U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-322/85-22

Docket No. 50-322

License No. NPF-19

Licensee: Long Island Lighting Company
175 East Old Country Road
Hicksville, New York 11801

Facility: Shoreham Nuclear Power Station

Inspection At: Shoreham, New York

Inspection Conducted: April 10-May 10, 1985

Prepared by: Jack Strosnider 8/1/85
for E. M. Kelly, Project Engineer date

Reviewed by: Jack Strosnider 8/1/85
J. Strosnider, Chief, Project Section 1B date

Approved by: Harry B. Kister 8/2/85
Harry B. Kister, Chief, Projects Branch No. 1 date

Summary:

A special inspection by a region-based project engineer (39 hours) of allegations related to the design, inspection and testing of the Shoreham Nuclear Power Station. The allegations, summarized in an attachment to this inspection report, were presented in a private citizen's letter to the Executive Director of the New York State Consumer Protection Board. The allegations were provided by that Board to the NRC in a March 12,1985 letter to the NRC Secretary, Samuel J. Chilk. The allegations were characterized by NRC Region I as 15 separate concerns related to instrumentation and controls (I&C) calibration practices and design problems, technician and supervisor qualifications, and I&C data collection. The problems were alleged to have occurred over a three year period, assumed to be 1982 through 1984.

Two of the allegations, relating to calibration of a non-safety related extraction steam pressure switch and a laundry drain tank level alarm, were substantiated. No evidence of unsafe instrument calibration practices were iden-

tified, although the practice of tapping Weston meters requires further evaluation by LILCO plant staff. Also, the calibration of HPCI pump low suction pressure switch PS-021L requires re-evaluation of nominal setpoint and accuracy, as well as procedural verification of impulse line venting. I&C technicians and supervisors were found to be appropriately qualified. Certain allegations (i.e. Bailey 24 VDC power supplies; radwaste expansion joints; GE protective relays) were problems previously reported to and followed up by the NRC. Five of the allegations could not be conclusively assessed due to a lack of specificity.

No violations or significant safety related problems were identified in this inspection. It is requested that LILCO evaluate the subject allegations, with the exception of those previously resolved in NRC inspections (numbers 3 and 6) and provide NRC with a written evaluation of their validity and significance and any associated corrective actions.

DETAILS

1. Principals Contacted

E. Brynolfson, I&C Supervisor
T. Carrier, I&C Engineer
L. Levin, Outage/Modification Manager
J. Kammayer, Manager, S&W Site Engineering
K. Moore, I&C Supervisor
A. Muller, Quality Control Division Manager
R. Purcell, Startup Manager
R. Paccione, Nuclear Engineer
G. Rhoads, Operational Compliance Engineer
W. Steiger, Plant Manager
R. Wiemann, I&C Engineer

2. Background

This inspection addresses allegations received by the NRC in a March 12, 1985 letter (R. M. Kessel to S. J. Chilk) from the New York State Consumer Protection Board. The allegations were provided to the Board by a private citizen who had accumulated the information from Shoreham instrumentation and control technicians, referred to as "rent-a-techs", over the period of the last three years. The allegations were received by NRC Region I on March 28, 1985, and were evaluated and subsequently characterized as 15 separate concerns. These concerns are listed in the attachment to this inspection report dated April 8, 1985, entitled "Synopsis of Shoreham Allegations," which was provided to the LILCo staff at the beginning of this inspection.

3. Summary of Findings

No evidence was found within the scope of this inspection which would substantiate three of the allegations (numbers 9, 13 & 14) relating to training, qualifications and experience of I&C technicians and supervisors. Three allegations (numbers 3, 6 & 8) relate to issues previously reported to the NRC, which are either being followed or resolved. Four allegations (numbers 1, 5, 11 & 12) lack specific information which would enable conclusive evaluation.

Two of the allegations (numbers 4 & 15), which refer to specific non-safety related instrumentation associated with low pressure steam interlocks and radwaste laundry tanks, were substantiated. However, those instances appear to have been isolated cases of errors made by personnel not generally involved in safety-related activities. Two allegations (numbers 2 & 7) were found to be substantiated in part although the practice of tapping Weston meters (Allegation Number 2) during calibration requires further evaluation by LILCO staff. The HPCI low suction pressure switch PS-021L (allegation number 7) was found to have had a previous problem with head correction which has since been corrected; however, no traps were apparent, as alleged, with the configuration of installed impulse tubing. Allegation number 10 was not substantiated.

While specific source(s), dates and (in most cases) instances for these allegations were not provided, the information available suggests the following. The programs at Shoreham affected were the end of the pre-operational test effort (1982) and the beginning of preparations for eventual plant operation (1983-1984). Two corresponding plant activities were involved: (1) the LILCO Start-up organization's initial calibrations performed as part of Checkout & Initial Operation (C&IO) testing, and, (2) the plant staff I&C Section, which reports to the Maintenance Division Manager, and their initial development of surveillance and preventive maintenance procedures for instrument calibrations. It should be noted that instrumentation surveillance was not required to be performed until December 7, 1984, when a low power license was issued for Shoreham, although LILCO had been implementing the program for approximately 18 months prior to that date.

Based on the findings of this preliminary inspection, the licensee is being requested to respond to all of the allegations except those reported and resolved in previous NRC Inspections; namely, allegation numbers 3 and 6 (Reference Inspection Report No. 50-322/83-05 items 03 and 11); and while allegation number 8 concerning protective relays is most probably the subject of a previous construction deficiency (CDR number 82-06) reported to the NRC in April-May 1982, the licensee is also being requested to address this allegation.

4. Allegations

4.1 Motor-Operated Valve Cycling

An alleged design error, prior to pre-operational checkout and initial operation (C&IO) testing on an unspecified motor-operated valve (MOV) located on the Turbine Deck, allowed this valve to "continue to cycle...after being powered". The valve was "signed-off and approved," but allegedly should not have been.

4.1.1 Findings

There are a total of approximately 530 MOVs in the plant, and an estimated 266 of these are in piping which involves safety-related systems. The general condition was discussed with licensee I&C and Test personnel, none of whom remembered an instance which occurred during the pre-operational test program that resembled the alleged problem.

The problem is most likely restricted to non-safety related systems, since there are only four safety-related MOVs in the vicinity of the Turbine Deck (elevation 63), and these are on steam lines located between elevations 44 and 51. The problem, as alleged, implies initial problems with the control circuits for the MOV in question.

In general, separate MOV circuits exist for opening and closing a valve, and these are both electrically and mechanically interlocked. The alleged cycling problem could have occurred because of limit and torque switch settings, or, for example, a level controller affecting the valve's control logic. The problem, since it is alleged to have occurred prior to C&IO testing, would have been restricted to the time after acceptance of the valve by the Startup Group (from Construction) during which wire checks and motor "meggaring" occurred. The jurisdictional red tag would then be lifted and a static valve stroke performed (under "zero" process conditions; i.e., no fluids or pressure) after which the torque and limit switches are set up. While these are all required prior to the first component C&IO test, it was typical to have multiple C&IO's performed before the system flush and functional testing which completed the pre-operational activity for the valve in question.

Following turnover of the system/MOV to Plant Staff from the Startup Group, Operations personnel have now had approximately two years during which corrective and/or preventive maintenance would have most likely been performed. Administrative procedures require preventive maintenance stroke testing for non-safety-related MOVs at least once every two years. Further, since the valve in question probably involves a steam or steam support system, startup testing during the Power Ascension Program will also exercise MOVs and detect potential problems with their control circuits.

4.1.2 Conclusion

While no specific MOV was identified by either the allegation or this inspection, the time frame and system(s) affected suggest that the problem would: (1) be restricted to a non-safety-related system, and (2) have little or no potential of going undetected beyond the initial C&IO testing performed more than two years ago. This alleged design error, while possibly having occurred, is also the very type of problem for which the progressive levels of testing (i.e. C&IO, Preop., Startup and Maintenance) employed at Shoreham are intended to surface and correct.

4.2 Tapping of Instrumentation During Calibration

During calibration of instrumentation, "tapping" was done which allegedly defeats the "hysteresis effect" and thereby invalidates the calibration. A specific example is Weston indicators, "found throughout the plant", which would otherwise fail their calibration if not tapped. This tapping is alleged to be done in the presence of QC personnel, who then "sign-off on this fudged data".

4.2.1 References

- -- Heise Gauges Technical Manual
- -- Process Instruments and Controls Handbook, Second Edition 1974, edited by D. Considine pp 1-23 through 27
- -- Shoreham Procedure (SP) No.46.030.01, Revision 1 (1/22/81); Calibration of Panel Mounted Meters.
- -- Shoreham Procedure (SP) No. 46.030.02, Revision 0 (1/8/83); Calibration of Electrical Panel Mounted Meters.
- -- NRC Inspection Report Nos. 50-322:
  84-04, Detail 2.2.4 (pp 8, 9), issued May 1, 1984.
  82-34, Details 7 and 8, issued January 3, 1983

4.2.2 Findings

Hysteresis is defined in the Process I&C Handbook as "... the maximum difference for the same input between the upscale and downscale output values during a full range transverse in each direction". That portion of the observed difference between upscale and downscale readings, which is due to friction or 'play' between the elements of an instrument, is termed "dead band". The remaining difference is attributed to what is termed hysteretic error."..where output is dependent on the history of prior excursions and the direction of current transverse".

In practice, a dead band (or sensitivity) test could be performed to distinguish it from a true hysteretic error. It is normal procedure to tap an instrument to observe its sensitivity. This does not invalidate a calibration, nor does it defeat the hysteresis. Rather, it is the only means of distinguishing between frictional dead band errors and the pure hysteretic effects. The following are steps from the Heise Gauge Manual section entitled "Check For Hysteresis":

1. Convert the gauge to a dead weight tester in a vertical operating position.

2. Set the pointer to zero using the dial adjustment.

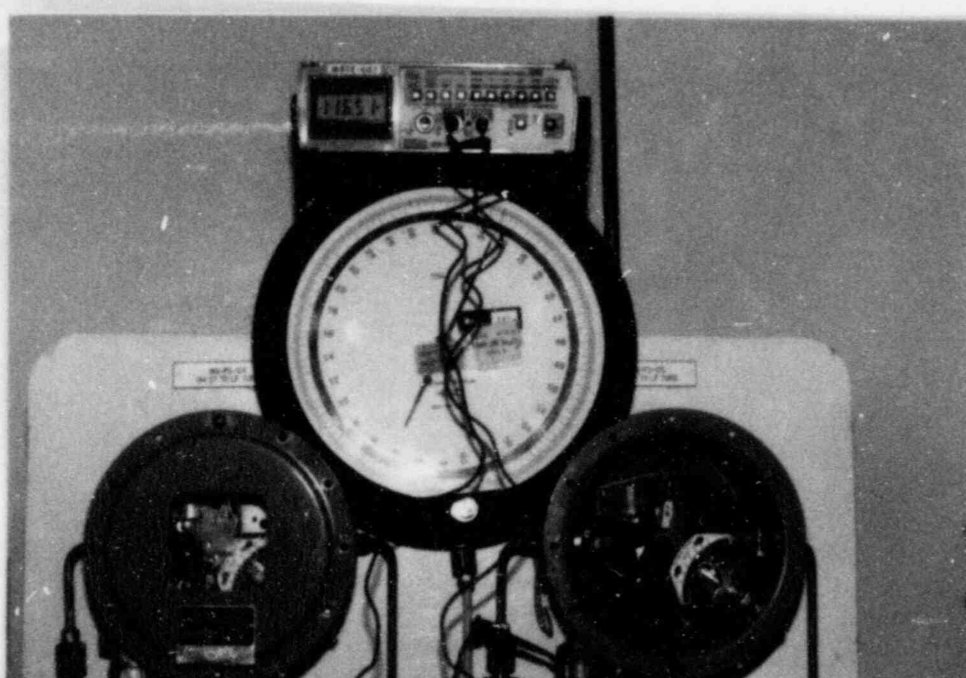
3. Applying the pressure slowly, load the gauge to one-half scale pressure and record the reading.

