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REGION I

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Facility Name:	Limerick Generating Station, Units 1 and 2
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Date

EXECUTIVE SUMMARY
Limerick Generating Station
Report No. 94-02 & 94-02

Plant Operations

On February 4, 1994, the inspectors observed the shut down of Unit 1. The inspectors concluded that the shutdown evolution was properly controlled and executed by the licensed operators (Section 1.3). The first of three problems associated with shutdown cooling on Unit 1 occurred when a licensed operator inadvertently isolated the ultimate heat sink from the 1B RHR heat exchanger, which was in the shutdown cooling mode of RHR (Section 1.4). Operations' response to a second problem with shutdown cooling was good, with immediate recognition of the isolation event and good corrective actions (Section 1.2). A review of PECO Energy's control of ignition sources and fire watch/patrols resulted in a cited violation for a failure to adequately control these activities, and a concern for the control of contractors performing the work (50-352/94-02-01). An unresolved item was opened concerning the use of a continuous fire watch when fire suppression is taken out of service in an emergency diesel generator cell (50-352/353/94-02-02) (Section 1.5). A special NRC inspection team is reviewing Limerick activities associated with a number of events that occurred during the current Unit 1 outage (Section 1.2, 1.4 and 1.5). The start of the Unit 1 refueling outage was delayed one week as a result of a review of available generating capacity and anticipated load, and forecasted weather conditions for the area (Section 1.3).

Maintenance

Observed maintenance activities, including the 1A RHR heat exchanger replacement and refueling activities, were performed adequately by knowledgeable workers, with good supervisory oversight and good coordination with health physics personnel.

Surveillance

During a diesel generator surveillance test, the generator's output voltage failed to automatically come up to rated voltage. The cause was determined to be that the voltage regulator was not properly returned to service after maintenance, due to a weakness in the procedural guidance. The third loss of shutdown cooling occurred during a surveillance test when a technician incorrectly performed a step in the test, and then correctly performed that same step out of sequence following a discussion with his foreman. The failure to execute a temporary change, or revise the procedure resulted in a cited violation (50-352/94-02-03) (Section 3.1).

Engineering

Observation of the recirculation jet pump hold down beam replacement modification, found that the activities were well organized and carried out with high regard for safety (Section 4.0).

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One instance was noted where a fuel bundle being lowered into the core was inadvertently lowered onto the upper core support plate. This instance will be discussed in NRC special inspection report 50-352, 353/94-01.

DETAILS

1.0 PLANT OPERATIONS (71707)[1]

The inspectors observed that plant equipment was operated and maintained safely and in conformance with license and regulatory requirements. Control room staffing met all requirements. Operators were found alert, attentive and generally responded properly to annunciators and plant conditions. The inspectors reviewed control room log books for trends and activities, observed control room instrumentation for abnormalities, and verified compliance with technical specifications. Accessible areas of the plant were toured; plant conditions, activities in progress, and housekeeping conditions were observed. Additionally, selected valves and breakers were verified to be aligned correctly. Deep backshift inspections were conducted on February 5, 6, 12, 13, 19, 20, and 21, 1994.

1.1 Operational Overview

At the beginning of the inspection period Unit 1 was in its end-of-cycle coastdown at 74% of rated power. The unit continued the coast down until it was shut down for a refueling outage on February 4, 1994, from 68% of rated power. See Section 1.3 of this report for details of the unit shutdown. The outage was originally scheduled to be completed in 42 days; however, the current schedule has the unit returning to power in 37 days, on March 11, 1994. This reduction was primarily due to the NRC issuing a license amendment allowing the third containment integrated leakage rate test to be conducted during the next refueling outage.

