U.S. Nuclear Regulatory Commission

Region I

REPORT NO. 50-322/85-43

DOCKET NO. 50-322

LICENSE NO. NPF-36

LICENSEE: Long Island Lighting Company
P. O. Box 618
Shoreham Nuclear Power Station
Wading River, New York 11792

INSPECTION AT: Wading River, New York

INSPECTION CONDUCTED: December 1 - 31, 1985

INSPECTORS: John A. Berry, Senior Resident Inspector

APPROVED: J. Strosnider — 1/31/86
J. R. Strosnider, Chief, Reactors Projects Section 1B, Division of Reactor Projects — Date Signed

SUMMARY: During the inspection period, December 1 - December 31, 1985 the licensee completed the Neutron Source Outage, and entered a transition period prior to the Reactor Water Level Reference Leg replacement outage scheduled to begin January 8, 1986. The licensee completed Environmental Qualification of Electrical Equipment and Fire Detection Instrumentation installation during this period.

Several incidents of personnel error causing Engineered Safeguard Feature actuations also occurred during this period.

Completion of the Transamerica Delaval Diesel Generator inspections required by an American Air Filter Part 21 report was accomplished, and repair and inspection of Anchor Darling Swing Check Valves continued.

This inspection involved 106 hours of inspection by the Senior Resident Inspector, and 12 hours of inspection by Region-based inspectors. Thirteen items were closed as a result of this inspection and 1 item was opened. No deviations or violations were noted.

DETAILS

1. Status of Previous Inspection Items

1.1 (closed) 50-322/85-39-03, Part 21 Notification - American Air Filter

NRC Inspection Report 50-322/85-39 detailed a potential deficiency with Intake Silencers supplied to Transamerica Delaval (TDI) for use on Emergency Diesel Generators. The deficiency involved the absence of required welds on an internal part of the silencer.

NRC Inspection Report 50-322/85-42 updated this open item to detail the licensee's inspection of two of the three TDI Diesel Generator Intake Silencers (EDGs 101 and 102).

The licensee completed inspection of the third and final TDI Diesel Generator (EDG-103) on December 28, 1985. The presence of the required welds was verified by Quality Controls Division inspectors. Upon completion of this inspection, the licensee closed LILCO Deficiency Report No. 85-167 on December 30, 1985.

This item is closed.

1.2 (Update) 85-36-02, RHR Bolt Failure

NRC Inspection Report 50-322/85-36 opened unresolved item 85-36-02 regarding the failure of bolts on the minimum flow bypass valve for RHR Loop B. The bolts which held the valve operator to the yoke had failed, disconnecting the operator from the valve. Subsequent investigation by the licensee of bolts in the RHR, HPCI, and Core Spray systems discovered other bolt problems. The licensee initiated a program to inspect the bolting material used on safety related motor operated valves to provide assurance that it is as specified.

By memorandum from the Nuclear Engineering Department to the Maintenance Division Manager the licensee established guidance regarding the method and schedule of inspections. The licensee began inspection of 278 safety-related valves on Tuesday, December 10, 1985. Inspection was completed on December 16, 1985. The results of the inspections are as follows:

- One hundred eighty-eight (188) passed the inspection.

- Fifteen (15) valves were found to contain one stud that was appropriately marked with the material grade. The licensee considers these valves acceptable at this time.

  Fifty-one (51) valves contained studs that were 5/16 inch diameter with no markings. These valves will be subject to a 10% sampling and inspection by NED.

- Two (2) valves with studs larger than 5/16" diameter were found to have no readable stud markings. One of these, 1E11*MOV055A, was marked, but the grade marking could not be determined. The other valve, 1N23*MOV-026, is in the steam tunnel near the turbine building. This valve is accessible from the platform at the main steam bypass valves.

- Ten (10) valves had their operators restrained with material that was considered either inappropriate or suspect.

- Twelve (12) valves with mounting bolts larger than 5/16" diameter were inaccessible for examination.

The licensee's evaluation of these results, as well as the results of the 10% sampling inspection will be detailed in a future NRC Inspection Report.

1.3 (Update) 50-322/85-39-01, RWCU Inboard Isolations While Adjusting Blowdown Flow

NRC Inspection Report 50-322/85-39 detailed problems that the licensee had experienced with spurious isolations of the Reactor Water Cleanup System (RWCU) during adjustment of blowdown flow to the Main Condensor. The licensee had attributed the cause of the problem to the flow sensing circuitry of the RWCU system. Action was taken to calibrate all of the components of the flow sensing circuitry to determine the cause of the problem.

The licensee submitted an update to Licensee Event Report 85-036 to the NRC on November 6, 1985 to provide revised information as to the cause of the isolation problem. The licensee had completed recalibration of the flow sensing circuitry in the system, after which, another system isolation occurred. Subsequent investigation and additional troubleshooting discovered a loose ground connection on the Square Root Extractor portion of the circuitry. This loose connection was retightened. The licensee feels that this will correct the problem of isolation of the inboard and outboard isolation valves. This will be verified upon return to rated conditions.

Additionally, the licensee has experienced spurious trips of the system inboard isolation valve only. The individual components of the RWCU inboard isolation circuitry are being examined to determine the cause of the isolations. The licensee will issue a supplemental report once the cause of these isolations has been determined and corrected.

1.4 (closed) 50-322/85-36-03, Reactor Water Level Deviation

NRC Inspection Reports 50-322/85-35 and 85-36 detailed deviations which occurred with the Reactor Vessel Narrow Range Level System. The licensee implemented corrective action to correct the deviation

problem, and the Nuclear Engineering Department and Plant Staff began an evaluation of the need for additional corrective action.

