U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 85-11 / 85-03

Docket No. 50-352 / 50-353

License No. NPF-27 / CPPR-107 Priority - Category C / A

Licensee: Philadelphia Electric Company

2301 Market Street

Philadelphia, Pennsylvania 19101

Facility Name: Limerick Generating Station, Unit 1 & 2

Inspection at: Limerick, Pa.

Inspection Conducted: February 1 - March 15, 1985

Inspectors: J. T. Wiggins, Senior Resident Inspector — 3/19/85 Date

J. T. Wiggins for R.W. Borchardt, Reactor Engineer — 3/19/85 Date

J.E. Beall, Project Engineer — 3/19/85 Date

Approved by: Robert M. Gallo — 3/27/85 Date
R. M. Gallo, Chief, Reactor Projects Section 2A

Inspection Summary: Combined Inspection Report for Inspection Conducted February 1 - March 15, 1985 (Report Nos. 50-352/85-11, 50-353/85-03)

Areas Inspected: Routine and backshift inspections by the resident inspector and region-based inspectors of: followup on outstanding inspection items; general walk-through inspections; review of special and routine reports; review of events occurring during the inspection; work accomplished during an outage; review of modification packages; maintenance and surveillance observations; and in-office review of event reports. The inspection involved 75 hours for Unit 1 and 2 hours for Unit 2 by the resident inspector and 203 hours for Unit 1 and 2 hours for Unit 2 by region-based inspectors.

Results: No violations or significant weaknesses were identified.

DCS Numbers:

50-352 - 841113
- 841115
- 841118
- 841123
- 841221
- 841231
- 841228
- 841229
- 841230
- 850101

- 850106
- 850108
- 850115
- 850110

- 850118
- 850124

- 850131
- 850228
- 850301

DETAILS

1. Persons Contacted

Philadelphia Electric Company (PECo)

J. M. Corcoran, Field QA Branch Head
J. Doering, Operations Engineer
P. Duca, Technical Engineer
J. Franz, Assistant Station Superintendent
G. Leitch, Station Superintendent

General Electric (GE)

A. Jenkins, Operations Manager

Also, during this inspection period, the inspectors discussed plant status and operational readiness with other supervisors and engineers in the PECo, Bechtel and GE organizations.

2. Followup on Outstanding Inspection Items

2.1 Violations

2.1.1 (Closed) Violation 84-65-01 Inadequate Control of a Design Change to the Recirculation Pipe Whip Restraint System

The inadequate control of a design change to the recirculation pipe whip restraint system resulted in the unauthorized removal of two whip restraints from the recirculation pump suction lines. As noted in inspection report 50-352/84-65, the licensee has reinstalled the restraints. The inspector reviewed the licensee's response to this violation dated February 11, 1985 and determined that adequate corrective actions have been taken. In addition to correcting the drawing discrepancies which caused this violation, the licensee performed a review of field drawings used to supplement General Electric design drawings and startup Work Orders written for the recirculation system. No additional discrepancies were identified. Job Rule 8031-JR-G-30 has been revised to formalize the method of requesting revisions to vendor drawings. The inspector has no further questions at this time.

2.1.2 (Closed) Violation 84-65-02 Reactor recirculation pump started without first performing the required surveillance test

The inspector reviewed the licensee's response to this violation dated February 11, 1985 and verified that surveillance test ST-6-043-390-1 was revised to ensure compliance with the temperature limits of TS 3.4.1.4. ST-6-043-390-1 now requires the operator to assess the temperature difference between an idle loop and the vessel as discussed in TS 3.4.1.4a. In addition, the inspector has observed numerous recirculation pump starts and is satisfied that the required surveillance test is being performed prior to each pump start. The inspector had no further questions.