4. Load to full scale pressure, release to one-half scale

pressure and compare the readings.

5. If the second reading is higher than the first it may be caused by either hysteresis or friction. With dead weight still at one-half load, tap the gauge gently. If the pointer returns to substantially the original one-half load reading, the difference in readings was caused by friction. If the amount of tap is not excessive it might be considered satisfactory for use. It is normal procedure to tap an instrument to observe its sensitivity. If the tap is excessive, it is usually remedied by cleaning the mechanism with solvent such as ether, carbon tetrachloride, Freon, etc.if after tapping the gauge the pointer still reads higher than the first reading, the cause is hysteresis. Increased hysteresis effect may be brought about by crystalization of the Bourdon tube due to excessive cycling. A similar condition may result from exposure to excessively high pressure causing a partial fracture of the tube. A new tube is the only remedy for these conditions and it should be installed at our plant.

The following picture depicts a Heise gauge used to calibrate the pressure switches which are the subject of allegation number 4 (detail 4.4 of this report).



(Note: The Heise gauges are precision Bourdon tube pressure devices used as Measurment and Test Equipment (M&TE) standards to calibrate plant-installed instrumentation).

Shoreham Procedures 46.030.01 and 02 provide instructions for the calibration of panel mounted meters, including the Weston Models 1201 and 1202, and the GE Model 180. Weston Model 1201 meters are located in main control room panels and provide remote visual indication of parameters such as level, temperature and pressure in various systems via small (e.g. 4-20 milliamps) DC input signals. Weston 1201 and 1202 meters are also used in electrical panels located in the main control room to provide remote visual indication of voltage or current (including watts, vars and frequency) via AC current or potential transformers. The GE Model 180 meter is similar to the Weston, with only a slight difference in accuracy. There are 390 Weston meters (and approximately 20 GE-180s) installed in main control room panels, and an unspecified small number installed at the Remote Shutdown Panel. All of these meters are seismically-qualified, but more than 90% are classified as non-safety-related (Category 2) devices.

There are 100 Weston meters (of the total 390) which are voltage or current-indicating, and these are found on the diesel panels in the main control room. Procedure SP 46. 030.02 is used by the LILCO Meter Department to calibrate these devices on a once per 12 month cycle. Procedure Step 8.6 requires the following:

Take three sets of readings (as found) at each cardinal point, up scale, down scale, and down scale tapped.

The calibration data are recorded on an Electrical Panel Mounted Meter Data Sheet in three columns entitled Up, Down, and Tap. The down scale tap serves to distinguish between dead band and hysteretic error inherent in the device. The tap discriminates between internal friction or play (e.g. dirt or loose mechanical obstruction) and true hysteresis present in the device.

Two examples of this type of calibration were investigated. Calibration of Safety-related meter R22 * MCB101-VM, used to remotely indicate voltage on emergency bus 101, was reviewed. The meter spans a range of 0-5250 volts, using six major (cardinal) divisions, with a required accuracy of 2% full scale. Since there are 10 minor divisions per major division, the required accuracy is ±1.05 minor divisions (equivalent to ±105 Volts). As found calibration data taken on May 21, 1985 were as follows:

Scale Mark (Volts x 1000)	Upscale	Downscale	Tapped
	(in minor divisions off mark)		
0	+.1	+.5	+.1
1	-.2	+.2	-.1
2	-.4	+.2	-.1
3	-.4	0	-.2
4	-.6	+.3	0
5	-.6	-.3	-.3
5.25	-.25	-.25	-.1

This calibration was approved on May 24, 1985, since all 21 readings were within the required accuracy of 1.05 divisions. The maximum inaccuracy found was within roughly half of the required limit. Total hysteresis (the difference between columns 1 and 2) was a maximum value of 0.9 divisions at an input corresponding to 4000 volts. Of that total, only one-third was attributable to dead band, while the remainder (the difference between columns 1 and 3) is a pure hysteretic effect. This was the fourth successful calibration of this meter since the initial C&IO on October 6, 1982; the last three being performed by plant staff. No trend has been noted with excessive drift, since the largest inaccuracy found has been consistently 0.4 to 0.6 divisions for over 2½ years, which is an accuracy to within ±50 volts.

Non-safety related meter B31-MG-001A is used to remotely indicate recirculation pump motor-generator set output power in a range of 0-6 megawatts. The required accuracy is 3% of full scale or ± 1.8 minor divisions (equivalent to ±180 kW). As found calibration data taken May 30, 1985 for this watt-meter were as follows:

Scale Mark (Megawatts)	Upscale	Downscale	Tapped
	(in minor divisions off mark)		
0	+.9	+1.0	+.9
1	-.1	+0.2	0
2	+.2	+1.0	+.7
3	+.4	+1.2	+.9
4	+.6	+1.5	+1.3
5	-.2	+0.7	+0.4
6	-1.8	-1.4	-1.4

This calibration was performed under maintenance work request (MWR) 85-2904 for troubleshooting of a transducer in the same loop, and was approved as-found since all 21 readings were within the required accuracy. The maximum inaccuracy found was the upscale reading at 6MW; maximum total hysteresis exhibited at 4-5 MW was 0.9 divisions.

The remaining 290 Weston meters, which are not voltage or current-indicating devices, are calibrated in accordance with Procedure SP 46.030.01 by I&C staff technicians. This procedure currently does not require a downscale tap reading, although discussions with I&C supervisors indicate that these instruments are also routinely tapped during their calibration. Since the Instrument Data Sheet only records up and down scale data, there's no distinction between a tapped and un-tapped condition. An example of this type is non-safety related Reactor Water Cleanup system temperature indicator TI-005A located on main control room panel 614. The instrument accepts a 4-20 mA input signal and has a range of 50-250°F with a 2% required accuracy (or ± 4 degrees). As-found calibration data (all recorded in °F) taken on December 4, 1984 were as follows:

Input	Increasing	Decreasing
50	52	52
100	101	102
150	151	152
200	201	202
250	250	250

While the data are within the required accuracy, with little observed hysteresis, the use of a tap cannot be ascertained. If its assumed that a tap was applied prior to recording the decreasing readings, then the difference between readings at any given input is a pure hysteretic effect (a maximum value of one degree in this case). However, the dead-band error is historically unknown for this and other devices calibrated similarly in accordance with SP 46.030.01.

There have been a number of operational difficulties experienced with Weston meters at Shoreham. This was the subject, in part, of special NRC Inspection No. 84-04, conducted in February 1984 at Shoreham, in response to a series of allegations, one of which concerned the use and calibration of Weston meters. As stated in detail 2.2.4 of the report documenting that inspection, very few of these meters are safety-related, and none provide an alarm or a direct control function. Further, there were no Technical Manuals provided for those indicators due to their relative simplicity with respect to operation and adjustment. An external front adjustment is provided, and disassembly for repair or cleaning is also easily accomplished. However, total replacement is not feasible since a spare inventory problem exists because Weston Aerospace has gone out of business.

The licensee has recognized this problem, and is currently developing a long-term replacement program for these meters. Alternative suppliers have been difficult to find, Westinghouse being the only contracted source to date. The Westinghouse meter is of different dimensions, and will require panel console modifications. Weston sold their business Metermod Co., which is in the process of qualifying a new meter similar to the original Weston device but with a more accurate internal movement manufactured by the Triplett Company.

Historically, a number of problems have been experienced, (and resolved), with Weston meters. There has been a performance trend of degrading accuracy over time, with attendant calibration difficulties and failures. Dating back more than five years, these problems have included:

- replacement Category I power supplies to bulbs, for more reliable back-light illumination, to read the indicator in event of a blackout.

- installation of a temperature compensation component to counteract a resistive change internal to the meter when the back panel door (open during calibration) was closed and the display consoles were energized. The higher temperatures were causing the meters to drift out of calibration.

  during re-design of the main control panels, iron filings were produced which were subsequently found inside of some meters. The meters were cleaned and repaired, and new gaskets were installed for more effective sealing.

- an input impedence problem whereby Weston meters manufactured in California required 5 thousand ohms while those from New Jersey required 100 thousand ohms. The resistance of loop wiring had to be closely evaluated to properly match impedences between the transducer and the Weston indicator for more accurate calibration.

- a recent effort to optimize and sharpen the projected image on these indicators by cleaning the lens and alignment of the bulb filament during preventive maintenance.

4.2.3 Conclusion

Tapping does not invalidate a calibration; it serves to distinguish between dead band and pure hysteretic error.

Tapping is procedurally required by SP 46.030.02 for electrical panel mounted Weston meters, although the downscale-tapped reading is an "extra" piece of information which is nonetheless recorded. The difference between the upscale and the downscale-tapped value is a measure of pure hysteresis, while the difference between the downscale and the downscale-tapped readings is a measure of internal friction or play which is more easily repaired by cleaning or minor adjustment. The inclusion of a tapped reading for calibration of these meters is most likely because of the experience and broad power plant background of the LILCO Meter Department, the group which calibrates these devices.

On the other hand, tapping is not required in the calibration of panel-mounted meters under SP 46.030.01, although tapping of those meters during such activities is a common practice amongst I&C technicians in the plant staff. The downscale (or decreasing) reading recorded in these cases does not distinguish between tapped or untapped; therefore, either practice could've occurred previously. Strictly speaking, a meter whose as-found (untapped) downscale value exceeded the required accuracy should fail its calibration, even if a tap subsequently restores it to within the limit. Calibrations performed under SP 46.030.01 could've possibly happened as alleged, especially considering the extensive difficulties experienced with Weston meters, although no instances to support that claim were identified. To avoid future uncertainty, and for consistency with the electrical panel meters, SP 46.030.01 should be evaluated for incorporation of a procedurally-required downscale tap, to be recorded with future calibration data.

