U.S. NUCLEAR REGULATORY COMMISSION
Region I

Report No. 86-04

Docket No. 50-352

License No. NPF-39 Priority -- Category C

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

Facility Name: Limerick Generating Station, Unit 1

Inspection Conducted: March 1 - April 13, 1986

Inspectors: E. M. Kelly, Senior Resident Inspector
S. D. Kucharski, Resident Inspector
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Reviewed by: J E Beall 5/15/86
J. E. Beall, Project Engineer Date

Approved by: Robert M. Gallo 5/16/86
R. M. Gallo, Chief, Reactor Projects Section 2A Date

Inspection Summary: Inspection Report No. 50-352/86-04 for Inspection Conducted March 1-April 13, 1986.
Area Inspected: Routine dayshift and backshift inspections (142 hours) of Unit 1 by the resident inspectors consisting of followup on outstanding items; review of the final report for startup testing; system walkdown of the Core Spray system; plant tours including fire protection measures; maintenance and surveillance observations; and review of LERs and periodic reports. Events which occurred during the period, and were reviewed, include: a reactor water level transient on March 25; increased Reactor Enclosure Inleakage on March 7; and a Radwaste Spill on February 27, 1986.

Results: No violations were identified. Unresolved items are discussed regarding Reactor Enclosure differential pressure surveillance testing (detail 6.2.2) and RPS power supply trip breaker performance (detail 8).

DETAILS

1.0 Persons Contacted

Philadelphia Electric Company

J. Corcoran, Engineer-In-Charge, Field QA
J. Doering, Superintendent of Operations
R. Dubiel, Senior Health Physicist
P. Duca, Technical Engineer
J. Franz, Station Manager
G. Leitch, Superintendent, Nuclear Generation Division
J. Milito, Supervisor of Field Engineering

Also during this inspection period, the inspectors discussed plant status and operations with other supervisors and engineers in the PECO, Bechtel and General Electric organizations.

2.0 Followup on Unresolved Items

2.1 (Closed) Unresolved Item 85-36-01; Off-Normal Procedures for ESW

A technical review of the Emergency Service Water (ESW) system performed by Brookhaven National Laboratory for NRC Region I and issued to the licensee by letter dated October 4, 1984 identified a concern for the availability of procedures which address off-normal operating alignments of ESW. An unresolved item was identified in NRC Inspection Report 50-352/85-36 and, in response to the inspector's concerns, the licensee developed Operating Procedure S11.0.A, Abnormal Operation of ESW System.

The inspector reviewed Revision 0 to S11.0.A dated March 5, 1986, and verified that the procedure addressed the following abnormal system alignments:

- one pump available in each ESW loop
- loss of either the "A" or "B" loop of ESW, including alignment of diesel generator cooling, ECCS room coolers, and the effect on HPCI and RCIC
- establishment of natural circulation cooling paths for the HPCI and RCIC rooms

The inspector had no further questions and concluded that the procedure adequately addresses the concerns of item 85-36-01.

2.2 License Condition 2.C.5 - Safety Parameter Display System

The Limerick Unit 1 Full Power License requires that the Safety Parameter Display System (SPDS) be operable within 30 days after the completion of the 100-hour warranty run. The warranty run was completed in January 28, 1986, and the licensee submitted information on SPDS validation testing and release for operability by letter dated February 25, 1986 to the NRC.

The inspector reviewed the licensee's summary of SPDS validation testing describing field verification tests, problems encountered and resolutions implemented in making the SPDS operable. The licensee concluded that functional performance and interface design requirements placed on the SPDS had been met for a full range of reactor power levels. The licensee's conclusion was based on extensive startup testing of the GE-supplied Emergency Response Facility Data System (ERFDS) software, data bases and hardware. Displays for the following ERFDS functions (which constitute SPDS) were validated:

- critical plant variables
- reactor power and temperature controls
- suppression pool level
- two-dimensional and trend plots
- validation displays

Startup test exceptions were documented and resolved, and no significant software problems are outstanding. The licensee concluded that the Limerick SPDS is operational, and that all startup test acceptance criteria had been met.

The inspector reviewed the results of Special Procedures SP-017, ERFDS Regulatory Guide 1.97 Reasonableness Test and SP-015, ERFDS Reasonableness Test. The tests verified the ERFDS displays against installed plant instruments. The licensee's PORC reviewed the reasonableness test results and concluded that SPDS design requirements had been satisfied.

The inspector also reviewed a summary description of SPDS display characteristics which was distributed to all licensed operators to provide general information on the use of SPDS. The inspector discussed the training information with operations personnel and concluded that operators are sufficiently trained in the use and interpretation of ERFDS displays as evidenced by daily control room observations and witnessing of startup testing. The inspector concluded that the SPDS was operational, effectively integrated into the control room environment, and accurately displayed plant indications and conditions. The Limerick ERFDS is therefore in accordance with NUREG-0737 Item I.D.2 for an SPDS, and the requirements of License Condition 2.C.5 have been met.