The evaluation has been completed by the licensee. The licensee has decided to perform modifications to the 'A' and 'B' Reactor Pressure Vessel Reference Legs as a permanent solution to the level deviation problem. This modification will involve the shortening of the steam piping from the Reactor Pressure Vessel to the reference leg condensing chamber. Additionally, more insulation will be added to the piping to prevent condensation from forming in the piping.

This modification work is scheduled to begin on or about January 8, 1986, and will continue for approximately two months. Activities related to this modification will be tracked as part of the routine monthly resident inspection report.

This item is closed.

1.5 (Update) 50-322, 85-20-01, Review of Licensee Response to GE SIL #402, Nitrogen Inerting of Containment

A region-based inspector conducted an in-office review of the licensee's response to SIL 402 recommendations 1 and 2 indicated in letters dated September 18, 1984 and November 8, 1984. As a result of the licensee's system design evaluation, the licensee has committed to a plant modification in Station Procedure Change Notice (SPCN) 85-1037 and Design Output Package (DOP) 84-275. This notification will accomplish the following:

a. A temperature-controlled valve will be added upstream of the nitrogen vaporizer.

b. A control panel local to the vaporizer (in the yard) will be installed. This will signal the temperature-controlled valve to close when the nitrogen temperature downstream of the vaporizer is below 40 degrees F.

c. A thermocouple will be located on the nitrogen piping inside secondary containment, and will provide the signal to the control panel in the yard.

d. A pressure relief valve (setpoint of 350 psig) will be installed upstream of the temperature-controlled valve.

These changes will be implemented prior to initial inerting of the containment. An additional requirement for licensee close out of work associated with SPCN 85-1037 is a revision to Station (Operating) Procedure (SP) 2.3.425.01 Rev. 8 which will then procedurally prevent cold nitrogen injection.

The licensee is not able to evaluate the operating experience of the inerting system (SIL 402 Recommendation 2) as Shoreham is not yet operational and the primary containment has not been interted.

An NRC re-review of the nitrogen injection system procedures will be made following completion of licensee activities associated with SPCN 85-1037.

1.6 (Update) 85-08-01, Leakage Reduction Program

NRC Inspection Report 50-322/85-08 cited the licensee for one violation involving the failure to establish and fully implement the Leakage Reduction Program from Primary Coolant Sources Outside Containment.

The inspector reviewed the licensee actions in response to the Notice of Violation and subject report. The licensee had been cited for:

a. Failure to establish a program to reduce leakage from those portions of the Reactor Building Floor Drains, Reactor Building Equipment Drains, and Reactor Building Standby Ventilation System outside containment.

b. The following items being absent from established program for the nine remaining systems:

(1) Procedure steps for Technical Specification required visual inspections and for NDE surface emission bubble testing per SP No. 84-002-01, Rev. 1

(2) Definition of parameters such as Test Pressure.

(3) Acceptance criteria for leakage rates.

(4) Requirements for retest after repair.

The licensee responded to the Notice of Violation and Inspection Report by letter dated May 14, 1985. (Ref: SNRC-1174, J. D. Leonard, LILCO to T. E. Murley, NRC, "Leakage Reduction Program, Personnel Qualifications and Training, Shoreham Nuclear Power Station, Docket No. 50-322, May 14, 1985). In that response, the licensee detailed the corrective actions to be taken to achieve compliance.

The inspector reviewed the licensee's corrective actions in this matter. The results of that review follow.

- NRC Inspection Report 50-322/85-08 noted that SP No. 12.080.01, Rev. 3, Leakage Reduction and Control Program, did not address or reference the subject of the qualification of personnel to be used in the program.

The inspector verified that SP 12.80.01 was replaced by SP 14.404.01, Leakage Reduction and Control Program Implementation, on July 2, 1985, and that Step 6.4 of the new procedure addresses these qualifications.

- The inspection report noted that SP 12.080.01 did not contain appropriate or approved data sheets for visual inspections.

  The inspector verified that these data sheets were incorporated in the new SP 14.404.01.

- The inspection report noted that SP 84.002.01, Leakage Reduction and Control Program Implementation, did not include three systems required by the Technical Specifications.

  The inspector verified that SP 84-002.01 was replaced by SP 14.404.01, and that the three systems were included in SP 14.404.01.

- The inspection report noted that SP 84.002.01 did not contain provisions for scheduling the Technical Specification required "periodic visual inspections", and that the procedure provided no detailed implementation steps for the Technical Specification required periodic visual inspections nor for maintaining the status of the visual inspections. The procedure also lacked data sheets addressing visual inspections.

  The inspector verified that the new procedure SP 14.404.01 incorporated scheduling and implementation of the TS required visual inspections in Sections 8.1 and 3.3.1, and that data sheets for these inspections were provided as Appendixes 12.2.A through 12.7.

- The inspection report noted that the SP 84.002.01 data sheets lacked sufficient detail for maintaining test status for leak tests.

  The inspector verified that SP 14.401.01 corrected this deficiency.

- The inspector report noted that SP 84.002.01 was deficient in its definition of the system boundary to be tested and the interfaces with other system boundaries

  The inspector verified that SP 14.401.01 corrected this deficiency.

- The inspection report noted that SP 80.002.01 did not provide detailed steps covering liquid bubble testing, nor did

it provide a reference to another NDE procedure covering this testing.

The inspector noted that the licensee, in their response to the Notice of Violation (SNRC-1174), stated that "Emission Bubble Testing is not used to quantify leak rates on systems. Make-up flow rate measurements are used to quantify system leakage. Bubble checks are only used to locate the source of leakage. As such, no procedure for NDE surface emission bubble testing is required". The inspector verified that SP 14.404.01 contains instructions on use of "Leak Tec (TM)" for bubble emission testing. The inspector finds this satisfactory.