While there have been design and operational problems with Weston meters, including difficulties in maintaining their calibrations within required accuracy, these problems have all been resolved to-date. Greater than 95% of the total 390 Weston devices are non-safety related; all of these devices are currently in at least their third calibration cycle; and, a long-term replacement program is underway. The meters are generally capable of retaining the required operational accuracy between calibration cycles. Also, a spare parts inventory problem has been recognized and is being resolved for long-term operational considerations.

4.3 Inadequate Power from Bailey Current Supplies

Bailey 24 VDC power supplies were alleged to inadequately power instrument loads such as Rosemont transmitters, causing voltage drops and inaccurate calibrations. Instruments were alleged to be required to be "turned off" in order to perform the calibration.

4.3.1 References

-- NRC Inspection Nos. 50-322;
83-05, Detail 8, (p 21-22), issued March 30, 1983
84-14, Detail 2 (p 24-25), issued July 16, 1984

-- LILCO letter (SNRC-886) letter to NRC dated May 9, 1983

-- E&DCR F-36983D, April 1983

4.3.2 Findings

NRC Inspection Report 83-05 identified questionable performance during C&IO testing in 1981 of 24 Volt DC supplies used to power safety-related instrumentation. Voltage drops between the power supplies and loop instrumentation had overdriven the supplies, exceeding their 20 ampere output rating and preventing maintenance of the 22 VDC minimum voltage required at the power input terminals for instrument loads. Four Bailey Meter Company 120 VAC /24 VDC power supplies installed in the Relay Room were turned over to the LILCO Production staff upon completion of admittedly "inconclusive" C&IO testing. A violation was assessed by the NRC for failure of that testing to demonstrate power supply conformance to design specifications. Unresolved inspection item 83-05-11 was initiated to track related concerns with the in-service operation of these supplies.

The LILCO response to this violation described retesting performed on April 28, 1983, to evaluate power supply performance under maximum and minimum conditions. One case of degraded operation was identified where the possibility existed of not meeting specified voltage levels (by a small amount) at one location in the system. Under rated full-load conditions, the minimum 22 VDC input voltage supplied from a single power supply may not have met the minimum 18 VDC criterion recommended by the supplier for a Rosemont transmitter.

This was because of a voltage drop in power supply output wiring contained within Panel H21*PNL 060. Conductor sizes were upgraded in a portion of the load-side circuit to eliminate this problem. Normally, both power supplies in a circuit are operated at loads less than 50% capacity. All other safety-related Bailey 24 VDC power supplies were verified to perform within design specifications under full connected load conditions. Station Procedure 46.007.02, was developed for functional testing to demonstrate acceptable in-service operation. The corrective action was reviewed during conduct of NRC Inspection 84-14, and found to be acceptable.

4.3.3 Conclusion

The alleged degraded voltage problem with Bailey power supplies was true, although no instances of inaccurate calibrations resulting in having to "turn-off" instruments were substantiated as part of this inspection. While such instances may have occurred, the problem was identified in 1981, corrected by LILCO in 1983, and resolved to the satisfaction of the NRC in 1984. Periodic surveillance of these supplies is currently performed to ensure their proper performance.

4.4 Pressure Switch Head Correction

Pressure switches PS-124 and 125, used as interlocks in a reheat steam system on Turbine Building elevation 37', were alleged to have an uncorrected design error. The error, which had previously been brought to the attention of a "Technical Support" group, was the lack of a head correction factor during initial calibration of the switches. This caused the switches to be allegedly "over-ranged", and therefore "made" all the time.

4.4.1 References

-- C&IO Test Procedure for Main Steam System, Revision 3, February 1, 1977 (Test results conducted and approved on 6/26/81, 6/3/82, and 7/22/82).

-- Test Loop Diagram - 1N11024, Revision 3; Low Pressure Turbine Inlet Pressure.

-- Main Steam Flow Diagram FM-29B, Rev. 17.

-- Elementary Diagram ESK-6N1126, Rev. 5; Steam Isolation and Drain Valves Interlock Circuit.

-- Logic Diagram LSK-3-1.2E, Rev. 7; Moisture Separator Reheater Steam Control.

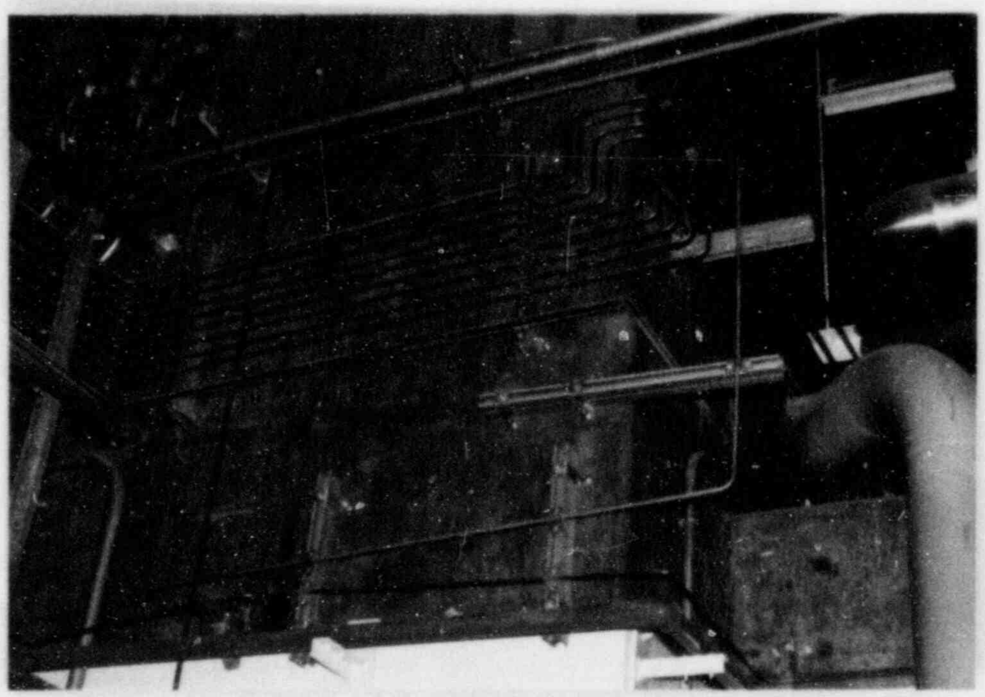
-- Instrument Calibration Data Sheets for 1N11-PS-124, 125 and PT-015 A&B.

-- Maintainability Task Force Problem Identification (un-numbered) dated June 18, 1983.

4.4.2 Findings

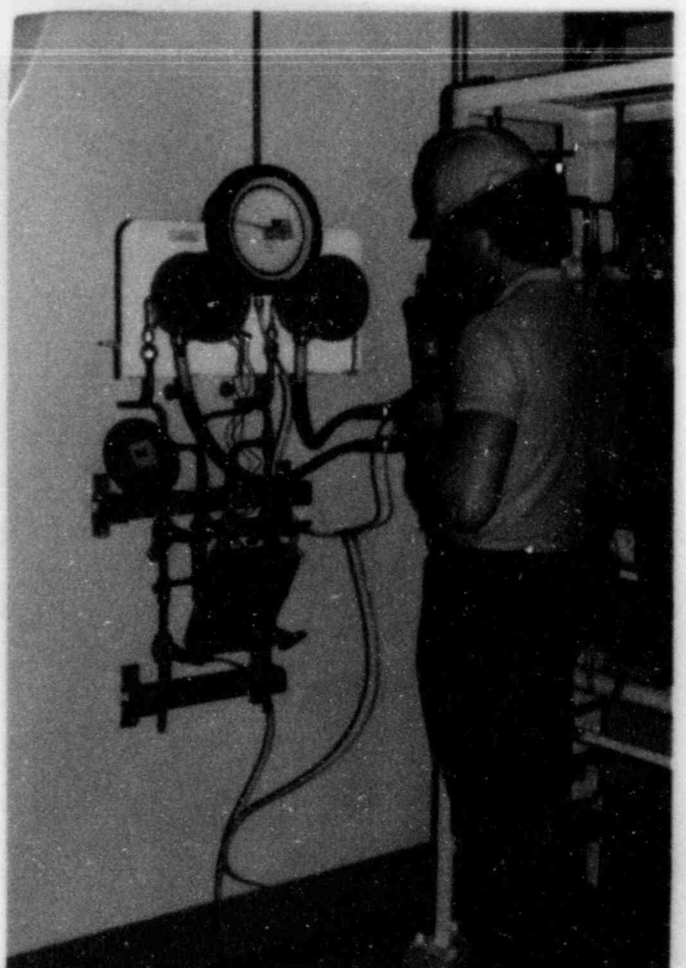
Pressure switches PS-124 and 125 for the main steam (N11) system are located approximately 61 inches above Turbine Building floor elevation (37'-6"), and sense low pressure turbine inlet steam conditions. Both switches are fed off of a common tap from a 36-inch steam line (el. 68'), downstream of combined intercept valve (CIV)-3 for Turbine 1B. That line supplies steam from the high to the low pressure turbines via Moisture Separator Reheater (MSR) E098-B. The switches are non-safety related and act as permissive interlocks which close when steam pressure falls below 24 psig (PS-125) and 4 psig (PS-124), corresponding to 20% and 10% turbine loads, respectively. Actuation of these switches will satisfy logic in the open and close control circuits of isolation valves 1N11*MOV 031A and B for second-stage reheating steam supplied to the MSRs, and the circuits for MSR condensate drain valves SOV 07A and B, 08A&B and 09A&B. The switches are manufactured by Mercoid and have a required accuracy of ±2%.