3.0 Review of Plant Operations

3.1 Summary of Events

The plant operated at full rated power throughout the inspection period. The annual emergency exercise was conducted on April 3, 1986.

3.2 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed and the status of control room annunciators was reviewed. Nuclear instrument panels and other reactor protective systems were examined. Effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area and vital island, the inspector observed access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment including portal monitors. No unacceptable conditions were found.

The inspector reviewed shift superintendent, control room supervisor, and operator logs covering the entire inspection period. Sampling reviews were made of equipment trouble tags, night orders, and the temporary circuit alteration and LCO tracking logs. The inspector also observed shift turnovers during the period. The operations activities were observed for conformance with the applicable procedures and requirements; no unacceptable conditions were noted.

3.2.1. Shift Memorandum

The inspector reviewed a memorandum from the Reactor Engineer to all Shift Superintendents dated March 25, 1986, regarding a rod withdrawal sequence error experienced during a March 18, 1986 startup at the Peach Bottom Station. The memo summarized the Peach Bottom event and its possibility of occurrence at Limerick. The memorandum stressed proper adherence to Rod Worth Minimizer control rod pull sheets and the proper operation of the Rod Sequence Control System (RSCS) at Limerick. The inspector verified that the memo had been read by all shift supervisors, and discussed the event and its applicability at Limerick with the Reactor Engineer. The inspector had no further questions.

3.2.2 Control Room Annunciators

The inspector observed various alarm conditions which were annunciated, or remained annunciated at various times during the inspection period.

The licensee tracks the status of annunciators in a daily planning meeting and documents the status in an associated TRIPOD report. Approximately 40 to 50 annunciators were being tracked daily throughout the inspection period as either under investigation or for which corrective action has been initiated. About half of these were identified as nuisance alarms, and all alarms were cleared and/or tagged out with maintenance requests and responsible work groups noted. The inspector interviewed operators with regard to annunciators alarmed in control room, and found them knowledgeable of and responsive to the cause and significance of the alarms.

The inspector also reviewed Operations memorandum OPS-0106 dated April 4, 1986, describing two human factors enhancements to the main control room annunciator windows which were instituted at the end of this inspection period. Transparent green plates were to be affixed to annunciator windows which are alarmed as a result of a normal plant condition which is expected to remain for an extended time. Also, certain mandatory response annunciators are now designated with orange triangles in the upper right window corner, requiring immediate response and reference to the Annunciator Response Cards. These enhancements allow for improved operator response to alarms, knowledge of plant status, and a better distinction between (and elimination of) nuisance alarms.

3.2.3 Administrative Procedure A-7

The inspector reviewed Revision 3 to Procedure A-7, effective April 9, 1986, Shift Operations, regarding changes to control room annunciators, panel indications and walk-downs, a new equipment status board, emphasis on access control, generation of Upset Reports, maintenance of a shift turnover log, conduct of shift briefing and creation of an Operations Group training manual. No unacceptable conditions were noted.

3.3 Station Tours

The inspectors toured accessible areas of the plant throughout this inspection period, including: the Unit 1 reactor and turbine-auxiliary enclosures; the main control and auxiliary equipment rooms; emergency switchgear and cable spreading rooms, and the plant site perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment ongoing maintenance and surveillance and availability of redundant equipment. No unacceptable conditions were found.

3.4 Core Spray System Walkdown

The inspector independently verified the operability of the Core Spray "B" loop by performing a walkdown of the accessible portions of the system and confirmation of the following items:

-- The system check-off list and operating procedures are consistent with the plant drawings and as-built configuration.

-- Valves and breakers are properly aligned, necessary instrumentation is functional, and appropriate valves are locked.

-- Control room switches, indications and controls are in the proper position or configuration.

The following references were reviewed:

-- Technical Specification 3.5.1

-- P&ID M-52, Core Spray

-- Core Spray Operating Procedure S52.1.A

No unacceptable conditions were identified.

4.0 Event Followup

4.1 March 25,1986 Water Level Transient

On March 25, 1986, with the unit at 100% power, I&C technicians removed a multi-channel recorder from the "B" and "C" feedwater pump minimum flow recirculation valve control circuitry. The valve flow controller current loops were being monitored with the recorder under the administrative control of a Temporary Circuit Alteration (TCA). The technicians were directed to remove the recorder, but failed to note the TCA tag hung inside of the valve panel which cautioned that removal of the recorder would interrupt the current loop. The removal of the recorder caused both minimum flow valves to go full open.