- The inspection report noted that SP 80.002.01 did not stipulate test pressures for conducting various system tests.

  The inspector verified that these pressures are incorporated in SP 14.401.01.

- The inspection report noted that SP 80.002.01 contained no initially developed acceptance criteria for leakage rates from systems in the Leakage Reduction Program.

  The inspector verified that FSAR Section III.D.1.1 and Step 3.3.1 of the new procedure satisfied this requirement.

- The inspection report noted that the procedure contained no requirement in the Leakage Reduction Program or Procedures that specified retest after repair to ascertain whether or not the repair was effective.

  The inspector verified that SP 14.404.01, Step 6.3 now contains retest requirements.

- The inspection report noted that SP 80.002.01 did not address or reference qualifications of personnel to perform test in accordance with the procedure.

  As previously noted, the inspector verified that Step 6.4 of SP 14.404.01 now addresses such qualifications.

- The inspection report noted, during Field Inspections, that the Core Spray and RHR system data sheets were minimally adequate (Core Spray) or inadequately (RHR) detailed for maintaining test status. The report further noted that the RHR test boundary interfaces were not defined nor were steps provided for inspecting insulated piping.

  The inspector verified that the data sheets in SP 14.404.01 and steps 8.1.4, 8.1.5, 8.1 and 8.2.d adequately address these concerns.

- The inspection report noted that many of the piping areas inspected would require additional lighting, or would require the use of mirrors for adequate inspection.

  The inspector verified that flashlights and mirrors are listed as Materials and Test Equipment in SP 14.401.01.

Two portions of NRC Inspection Item 85-08-01 remain open, the revision of procedures SP 74.030.02, "RBSVS in Place Filter Testing", and SP 84.402.01, "Hydrogen Recombiner System Leak Rate Test", to include reference to the qualifications of personnel used to conduct the tests. The licensee has committed to completing these procedure revisions by January 31, 1986. Upon verification by the inspector that these procedural revisions are complete and approved by the Review of Operations Committee, NRC Inspection Item 85-08-01 will be closed.

1.7 <u>(closed) Various NRC Inspection Report 50-322/84-46 Fire Protection System Open Items</u>

Between December 3 and 7, 1985, members of the NRC staff from the Office of Nuclear Reactor Regulation and from NRC Region I inspected the licensee's activities in relation to Appendix R of 10CFR50. On December 21, 1984, NRC Inspection Report 50-322/84-46 was issued summarizing the results of that inspection. Twelve (12) items were designated as unresolved pending evaluation by NRR.

By letters dated January 29, April 5, and June 3, 1985, the licensee provided additional information on these items, including commitments to implement fire protection modifications in certain areas.

The NRC staff's evaluation of that information was formalized in Supplement No. 9 to the Safety Evluation Report related to the operation of Shoreham Nuclear Power Station, Unit No. 1, NUREG-0420. This SSER was issued in December 1985.

Based on this SSER, the following items are closed. Details on these items, and their closure may be found in NRC Inspection Report 50-322/84-46 and NUREG-0420, Supplement No. 9.

1.7.1 (closed) 50-322/84-46-05, Spacing of Fire Detectors
1.7.2 (closed) 50-322/84-46-07, Fire Door Degredations
1.7.3 (closed) 50-322/84-46-08, Diesel Fire Pump Cables
1.7.4 (closed) 50-322/84-46-09, Fire Damper in Heating, Ventilation, and Air Conditioning Chiller Rooms
1.7.5 (closed) 50-322/84-46-10, Design Concentration of Carbon Dioxide in Battery Rooms and Cable Tunnel
1.7.6 (closed) 50-322/84-46-11, Fire Detectors in Computer Room
1.7.7 (closed) 50-322/84-46-12, Damaged Fire Proofing
1.7.8 (closed) 50-322/84-46-13, Fire Hazards Analysis for Control Building Corridors and Manhole #1

1.7.9 (closed) 50-322/84-46-14, Single Water Supply Header in the Reactor Building
1.7.10 (closed) 50-322/84-46-15, Structural Integrity of Penetration Seals
1.7.11 (closed) 50-322/84-46-16, Sizing of Water Storage Capacity

1.8 (Update) 50-322/85-42-01. Check Valve Failures

NRC Inspection Report 50-322/85-42 detailed failures on High Pressure Coolant Injection System Swing check valves manufactured by the Anchor/Darling Valve Co. The report stated that the licensee would be conducting an inspection of all Anchor/Darling swing check valves, and determining a course of corrective action. This update details the results to date of this licensee's actions.

As discussed in Inspection Report 50-322/85-42, the licensee discovered, on November 4, 1985, that the swing check valves located in the steam discharge line of the High Pressure Coolant Injection System (HPCI) Turbine had come apart. The cause of the valve failures was determined to be the separation of the hinge support assembly from the valve bonnet due to the disengagement of the two capscrews holding the pieces together.

The licensee initiated an investigation into the cause of the valve failure. As part of this investigation, all other Anchor/Darling swing check valves were to be inspected, the failure mechanism of the HPCI valves was to be analysed, and determination of whether there was a valve assembly deficiency was to be made.

On December 20, 1985, the licensee issued Interim Report No. 412-0005, "An Investigation Into Failure of the HPCI Turbine Exhaust Check Valves manufactured by Anchor/Darling for the Shoreham Nuclear Power Station". The report presented the licensee's findings to that date resulting from their investigation.