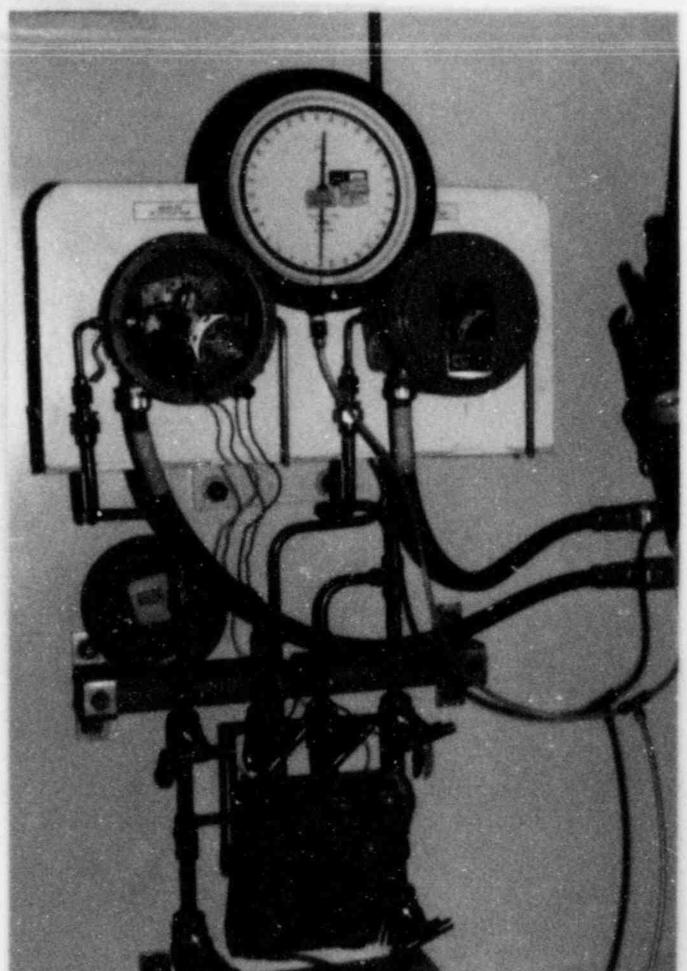
Both switches are installed approximately 307 inches below the location of the common tap, and require a static pressure head correction of 11.1 psi above their nominal control settings. (See picture below of a portion of the field-routing tubing).



Both switches were calibrated on three separate occasions between the period June 1981 - July 1982 as part of preoperational C&IO testing. The first (and only - prior to this inspection) calibration of these switches by plant operations staff occurred on September 13, 1983. None of the initial calibrations incorporated the required 11.1 psi correction factor to account for the difference in elevation between the sensors and the piping tap.. The inspector observed the calibration (see pictures) of these switches on May 8, 1985, which incorporated the additional 11.1 psi correction factor under 85-2499, as follows:

(Accuracy ±2%)	Setpoints (psig) Increasing/Decreasing) Nominal	As Found	As Left
PS-124 (±0.3 psig)	4.0/5.5	4.2/6.0	15.0/16.7
PS-125	24.0/25.5	24.5/26.9	34.7/37.3





These switches are non-safety related and generally require calibration every two years. The nominal range while not specified on the Instrument Data Sheets, is typically 30 psig. The new corrected settings for PS-125 slightly exceed that value, although the recent calibration was successful. The required accuracy of ±2% has been stringently applied to the nominal setpoint, as opposed to a percentage of full range. For example, PS-124 is intended to close and allow for isolation of reheat steam to the MSR (and open the MSR drain) when steam pressure is less than 4 psig (equivalent to below 10% load) and decreasing; the switch opens when pressure is greater than 5.5 psig (equivalent to above 15% load) and increasing. Adding the 11.1 psi correction factor results in settings of 15.1 (decreasing) and 16.6 (increasing) and a required accuracy of ±2% or 0.3 psi. A successful calibration must therefore result in a trip at falling pressure within the range of 14.8-15.4 psig, and reset at rising pressure within 16.3-16.9 psig.

During operating conditions, there would least 11.1 psi sensed because of the static column of condensed steam above the switches. However, if uncorrected, the PS-124 contacts would've constantly remained open, since the trip setting could never have been reached as long as fluid was present in the piping. The effect of this error on the MSR reheat steam supply valves MOV-031A and B would be to prevent their automatic closure for isolation of the MSRs under these conditions. Also, the MSR condensate drains would not have been opened. Dynamic calibration of these switches has not yet been performed since there has been no steam produced at process conditions in this piping to-date.

An I&C Supervisor, who was involved in the initial C&IO calibration program, as well as the subsequent development of the surveillance program, produced a Maintainability Task Force Problem Identification Form which had been initiated by a contract I&C technician on June 18, 1983, describing the above uncorrected problems with switches PS-124 and 125. The form was never presented for MTF consideration and, in retrospect, was not the most appropriate means of effecting proper resolution. Other conceivable administrative solutions (at that time) that could've been used were C&IO re-test, initiation of an LDR, E&DCR or MWR, or a simple note (which the unprocessed MTF Form was, in fact) attached to the soon-to-be completed Data Sheets for these instruments.

4.4.3 Conclusion

The allegation was substantiated in that no head correction factors were applied to PS-124 and 125, in spite of the problem being brought to the attention of an I&C supervisor.

This "design error" was actually an oversight by the Startup Test Engineer who approved the previous C&IO test results but failed to note the absence of the necessary head correction. Similar pressure switches for extraction steam line drains, located adjacent to PS-124 & 125 and off of the same steam line tap, did have a proper correction of 12.5 psi for static head. Pressure transmitters N11-PT-015 A/B, which provide remote indication (0-300psi) and computer input were originally corrected in February 1981 for the difference in elevation between tap and transmitter. This suggests that the error associated with PS-124 & 125 was most probably an isolated case.

Upon addition of the 11.1 psi correction to PS-125, the allowable trip and reset points fall within a range of 34-37 psig. This is slightly "over-ranged", assuming the Mercoid switch nominal range (unspecified on the I&C Data Sheet) is 0-30 psig. However, a successful calibration was performed on May 8, 1985.

Regarding the switches being "made" all the time, PS-124 would not have enabled automatic closure of MOV-031A&B, or closure of the MSR drains, upon decreasing low pressure steam conditions below 4 psig (between the HP and LP Turbines). The consequence of that condition is a balance-of-plant efficiency consideration, and a minor operational problem in that the MSRs would not be automatically isolated and drained. Also, no steam has yet been introduced at process conditions to this equipment although this will ultimately occur during the Power Ascention Test Program. The error with these switches would most likely have been discovered at that time.

4.5 Flow Indicator

An unspecified "Reactor Cooling Water" system flow indicator was alleged to not meet "required specifications".

4.5.1 References

-- FSAR Section 5.5.8, Reactor Water Cleanup (RWCU), Figure-5.5.8-1 (P&ID).

-- Instrument Data Sheets for RWCU System Flow Indicators FI-11, 13 and FDI-10.

-- Shoreham Procedures SP44.709.01 and 08.

4.5.2 Findings

Although the allegation is generally stated, with no specific system or instruments identified, the wording suggests a "Reactor" water system with possibly intricate flow measurement provisions. The RWCU (G33) system meets these criteria, although the phrase "not meet required specifications" could imply any of a number of flow indicator problems.

Restricting this discussion to the calibration of RWCU flow the loop calibration of the three flow elements used to calculate reactor coolant pressure boundary leakage is of significance and merits discussion. Discussions with I&C personnel and GE test engineers verified this that the calibration, performed in accordance with SP44.709.01, is difficult and confusing to set up.

RWCU is a system used to continuously remove primary coolant impurities by taking suction off of both recirculation pump suction lines and the vessel bottom head, cooling that flow and running it through demineralizers, and returning it to the vessel via the main feedwater piping. During normal reactor operation, the system recirculates a flow of between 240-266 gpm, with provisions for blowdown of a portion to the main condenser or waste surge tank. The system also serves to control primary water volume during other plant conditions (i.e. Startup, Shutdown, Hot Standby) as well as to minimize thermal stresses in the recirculation piping. Flow transmitters monitor RWCU inlet, blowdown and return flow; output signals are processed through square root extractors to remote Weston indicators FI-11 and 13 located at main control panel 602. The transmitters also input into a flow totalizer (FN-10) which calculates a temperature-compensated differential flow measurement that: (a) is read from a "total" flow indicator FDI-10; (b) initiates RWCU isolation for a preset flow imbalance (normally 7%) indicative of primary coolant leakage; and (c) is annunciated in the main control room. The transmitters, extractors, and totalizer are safety-related Category I devices which are surveilled and calibrated on an 18 month cycle. The flow indicators are non-safety related, although they're also calibrated concurrently as an 18 month preventive maintenance activity.

Initial C&IO calibrations were performed for the flow indicators in August 1981. Subsequent plant I&C staff calibrations were performed for FI-13 (November 1984) and FI-11 (March 1985). FDI-10 will be calibrated as part of the entire loop, including leakage calculation and system isolation checks, during the Power Ascention Test Program when rated conditions (532 °F coolant) are achieved.

4.5.3 Conclusion

Based on the available information, one possible example of the alleged problem could involve the RWCU system flow totalization network. The loop calibration has not been performed for rated conditions. No outstanding design problems were evident when the subject was discussed with responsible I&C and test engineers.

4.6 Generic Problem with Radwaste Expansion Joints

A generic problem was alleged with radiation waste feed line expansion joints.

4.6.1 References

-- NRC Region I Inspection Report Nos. 50-322:

84-18, Detail 5; issued June 5, 1984
85-18, Detail 2.6; issued April 9, 1985

-- E&DCR F-25796A

4.6.2 Findings

On May 9, 1984, 7000 gallons of uncontaminated water were spilled from the regenerative evaporator into the Radwaste Building floor drain filter room. A flexible rubber piping joint ruptured at the evaporator's discharge pump, causing a 3/4-inch diameter hole in the 12-inch discharge piping. Minor flooding, of about 2-inches of water on the floor, occurred because a floor drain sump pump had been out of service at the time for sump cleaning. No damage to any equipment was incurred, and cleanup was completed within 3 hours. The plant was in a preoperational test status at the time, and fuel loading was still 6 months away.

Inspection of the ruptured joint revealed that it had been improperly installed. The joint (G11-EXJ-046) was overstretched by approximately 0.70 inches and its control rods (for proper mating) were installed with improperly-positioned nuts on the inside of the joint flange face, in violation of intended design requirements outlined in E&DCR F-25796A. This problem was reported to and followed up by the NRC, as documented in Inspection Report 84-18, and an unresolved item (84-18-01) was initiated to track its status. LILCO corrective action to-date has included a sample survey of other piping flexible joints which identified four additional instances of installation problems. Deficiency Reports (LDRs) were written to document these findings and ensure corrective action. Based on these findings, the licensee's survey has been expanded to an increased sampling of flexible joints. The four new instances involved non-safety related applications in the Turbine Building Closed Loop Cooling and Service Water systems, and the Circulating Water system. Problems typically encountered were missing or improperly adjusted control rods, undersized flange bolts and improper flange-to-flange dimensions. Recent NRC review of the status of this unresolved item is documented in Inspection Report 85-18.

4.6.3 Conclusion

The rupture of a flexible joint in a radwaste system on May 9, 1984, was identified and evaluated by both the licensee and the NRC . Possible generic implications were (and continue to be) assessed by a sampling survey of other piping system rubber expansion joints; findings to-date indicate minor problems attributable to improper installation. Unresolved item 84-18-01 will receive further review in subsequent NRC inspections.