The "B" valve opened but, because of a block valve closed downstream to limit leakage, did not affect reactor vessel water level. However, the "C" valve opened and caused approximately 25% of the "C" pump flow to be routed to the main condenser rather than to the reactor vessel. A corresponding vessel water level decrease occurred from normal (+35) to +24 inches. Level was recovered by the feedwater level control system which increased flow through the "B" and "C" feedwater pumps. Reactor power subsequently decreased by 3% and vessel water level stabilized at the normal level. All systems functioned as designed and the "A" feedwater pump was unaffected. Plant operators followed Operational Transient procedures to further reduce reactor power by lowering recirculation flow to minimize overcompensation by the feedwater level control system. The "B" and "C" minimum flow valve controller current loops were reconnected, the valves were manually returned to their full closed positions and plant operation was restored to 100% power.

The inspector discussed this event with plant operators and plant management. The licensee evaluated existing administrative controls as adequate, and counselled I&C technicians on the use of TCAs. I&C supervision also emphasized the importance of informing control room supervision prior to altering plant equipment by application or removal of a TCA. The inspector reviewed Station Upset Report - 024 which described the level transient, proposed appropriate corrective action and was provided to licensee senior management. The inspector had no further questions and no violations were identified.

4.2 Reactor Enclosure Inleakage

The licensee performed maintenance on the Reactor Enclosure normal ventilation exhaust fans during the week of March 3, 1986. The work involved shutting down the exhaust fans which then required manual isolation of the Reactor Enclosure (RE) secondary containment to maintain a negative building pressure of 0.25 inches water gauge using the Reactor Enclosure Recirculation and Standby Gas Treatment (SGTS) systems. Prolonged operation with SGTS is limited to approximately 6-8 hours for RE area and equipment temperature considerations because RE recirculation flows are reduced to one-third of the normal ventilation circulation and do not include air cooling provisions.

During RE isolation operation on the afternoon of March 7, control room operators noticed fluctuating SGTS flow rates between 1500-2000 cubic feet per minute (cfm). Technical Specification Surveillance 4.6.5.1.1 specifies that secondary containment integrity be demonstrated, in part, by operating a single train of SGTS for one hour every 18 months. The 18-month test is required to maintain a 0.25 inch RE vacuum at an SGTS flow rate not exceeding 1250 cfm. The licensee evaluated the operation of SGTS in excess of the 1250 cfm flow rate and entered a four-hour action statement to restore secondary containment integrity. The SGTS flow was subsequently reduced to approximately 1000 cfm, by application of additional sealing of reactor cavity and drywell head structural sections on the refueling floor to reduce RE inleakage paths.

The inspector reviewed the bases for the SGTS 1250 cfm flow limit outlined in FSAR Sections 6.2.3, 6.5.1, and 15.6.5. The flow limit is a design RE inleakage corresponding to one building free air volume per day. The 1250 cfm limit also corresponds to the steady state rate of treated release to the environment via the SGTS assumed in FSAR Chapter 15 accident analyses. The FSAR analyses assume the same amount of unfiltered exfiltration during the period when RE pressure is above the 0.25 inch vacuum maintained by SGTS (assumed to be the first 5 minutes of RE drawdown time per FSAR Table 15.6-27). Therefore, the 1250 cfm SGTS flow represents the design leakage of the RE, and steady state flows in excess of this rate are outside of the bounds of analyzed post-accident offsite dose projections.

The inspectors observed the licensee's actions to reduce RE inleakage at the refueling floor on March 7. Coincident with the inleakage event were unusually high outside winds which gusted to approximately 50-60 mph. High winds have been observed to affect the SGTS flow controller because of the method used to measure outside air pressure relative to interior RE pressure. In addition to re-evaluation of the reactor well plug seals on the refueling floor, the licensee conducted walk down inspections of the refueling floor area for potential RE inleakage paths including the spent fuel pool cooling system alignment and other vents and drains. The licensee is evaluating the potential affects of transient air lock openings, flow indicator calibration, RE heating and other secondary effects on SGTS flow during isolation of the RE.

The inspector discussed this event with plant operators who were knowledgeable of the significance of the 1250 cfm limit. The inspector noted that, during similar RE isolations for ventilation supply fan maintenance during the week of April 7, control room operators monitored SGTS flow for sustained inleakage above 1250 cfm. During a 6-hour RE isolation on April 10, SGTS flow was observed to exceed 1250 cfm for 85 minutes and operators appropriately entered the Technical Specification action statement for secondary containment integrity. No violations were noted and the inspector will follow the results of the licensee's additional inspections and evaluation of potential inleakage paths to the RE.

4.3 Condensate Phase Separator Overflow

Approximately 16,000 gallons of flush water from the condensate storage tank (CST) spilled onto the basement level of the radwaste building to a height of about one inch on February 26, 1986. The spill lasted for 17 minutes, after a radwaste operator had left the radwaste control room, as water overflowed the "B" condense phase separator tank due to a 60-second timer failure which should have terminated a condensate filter-demineralizer water/resin flush.