There are a total of 12 Anchor/Darling swing check valves installed in the Shoreham plant. They are:

2 HPCI Steam Discharge 18 inch valves
2 HPCI Pump Suction 16 inch valves
4 Residual Heat Removal System Pump Suction 16 inch valves (one for each of the four RHR Pumps A - D)
2 Feedwater Discharge 18 inch valves
2 Fuel Pool Cooling System 6 inch valves

Of these 12 valves, 9 are of the design where the hinge support piece bolts to the bonnet (including the two failed HPCI Steam Exhaust valves). Three valves, (the two Feedwater, and one of the two Fuel Pool Cooling), are of the hinge support to body type. Ten of the twelve valves are carbon steel, while the two Fuel Pool Cooling Valves are stainless steel.

During the licensee's inspection of these valves, they discovered, on December 3, 1985, that valve 1E11*16V0020B, (RHR Pump 'B' Discharge Check Valve) was missing one of the two capscrews. The hinge support piece was still intact, held firmly by the remaining capscrew. The capscrews, as in the case of the HPCI turbine exhaust valves, were neither tack welded nor lock-wired.

As of the end of the inspection period, December 31, 1985, the licensee had completed inspection of 8 of the 12 Anchor/Darling check valves. With the exception of the two HPCI steam valves, and the RHR Pump 'B' discharge check valve, all valves had capscrews intact with no signs of loosening. None of the valves inspected had their capscrews tack-welded or lock-wired.

The licensee has concluded that the failure of the valves is the result of the lack of a suitable locking mechanism on the capscrews. Licensee review of the Anchor/Darling vendor generic documentation for swing check valves of this design indicates that the hinge support piece capscrews should be tack-welded. Review of Shoreham specific valve drawings indicates no such weld for any of the valves except the 6" stainless steel Fuel Pool Cooling System valves. The licensee, Stone & Webster, and Anchor/Darling are investigating the discrepancy between the vendor drawings and Shoreham specific drawings.

As detailed in Inspection Report 50-322/85-42, there were three capscrews and two spring pins missing from the HPCI check valves when they were disassembled following discovery of their failure. An inspection of the sparger in the steam line failed to discover the missing parts. There was also a missing nut and washer from the RCIC check valves which had failed. The nut and washer were discovered in the RCIC steam exhaust sparger in the Suppression Pool.

When the licensee inspected the RHR pump 'B' discharge check valve they determined that the capscrew which had come out was also missing. This capscrew is approximately 5/8" in diameter and 2 1/2 inches long.

On December 16, 1985, a diver was sent into the Suppression Pool to attempt to locate the missing valve pieces. The diver recovered one missing spring pin and one capscrew from the HPCI check valves. Still missing are two 5/8" diameter by 2 1/2" long capscrews from HPCI and one 3/16" diameter by 2 inch long spring pin. These pieces are still assumed to be in the Suppression Pool. Further diver inspections will be performed to attempt to locate these parts. Additionally, the licensee is performing an engineering analysis to document the effect of any unrecovered parts on system operability. The missing capscrew from the RHR system is assumed to be in the RHR piping. The licensee is presently analysing the effect this capscrew could have on RHR system operation, as well as the potential for its migration throughout the system and to the reactor vessel due to

system flow. The results of these analyses will be the subject of future NRC inspection reorts.
The licensee has decided upon a course of corrective action for both the HPCI check valves, as well as for all other Anchor/Darling swing check valves. These actions are as follows:

HPCI Turbine Steam Exhaust Check Valves - The licensee has concluded that the HPCI steam valves will be reassembled with the capscrews lock-wired. By letter from M. D. Cowell, Project Engineer for Anchor/Darling to Tom Bennet, LILCO, the valve manufacturer has informed the licensee that lock-wiring the capscrews is a satisfactory mechanism to prevent loosening. The licensee determined that the valves could be returned to service with lock-wiring based upon:

- The fact that examination of the recovered capscrews found them to be intact with no signs of distress.

- The fact that other nuclear power plants with Anchor/Darling swing check valves which are properly lock-wired or tack-welded have not experienced the type of failures seen at Shoreham.

- The licensee's implementation of an augmented inspection of the HPCI valves, and other Anchor/Darling valves in the plant.

The licensee has also committed to replacement of the HPCI Turbine exhaust valves at the first plant refueling outage. These valves will be replaced with lift-check valves which have been shown to perform better in this type of service.

Other Anchor/Darling Check Valves - The licensee will lock-wire all other Anchor/Darling swing check valves that lack the required tack weld. The justification for lock-wiring comes from the Anchor/Darling memo discussed above. The licensee will then implement an augmented inspection schedule for these valves to ensure that this corrective action is effective.

The licensee's continued action in this matter, as well as the results of their further inspections will be the subject of future inspection reports. Pending completion of the licensee's actions, and review by the NRC, this matter will remain open.

2. Review of Facility Operations

2.1 Operational Safety Verification

The inspector toured the control room daily to verify proper shift manning, use of and adherence to approved procedures, and compliance with Technical Specification Limiting Conditions for Operation. Control Panel instrumentation and recorder traces were observed and the status of annunciators was reviewed. Nuclear instrumentation and reactor protection system status were examined. Radiation monitoring

instrumentation, including in-plant Area Radiation monitors and effluent monitors were verified to be within allowable limits, and observed for indications of trends. Electrical distribution panels were examined for verification of proper lineups of backup and emergency electrical power sources as required by the Technical Specifications.

The inspector reviewed Watch Engineer and Nuclear Station Operator logs for adequacy of review by oncoming watchstanders, and for proper entries. A periodic review of Night Orders, Maintenance Work Requests, Technical Specification LCO Log, and other control room logs and records was made. Shift turnovers were observed on a periodic basis.