4.7 HPCI Impulse Line Trap

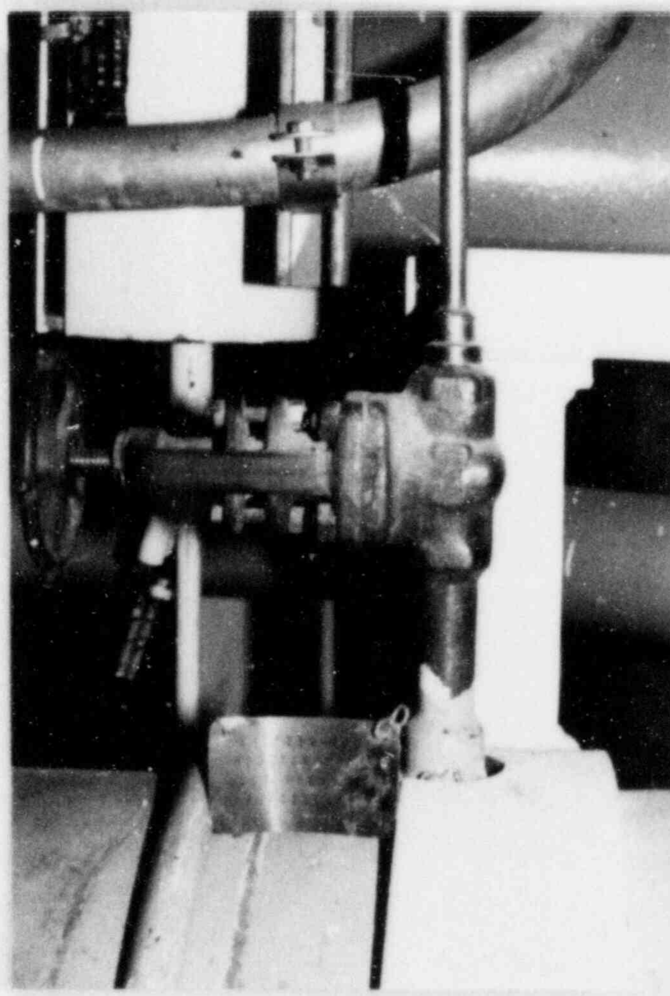
A pressure sensing impulse line, installed on the High Pressure Coolant Injection (HPCI) system, was alleged to create a "trap", presumably because of its field-run configuration. The trap was alleged to cause false indication to HPCI pump suction pressure switch PS-121L, which results in keeping the 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" had been allegedly requested (by an unidentified source); however, "the foreman told the technician that management didn't want to hear about things like this now".

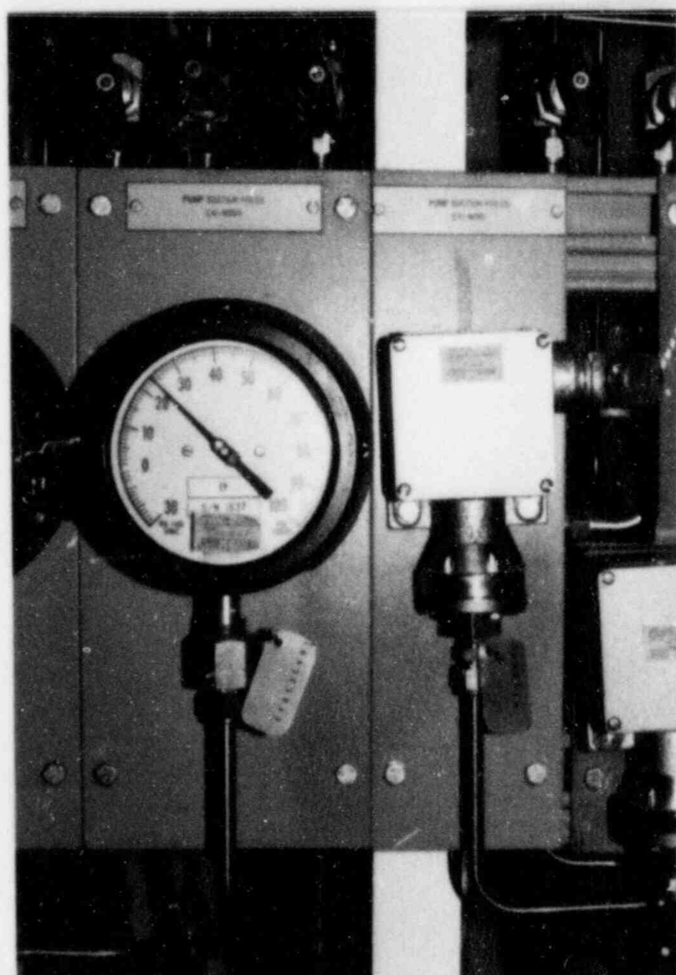
4.7.1 References

-- FSAR Table 6.3.2-2, NPSH For HPCI
-- E&DCR L-502 approved 4/30/84
-- E&DCR L-502A, approved 5/22/84
-- E&DCR L-502B, approved 8/20/84
-- HPCI Flow Diagram, FM-25B, Rev. 16
-- Instrument Data Sheets for 1E41*PS-021
-- Shoreham Specification SH1-343 (Jan. 1983); Installation of Instrument Tubing, Line Items 18.39-43.
-- GE Elementary Diagram 1.61-124M
-- GE FDDR K31-2275 issued 5/8/84, Replacement of HPCI PressureSwitch
-- MWR-83-8044; September 28, 1984

4.7.2 Findings

Pressure switch E41*PS-021L senses High Pressure Coolant Injection (HPCI) system suction pressure at a location just upstream of the HPCI booster pump. The instrument sensing (impulse) line taps off of 16-inch HPCI suction piping a point approximately five feet above the pump suction and runs vertically upwards another ten feet to the ceiling. The tubing is then horizontally run across the ceiling for a span of about 20 to 25 feet, before it drops down to PS-021L located on an instrument rack near Reactor Building floor elevation-8. The switch is 23 inches vertically below the pump suction. The estimated total run of tubing is 50 feet, from tap to sensor, with approximately 10-12 installed 90-degree bends in-between. Horizontal portions were observed to contain no "negative" slopes, or potential traps, although the typically-recommended pitch of 1/2-inch per foot of tubing towards the instrument (Specification SH1-343) was difficult to assess. The actual field condition of this impulse line resembles an inverted U-tube manometer, closed on one end with unequal size legs of roughly 10 and 17 feet. The pictures below depict the tap and sensor locations of PS021L.





The low pressure switch is designed to protect the HPCI booster and main pumps against cavitation by actuating the HPCI turbine trip logic. The required net positive suction head (NPSH), or the pressure below which pump performance tests predict that it will cavitate, is 18.0 feet of water (equivalent to 7.8 psig). This is equivalent to a vacuum condition of 14 inches (Hg.). Operation of the HPCI system was analyzed for available NPSH from its two sources of water, the condensate storage tank (55.4 ft. available) and suppression pool (35.2 ft). The system was determined to conservatively exceed the minimum required NPSH. Discussion with GE test engineers indicated that a dramatic decrease in pump suction pressure, for which PS-021L is designed, would be expected under the following conditions:

-- unexpected suction valve closure
-- HPCI quick-start with suction aligned to the suppression pool
-- depletion of CST inventory (normal HPCI water source) with failure to swap-over to suppression pool

Rated flow for the HPCI system is 4250 gpm and, since the suction piping is 16-inches in diameter where the instrument tap is located, a relatively high linear flow rate on the order of 400 feet per minute (7 ft/sec) would exist. Therefore, any of the above-possible transients would result in a rapid drop in suction pressure to the intended setpoint of PS-021L.

PS-021L was initially calibrated during C&IO testing in August-September 1981. The nominal setting specified on its Instrument Data Sheet was 15 inches (mercury-vacuum), with a required accuracy of ± 1 inch and a head correction factor of 6.2 inches. The calibrated setting, as left on September 12, 1981, was 21 inches.

The switch was later found to not consistently reset, and procurement began in April 1984 for a qualified replacement. This was accomplished by General Electric FDDR No. KS1-2275, dispositioned and approved by E&DCR L-502A on May 22, 1984. During installation and calibration of a new Static-O-Ring, Inc. switch (Part. No. 219B4965-P007) by I&C personnel in August 1984, mounting difficulties were encountered. Questions, were also formally raised related to the proper range and head correction to be applied. Stone and Webster engineering resolution was provided in E&DCR L-502B approved on August 20, 1984. The original head correction was stated to be wrong, and the switch was recommended to be set at ...14-inches Hg. (vac.) with head correction". A calibration was performed by a plant staff I&C technician on September 28, 1984, under MWR 83-8044, with a new head correction factor of 1.7 inches and a required accuracy of 2% full span or ±0.6 inches. The as-left trip setting was recorded as 13.4 inches (vacuum increasing), with a reset at 12.5 inches (vacuum decreasing).

The following evaluation of the current switch settings was made as part of this inspection:

The current head correction factor of 1.7 inches Hg. is appropriately based on the switch being located approximately two feet lower than the pump suction centerline.

The current head correction factor was properly applied to the nominal setpoint of 15 inches Hg.; that is, it was subtracted. From a vacuum condition the sensor sees a slightly higher pressure due to the static head of fluid above.

The nominal (uncorrected) setpoint of 15 inches Hg. is apparently incorrect. Assuming a required NPSH of 18 feet (water), this pressure is equivalent to 7.8 psia which is equivalent to 14 inches Hg. vacuum.

The as-left trip setpoint of 13.4 inches Hg. would most likely not prevent the onset of pump cavitation. Considering the required accuracy, the switch would be expected to trip in a 12.8-14.0 inch range. This corresponds to a process condition at pump suction of 17.5-16.1 feet of water; below the minimum required NPSH.

The as-left reset value of 12.5 inches falls outside of the newly-required setpoint range of 13.3 ±0.6, technically failing the calibration by a slight amount (0.2 inches Hg.).

Assuming the stated 2% accuracy and a head correction of 2 feet, a calibration which would ensure that PS-121L actuates a HPCI turbine trip prior to predicted pump cavitation should implement a setting which is less than or equal to 11.7 inches of Hg vacuum.

4.7.3 Conclusion

The field-run impulse line from the HPCI booster pump suction piping to PS-021L was in conformance with Specification 343, and was observed to have no obvious "traps" in its horizontally-run tubing. No apparent negative slope (pitched away from the sensor) was developed in the horizontal portions. The inverted U-tube configuration, while not required to have a high-point vent valve for proper operation, would have to be "solid" or completely filled with fluid from tap to sensor. Consideration should be given to a procedural step or caution which assures that this impulse line is vented and filled "solid" during and following any maintenance or calibration. Air pockets or non-condensible gas in any portion of the impulse line would result in questionable sensor operation. That condition (solid versus

partially-filled) was not verified during this inspection, either for the HPCI impulse line or any other similar instrument arrangements. Proper operation of PS-021L will be verified during power ascension testing as one of a number of safety-related HPCI turbine trips. The head correction factor determined for preoperational C&IO calibration in August 1981 was conservatively high and incorrectly applied (added rather than subtracted) to the required setpoint. The static head error was based on the difference in elevation between the sensor and it's tap (7 feet), instead of to the process point-of-interest or pump suction (2 feet). The 7-foot correction corresponds to 3 psi or 6 inches Hg. However, while conservatively high, this was erroneously added to the 15 inch Hg. setpoint. The as-left setting of 21 inches Hg. remained for three years. There was no requirement for HPCI system operation, or a low suction pressure pump trip, during that time. The protective trip (if uncorrected) would have occurred if needed, but not until pressure conditions at pump suction were decreasing below approximately 11 feet of water; 7 feet less than the minimum required NPSH. Thus allowing cavitation of the pumps to possibly occur.