The inspector discussed the event with radwaste operators, Operations engineers and plant management. The inspector also reviewed Station Upset Report-021 approved on March 10, 1986, which described the event. The inspector observed the affected areas and hallways, and verified that no personnel exposures were incurred as a result of the spill. Although both radwaste sumps and the Floor Drain Collection Tank and Equipment Drain Collection Tank were contaminated with resin, the spill was contained within the sumps, drains and collection tanks in the Radwaste Building. No violations were identified.

The licensee evaluated the cause of the spill as the failure of condensate flush valve HV-67-102 to close due to faulty auxiliary relay in the flushing logic sequence. Flush valve binding was investigated but ruled out, as the failure could not be duplicated. Subsequent transfers from the BWRT to the phase separators, including the flushing sequence using the same transfer pump, showed no problems with HV-67-102. The auxiliary relay in the flushing logic sequence was replaced, and no further flush valve failures have occurred. The inspector reviewed Operations memoranda-0073 and 76 issued to all control and radwaste operators which addressed response to trouble alarms, communications between the main room and remote radwaste control rooms, and awareness of radwaste processes in progress that affect plant interfacing systems and general plant radiation levels. The inspector interviewed various plant operators, found them knowledgeable concerning this event, and had no further questions.

5.0 Licensee Reports

5.1 In-Office Review of Licensee Event Reports

The inspector reivewed Unit 1 LERs submitted to the NRC Region I office to verify that details of each event were clearly reported, including the accuracy of description of the cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were involved, and whether the event warranted on-site followup. The following LERs were reviewed:

LER Number	Report Date	Subject
86-009	February 26	Overdue Calibration of Remote Shutdown Panel Instruments
86-010 (Note a)	March 3	Feedwater Flow Transmitter Miscalibration - License Condition 2.C.(1) on Maximum Power Level
86-011 (Note a)	March 14	Reactor Scram on High Neutron Flux
86-012 (Note c)	March 14	RHR Service Water Radiation Monitor Downscale Failure and Isolation
86-013 (Note b)	March 25	Reactor Water Cleanup Isolations
86-014 (Note c)	March 27	Reactor Enclosure Isolation due to Breach in Equipment Access Airlock
86-015	April 2	Chlorine Analyzer Failure and CREFAS Actuation

Notes:

a. Addressed in Inspection Report 50-352/86-03

b. Addressed in Detail 5.2 of this report

c. Addressed in Inspection Report 50-352/86-09

5.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite followup as noted in Section 5.1, the inspector verified the reporting requirements of 10 CFR 50.73 and Technical Specifications had been met, that appropriate corrective action had been taken, that the event was reviewed by the licensee, and that continued operation of the facility was conducted in accordance with Technical Specification limits.

5.2.1 LER 86-013; RWCU Isolations

Reactor water cleanup (RWCU) inboard isolation valve closures occurred on February 23 and March 12, 1986, during daily surveillance testing of RWCU area temperatures. The isolations occurred because of a defective temperature module that, when taken to the "Read" position to check Steam Leak

Detection System circuitry, caused a momentary trip signal which closed the RWCU inboard isolation valve. The first isolation was attributed to a faulty connection but the second isolation was associated with the same temperature module (manufactured by Riley Co.) which was defective and was replaced.

Because of previous LERs describing similar RWCU isolations caused by Riley temperature modules, the inspector discussed the events with licensee technical engineers and reviewed modification package (MDCP) 85-328 implemented on February 17, 1985. MDCP-85-328 added resistors to the temperature switch points to eliminate voltage spikes in associated comparator circuits by suppressing the switching transient when manipulating the Read/Set switch. There are 24 different modules associated with RWCU room and differential temperatures which are switched and read daily as part of surveillance test ST-6-107-590 for the Steam Leak Detection System. There have been 6 reported instances of RWCU isolations after implementation of MDCP-85-328 caused during the conduct of ST-6-107-590. However, considering the relatively large number of challenges (24 per day) in relation to the failures experienced since implementation of MDCP-85-328, the inspector concluded that the defective module described in LER 86-013 represents an isolated case and is not indicative of a continued generic problem with Riley Model 86 temperature switches. The inspector also reviewed daily checks of RWCU area temperatures in accordance with ST-6-107-590 for the week of March 24, 1986, and identified no discrepancies or problems. The inspector had no further questions.

5.2.2 Fire Protection LERs 85-075, 85-087 and 86-006

A fire protection program reviewed the subject LERs associated with fire door and hose station surveillances which were missed, and a license condition related to safe shutdown capability.

LER 85-087 described the licensee's discovery of three cables routed through fire areas with redundant equipment whereby a design basis fire could affect safe shutdown capability, specifically a fire in the auxiliary equipment room affecting the RCIC system. The licensee had previously maintained a continuous fire watch in the auxiliary equipment room, and smoke detectors were operable and capable of detecting and annunciating a potential fire affecting the cables in question. Automatic or manual initiation of the halon extinguishing system was also available. The licensee encapsulated the affected cables with 3-hour fire wrap and is performing a re-evaluation of all cables required for safe shutdown to verify proper physical separation. No unacceptable conditions were noted, and the inspector had no further questions.