The inpsector also observed and reviewed the adequacy of access control to the Main Control Room, and verified that no loitering by unauthorized personnel in the Control Room Area was permitted. The inspector observed the conduct of Shift personnel to ensure adherence to Shoreham Procedures 21.001.01, "Shift Operations" and 21.004.01, "Main Control Room - Conduct for Personnel".

Due to the activities related to the maintenance and modification work during the neutron source outage, the inspector conducted periodic detailed reviews of Station Equipment Clearance permits and Tagging Orders. The inspector also verified proper tagging in the control room and in the plant. Tags were verified to be hung properly, with valves, breakers and components in their proper position. The inspector verified proper completion of SECP forms, and double verification of tags hung.

No unacceptable conditions were identified.

2.2 Plant and Site Tours

The inspector conducted periodic tours of accessible areas of plant and site throughout the inspection period. These included: the Turbine and Reactor Buildings, the Rad Waste Building, the Control Building, the Screenwell Structure, the Fire Pump House, the Security Building, and the Colt Diesel Generator Building.

During these tours, the following specific items were evaluated:

- Fire Equipment - Operability and evidence of periodic inspection of fire suppression equipment;

- Housekeeping - Maintenance of required cleanliness levels;

- Equipment Preservation - Maintenance of special precautionary measures for installed equipment, as applicable;

- QA/QC Surveillance - Pertinent activities were being surveilled on a sampling basis by qualified QA/QC personnel;

- Component Tagging - Implementation of appropriate equipment tagging for safety, equipment protection, and jurisdiction;

- Personnel adherence to Radiological Controlled Area rules, including proper Personnel frisking upon RCA exit;
- Access control to the Protected Area, including search activities, escorting and badging, and vehicle access control;

- Integrity of the Protected Area boundary.

No unacceptable conditions were identified.

3. Licensee Reports

3.1 In Office Review of Licensee Event Reports

The inspector reviewed Licensee Event Reports (LERs) submitted to the NRC to verify that details were clearly reported, including accuracy of the cause description and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were involved, and whether the event warranted onsite follow-up. The following LERs were reviewed.

LER Number	Title
85-52	RPS Actuation when switching from RPS ALT to RPS "A" Bus
85-53	Temporary Procedure Change Notice not approved in time limit specified in Tech. Spec.
85-54	Loss of RPS 'A' due to operator error
**85-49, Rev. 1	Update on LLRTs which exceeded the Allowable Tech. Spec. limits
*85-55	Environmental Qualification of Electrical Equipment

*Discussed in NRC Inspection Report 50-322/85-42
**This revision concerns the failure of the RCIC Turbine exhaust check valves. Details may be found in NRC Inspection Report 50-322/85-42.

3.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite follow-up, the inspector verified; the reporting requirements of 10 CFR 50.73 and Technical Specifications had been met, that prompt and effective corrective action had

been taken, that the licensee had reviewed the event to determine ways to prevent future occurrence, and determined whether follow-up action is required.

The inspector conducted on-site follow-up on LER 85-54, 'Loss of RPS "A" due to Operator Error', as well as two LERs from NRC Inspection Report 50-322/85-42, (85-48, "B" RBSVS Initiation due to Technician Error", and 85-50, "RBSVS/CRAC 'B' side initiation due to Technician error").

These LERs were chosen for review due to their relation to the subject of 'personnel error'. Details on this subject may be found in Section 7. of this report, entitled "Personnel Errors".

3.3 Review of Periodic and Special Reports

During the inspection period, the inspector reviewed the Shoreham Startup Test Report submitted to the NRC by letter dated November 22, 1985. (Ref: SNRC-1216, J. D. Leonard, Jr., Vice-President, Nuclear Operations to Harold R. Denton, Director, Office of Nuclear Reactor Regulation, "Startup Test Report-Shoreham Nuclear Power Station, Docket No. 50-322). This report is required by the Shoreham Technical Specifications, Section 6.9.1.1 through 6.9.1.3. The report addresses the startup tests identified in Chapter 14 of the Shoreham Final Safety Analysis Report (FSAR) which were performed in the test conditions "Open Vessel and Heatup." In the report, the licensee describes the measured values of the operating conditions or characteristics obtained during the startup test program to date. The values are compared to the pre-determined acceptance criteria, and where necessary, corrective actions and/or test exceptions are described. The report also includes a discussion of license conditions which affect plant startup and power escalation testing.

The report noted that, as Shoreham has not completed its startup test program, the tests identified in the FSAR to be performed in test conditions 1 through 6, and during the warranty demonstrations are outside the scope of the report. The report also noted that modification activities on the reactor vessel level instrumentation system and the High Pressure Coolant Injection System will require startup retesting. These modification activities involve the replacement of the condensing chambers and piping for the reference legs of the water level system, and modification to the HPCI Woodward Governor Control system. These modifications will invalidate the results of the portions of STP-9 and STP-15 which were completed in the startup test program.

The inspector noted that the report indicated, with exception of the following items, that all test results met acceptance criteria or approved test exceptions. The items which did not meet acceptance criteria, or which will require further corrective action are:

- Control Rod Drive 22-35 was inoperable at the time rods were scrammed at rated pressure. Rod 22-35 was replaced during the source outage, and will be retested prior to entering Test Condition 1.

- The control rod drive flow controller's decay ratio has not yet been analysed. This will be completed upon retesting after the outage.

- Problems with the A and B reference legs were discovered during the testing program (see NRC Inspection Reports 50-322/85-35, and 85-36). The licensee is replacing the piping from the vessel to the reference leg condensing chambers, and complete instrument loop calibration will be performed when retesting begins.