2.1.3 (Closed) Violation 84-65-05 Liquid Release with the Discharge Pipe Sample Rack Out of Service

This violation was a result of the Radwaste Control Room operator's misunderstanding of a panel annunciator and the subsequent release of liquid while the radiation monitor was out of service. The inspector reviewed the licensee's response dated February 11, 1985, and physically verified that the corrective measures discussed below have been taken. The annunciator window previously labeled "Liquid Radwaste Discharge Hi/Lo Flow" has been changed to read "Sample Pump Hi/Lo Flow" which more accurately describes its true meaning. Procedure CH-1017 "Procedure for Preparation and Control of Liquid Radwaste Discharge Permits" has been revised to require the Radwaste Operator to verify that the radiation sample rack is in service prior to each discharge. The inspector has no further questions at this time.

2.2 Information Notices

2.2.1 (Closed) Information Notice 85-09 Isolation Transfer Switches and Post-Fire Shutdown Capability

This information notice described a situation where a fire in the control room could disable the operation of a plant's alternate shutdown system. This situation existed because the electrical scheme for the transfer of control of equipment to the remote shutdown panel was dependent upon a single set of fuses instead of having each alternate shutdown control independently fused. The inspector reviewed the arrangement of the licensee's transfer scheme and determined that each alternate shutdown component was independently fused from the remote shutdown panel when

control of the component was from the panel. A review of Residual Heat Removal, Automatic Depressurization System, Emergency Service Water and Reactor Core Isolation Cooling components showed that a fire in the control room would not disable the operation of the alternate shutdown system.

2.2.2 (Closed) Information Notice 84-92 Cracking of Flywheels on Cummins Fire Pump Diesel Engines

This notice informed licensees of a problem with Cummins fire pump diesel engines in which the engine flywheels, part number 3453, develop cracks which are not noticeable until they propagate through the thickness of the flywheel and appear on their outer surface. The cracks were identified at LaSalle, and were found to have initiated after 34 hours of engine operation. The notice indicated that one of the four Cummins engines equipped with flywheel part no. 3453 is the model NT 855 F1.

The inspector examined the Limerick diesel fire pump and found it to be a model NT 855 F1. The inspector requested that the licensee describe the results of its evaluation of the IE notice. In response, the licensee indicated that no corrective actions were warranted at this time based on the following reasons which were provided to the licensee by a Cummins representative:

1) The vibration induced cracking is directly related to the size (horse power rating) of the engine and cracked flywheels have only been found on engines rated at over 300 HP. The engine at Limerick is rated at 255 HP.

2) The engine at Limerick has only run 20½ hours to date.

3) Cummins is still considering the use of their standard truck engine flywheel and is simultaneously exploring the use of different materials for the present flywheel.

Based on this information the licensee felt that until either a replacement flywheel can be obtained or a new type of flywheel can be specified, the disassembly and inspection of the Limerick engine should be postponed. The resident will continue to monitor the licensee's actions in this matter.

3. Plant Tour

3.1 Unit 1

Periodically during the inspection period, the inspectors toured the Unit 1 containment, the reactor enclosure, the control enclosure, the turbine enclosure, the diesel generator enclosures, the radwaste enclosure, the off-gas enclosure, and the site perimeter outside the power block. The inspectors examined preventive and corrective maintenance, surveillance testing, tagging of equipment, housekeeping, radiological control practices, portal monitoring, security, lighting, vehicular control, power block control points, security fencing, fire protection equipment, environmental controls, and general plant operations. The inspectors routinely toured the control room to verify proper control room manning, procedural compliance, safety system availability, and nuclear instrumentation operability. Operating logs, the jumper-bypass log, the temporary circuit alteration (TCA) log, operating orders and plant trouble reports were reviewed to verify that all technical specification requirements were met. Interviews and discussions were routinely conducted with licensee operators and staff concerning the status of off-normal alarms, compliance with technical specifications and general plant conditions.

Valve lineup verification checks were performed on the 1C Diesel Generator, High Pressure Coolant Injection System, 'A' loop of Residual Heat Removal System, 'A' loop of Core Spray System and the 'B' loop of the Core Spray System.

No violations were identified.