LERs 85-075 and 86-006 involved instances where fire door and hose station surveillance tests were missed because of administrative oversight or poor communication between fire protection personnel. Each case was reviewed and discussed with the Regulatory Engineer and Fire Protection Group personnel. Each case was considered by the inspector to be an isolated instance of minimal fire safety concern due to the duration of the events, the availability of backup systems, and subsequent successful test results for the fire door and hose stations in question. The licensee's corrective actions were adequate, should prevent future similar instances, and are an improvement to existing fire program test controls. No violations were identified and the inspector had no further questions.

5.3 Review of Periodic and Special Reports

Upon receipt, periodic or special reports submitted by the licensee were reviewed by the inspector. The reports were reviewed to determine that the report included the required information, that test results and/or supporting information were consistent with design predictions and performance specifications, and whether any information in the report should be classified as an abnormal occurrence.

The following reports were found to be acceptable:

-- Monthly Operating Report for February 1986

-- 1985 Annual Report of Challenges to Safety Relief Valves, dated February 27, 1986

-- Annual Occupational Exposure Tabulation for Calendar Year 1985, dated February 28, 1986

-- Semi-Annual Effluent Release Report No. 3 for July through December, 1985; and, 1985 Tower No. 1 Joint Frequency Distributions of Wind Direction and Speed, dated February 28, 1986

-- Startup Test Program Change; Performance of STP-25.3, MSIV Full Closure Testing at 91.7% Power, dated March 4, 1986

-- Special Report of HPCI System Actuation and Injection on January 2, 1986, dated March 24, 1986

5.3.1 Startup Test Program Summary

The inspector reviewed the summary report of the Startup Test Program transmitted by letter to the NRC dated March 20, 1986. The inspector verified that Revision 2 to the Final Report of Initial Plant Startup included information required by Technical Specifications, that test results were accurately described and compared with test criteria, and that corrective actions adequately resolved identified problems. The full report covered events started with initial fuel loading on October 26, 1984 and ending with completion of the Warranty Run following Test Condition 6 on January 28, 1986. The inspector concluded that the report was satisfactory.

5.4 Part 21 Reports

5.4.1 Colt Industries Connecting Rod Nuts

The inspector reviewed the licensee's disposition of a defect reported to the NRC on November 26, 1985 by Colt Industries-Fairbanks Morse Engine Division concerning improper fitup of connecting rod nuts to the mating surface of the connecting rod bearing caps for Model 38 TD8-1/8 emergency diesel engines. The nuts in question were found to have faces not perpendicular to the thread pitch line such that, with bending loads imposed, stresses beyond design limits could be induced. The suspect nuts were from vendor shipments received after April 9, 1984 and, for Limerick Station, onsite spares were identified by Colt as potentially deficient. No operating engines were identified as having defective nuts installed.

The inspector reviewed PECO Nonconformance Report 86-007 dated February 5, 1986, which identified 20 defective items in the Limerick storeroom. The items were recommended for return to Colt Industries in a memorandum from the licensee's Maintenance Engineer. Bill of Lading Number 14258 documented the return of the defective items on February 18, 1986. The inspector discussed the defective nuts with licensee QA representatives, who stated that subsequent replacement items were received on March 6, 1986.

5.4.2 Clow Butterfly Valves

The licensee submitted a Part 21 Report to the NRC by letter dated March 13, 1986, describing a potential galvanic corrosion problem between the carbon bearings and stainless steel shafts on butterfly valves manufactured by the Clow Corporation and installed in the containment atmospheric control system (CACS) at Limerick. The galvanic attack was discovered at Peach Bottom Station on January 6, 1986 on similar Clow valves which were metallurgically examined by the licensee and determined to be defective.

The potentially affected Clow valves installed at Limerick include 15 valves in the CACS, 11 of which are normally closed and infrequently opened for inerting and de-inerting. The remaining four are installed on the containment hydrogen recombiner inlet and outlet lines and are also normally closed, but required to be manually opened after an accident to control containment hydrogen concentration. The recombiner valves are containment isolation valves which are stroked quarterly in accordance with Technical Specifications and surveillance test ST-6-057-200-1.

The inspector reviewed the results of seven quarterly stroke tests for the recombiner valves conducted between November 1984 and February 1986. All tests were successful in meeting the maximum allowable open and close time of 9 seconds; all recorded stroke times were between 4.2 and 5.7 seconds; and, no adverse or declining trends were noted. The licensee developed special test procedure ST-6-B57-200-1 to stroke the four recombiner valves weekly until the valve bearings are replaced with an improved material to alleviate the chemical and galvanic attack which was experienced at Peach Bottom.