- LPRM Calibration testing identified 10 LPRMs which must be retested at higher power levels, and one (LPRM-20-37-C) will be repaired prior to retesting at higher power levels.

- The RCIC system exhibited flow oscillations during Reactor vessel injection system testing on September 26, 1985 and October 4, 1985. The RCIC speed and control systems will be recalibrated to stabilize the circuitry. Retest of the system will be completed upon return to power.

- HPCI Woodward governor modifications, mentioned earlier, will require HPCI retest.

- Safety Relief Valve 'A' failed to meet the acceptance criteria which requires that steam flow through each relief valve, as measured by the initial and final bypass valve position, shall not be less than 10% of valve position under the average of all valve responses. This SRV will be retested at rated pressure during Test Condition 2. The decision to delay retest to test condition 2 was made to limit the amount of cycling of the SRVs at low pressure.

- The Recirculation Flow Control System for the 'B' Recirculation MG-Set test indicated violations of the acceptance criteria regarding limit cycles. This is believed to be caused by non-linearities which exist in the scoop tube position vs. speed characteristics in the 20% to 30% range. Corrective action to prevent MG-Set operation below 24% will be taken prior to entering Test Condition 1. After completion of TC 1-3 testing, an evaluation will be made as to the need for reshaping of the scoop tube cam to eliminate the non-linearities.

- Reactor Water Cleanup system testing determined the need for replacement of a Flow Transmitter in the bottom head

drain line. This transmitter was replaced during the source outage and new data will be obtained upon retesting.

No unacceptable conditions were identified.

4. Monthly and Maintenance Observation

4.1 Maintenance Activities

The inspector observed the conduct of various maintenance activities throughout the inspection period. During this observation, the inspector verified that; maintenance activities were conducted within the requirements of the plant's administrative procedures and technical specifications, proper radiological controls were implemented and observed, proper safety precautions were observed, and that activities which have the potential to impact plant operations are properly coordinated with the control room.

Activities related to the neutron source outage maintenance and modification work were observed by the inspector. See Section 8.0 for details of these activities.

No unacceptable conditions were identified.

5. Review and Followup of IE Notices, Bulletins and Generic Letters

5.1 IE Notices

The inspector reviewed notices issued by the Office of Inspection and Enforcement during the inspection period. Review was to determine; if the subject of the notice was applicable to the Shoreham Nuclear Power Station, and if followup of the licensee's action was required by the inspector.

6. Licensee Response to NRC Inspection Report No. 50-322/85-22

Allegations involving the calibration of certain instrumentation and controls, as well as training and qualification of instrument technicians and supervisors, were made to the New York State Consumer Protection Borad by a private citizen. These allegations were the subject of a special NRC inspection conducted during the period April 10 - May 10, 1985 by an inspector from the NRC Region I Office.

The results of that special inspection were documented in NRC Inspection Report 50-322/85-22. The transmittal letter for that report required the licensee to respond to those allegations that were substantiated as a result of that inspection, and to also provide additional information on

calibration procedures. (Ref: R. W. Starostecki, NRC, to J. D. Leonard, Jr., LILCO, "Subject - Inspection 50-322/85-22", dated September 10, 1985)

The licensee responded to NRC Inspection Report 50-322/85-22 on November 1, 1985 by letter, (Ref: SNRC-1212, J. D. Leonard, Jr., LILCO to T. E. Murley, NRC Region I, Inspection Report No. 50-322/85-22 Shoreham Nuclear Power Station - Unit 1, Docket No. 50-322"). The following provides details of NRC Region I's review of that response.

6.1 Response to Detail 4.2: Tapping of Instrumentation During Calibration

It was alleged that during calibration of instrumentation, tapping was done to defeat the hysteresis effect, which thereby invalidates the calibration. It was alleged the Weston indicators located throughout the plant would fail the calibration if not tapped. It was stated that QC personnel witness the tapping and then "sign-off on this fudged data".

Licensee response has indicated that both procedures for panel-mounted meters (SP 46.030.01 and SP 46.030.02) will be revised to require upscale, downscale and downscale-tapped readings. The revision will also change the acceptance criteria to clearly indicate that all three sets of data must be within the allowable tolerances. This will allow for the determination of hesteresis effect and deadband of the meter.

Licensee further states that this allegation should not be considered confirmed as their research demonstrated no utilization of the tapped reading for calibration purposes.

6.2 Response to Detail 4.4: Pressure Switch Head Correction

It was alleged that pressure switches PS-124 and PS-125 had an uncorrected design error which had previously been brought to the attention of a "Technical Support" group. The lack of a head-correction factor during initial calibration of the switches caused them to be over-ranged and "made" (i.e., contacts closed) all the time.

Licensee response indicates that this alleged "design error" was, in fact, an oversight by a Startup Test Engineer. The licensee also indicates that this is an isolated case with no broad implications as it has been ascertained that the engineer concerned had correctly applied head correction factors in the calibration of other, similarly configured, instruments for which he was responsible.

With regard to the switches being "over-ranged", the nominal range of these units is typically 30 psig. The current setting of PS-125 slightly exceeds this value. An EEAR has been initiated to evaluate the long-term acceptability of this condition, and if necessary, specify a replacement switch. The licensee further states that no

immediate corrective action is required since the calibration was successfully completed and the switch is currently functioning normally.

With regard to the "design error" having been reported to a "Technical Support" group, the licensee states that the concern was written up on a Maintainability Task Force (MTF) Problem Identification Form. It has been determined that this form was never processed and presented to MTF for consideration since it was not identified as a problem with the ability to maintain the instrument (which was the intent of the form). The correct method of identifying design, engineering and calibration problems is through the use of E&DCR or LILCO Deficiency Report, which will receive the appropriate attention and resolution.