3.1.1 Review of Quality Assurance (QA) Activities

During this period the inspector reviewed selected operations, QA audit reports, the identified deficiencies and the response to these deficiencies. The review was performed to verify that the scope and depth of the audits were adequate, that the auditors appeared qualified to perform audits in the areas addressed and that the corrective actions for the identified discrepancies were timely and adequate. The following reports were reviewed:

AL-84-102-PL	AL-84-70-TR
AL-84-90-PL	AL-84-69-MEM
AL-84-86-PL	AL-84-58-PR

One problem was identified. Audit 84-90 examined the qualifications of vendor-supplied health physics (HP) technicians who had been granted unescorted access to the protected and vital areas at Limerick. The audit addressed both the technical qualifications of the technicians and the background screening checks which had been made. Regarding the background security checks, eight problems were identified by the auditors regarding the extent of documentation available at the contractor's offices. However, in all but one case, the inspector could find no indication that the QA auditor, or his management, had notified either the PECo corporate security organization or the site security organization. Discussions with representatives of corporate and site security appeared to confirm that they were not formally informed of the audit findings. This problem was discussed with an NRC Security inspector who further reviewed the matter during inspection 50-352/84-12.

No violations were identified.

3.2 Unit 2

The inspector periodically toured the Unit 2 reactor building, including the drywell and the Unit 2 side of the turbine building. These tours were conducted to verify adequate housekeeping and in-storage maintenance of equipment during the suspension of construction activities. Additionally, the inspectors briefly examined the control rod drive mechanism support grid which had been erected within the reactor pedestal by Reactor Controls Incorporated personnel.

No violations were identified.

4. Review of Special and Routine Reports

4.1 Review of Licensee Event Reports (LERs)

The inspector reviewed the licensee event reports (LERs) listed below to determine whether: the information provided was accurate and submitted in a timely manner; the event cause was properly identified and corrective actions were appropriate; the report described a potentially generic issue; and the report satisfied the licensee's reportability requirements. These reports were found to be acceptable. Those event reports annotated with an asterisk (*) required additional inspector followup and are discussed later in this paragraph.

84-006	Main Control Room Ventilation System Isolation 11/13/84
84-008	Control Room Chlorine Analyzer Failure 11/15/84
84-010	Control Room Chlorine Analyzer Failure 11/18/84
84-020	Main Control Room Ventilation System Isolation 11/23/84
84-021	Reactor Water Cleanup System Valve Isolation 11/15/84
*84-039	Reactor Scram and NSSSS Isolations 12/21/84
*84-040	Loss of Power to the B RPS and UPS 120 VAC Distribution Panel 12/21/84
*84-042	Drywell Radiation Monitoring System Isolation Valve Failure to Close 12/31/84
*84-043	Procedural Deficiency in the Containment Atmosphere Control Valve Test 12/28/84
84-044	Failure to Demonstrate Adequate Shutdown Cooling 12/29/84
84-045	Reactor Enclosure HVAC Isolation 12/30/84
84-046	Control Room Chlorine Analyzer Failure 12/30/84
*85-001	Reactor Water Cleanup Isolation 1/1/85
85-004	Initiation of Shutdown due to HPCI Inoperability 1/6/85

85-005	Reactor Enclosure HVAC Isolation 1/3/85
*85-006	Failure to Comply with the Primary Containment Isolation Requirements 1/15/85
85-007	Failure of 1B RPS Static Inverter 1/10/85
85-012	Reactor Enclosure HVAC Isolation 1/18/85
*85-017	Improper Operation of the Control Room Ventilation System 1/24/85

4.1.1 LERs 84-039 and 84-040

On 12/21/84 the 'B' RPS static inverter output developed an overvoltage condition which caused the inverter output breakers to trip. This trip deenergized an uninterruptible AC electrical panel (10BY160) which subsequently caused various nuclear steam supply shutoff system (NSSSS) isolations, recirculation pump trips, and a half scram signal. A surveillance test being performed on the 'A' RPS logic generated a half scram signal which then resulted in a full scram. Because the plant was in OPCON 4 with all rods in, no rod motion occurred. The alternate AC supply to panel 10BY160 was selected and all isolations and the scram were reset. When an attempt was made to start the 'B' recirculation pump, both electrical supply breakers to panel 10BY160 tripped on an undervoltage condition. This resulted in the same NSSSS isolations and recirculation pump trips. The large electrical demand of starting the recirculation pump caused the voltage to dip low enough to trip the 10BY160 Supply breakers. The 1B RPS and uninterruptible power supply (UPS) static inverter was selected to its preferred DC source, the supply breakers to 10BY160 were closed, and all isolations were reset.

