on December 25, 1984
- A sampling of once-per-cycle surveillances required by Technical Specifications
- Main steam isolation valve timing tests in accordance with procedure 8.7.4.4

The maintenance and modification items reviewed included the following:

- Plant Design Change 8360; modification of nitrogen supply system
- Maintenance Request (MR) 84-605; SV-5065-92, adjust limit switches, December 24, 1984
- MR 84-606; Rt-1705-18A, stack gas rad monitor, December 25, 1984
- MR 84-608; RCIC, adjust overspeed trip, December 25, 1984
- MR 84-609; MO 1001-28A valve, may be leaking by seat, December 26, 1984
- MR 84-610; MO 1001-29A valve, valve will not close, December 26, 1984
- MR 84-611; HPCI, turbine speed control not regulating properly, December 26, 1984
- MR 84-13-72; RCIC, reinstall RCIC coupling after turbine overspeed test, December 19, 1984
- MR 84-614; HPCI, adjust turbine overspeed trip, December 26, 1984
- MR 84-615; MO 1001-28B valve, valve control problem, December 26, 1984.

BOSTON EDISON COMPANY
800 BOYLSTON STREET
BOSTON, MASSACHUSETTS 02199

WILLIAM D. HARRINGTON
SENIOR VICE PRESIDENT
NUCLEAR

December 21, 1984
BECo Ltr. #84-212

Mr. Edward C. Wenzinger
Chief, Projects Branch No. 3
Division of Project and Resident Programs
U.S. Nuclear Regulatory Commission
Region I - 631 Park Avenue
King of Prussia, PA 19406

Docket Number 50-293
License DPR-35

Subject: NRC Notice of Violation 84-26-04

References: (a) NRC Letter 1.84.345, E. C. Wenzinger (NRC) to W. D. Harrington (Sr. VP-Nuclear-BECo), 11/21/84

Dear Mr. Wenzinger:

This letter responds to the violation identified during a routine safety inspection by Mr. J. Johnson of your office between August 28, 1984 and October 8, 1984 and communicated to Boston Edison Company in Appendix A of Reference (a).

Notice of Violation (84-26-04)

10CFR50, Appendix B, VI, requires that measures be established to assure that documents including procedures are reviewed for adequacy and approved for release. Boston Edison Co. Quality Assurance Manual (BEQAM), Section 5, "Instructions, Procedures, and Drawings," Revision 11, dated May 14, 1984, requires that the quality assurance program-related procedures listed in Exhibit II-5-1 be reviewed and approved by the Quality Assurance Manager.

Contrary to the above, on September 14, 1984, four procedures listed in Exhibit II-5-1 of the BEQAM were not reviewed and approved by the Quality Assurance Manager.

Corrective Steps Taken and Results Achieved

Corrective steps have been taken to assure that all quality assurance program-related procedures are identified, reviewed, and approved by the Quality Assurance Manager. These steps include the following:

1. BEQAM II, Section 5, was clarified in Revision 12, dated 10/26/84. The clarification requires identification of quality program-related procedures (as defined in BEQAM II, Paragraph 5.2.1) in the "Index of QA Program-Related Procedures to 10CFR50, Appendix B Criteria." This index is a controlled document, and supersedes Exhibit II-5-1.

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2. The following four PNPS procedures, identified as not reviewed and approved by the QA Manager in Reference (a), have been reviewed by the QA Department:

   - o PNPS 3.M.1-1, "Preventive Maintenance"
   - o PNPS 3.M.1-8, "Disposition of Nonconforming Materials"
   - o PNPS 3.M.1-10.1, "Torque Wrench Calibration"
   - o PNPS 3.M.1-10.3, "Calibration of Noncontrolled Lab Equipment"

   Our review revealed that PNPS 3.M.1-1 was not required to be listed in the index; therefore, it does not require QA Manager approval. The other three procedures were found to need revisions before QA Manager approval. The subject revisions were made by the Station, and QA Manager approval was subsequently obtained. It is expected the procedures will be reviewed and approved by the ORC Chairman by 1/15/85.

3. PNPS personnel have conducted an additional review of procedures in the controlled index to ensure that the current versions of those procedures contain a QA Manager approval signature. Procedure 6.1-022 was the only exception found, and we have since obtained QA Manager approval.

<u>Corrective Steps to Avoid Further Violations</u>

The clarification of BEQAM II, Section 5, mentioned above provides identification control of QA program-related procedures through use of a controlled index. This index is to be updated, as needed, according to Section 5 requirements. In addition, the QA Department will periodically review issued procedures against the "Index of QA Program-Related Procedures to 10CFR50, Appendix B Criteria" to assure that all QA program-related procedures are reviewed and approved by the QA Manager. The first review will be complete by 1/31/85.

Additionally, the station procedure used as guidance to station personnel in obtaining required QA Manager reviews and approvals will be revised to ensure implementation of Section 5 of the BEQAM. The subject revisions will be completed by 4/1/85.

Until the station procedure is revised, however, our interim corrective action is that the appropriate station personnel have been instructed in following the requirements of BEQAM II, Section 5.

Date When Full Compliance will be Achieved

Full compliance will be achieved or 1/15/85, the date by which the four above-mentioned procedures will have been approved by the ORC Chairman.

If you have any further questions or require additional information regarding the above issue, please do not hesitate to contact me.

Respectfully submitted,

W D Harrington

W. D. Harrington