The inspector: (a) discussed the potential for corrosive damage with with licensee design engineers and plant management; (b) reviewed the weekly procedure developed to stroke the four recombiner isolation valves; and, (c) evaluated the results of weekly testing performed on March 13, 17 and 24, 1986. The test results were found to be satisfactory.

The licensee continued weekly testing of the recombiner isolation valves through the end of the inspection period, and had not opened the other 11 potentially-affected CACS valves as of the end of the period. The inspector will follow the licensee's continued testing and subsequent corrective actions.

6.0 Maintenance and Surveillance Observations

6.1 Maintenance on HV51-1F024B

The inspector reviewed completed maintenance performed on the "B" RHR full flow bypass valve HV51-1F024B to correct an anti-rotation collar misalignment and to properly reset the valve stem limit switches. Work was performed under MRF86-01394 on March 6, 1986, in accordance with maintenance procedures PMQ-500-052 and 087. Maintenance data record forms were properly documented and approved, completed work incorporated QA-sign offs at all appropriate steps, open and close currents and torque switch settings were satisfactorily documented, and successful post-maintenance testing was performed.

The licensee entered a Technical Specification action statement for suppression pool cooling while the "B" RHR full flow test valve was removed from service for maintenance. The full flow test valve's rotation collar was repaired, the valve was returned to service in accordance with procedural requirements, and the Technical Specification action statements were cleared. The open limit for the valve was reset to 15.7 seconds for a flow of 10,700 gpm and the valve was stroked closed in accordance with quarterly test requirements. No unacceptable conditions were identified by the inspector.

6.2 Surveillance Activities

6.2.1 Test Observations

The inspector observed the performance of and/or reviewed the results of the following tests:

-- ST-6-052-232-1; "B" Core Spray Pump and Valve Flow Test, conducted March 24, 1986

-- ST-6-052-702-1; "B" Core Spray Loop Contaminated Piping Inspection, conducted March 24, 1986

-- ST-2-047-600-1; Scram Discharge Volume High Water Level Channel Functional Test, conducted March 26, 1986

-- ST-6-107-590, Item 38; Scram Discharge Volume Level Transmitter Channel Checks, conducted daily March 1-31, 1986

The tests were observed to determine that test procedures conformed to Technical Specification requirements; proper administrative controls and tagouts were obtained prior to testing; testing was performed by qualified personnel in accordance with approved procedures and calibrated instrumentation; test data and results were accurate and in accordance with Technical Specifications; and equipment was properly returned to service following testing.

No unacceptable conditions were noted.

6.2.2 Reactor Enclosure Differential Pressure Calibration

The inspector reviewed performance of ST-2-076-401-1 on March 25, 1986 for the isolation of "B" channel Reactor Enclosure (RE) ventilation on low differential pressure. During the test, the "B" channel was inoperable in excess of the two hours allowed by Technical Specifications, after which an isolation must be initiated.

The licensee discovered that the limit was exceeded approximately three hours after the RE should have been isolated per Technical Specifications. Proper action was then taken to manually initiate a Group VI-B damper isolation and start the Standby Gas Treatment System (SGTS). The group VI-B isolation involves re-alignment of RE ventilation dampers, initiation of SGTS, and closure signals to normally-closed containment purge valves. The "A" channel outside atmosphere-to-RE low differential pressure transmitter was operable and would have initiated a similar isolation of secondary containment if necessary. The "B" channel transmitter was calibrated and returned to service three hours after the manual isolation of the RE.

ST-2-076-401 is a calibration functional test performed every 92 days for instrumentation associated with RE and refuel floor isolation systems. Because of the large number of devices (11) related to channel "B" secondary containment isolations versus the relatively short amount of time (2 hours) to perform the calibrations, the test has been broken up into five separately performed surveillance tests. The 2-hour restriction, after which an RE isolation must be initiated, provides little time to perform the calibration check especially if recalibration is found to be needed.

On March 25, 1986, a partial ST-2-076-401 involving recalibration of transmitter PDT-76-498B was being performed because the I & C technician conservatively decided that the as-found output of the transmitter was too close to the lower acceptance limits.

Approximately 1-3/4 hours into the surveillance test, the I & C technician left the RE to return to the control room. The technician discussed the calibration difficulties being experiened, and inquired as to possible RE ventilation transients or fan swaps which operators may have been performing. However, ineffective communication between the technician and operator failed to clearly identify that the 2-hour limit was being approached, although ST-2-076-401 contains clear precautions to that effect. The miscommunication occurred at shift turnover, when other distractions were possibly present, and the channel remained out-of-service without the required Technical Specification action being taken for approximately four hours. The problem was discovered after I & C technicians later discussed the continued problem of re-calibrating the transmitter with control room operators.