The licensee's corrective action for the undervoltage condition was to revise procedure S43.1A "Startup of the Recirculation Pump" to require that prior to a pump start the inverters are selected to the preferred DC source. A modification to change the source of AC power to another regulated AC power supply is being implemented.

A voltage regulator board was replaced in the static inverter as corrective action for the overvoltage condition. A similar overvoltage condition caused a trip of the 1A RPS/UPS inverter output breakers during this inspection period. The licensee has determined that the voltage regulation problem is being caused by an elevated temperature in the inverter caused by inadequate ventilation in the inverter room and through the inverter cabinet. A modification has been performed to provide added cooling to the inverter cabinets.

4.1.2 LER 84-042

The inoperability of two containment isolation valves was the subject of special inspection report 50-352/85-01. A detailed review of this issue is provided in that report.

4.1.3 LER 84-043

Prior to 12/28/84, the closure time of suppression pool level instrumentation solenoid valve SV-52-139 was not verified to be within technical specification limits. The omission of this requirement from surveillance testing was identified by the licensee and the valve was satisfactorily tested on 12/29/84. The inspector verified that surveillance test ST-6-057-200-1, Containment Atmospheric Control (CAC) Valve Test, had been corrected to include the measurement of the closure time for valve SV-52-139. The inspector had no further questions.

4.1.4 LER 85-001

A Reactor Water Cleanup (RWCU) Isolation was initiated by setting an ambient temperature switch to the "Read" position. The licensee and the vendor investigated the defect in the ambient temperature transmitters which caused this and other spurious RWCU isolations. (LERs 84-012, 84-026, 84-034, 84-035 and 84-036) The modification installed to correct this problem is discussed in paragraph 7 of this report.

4.1.5 LER 85-006

The failure to comply with the primary containment isolation requirements was the subject of special inspection report 50-352/85-08.

4.1.6 LER 85-017

The improper operation of the Control Room ventilation system was cited as violation 85-02-03 and is discussed in inspection report 50-352/85-02.

5. Review of Events Occurring During the Inspection

5.1 Reactor Scram Event of January 31, 1985

At 8:05 p.m., 1/31/85, a reactor scram occurred as an operator was clearing permit 1-42-0060 to return the jet pump total developed head instrument (PDI-42-1R005) to service. This instrument had been removed from service to correct an error in its installation. Opening the low pressure rack isolation valve for this instrument resulted in a transient pressure drop in the process line used as the low pressure leg for the instrument. The momentary pressure spike affected level transmitters LT-42-1N080A and B, which are connected to the same process line and are used to initiate reactor scrams on low reactor vessel water level, causing them to trip. A full scram occurred, but no other safety systems actuated. An Unusual Event was declared at about 8:09 p.m. due to the unplanned reactor shutdown.

After the scram, the operators noted that 34 of the 185 control rods did not show a full-in indication on the full core display panel or on the RSCS panel. However, all but rod 42-27 were indicated to be at position 00 on the four-rod display and on the process computer. No position indication was available for rod 42-27 which had been at position 08 prior to the scram because the rod position indication system was showing a data fault for this rod. Using indications available on the rod sequence control system panel, the operators determined that the rod was inserted to at least position 04, an acceptable post-scram position for the rod.