6.3 Response to Detail 4.7: Impulse Line Trap

A pressure sensing impulse line in the High Pressure Coolant Injection (HPCI) system was alleged to create a "trap" due to its field-run configuration. The "trap" was alledged to cause false indication to HPCI pump suction pressure switch PS-1211, which results in keeping the pump "off". Also the calculated head correction factor was allegedly applied wrong to the switch setpoint. Review of this problem by the licensee's "Technical Group" was alleged to have been requested (by an unidentified source), however, "the foreman told the technician that management didn't want to hear about things like this now".

The licensee agreed with the results of the NRC investigation there were "no obvious traps". The licensee concluded that there were two areas of concern relative to the initial calibration. The first area was that the head correction was not properly applied during the C&IO in 1981. This condition was subsequently discovered and corrected by plant staff in 1984. The proper head correction factor assumes that the impulse line is full of water. The HPCI system Operating Procedure (SP 23.202.01) will be changed to add a step requiring the instrument sensing line to be vented every time the system is filled and vented. The second concerns the setpoint. The nominal setpoint was originally 15". For a period, during 1984, a setpoint of 14" was used due to the temporary use of a 0-15" switch. This switch was used as a replacement for a malfunctioning switch, until the correct replacement could be obtained. A decision was made to not use the switch at the absolute limit of its range. The correct switch has since been obtained and installed, and the 15" setpoint returned. The licensee further states that the 15" setpoint is acceptable since the purpose of this switch is to protect the pump from a loss of suction (due to improper valve lineup, blocakge of suction line, or loss of inventory). Protection from cavitation is not the primary function of the switch. In addition, the 2% tolerance applies to the trip point, not the reset point. The licensee states that this application is standard practice.

6.4 Response to Detail 4.15: Radwaste Laundry Drain Tank

The licensee states that they do not agree that the allegation was fully substantiated. Although the switches are set slightly high (80%) they are still below the overflow level (90%). The licensee does agree that there is a difference between actual and indicated inventories in the tank, however this does not consititute a problem of great safety significance. Any overflow from one tank goes to the other, and excess beyond tank capacities goes to the Radwaste Building Floor drain sump. To improve the situation, high level alarms have been calibrated so that alarm occurs at 1338 gallons, which is within 2% of intended 80% setpoint, and results in perfect agreement between high level alarm and indicated gallons. Instrument 0 has been changed to the center of the sensing line tap.

This gives excellent accuracy (1.2%) error) from 50% -75%. This also results in a difference from indicated level by approximately 9% for the full range of the instrument.

The licensee has committed to review the calibration methodology of all radioactive waste tank level instrumentation loops during their next regularly scheduled preventive maintenance period.

The inspector concluded that the licensee's response to the individual allegations is acceptable. Revisions to procedures SP 46.030.01, SP 46.030.02 and SP 23.202.01 will be reviewed by the resident inspector when they are completed. The response to Detail 4.4, relating to pressure switch head correction points up a weakness in training, in that it shows that personnel were not aware of the correct means of reporting and resolving engineering, design and calibration problems. The licensee should review this aspect of training and implement means to strengthen as necessary.

7. Personnel Errors

During this inspection period, December 1 - December 31, 1985, as well as during previous inspection periods, a number of events occurred, including actuations of Engineered Safeuard Feature systems, which were the direct result of errors by plant personnel.

During December 1985, the following three events, which were required to be reported to the NRC, occurred:

- On December 17, 1985 during performance on a surveillance test, a technician accidentally pushed a wrong contact and caused an ESF Actuation of the RBSVS system.

- On December 18, 1985 during performance of a surveillance test, a technician error caused isolation of the shutdown cooling and reactor

water cleanup systems, initiation of the RBSVS system, loss of the 'B' RPS MG set, and a Main Steam Line Hi Radiation isolation signal.

- On December 19, 1985 a half scram, full isolation, 'A' RBSVS initiation occurred when the RPS EPA breaker, 1C71*BKR-004B was de-energized. The direct cause of this event has not been determined, but the breaker was either deliberately placed in the "off" position by someone, or was accidentally bumped to the "off" position during work in the area.

During November 1985, three events, which were required to be reported to the NRC, occurred. Additionally, one event was not required to be reported only due to plant conditions at the time. They were:

- On November 2, 1985, during performance of a surveillance test, a technician error caused initiation of the RBSVS/CRAC side 'B' system.

- On November 4, 1985, a full reactor trip and isolation occurred when personnel were transferring the power supply for the 'A' RPS bus from its alternate source back to its normal source of power. This was due to the switch being taken too far.

- On November 12, 1985, the wrong breaker was opened by personnel during a taggout. This caused a half-scram, half-isolation and RBSVS initiation due to the loss of RPS Bus 'A'.

- On November 8, 1985, due to personnel error, Discharge Waste Sample Tank 'B' was receiving influent from the waste evaporator at the same time the tank was being discharged overboard. This event was non-reportable only because activity of the discharged water was within limits.

These events, as well as other personnel errors over the previous months, have raised concern within the NRC. On December 20, 1985 the Senior Resident Inspector met with the Plant Manager, Operations Division Manager, Maintenance Manager, Outage and Modifications Division Manager and Operational Compliance Engineer to discuss this matter. Prior to that meeting, the inspector had given the Plant Manager a list of topics for discussion. The NRC desired to have the licensee address these topics in relation to the problem of personnel errors at the plant. These topics included:

- What is the cause of these problems
- What are short and long term corrective actions?
- Have these problems been addressed in the past?
- Are there related problems or undiscovered other problems that could exist due to the same root causes?
- What can be done to ensure management that the root cause of such problems are really discovered and solved?