The licensee evaluated this event and discussed the importance of enhanced and clear communications between test technicians and licensed operators in an "all-hands" I & C group meeting. The inspector discussed the event and its cause with licensee management, including a similar problem previously identified in LER 85-014 issued on February 15, 1985. The licensee is considering additional corrective measures to prevent recurrence of this problem. The effectiveness of additional corrective actions is unresolved and will be followed as unresolved item 50-352/86-04-01.

6.2.3 Daily Surveillance Log

The inspector reviewed a reformatting of the daily surveillance log ST-6-107-590. The log is a compilation of required operating and surveillance data, taken on each shift, to satisfy Technical Specification requirements such as daily or shift, to satisfy Technical Specification requirements for channel check and process parameters such as drywell temperature and pressure. The reformatting was compared against the former revision of ST-6-107-590, and found to be accurate and more logical for making entries. No unacceptable conditions were noted.

6.3 Post-Modification Testing

The inspector reviewed revisions to Electrical Engineering Division Procedure No. EE-11.38, Procedure to Control Retesting, which added requirements for independent ANSI Level III personnel review and approval of proposed retests associated with Field Engineering electrical modifications to Unit 1. Additionally, changes to the retest during implementation of a modification are now subject to independent review and approval by a supervising engineer, shift supervisor or STA. The changes to EE-11.38 were part of corrective action associated with LER 85-098 which described an isolation of RWCU system caused by implementation of modification MDCP85-0806 to the Standby Liquid Control System on December 9, 1985. The inspector discussed the procedural changes with the Supervising Field Engineer, and concluded that the changes should properly control the effects of modifications on interfacing systems.

No unacceptable conditions were noted.

7.0 Standby Liquid Control Explosive Valve Wiring

The inspector reviewed maintenance procedure PMQ-048-003, Replacement of Standy Liquid Control System (SLCS) Explosive Valves, and Conax Corporation Instruction Manual IM-8. The review confirmed proper wiring of the valve firing circuits at Limerick, and was prompted by a wiring error discovered on February 8, 1986 at the Vermont Yankee Nuclear Plant which resulted in failure of the explosive valves to fire and open when the system was tested. The wiring error was indeterminable via the continuity test lights in the main control room. The miswiring at Vermont Yankee occurred in a local terminal box and was compounded by valve primer connector wiring errors on the primer charge assembly.

The primer charge assembly, Conax Part No. 1621-240-1, is a standard design which is also employed at Limerick. Conax Corporation issued a Part 21 Report to the NRC on February 14, 1986, and identified potentially defective parts including 10 assemblies (Serial Nos. 699-708) provided to Limerick. The assemblies in question had changed pin-numbering/color coding for connectors used in the valve internal firing circuits.

The inspector discussed the Vermont Yankee error with PECO personnel, and the GE site representative at Limerick. The licensee had previously identified that the female Conax connectors supplied to connect to the Limerick SLCS explosive valves were not pinned-out per design drawings (rotational sequence incorrectly color coded) during preoperational testing in April 1984. The pin connector discrepancy was identified and documented via GE Field Deviation Disposition Report (FDDR) No. HH1-4351. The correct pin-to-bridgewire grouping was verified by a bridgewire circuit resistance check per Step 5.3.2 of the Conax Instruction Manual IM-8. Also, Startup Change Notice No. 391ES dated May 4, 1984, revised the connection lists to correctly reflect the wiring between the terminal box and the as-built valve pins. It should be noted that the Limerick valves would have successfully fired in either circuit configuration.

Three explosive valves were fired as part of preoperational test 1P-53.1 at Limerick on July 14, 1984. The explosive valves were replaced following the preoperational test. An inadvertent activation of the "A" SLCS pump also occurred in October 1985. The inspector reviewed the replacement of valve XV-048-1F004A October 12, 1985 under maintenance request MRF-85-08078 and in accordance with procedure PMQ-048-003 on. Satisfactory bridgewire resistance checks were performed, and QC witness and sign-off was provided for the checks. The trigger assembly fired was serial number 702, and was replaced with serial number 704. The manufacturing date stamped on the assemblies was January 1984, and both assemblies were from test lot CNX-22-1 from which a test firing was previously performed.

Since the Conax Manual IM-8 specifies a 5-year shelf life, the five remaining assemblies from test lot CNX-22-1 (3 currently installed and 2 spares) are still within their qualified life. Further, the 18-month functional test of SLCS is scheduled to be performed in May 1986 and will involve firing of two more explosive assemblies. The inspector will follow the performance of ST-3-048-320, including provisions for assurance of proper shelf life for the trigger assemblies, in a subsequent inspection.

The inspector discussed this issue with plant management, responsible test engineers and the GE site representative. The licensee initiated a walkdown and wiring verification, performed by the SLCS system engineer and GE representative, confirming the proper as-built connections to the explosive valves. The inspector independently confirmed the installed serial numbers, and had no further questions.