To obtain full-in indications and to verify that rod 42-27 was fully inserted, the shift superintendent directed that the mode switch be placed in Refuel and that the reactor operator apply an insert signal to each rod which lacked its full-in indication. Further, the shift superintendent directed that no rod withdrawal be performed while the mode switch was in this position. For each selected rod except 42-27, the rod briefly inserted beyond position 00, the full-in indication was obtained on both the full core display and the RSCS panel and the rod settled back to 00. Technicians were then able to determine that the data fault for rod 42-27 was caused by the reed switches for position 00 and 06 being closed at the same time. While the rod position indication problem was being resolved, other

operators were securing reactor steam loads such as the steam seal evaporator and the steam jet air ejectors by aligning steam from the auxiliary boiler to these components. Other reactor steam loads at the time of the scram included one reactor feed pump turbine, a partially-open bypass valve and the main steam line drains. Because the cooling effects of the steam loads on the reactor coolant system exceeded the heat input rate from decay heat, a high cooldown rate developed after the scram. The main steam isolation valves (MSIVs) were closed at 8:42 p.m. to slow the cooldown rate. The licensee later determined that the reactor coolant system water temperature had decreased at a rate of about 113°F per hour while the MSIVs were open.

At about 9:05 p.m., 1/31/85, the Unusual Event was terminated because the licensee had identified the cause of the scram and had decreased the reactor coolant system cooldown rate. Early on 2/1/85, the mode switch was placed in Shutdown, which caused the reactor protection system to initiate another scram. The full-in indications for rods 42-47, 38-27, 34-11 and 18-11 were again lost and rod 42-27 still had a data fault for its position indication. No further actions were taken at the time.

On 2/1/85 and on 2/8/85 the resident inspector and the NRC Project Section Chief discussed the event, its causes and proposed corrective actions with the Station Superintendent and his senior staff. Regarding the installation error for the jet pump total developed head instrument, NRC determined that the licensee had identified, in December 1984, that the high and low pressure connections were initially reversed upon installation. To correct the problem with the gauge's installation, Plant Staff Field Report (PSFR) 0139, Maintenance Request Form (MRF) 8406057 and permit 1-42-0060 had been processed. The physical work had been performed under the control of PECo construction. The instrument tubing was reversed and the gauge recalibrated. The work was completed on about 1/30/85. The MRF was returned to the shift for clearance of the permit. A plant operator (PO) was given the task of clearing the tags shown on the permit which included the high and low side rack isolation valves. Before operating these valves, the PO obtained authorization from the licensed control operator. When the PO opened the rack isolation valves, apparently the instrument lines between the valves and the gauge filled thus causing a pressure reduction in the process lines to the rack.

Regarding the control rod position indicating problem, the inspectors were informed that there are three separate reed switches which are used to provide full in indications to

various readout locations. The position 00 reed switch provides indication to the four rod display and the process computer. Reed switches S51 and S52 are located about 0.38 in. and 1.26 in., respectively, above the 00 switch and either one would provide full in indication to the full core display and to RSCS. Apparently, the magnetic coupling between the control rod and the reed switches was insufficient to maintain either S51 or S52 closed.

Regarding the high cooldown rate which occurred, the licensee determined that the control room operators had not received sufficient training in scrams from low decay heat conditions. Additionally, the licensee determined that identification of the high cooldown rate had been delayed partly because the surveillance procedures normally used to monitor cooldown/heatup rates were not immediately available in the control room. Further, the licensee determined that clarification was needed regarding the heatup and cooldown rate limits in Technical Specifications to identify whether the limits apply to coolant system temperatures or to vessel metal temperatures.

For corrective actions, the licensee indicated that hardware, procedures and training activities were necessary. These activities included:

1) procedure changes to more carefully control manipulation of instrument block, rack and root valves;

2) completion of an analysis of the effects of the cooldown rate on the reactor pressure vessel;

3) replacement of the position indicating probe for rod 42-27 and development of procedures which address the operators' expected response to a loss of rod full in indications;

4) increased operator training in scrams with low reactor decay heat; and

5) changes to the plant post-scram recovery TRIP procedures to address monitoring of reactor coolant cooldown rates.