A new replacement Static-O-Ring Inc. switch was installed as PS-021L on September 28, 1984. A proper head correction of 23 inches was applied, in the correct sense (subtracted), to the 15 inch Hg. setpoint. However, that nominal setpoint should be 14 inches Hg. if its to correspond to the required NPSH. Considering the switche's accuracy, and correcting for static head, a setting of less than 12 will ensure a trip at or before minimum NPSH. The difference in time to reach a decreasing pressure of 18 ft. of water as opposed to 11 ft. of water would predictably be about one second under rated conditions due to the large flow rates involved. Nevertheless, justification for the nominal setpoint, as well as for the as-left reset pressure which is slightly outside of the required set-range, is required.

Assuming that the impulse line is filled solid (an assumption that must be verified periodically) then there are no traps created by the instrument tubing which could conceivably affect the operation of PS-0211. This failure of the switch's contacts to close would not prevent the HPCI pumps from running. Rather, this would allow the pumps to keep running, below their limit of minimum NPSH, causing potential damage due to cavitation. The previous preoperational calibration, if unchanged, would have tripped the pumps at a short time after they had theoretically begun to cavitate.

While there were errors involved in the initial calibration of PS-021L, no evidence was found to substantiate the allegation that a foreman had discouraged an I&C technician from directing these problems to LILCO management's attention. Even if that alleged situation had occurred, the head correction error was eventually found by licensee personnel, and received appropriate engineering resolution and I&C supervisory attention.

4.8 Generic Relay Problem

A "widespread, generic" problem was alleged to exist with 12 relays in the Moisture Separator Reheater (N35) system. The problem was allegedly identified by the I&C group, and involves the '86' relays, which are also used on the diesel generators. Some actual failures were alleged to have occurred.

4.8.1 References

- Station Modification (SM) 85-021

- Shoreham Construction Deficiency Report No. 82-06; reported by phone to NRC Region I on April 7, 1982.

- General Electric letter to LILCO dated 3/26/82 (SAL 721-PSM-167.1).

- LILCO letters to NRC Region I dated 5/13/82 (SNRC-697) and 2/7/83 (SNRC-819).

- NRC Region I Inspection Report No. 50-322/83-16, Detail 3 (p5) issued June 7, 1983.

- FSAR Figures 8.3.1-5,6,7;
  4160 Volt Single Line Diagrams

4.8.2 Findings

A constructi deficiency was reported by LILCO in accordance with 10 CFR Part 50.55e to NRC Region I in April 1982. The problem was identified by General Electric during routine factory testing of GE "SAM" type relays, a time delay device usually used in conjunction with an over current or under voltage protective relay. The problem involved the separation of a contact button from the contact arm on a subcomponent of the SAM relay; a standard switching or "telephone" relay manufactured by the Liberty Control Company and integrally mounted on the SAM. The suspected deficient batch of relays was limited to those manufactured between July 1980-February 1982.

The SAM relay is generically known as a '62' relay (in accordance with IEEE standards) or a general time-delay relay which, if activated and after it times-out, operates the integral telephone relay. Those output contacts are, in turn, in series with overcurrent protective relays which are then energized and "locked-out". The typical over current device used at Shoreham is a GE Type HEA or '86' relay. The SAM '62' relay is therefore a permissive for the HEA '86' protective lockout relay. The SAM relay allows for the momemtary in-rush of surge current on a 4160 Volt emergency bus, when closing a normal service station transformer (NSST) tie-breaker and loading that bus, without tripping bus switchgear on an over-current condition. This would occur, for example, when loading a 4160 Volt bus by closing a tie-breaker from the Normal Station Service Transformer (NSST) or Reserve (RSST) unit.

GE provided a list of all relays at Shoreham incorporating an integral telephone relay from Liberty. A list and location of 71 potentially defective relays was prepared by Stone & Webster in September 1982 (none from the moisture separator drain system). Subsequent field surveys found 14 safety-related and 27 non-safety related relays that had suspect or missing QC date codes; however, no actually defective relays were found at that time. On December 22, 1982, one actual failure was reported by the LILCO Startup group for a Type NGV relay (which also uses the integral telephone relay) on the LPCI Motor-Generator Sets. This relay was later evaluated by Engineering, found to be unnecessary, and was removed. The NGV is an undervoltage '59' relay used on the tie-breaker for all three TDI diesel generators.

A visual surveillance has been performed as a monthly preventive maintenance activity by the I&C group since February 1983 for all safety-related Class 1E relays; no failures have been experienced in these 30 months. NRC Inspection 83-16 conducted at Shoreham in May 1983 reviewed the status of this item. There are currently 12 safety-related Class 1E relays which are identified for eventual replacement:

Type	Function	Number
SAM	NSST #1 Tie-Breaker	3
SAM	RSST #2 Tie-Breaker	3
SAM	4.16 kV Tie-Breaker	3
NGV	TDI diesel Tie-Breaker	3

The replacement of these relays is being implemented by Station Modification 85-021, which is scheduled for evaluation by the Review of Operations Committee by the end of June 1985.

4.8.3 Conclusion

The alleged generic problem was not associated with the Moisture Separator Reheater (N35) system, but did involve Class 1E 4160 Volt switchgear, as well as the TDI diesel generators. The problem does involve the '86' relays, although indirectly, in that the GE SAM "telephone" relay output contacts are in series with the GE HEA protective '86' lockout relays. One actual failure occurred at Shoreham, on December 22, 1982, involving a GE NGV relay which used the Liberty subcomponent in question. Use of that particular relay (in the Low Pressure Coolant Injection system MG sets) was eliminated, although the Type NGV relays are used for TDI diesel generator under voltage protection.

The problem was found by GE (not the I&C group) in early 1982, and evaluated and reported by LILCO to the NRC later that year. Although initially evaluated as potentially widespread, attention was focused within a year to a total number of relays less than 40, of which 12 are Class 1E and will be eventually replaced. In the interim, a monthly visual surveillance has verified no failures in the past 30 months. The surveillances will be continued, and the item will be followed as part of NRC inspections, until the permanent replacements are in place and tested.

4.9 I&C Technician Qualifications

I&C technicians were alleged to: (1) not have annual eye tests; (2) have no "mandated" required reading; (3) not have orientation classes made "current"; (4) run tests and sign off work, although "uncertified"; and (5) have been employed on the basis of resumes which did not match their "security clearance papers".

4.9.1 References

- NRC Inspection Report Nos. 50-322:
  82-14, Detail 2.2.2.3 (p-5) issued 9/3/82.
  82-34, Details 7 and 8 issued 1/3/83
  84-04, Detail 2.2.20 (p 23-24) issued 5/1/84
- LILCO Startup Manual, Section 4.5; Personnel Qualification
- ANSI Standard N45.2.6-1973, Qualifications of Inspection, Examination and Test Personnel
- OQA Audit Report 81-17; 5/27-6/5/81
- NRC Generic Letter 81-01 data 5/4/81; Qualifications of Test Personnel

4.9.2 Findings

The LILCO Startup organization was committed to ANSI N45.2.6-1973 which delineated requirements for I&C technicians at LILCO who were certified as Level I test personnel in accordance with that standard. That level of capability required no previous nuclear experience; only one year of "equivalent" QA test experience plus a high school diploma. A Level I technician was certified (after 1980) for a period of two years to record data or implement test procedures. His work was directed by a foreman or Startup Test Engineer certified to a higher level (II), and capable of conducting test evaluations, and reviewing and approving test results. The technician would be hired on the basis of a resume; references were usually checked, and the individual interviewed by a phone call. Following an offer, a relatively simple indoctrination and training program lasting one day would be given. The new technician would be rated, assigned to an experienced technician, and essentially placed on a 6-week probationary period for evaluation of work habits. An annual eye test was required and was documented, along with the above requirements, in a Startup Technical Personnel Qualifications (TPQ) file.

The preoperational test program at Shoreham had its largest demand for I&C technicians in 1982-83, with a peak of about 110 contract technicians from three principal employers (LPL, JCI and NSS). In the three year period covering 1980 through 1983, a total of approximately 200 I&C "rent-a-techs" were employed at Shoreham.

A number of NRC inspections audited the qualifications and training of test personnel during preoperational testing. LILCO audits also verified the use of established administrative controls for the use of contractor personnel. Both LILCO and NRC audits identified findings in those areas, including isolated and relatively few cases of the alleged problems concerning TPQ files, eye exams, expiration of certifications, and occasional background discrepancies. Security clearances were not typically required for technicians during the preoperational test phase.

4.9.3 Conclusion

No specific dates, events or individuals were provided by the alleger. It is assumed that the allegation refers to the preoperational test program, which utilized over 200 I&C contract technicians, the majority during the peak period of early 1982 through mid-1983.

The information obtained during this inspection was provided during a discussion with the former lead I&C Engineer for the LILCO Startup organization, who personally hired and was responsible for every one of the technicians, and was most familiar with their previous background, indoctrination/certification and performance while at Shoreham. In generally addressing this allegation, the following observations were made:

-- I&C technicians were certified to ANSI Level I, and as such had no test direction, review or approval authority. Their work was subject to the evaluation of a Level II individual.

-- The Indoctrination and Training Program lasted less than one day and was relatively simple, yet met the provisions of the ANSI Standard and the requirements of the LILCO Startup Manual.

-- The TPQ files were occasionally found to be discrepant. Eye exams or training documents were found to be expired or missing in a relatively small number of cases. These instances were identified, documented and corrected by the licensee.

-- No security clearance was required of these individuals during preoperation testing.

Based on (1) the lack of specificity, (2) previous LILCO QA and NRC audits in this area, and (3) the above observations, this allegation cannot be substantiated.

4.10 Instrument Data Card Updates

Instrument data cards were allegedly "historically incorrect", either not being kept up to date or in some cases not filled out at all. Technicians were alleged to make "unauthorized changes" to calibrations.