8.0 RPS Power Supply Breakers

8.1 References

The inspector reviewed the following documentation associated with the Reactor Protection System (RPS) power supply breakers:

- ST-8-036-419 thru 422-1; RPS-Electrical Power Monitoring Channel Calibrational/Functional; 18-month surveillance test
- SG-8-036-621 thru 624-1; RPS-Electrical Power Channel Functional; 6-month test
- FSAR Section 7.2.1.1.3, RPS Power Sources
- Technical Specification 3/4.8.4.3, RPS Electrical Power Monitoring
- Modification Package MDCP-490
- Emergency Procedures E-1AY160 and 1BY160; Loss of "A" and "B" UPS RPS Power

-- Schematic Diagram E-392, Rev 6; RPS Breaker Panel Protective Devices, RPS/UPS Systems

-- Field Engineering Report on RPS/UPS System Problems dated February 20, 1985

-- LER Nos. 84-05, 39, 40; 85-07, 24, 26 and 88

-- E & R Q A Meeting Minutes dated 4/11/86 for NRC Onsite Inpsection dated 3/25/86 by Vendor Programs Branch Inspectors

-- PECO Memorandum dated 2/26/86, C. Patton to W. Ullrich, Preliminary Investigation of RPS Breaker Failures

-- PECO Memorandum dated 3/13/86, J. Ferencsik to G. Leitch, RPS Circuit Breakers

-- April 16, 1986, Conference Call; NRC Region 1 and PECO, including Limerick and Peach Bottom sites and Corporate Engineering

8.2 Background

Failures of Westinghouse Type LBB molded case breakers were experienced in January-February 1986 at Peach Bottom. The breakers protect the RPS scram solenoids from power supply over/undervoltage and under-frequency transients using safety-related protective relays. The failures were experienced with DC-powered shunt trip coils which were found to be burned out. The shunt trip coil opens the breaker when energized. The coils are designed for intermittent duty and may burn out if energized continuously.

The circuit breakers are Westinghouse 2-pole Type LBB, Model No. 2225, rated for 6000 Volts AC and a continuous current of 225 amperes. There are two breakers in series for each RPS power supply channel, and each breaker is activated open on overvoltage (greater than 132 VAC), undervoltage (less than 109 VAC), and under frequency (less than 57 Hertz) conditions. Protective relays monitor power from either the normally in-service RPS static inverter, or the alternate AC power supply. The protective relays operate contacts which energize the shunt trip coils, causing the circuit breaker(s) to open. The shunt trip coils are factory-installed on the breakers and operate on 125 VDC.

8.3 Failures at Limerick

RPS circuit breaker failures occurred in July and November, 1984 at Limerick due to repeated attempts by operators to close the breaker - after tripping - with the trip signal condition still present. A caution label was affixed to the breaker panels directing operators not to attempt closing the breaker with the trip signal uncleared. No similar failures at Limerick have since been experienced.

The inspector discussed the previous failures at Limerick with licensee field engineers, including a study performed by Field Engineering of the RPS breaker problems. The inspector also reviewed seven LERs related to failures or activations of the RPS power supplies and/or breakers. Both the Field Engineering study issued in February 1985 and the LERs point to the fact that the misoperation of the breakers described above has been the apparent cause for the DC shunt coil failures.

The inspector reviewed the results of the 6-month channel functional testing performed in accordance with surveillance procedures ST-8-036-621 thru 624. The inspector also reviewed the results of the last 18-month calibration functional test performed on September 23, 1984 in accordance with ST-8-036-419 thru 422. The testing successfully verified the protective relay trip settings and, in the case of the 18-month tests, activated the circuit breakers without any shunt trip coil malfunctions. The calibration functional testing, which includes circuit breaker movement, is scheduled to be performed during the May 1986 outage.

8.4 Corrective Action

Westinghouse is currently evalutating the Peach Bottom breaker failures for potential generic or Part 21 reportability. ASCO Electrical Products Co. informed the NRC of a potential defect with the Westinghouse breakers in-question in an April 14, 1986 letter.

The inspector independently verified that caution tags are affixed to the RPS breaker panels which warn operators not to attempt closing of the breakers when the shunt trip coil "tripped" light is on, indicating the presence of an uncleared trip signal condition.

8.5 Conclusion

A conference call was held on April 16, 1986, between licensee representatives and NRC personnel to discuss the RPS breaker failures experienced recently at Peach Bottom and the relation of those failures to the identical breakers installed at Limerick. Functional testing, modification of protective relays, Westinghouse evaluation of Type LBB breakers, and associated PECO corrective action will be followed as unresolved Item 50-352/86-04-02.

9.0 Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable or constitute a deviation or a violation. Unresolved items are discussed in Details 6.2.2 and 8.0.

10.0 Exit Meeting

The NRC resident inspector discussed the issues in this report throughout the inspection period, and summarized the findings at an exit meeting held with Mr. John Franz and others of your staff on April 18, 1986. At this meeting, the licensee's representatives indicated that the items discussed in this report did not involve proprietary information.