On 2/4/85, the inspector examined the installation of the jet pump developed head gage (PDI-42-1R005) on rack 10C010, located on elevation 217 of the reactor enclosure including the connections between rack isolation valves RKVH-42-1F060.41 and RKVL-42-1F064B.10 and instrument block valves IBVH-42-1F060.42 and IBVL-42-1F064B.11. The inspector determined that, although the instrument piping was properly installed, the valve identification tags on the instrument

block valves had not been changed after the MRF caused the instrument line connections to be reversed. The tags indicated that the high side rack line was connected to the low side of the instrument. The inspector informed the licensee who later changed the instrument block valve identification tags to their correct location.

On 2/19/85, the inspector examined or observed some of the licensee's corrective actions which had been completed. These included:

1) the replacement of the 42-27 position indicating probe;

2) the posting of an Operator Aid to the post-scram TRIP procedure cautioning operator's to be aware of high cooldown rates after scrams from low decay heat conditions and prescribing a planned course of action for dealing with these situations;

3) the development of a PORC Technical Specification Position regarding the interpretation of the heatup and cooldown rate limits and requiring checks of both coolant temperature and vessel metal temperature;

4) the implementation of procedures to be used to guide the operators' reaction to not receiving full in rod position indications after scrams;

5) the establishment of a new simulator scenario to train the operators in scrams from low decay heat rate conditions; and

6) the issuance of a memorandum to be read to each operating shift discussing the procedures described in 4) above.

The inspector had no further questions and identified no violations.

5.2 Feedwater Transient of February 28, 1985

On 2/28/85 at approximately 8:05 p.m. the 'A' reactor feed pump (RFP) turbine experienced abnormally high vibration levels and a decision was made by the operating shift to switch to the 'B' RFP. Control rods were inserted to reduce power prior to the pump switch. The estimated power prior to the pump switch was 3.34%. The transient which resulted from the start of the 'B' pump caused an increase in feedwater flow to the vessel and an insertion of cold water which in turn caused reactor power to increase. An analysis was performed by the station's Reactor Engineer which showed that, based on the increase in Intermediate Range Monitor indications, the peak power level reached during

the transient was 4.88%. The operator quickly gained control of the feedwater flow rate and power level returned to approximately 4%.

This transient was caused by differences between the 'A' and 'B' RFP flow control capabilities. The 'A' RFP has an automatically controlled startup bypass valve whereas the 'B' and 'C' RFPs' startup bypass valves must be manually controlled. The slower response time associated with the manual control method could not compensate for the initial pump startup transient. Reactor pressure was slowly decreased until the RFP was no longer required and the condensate pumps were used for reactor water level control until plant shutdown on March 1, 1985.

No violations were identified.

5.3 Plant Shutdown on March 1, 1985

The licensee completed physical testing associated with the low power phase of the startup test program on 3/1/85 and conducted a plant shutdown in preparation for a three-to-four week maintenance outage. The unit was shutdown using a special procedure to closely monitor rod position indications from selected rods during the manually initiated scram. This special procedure was developed to monitor rods which did not show a full-in indication after the 1/31 scram (see paragraph 5.1). All rods were fully inserted by the scram and the proper full-in indication was obtained for each rod on the full core display immediately after the scram. However, when the scram signal was reset the full-in indications for 3 control rods (18-11, 42-47 and 38-27) were lost. The licensee verified that these 3 rods were still fully inserted through indications on the 4 rod display and the process computer. The licensee indicated that minor adjustments would be made to the Position Indicating Probes (PIP) for rods 18-11, 42-47 and 38-27 during the upcoming maintenance outage.

All other systems operated correctly during the plant shutdown. The inspector witnessed the shutdown and has no further questions at this time.

No violations were identified.