4.10.1 References

-- SPF 41.001.01-1 through 5; Instrument Calibration Data Sheets

4.10.2 Findings

There are approximately 20,000 calibratible instruments at Shoreham, with roughly 19,500 C&IO calibration data sheets (500 instruments did not require an initial preoperational checkout). The initial calibration recorded by a C&IO test during the preoperational phase was performed by the LILCO Startup group, typically in 1981-82. That calibration became the baseline for future calibrations, some of which did not occur for two or more years later, until plant I&C staff began readying and maintaining the instruments for eventual operation. The calibration program became mandatory on December 7, 1984, when issuance of the low power license included the requirements of Technical Specification surveillances.

Instrument data sheets for the N11 Main Steam system were randomly checked for completeness, and found to be satisfactory. This system is the largest in terms of instruments with over 150 cards. Key information was found to be supplied with surveyed cards in addition to the initial C&IO baseline data, such as:

- name, model, manufacturer and serial no.
- calibration procedure number
- range, accuracy and settings
- recommended actions and additional data

Another similar check of the G33 Reactor Water Cleanup system temperature switches (total of 6) found no discrepancies.

The Instrument Record System at Shoreham consists in part of calibration cards filed in a cabinet and controlled for record of subsequent calibrations maintenance. The system was initially "loaded" from C&IO test data which, although originally typed, proved to be a very large administrative project. Cut-and-paste of the C&IO data onto the instrument card was also practiced. A program had just begun during this inspection to prepare a comprehensive data card for each instrument which will probably take a number of years to complete. Entitled the Equipment History Program, one aspect will be another verification of setpoint, range and accuracy by cross-reference to instrument calibration cards, composite component listings and other documents.

4.10.3 Conclusion

No alleged instances of incomplete or missing instrument calibration cards were provided, and none were found during this inspection. Neither were any instances of alleged unauthorized calibrations provided, or found.

The approved preoperational test procedures, including C&IO test packages with initial instrument calibrations, constitute an original approved source of "historical" calibration data.

4.11 Fudged Data

A generic problem was alleged that "many workers had corrected at least a half-dozen instances of fudged data".

4.11.1 References

NRC Inspection Report 50-322/84-04 issued May 1, 1984

4.11.2 Findings

A similarly non-specific allegation (from the same alleger) was investigated as part of NRC Inspection 84-04 and found to be unsubstantiated.

A discussion with the former Startup Manager indicated that he remembered only one known individual (out of approximately 200 technicians over the 4-year period of late 1979-mid-1984) who was terminated for suspected forged data. The individual was a contract I&C technician employed from October 1979-February 1981 . He was suspect because his recorded data were "way-off" and obviously not genuine. All of the work packages in which he was involved were pulled and reviewed; some re-calibrations were later required.

4.11.3 Conclusion

Fudged data would generally be difficult to determine, unless experience with a particular instrument implied that the numbers were "too good" or close. Further, the allegation implies that previously fudged data was corrected; nevertheless, all calibrations are periodically redone on anywhere from a monthly to two-year cycle. This would tend to self-correct any unknown "fudged" or incorrectly recorded data over a period of 1 to 2 years. Most safety-related instruments are currently experiencing their second or third calibration by plant staff, following an initial C&IO calibration.

Considering that only a "half-dozen" instances were corrected, this is a relatively small amount of rework when compared with 200 technicians and 15-20 thousand instruments. Any possible instances of initially fudged calibration data would have since been identified and corrected. The validity of this allegation could not therefore be assessed although any lodged data should have been converted through the normal recalibration program.

4.12 QC Witness of Calibrations

LILCO QC was alleged to be in violation of "code" by "sign-off of paperwork without on site review of systems".

4.12.1 Findings and Conclusions

It's presumed that the allegation refers to LILCO OQA audit and surveillance of preoperational C&IO testing and instrument calibrations, as required by the LILCO QA Program for Operations in accordance with the Code of Federal Regulations (10 CFR 50 Appendix B).

QC audits are an elective process, applied only to some fraction of safety-related activities, and does not fulfill an approval function. Periodic audits and surveillance of testing would also include procedure or data review without necessarily involving direct witness. This allegation could not be assessed as either substantiated or not, based on a lack of specific information.

4.13 I&C Supervisors

I&C supervisors were alleged to have no nuclear experience, and also allegedly asked workers to "shortcut" surveillance procedures.

4.13.1 Findings

There are currently about 50 I&C plant staff personnel reporting to the Maintenance Division Manager. This number includes an I&C Engineer, four supervisors (one each for M&TE, MWRs, PMs and Surveillance) and five foremen (including a contract employee).

All I&C supervisors have had previous nuclear experience in addition to 2-5 years at Shoreham. The staff I&C organization was at about half that complement two years ago, with no formal positions designated as "supervisor". If the allegation refers to the I&C Foremen as supervisors, then this is substantiated to some degree since (until about one year ago) the two existing foremen had no previous nuclear experience, although both had 15-20 years with LILCO and were certified to ANSI Level II. The group has also had a number of consultants, who could technically be considered as supervisors, to oversee training, procedure development, spare parts, coordinate GE Information Letter resolution, and structure the surveillance program. The I&C staff, while adequately and competently staffed, is busy and has not yet reached its full complement. The staff also draws considerable experience from the Shoreham preoperational test program.

I&C procedures for surveillance and calibration were developed and initially performed over the past two years. There are 150-165 calibration procedures, and the initial "de-bugging" began at a time approximately 1½ years prior to being required.

There was an extensive use of temporary procedure change notices (TPCN) during the initial period for the sake of getting through the tests the first time. This practice may have been interpreted by the alleger as a "shortcut".

4.13.2 Conclusions

I&C foremen are certified ANSI Level II personnel with appropriate qualifying background. I&C supervisors all have some nuclear experience, including at Shoreham for at least 2 years, and most are degree-ed engineers. The I&C Engineer stated that he knew of no situation when a direction was given to shortcut a surveillance procedure. The development of these procedures initially involved some amount of interpretation, and an admittedly excessive use of TPCNs to conduct the tests for the first time. Surveillance was, however, only required to be performed after license issuance on December 7, 1984.

4.14 Unqualified Startup Technicians

Unqualified Startup technicians allegedly allowed design errors (unspecified) which went undetected during system walk downs prior to turnover to plant staff. These allegedly cannot be identified by inexperienced "maintenance" technicians. Allegation number 4 (N11-PS-124, 125 head correction error) is an example of this kind of error.

4.14.1 Findings and Conclusion

No specifics were provided by this allegation. Generally speaking, instrument calibration errors similar to the omission of a head correction error (see allegation numbers 4 and 7) would be most likely discovered in future calibrations, surveillance, or Power Ascension testing.

Those errors observed were not made by technicians, rather, it was the responsibility of a Startup Test Engineer to review and approve setpoint calculations. After system turnover to plant staff, the I&C engineer or his supervisors review and approve calibrations, and have demonstrated a capability for recognizing these types of problems and pursuing engineering resolution. Further, Reactor Engineering will be responsible for systems startup testing as part of the Power Ascension Program. Design errors involving instrument setpoint calculations are the province of ANSI Level II certified personnel and engineers; not technicians, who are typically Level I certified.

4.15 Radwaste Laundry Drain Tank

Radwaste laundry tank numbers G11-20A&B have high level alarms which were alleged to be incorrectly set. A level transmitter's 'zero' reference had been "suppressed" by 10½ inches, and the tank would allegedly overflow before reaching the full-indicated point. The original calibration was incorrect; however, the problem may have been since corrected. Instrument data sheets had specified the alarm point as 8'6", but the radwaste operator's indicator had read out as 900 gallons.

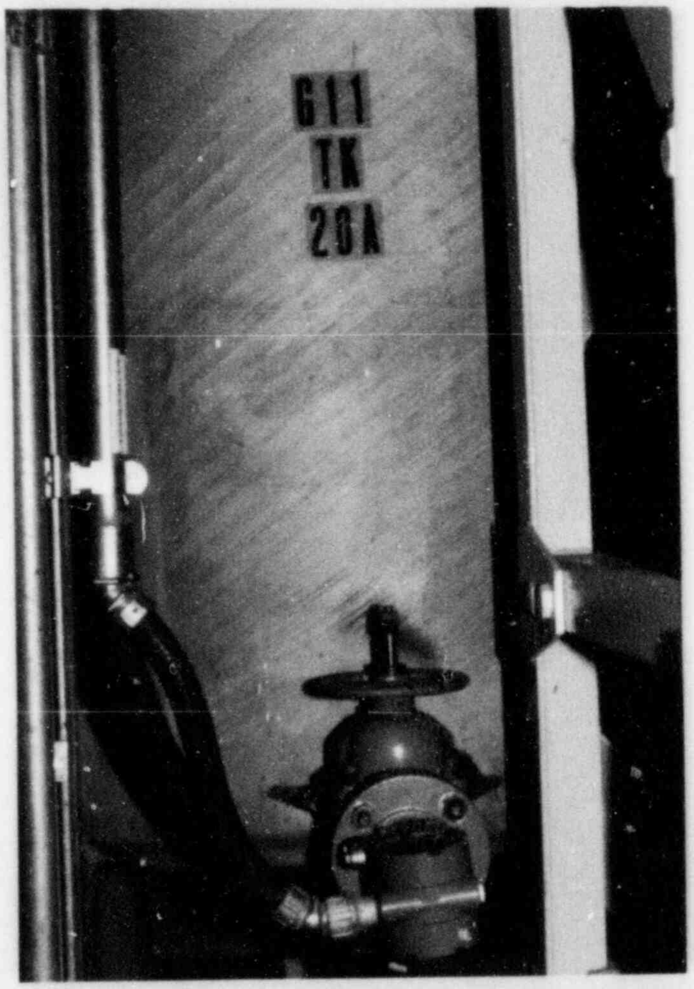
4.15.1 References

- -- C&IO Test Package For Radwaste Level Transmitters
- -- G11D-LT-272 A and B
- -- Shoreham Radwaste Flow Diagram FM-17E8
- -- Liquid Radwaste System Description G11, October 18, 1979, Rev. 1
- -- Vendor Print 3.25 - 116D, Laundry Drain Tank
- -- 480VAC Elementary Diagram ESK6-G1121, Laundry Drain Tank Pumps
- -- Radwaste Test Loop Diagrams
  TLD 1G11-265, Laundry Drain Pump
  TLD 1G11-266, Laundry Drain Pump
  LS-274 A and B, Laundry Tank High Level
- -- Loop Calibrations for G11-272 A and B and G11-274AandB