At the meeting, the Plant Manager emphasized to the inspector the licensee's concern over this matter and their intention to correct the problem. The licensee has initiated an extensive investigation into the situation to determine root causes and corrective actions. The Plant Manager stated that the results of this investigation would be completed and submitted to NRC for its review no later than January 10, 1985. The licensee's immediate corrective action for the situation included a briefing for all supervisory personnel, from the foreman level up, on the need for caution and attention to detail. The foreman were instructed to ensure that personnel under their supervision were cognizant of all aspects of their jobs, and were aware of the need for a reduction in personnel errors. Foreman and supervisors were also instructed to increase their direct supervision of personnel in the "field" to help minimize errors.

The licensee has committed to provide NRC with the results of its detailed investigation, and its proposed corrective action by January 10, 1986. NRC will review this information, and a determination will be made at that time as to what further actions, if any, need to be taken by the licensee or the NRC. Pending submission of the licensee's report, and review by NRC, this is designated as a inspector followup item 50-322/85-43-01.

8. Neutron Source Outage and Environmental Qualification of Electrical Equipment

On December 30, 1985, the final Environmental Qualification (EQ) modifications were completed, bringing the Neutron Source Outage which had begun on October 8, 1985 to a close. The licensee entered a transition period until the start of the Reactor Reference Leg modification. This was scheduled to begin on or about January 8, 1986.

The final EQ modification, which was completed on December 30, was replacement of the flow transmitters in the Main Steam Isolation Valve-Leakage Control System. This modification was one of the six that had not been completed by the November 30, 1985 deadline (see NRC Inspection Report 50-322/85-42). Completion of the other five modifications had been accomplished on; December 24 for the Low Range Accident Monitoring Panel, December 26 for the Hydrogen Recombiners, December 27 for the High Range Area Monitor Assemblies, December 18 for the Low Pressure Coolant Injection MG Set Power Supply and December 20 for the Raymond Actuators in the Reactor Building Standby Ventilation System. Although the EQ portion of two of the modifications, the Raymond Actuators and High Range Area Monitor Assemblies, were completed, some non-EQ problems were being worked as of the end of the inspection period.

In addition to EQ modification work, the licensee also completed other maintenance and modification activities during the neutron source outage.

The Reactor Core Isolation Cooling (RCIC) system turbine exhaust check valves were replaced. The two old valves were of the swing-check design. The licensee, based on General Electric and vendor recommendations, determined that these valves should be replaced with lift-type check valves.

(See NRC Inspection Report 50-322/85-42 for further details). The installation of these valves was completed during this inspection period.

Reassembly of the Main Generator, after work on the stator water cooling system, was complete on December 16, 1985. The licensee plans to complete all Turbine & Generator work so that it will be in a state of readiness for roll and initial synchronization by February 7, 1986.

The licensee implemented inspection and modification to Anchor/Darling swing check valves during this outage (See Section 1.8). Modification 85-267 was generated to accomplish lock-wiring of the check valves. Completion of the lock-wiring must be coordinated with other outage work due to system availability, and this modification will be carried through to the reference leg outage.

The licensee completed Fire Detection installation work, and is now in the process of testing. The licensee submitted a proposed Technical Specification change to the Office of Nuclear Reactor Regulation (Ref: SNRC-1211, J. D. Leonard, Jr., LILCO to H. R. Denton, NRC, "Licensee Change Application #2, Shoreham Nuclear Power Station-Unit 1, Docket No. 50-322, Operating License NPF-36", Dated November 16, 1985) to reflect changes in the number and type of fire detectors. The modifications to the fire detection system were made in response to the findings of NRC Inspection Report 50-322/84-46. That report required the reworking of the fire detectors in all safety-related areas to comply with NFAP Nos. 72D and 72E. On December 9, 1985 the licensee submitted an update to this Technical Specification change to account for changes made in the as-built location of some fire detectors (Ref: SNRC-1220, J. D. Leonard, Jr., LILCO to H. R. Denton, NRC, "Additional Information Concerning License Change Application #2, Shoreham Nuclear Power Station-Unit 1, Docket No. 50-322. Operating License NPF-36, dated December 9, 1985). As of the end of the inspection period, the NRC had not dispositioned LILCO's request for a Technical Specification change.

With the completion of the source outage, the inspector noted that the licensee had completed a significant number of activities with few problems. The inspector noted that activities were well coordinated among all licensee organizations to ensure that schedules were met and that problems were alleviated. The inspector noted that management of outage activities by Outage and Modifications Division personnel, at all levels, was excellent. The inspector also noted that licensee Senior management attention to the details of the outage was evident, and that this attention permitted prompt and effective action to mitigate problems that arose.

No unacceptable conditions were identified.

9. <u>10 CFR 73.71 Report</u>

On December 29, 1985, the licensee made a one-hour Physical Security/Safeguards notification to the NRC under provisions of 10 CFR 73.71.

The notification involved a security guard who was found sleeping on duty. The inspector reviewed the licensee's actions with regard to the event and found them acceptable.

10. Unresolved Items

Areas for which more information is required to determine acceptability are considered unresolved. One Unresolved item is discussed in Section 7.0.

11. Management Meetings

At periodic intervals during the course of this inspection, meetings were held with licensee management to discuss the scope and findings of this inspection.

Based on NRC Region I review of this report, and discussions with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.

The inspectors also attended entrance and exit interviews for inspections conducted by region-based inspectors during the period.