6. Review of Work Accomplished During the February 4 - 17, 1985 Mini-Outage

Following a reactor scram on 1/31/85, the licensee decided to enter a mini-outage to perform needed repair work and to implement certain modifications which were felt necessary to correct design deficiencies which had been causing spurious actuations of engineered safety features. The resident inspector monitored the licensee's activities

throughout the outage which ran until 2/17/85. The work performed during the outage included:

1) repair of the RHR service water radiation monitors;

2) replacement and retesting of the position indicating probe for control rod 42-27;

3) replacement and recalibration of the Division III ECCS initiation card which monitors low reactor pressure

4) installation of the low pressure flow orifices in the full flow test lines for the high pressure coolant injection and reactor core isolation cooling systems;

5) modification and retesting of the Riley temperature modules for the steam leak detection system;

6) modification and retesting of the control circuitry for refueling area and reactor enclosure ventilation isolation systems;

7) modification to the room ventilation in the Unit 2 reactor protection system (RPS) inverter room and modification to the Unit 1 RPS inverter cabinets to provide added cooling to the inverter units;

8) cable pulling for a modification to provide an additional regulated AC power supply from the Technical Support Center to the RPS inverter units; and

9) installation of some supports which will be used to add head chambers to NSSS instrument racks.

The inspector performed a detailed followup of activities 5) and 6) above. The results of this followup are documented in section 7 of this report. Following the outage, the plant was restarted on 2/17/85.

No violations were identified.

7. Review of Selected Modification Packages

The inspector reviewed the modification packages listed below to determine the purpose for each modification, and to verify that each package had received an appropriate technical and administrative review. The inspector also verified that a safety evaluation had been performed and the results reviewed and accepted by the Plant Operations Review Committee. Further, the inspector reviewed the results of testing performed in connection with the implementation of these modifications.

7.1 Modification Design Change Package (MDCP) 85-328: addition of resistors to the circuits in the Riley temperature modules. This MDCP added 5-6K ohm resistors to the comparator circuits in the temperature modules manufactured by Riley and used by the steam leak detection system to isolate systems, such as the reactor water cleanup system, in response to indications of fluid leaks in these systems. The intent of the MDCP was to eliminate the spurious trips of these Riley modules which had been frequently occurring while operators attempted to read the temperatures indicated on these modules. Post-installation testing included performance of surveillance tests on each of the modules which were modified and which initiate protective actions such as automatic containment isolation valve closure.

7.2 Modification Design Change Package 324 and 325: replacement of the Agastat time delay relays which are used to initiate reactor enclosure and refueling floor isolations on indications of low differential pressure and the cross connection of the masts used to sense outside air pressure. These two modifications were intended to eliminate spurious secondary containment isolations which had been occurring during high wind conditions. MDCP 324 replaced the time-delay relays which had been initially installed with Agastat ETR 14D3G relays set for a 100 second time delay. MDCP 325 installed tubing and valves to permit the cross connection of the masts which are located on the east and west side of the reactor enclosure roof. Cross connection of the masts should allow the A and B channel outside air pressure sensors to see an equalized condition. The inspectors reviewed the PECo Field Engineering and Plymouth Laboratory test records which documented that the Agastat timers were correctly set and the relays were correctly installed in their respective control circuits.

No violations were identified.

8. Maintenance Observations

The inspector periodically reviewed the status of selected maintenance request forms (MRF) to verify compliance with the station's administrative procedures and to track the status of maintenance on safety related equipment.

8.1 Mode Switch Repairs

Upon attempting to place the reactor mode switch into the Startup position at about 11:00 p.m. 2/16/85, the operators noted that the switch appeared to be stuck in place in the Shutdown position. The Shift Superintendent (SST) notified an I & C technician who responded to the control room. Under the authorization of the SST, the technician commenced a troubleshooting activity by

first attempting to remove the mode switch from Unit 2. Using the Unit 2 switch as a mockup trainer, the technician determined the method to be used to remove the switch handle and locking assembly. He then obtained the SST's permission to work on the Unit 1 switch. The switch mechanism was removed without disturbing any of the gearing between the main drive gear and the 4 individual gear assemblies for the 4 contact blocks which the mode switch normally drives.

Upon examination of the switch assembly that was removed, the I & C technician identified that one of the two brass screws which are used to connect the mode switch handle to the rotating locking assembly had backed out of its seat. Apparently, this screw had restrained the locking assembly such that the mode switch was incapable of movement.