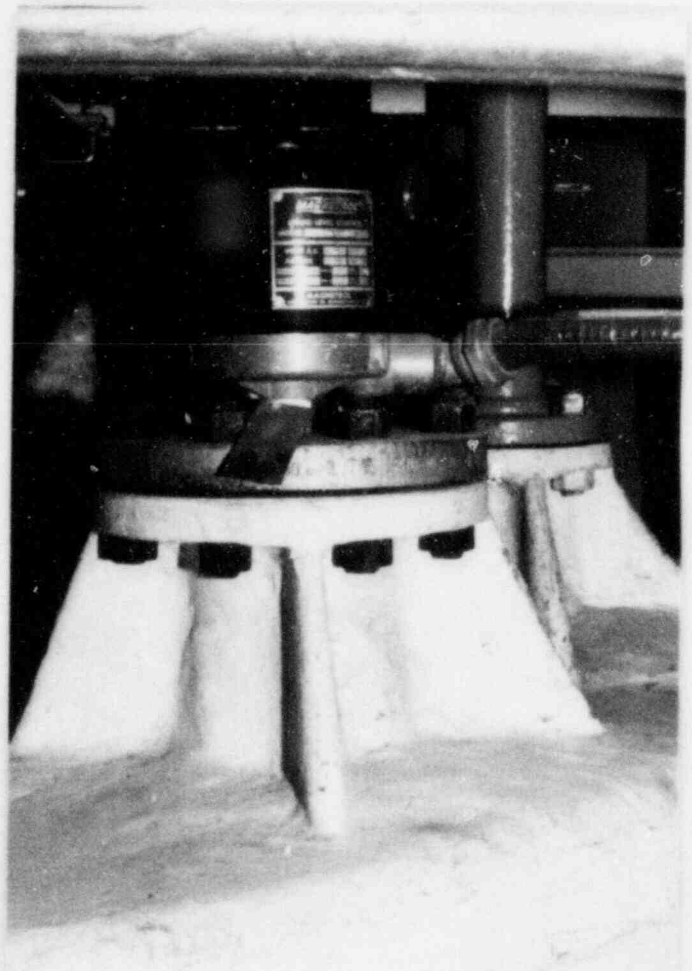
4.15.2 Findings

Radwaste laundry drain tanks G11-20A and B collect low level contaminated laundry and shower water on a batch basis. Each tank is of fiberglass reinforced plastic, 5-feet in diameter by 10'-9" high (from 'bend' line to top) with a dished-head bottom, and designed for atmospheric pressure and a full capacity of 1653 gallons. The non-safety related tanks are manufactured by the Wallace-Murray Corporation, and are capable of being recirculated or pumped through filters to the liquid radwaste sample/discharge tanks. The tanks are cross-connected by a common 4-inch overflow line which allows a full tank to overflow to the other tank. The cross-connect line incorporates an elevated overflow/vent connection which drains via a loop seal to the Radwaste Building floor drain sump.

Each tank has a high level switch LS-274 A/B, preset at 8'-6" above the tank's bend line, which alarms in the Radwaste control room. The alarm is initiated at an actual tank level of approximately 1320 gallons (80% capacity), which is 12 inches (and 150 gallons) below the centerline of the overflow connection. The overflow is a horizontal flanged connection at the 90% capacity level. Each tank also has a separate level sensing instrument loop consisting of a level transmitter LT-272 A/B which drives an indicator LI-272 A/B in the Radwaste control room and feeds a low level switch LS-272 A/B. The transmitter is located off of a horizontal tap whose centerline is 1½-inches above the tank's bend line. There is an estimated 90 gallons of capacity below the instrument's tap. The transmitter is a Rosemount Model 115 with a range of 0-125 inches and a 4-20 mA output. The indicator is a GE/Reliance Model 185 with a range of 0-2000 gallons. The low level switch is set to actuate at a level 4-inches (above the transmitter's zero reference) and will stop the laundry drain tank pump.



Level Transmitter LT-272



High Level Switch LS-274

Initial loop calibrations were performed as part of the pre-operational C&IO testing during December 1979-August 1981. The high level switches LS-274 A/B were calibrated on June 19, 1981 to alarm at an indicated level of 1628 gallons. No record of subsequent calibration for these switches could be found. The as-left setpoints for these switches were at indicated levels of 1650 and 1625 gallons respectively. However, these were based on an input from a different instrument loop; that is, LT-272 which drives LI-272. The correct setting of that high level alarm will be dependent upon how it's measured, but should be always at a point 102 inches above the tank's bend line.

The level read from LI-272 is dependent upon where LT-272 is zeroed. The transmitter is installed at a point 1½-inches above the bend line. With no adjustment, the transmitter would output a signal of 4 mA at an inventory at or below that level (92 gallons actual), and would indicate 0 gallons in the Radwaste control room on LI-272. At increased inventories, the transmitter's output would proportionally increase to its upper range of 20 mA which would be equivalent to 1622 actual gallons and 2000 indicated gallons. There can't be a one-to-one correlation between actual and indicated tank capacity (except at one point) because:

- LT-272 has a range of only 0-125 inches, whereas tank height from bend line to top is 129 inches.

- LI-272 has a range of 0-2000 gallons but is driven by a 4-20 mA input from the transmitter.

C&IO loop calibrations were set up for the transmitter/indicator on three separate occasions during preoperational testing. On the third and last C&IO on August 5, 1981, the transmitter's zero point was elevated (adjusted) 10½-inches above the tap centerline. This resulted in a monitored level of from 12 to 129 inches above the tank's bend line, equivalent to 220-1653 actual gallons (and 0-1872 indicated gallons). The upper end of the transmitters output (129-137 inches) would never be reached, since its above the top of the tank.

The most recent (and only) calibrations by plant I&C staff since turnover from the Startup organization were performed on August 8 and May 18, 1983, for loops A and B, respectively. The loop A calibration for Tank 20A maintained the 10½-inch adjustment to the transmitter's zero reference. However, the loop B calibration re-adjusted (or suppressed) the instrument zero back to the original (unadjusted) zero point for Tank 20B. In the Remarks section of the Instrument Calibration Record for LT-272B, this re-adjustment was stated to be made "due to the fact that an elevated zero of 10.5 inches will give you 135.5 inches at 100% and overflow the tank".

4.15.3 Independent Evaluation

The existing, indicated and required values for laundry drain tank high level alarms and levels are currently confusing and apparently discrepant. The following evaluation was conducted independently, as part of this inspection, for each tank. Compared are actual tank inventory, indicated level, and corresponding percent difference. These are based on nominal tank dimensions and capacity, and most-recent calibration data and instrument characteristics. This evaluation also assumes that the high level alarm should be set at a height of 102 inches above the tank bend line, where actual inventory would be 1322 gallons or 80% capacity.

Laundry Drain Tank 20A
Instrument Loop G11-272A
(LT zeroed 10½-inches above tap)

Actual Inventory (Gallons)	Capacity (% full)	Readout on LI-272A (Gal.)	Error or Indicated/Actual (%)
1653	Full	1872	+13.2
1469	90 (overflow)	1632	+11.1
1338	81	1460 (existing alarm)	+ 9.1
1322	80 (required alarm)	1439	+ 8.9
1200	73	1280	+ 6.7
1100	67	1149	+ 4.5
1000	60	1018	+ 1.8
940	57	940	None
900	54	880	- 1.4
826	half	791	- 4.4
700	42	626	-11.8
600	36	495	-21
500	30	365	-37
270 (existing pump trip)	16	64	
221	13	0	
123	7.4 (required pump trip)	0	

The "A" tank indicated level is within ±12% of actual for the 40-95% capacity range, and is conservatively over-indicated above half full. The as-left setting of LS-274A would initiate an alarm prior to reaching the overflow level, and at an indicated level 122 gallons above actual.

Laundry Drain Tank 20B
Instrument Loop G11-272B
(LT zeroed at tap)

Actual Inventory (Gallons)	Capacity (% Full)	Readout on LI-272B (Gal.)	Error or Indicated/Actual (%)
1653	Full	2000	over-ranged
1622	98	20000	+23.3
1550	4	1905	+22.9
1469	90(overflow)	1800	+22.5
1338	81	1628(existing)	+21.7
1322	80 (required alarm)	1607 alarm)	+21.6
1200	73	1448	+20.7
1000	60	1186	+18.6
826	half	959	+16.1
700	42	794	+13.4
600	36	663	+10.6
500	30	533	+ 6.6
393	24	393	none
141(existing trip)	8.5	64	
123	7.4(required trip)	40	
92	5.6	0	

The "B" tank level is always over-indicated, and by an amount of approximately 20% for levels more than half-full. the as-left setting of LS-274B would initiate an alarm slightly (16 gal.) above the required setting, but still below the overflow level by an adequate margin. The existing low level pump trip occurs 18 gallons above the intended level.

4.15.4 Conclusion

Non-safety related high level alarm switches for laundry drain tanks G11-20A/B are set at a level slightly above where required, but still below the level at which tank overflow would begin. Overflow from either tank is directly piped into the other tank via a 4-inch common cross-connect line. continued overflow, beyond the capacity of both tanks, is collected in the floor drain sump. The tanks collect potentially contaminated water of relatively low radioactivity, and any overflow is completely contained within the floor drain system inside of the Radwaste Building. Discussions with Radwaste operators indicated that no actual overflow incidents have been experienced with these tanks to-date. The high level alarm would signal an operator at the radwaste control panel to manually isolate that tank, and trasfer to the other tank.

A separate instrument loop monitors level and provides remote indication in the radwaste control room. Because of the range of the transmitter and indicator used in the loop, there is an inherent discrepancy between actual and indicated tank level. Adjustment of the transmitter's zero-reference was utilized to partially compensate for that discrepancy in August 1981.

The last preoperational C&IO test calibration of record showed that the transmitter zero point had been elevated by 10½ inches above tap centerline. However, the first (and current) calibration by plant I&C staff readjusted level "zero" for the "B" tank back to the tap centerline for overflow concerns. Indicated levels are always different from actual capacity, but more so in the uncompensated case of tank "B". The discrepancy is minimized for the "A" tank where transmitter zero is elevated by 10½ inches above the tap. The high level alarm is intended to be at a fixed point 102 inches above the tank's bend line, at 80% capacity. Because of the inherent difference in actual and indicated levels, as well as the inconsistent adjustments of instrument zero, the indicated levels are 9 and 22% greater than actual for tanks A and B, respectively, when the high level alarm is initiated. Also, no calibration has been performed for the high level alarm switches since June 1981.

The instrument loop driven by transmitter LT-272 also provides input to a low level pump cut-off switch. That setting is intended to be fixed at 4 inches above the tank's bend line, which corresponds to an actual inventory of 123 gallons remaining in the tank. Both tanks' low level switches LS-272A/B were found to be set at levels above the required pump trips.

Assuming a two-year preventive maintenance cycle, both tank loops are currently scheduled for calibration this summer.

5. <u>Exit Interview</u>

The inspector discussed the preliminary findings of this inspection with the I&C Engineer on May 10, 1985. Phone conversations were subsequently held with other LILCO personnel to clarify the details presented herein.

The attached synopsis of the allegations investigated was provided to the licensee at the beginning of the inspection.