The technician then tightened the screw and reinstalled the switch assembly. The operators then tested the mode switch to assure it had been properly reinstalled and had been recoupled to the main drive gear for the contact stacks. The test involved rotating the switch clockwise from the Shutdown to the Refuel position and back to Shutdown. The mode switch appeared to function properly as indicated by the full scram signal which resulted from placing the mode switch in Shutdown. The mode switch was then made operable at about 2:00 a.m., 2/17/85. The disassembly, repair, reassembly and testing of the mode switch was witnessed by a PECo Quality Control inspector.

On 2/19/85, the inspector inquired about the extent of documentation for the repair work which had occurred. The inspector was informed that a maintenance request form (MRF) had not been prepared to cover this job. The work activity was considered to be a troubleshooting effort undertaken prior to preparation of a MRF to determine the repairs which would be needed. Because the repair activity only involved tightening an already installed screw, this work was accomplished without first issuing a MRF. The inspector indicated to the licensee that some documentation was required to record the problem which was identified and the corrective actions taken.

Subsequently, the inspector reviewed the QC Inspector's Report (QCIR) LGE-85-0443, which described the activities witnessed by the QC inspector and which indicated that MRF 85-2138 had been issued after the fact to record the work accomplished. Further, the inspector was informed that a Plant Staff Field Report had been issued on 2/20/85 to request an engineering solution to prevent a recurrence of similar problems with the mode switch assembly.

The inspector informed the licensee that, although the troubleshooting, repair and retesting activities were adequate to address the immediate problems with the mode switch, these troubleshooting activities were not performed under the control of a suitable Administrative Procedure. Not having a procedure to control troubleshooting has previously been identified as a violation of Technical Specification 6.8.1 in Inspection Report 50-352/85-06. The licensee's actions in regard to the findings in this previous inspection report will be monitored to assure that they acceptably address controls for work such as was performed on the mode switch. (50-352/85-11-01)

No additional violations were identified.

9. Monthly Surveillance Observation

The inspector observed and reviewed surveillance tests ST-2-074-406-1 "IRM C Channel Calibration Test" and ST-4-107-950-1 "CRD Housing Support Visual Inspection" to verify that the tests had been properly approved by shift supervision, control room operators were knowledgeable regarding the tests, approved procedures were being used, test instrumentation was calibrated and test acceptance criteria were met.

No unacceptable conditions were identified.

10. Inoffice Review of Event Reports

The SALP report for the period 12/1/83 - 11/30/84 noted a trend in personnel errors and Inspection Report 50-352/84-65; 50-353/84-14 contained findings involving personnel errors. As part of a followup effort, the inspector reviewed the licensee's written response to that inspection report, met with licensee personnel to discuss the topic, and conducted an independent review of events reported under 10 CFR 50.73 during 1984.

Licensee corrective actions regarding personnel error-related events have been extensive and aggressive and have included independent investigations and analyses of each reportable event to determine the root cause, new plant-wide programs offering a reward to groups with fewest personnel errors, and the pursuit of modifications to correct conditions which provide easy opportunities for personnel error. These measures were discussed at a meeting with the licensee held at the Region I office on February 22, 1985. At this meeting the licensee committed to submit a report in late March which will discuss in detail the implementation and results of the corrective actions taken.

The inspector's independent study used telephone reports made under 10 CFR 50.72 and Licensee Event Reports (LERs) made under 10 CFR 50.73. Where additional details were needed, the inspector reviewed regional inspection reports concerning the specific events. The reported events were grouped on the basis of common cause for the identification

of possible trends or underlying factors. The results of this review were compared to similar reports by the licensee; no major items of disagreement were identified between the results of the inspector's and the licensee's analyses. The inspector verified that the conclusions of the licensee's study were being factored into the licensee's proposed program of corrective actions.

No violations were identified.

11. Exit Meeting

The NRC resident inspector discussed the issues and findings in this report throughout the inspection period and at an exit meeting held with Messrs. J. Corcoran and G. Leitch on March 19, 1985. At this meeting the representatives of the licensee indicated that the items discussed in this report did not involve proprietary information.

No written material was provided to the licensee during this period.