Unit 2 operated at full power from the beginning of the inspection period, with minor power reductions for routine testing and control rod pattern adjustments, until February 16, 1994, when power was reduced to 35% of rated following a 2A recirculation pump run back to minimum speed. Following the performance of a Unit 2 reactor HVAC surveillance test (ST-6-076-250-2), the 2A recirculation pump motor generator (MG) scoop tube was locked in accordance with appropriate procedures for the HVAC system restoration. Past experience has shown that voltage swings, while placing HVAC in service, could affect MG set operation. Once the HVAC was restored, the Unit 2 reactor operator performed the necessary procedure steps for resetting the 2A MG scoop tube. A problem with the process computer point, for the recirculation pump controller output deviation, led the operator to believe he had the required zero deviation between controller output and actual recirculation pump speed. In fact, the controller was calling for minimum speed on the pump. When the scoop tube lockout was reset the MG set ran back to minimum speed. The operator immediately reapplied the scoop tube lockout; however, the MG set was already at minimum. Reactor power was then lowered to 35% of rated per procedure, and the 2B recirculation pump flow was reduced to match the 2A pump's flow within 10% per technical specifications. Unit 2 was restored to full power, shortly after this event, and operated at that power level for the remainder of the inspection period.

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[1]The NRC Inspection Procedures used as guidance are listed parenthetically throughout this report.

1.2 Event Reports

On February 9, 1994, PECO Energy made a four-hour report to the NRC pursuant to 10 CFR 50.72. The report concerned an isolation of the Unit 1 B loop of Residual Heat Removal (RHR), an ESF actuation. Instrumentation and controls (I&C) technicians were performing an in kind replacement of a relay in the auxiliary equipment room, when a technician inadvertently shorted a lead to ground that resulted in a blown fuse, causing an outboard logic isolation signal to be generated. The 1B RHR shutdown cooling outboard suction valve (HV-51-1F008) and the shutdown cooling return isolation valve (HV-51-1F015B) closed, as did all other outboard valves associated with the logic for the reactor enclosure chill water, drywell chill water, and instrument gas systems. All isolations occurred as expected. The shutdown cooling mode of RHR was lost for approximately 26 minutes and resulted in an increase in reactor coolant temperature of 5 degrees, from 79 to 84 degrees F. At the time of the event, the reactor vessel head was removed and the reactor cavity was flooded. The fuel pool cooling system was in service and capable of removing decay heat.

Operations' response to this event was good. The Unit 1 operators immediately recognized the isolation event and implemented Off Normal procedure (ON)-121, Indications of Inadvertent Loss of Shutdown Cooling. The cause of the isolation was identified with the aid of the I&C technicians, and the blown fuse was replaced. All isolations were reset and the 1B loop of RHR was returned to service. All other systems were returned to normal configuration for the operational condition. The immediate corrective actions for this event included placing a hold on all relay replacement work until a thorough review of all potential problems could be identified, and actions to prevent the problem could be taken. This review will be conducted by the lead I&C technician and an operations assistant shift supervisor.

On February 10, 1994, with Unit 1 shut down, PECO Energy made a four-hour report to the NRC pursuant to 10 CFR 50.72, following a full reactor scram inadvertently initiated on Unit 1. At the time of the event a B2 half scram had been initiated as a result of relay replacement work in the auxiliary equipment room. An A1 half scram was inadvertently initiated when removing jumpers associated with a tagging clearance, in place for a modification in the power range monitoring cabinet. A neutron monitor trip signal (A1 half scram) was generated following the jumper removal in the power range cabinet. The A1 and B2 half scram signals completed the logic requirements for a full reactor scram and control rod 18-51, which was withdrawn at the time for a control rod drive exchange, fully inserted. All other rods capable of insertion were fully inserted prior to the scram signal. The control rod drive exchange had just been completed on control rod 18-51 and the rod was ready to be restored when the scram signal caused the rod to insert; no fuel was adjacent to the rod which inserted. The clearance was reapplied so that the scram could be reset, allowing I&C personnel to perform an investigation. PECO Energy determined that the cause of the A1 half scram signal was due to a contact on the connector, in the E Average Power Range

Monitor (APRM) drawer, that was not fully mated. The loose connection was repaired and the clearance removed without incident. The inspectors had no further questions concerning these events.

The inspectors will review the Licensee Event Reports associated with these events as part of the routine inspection program. On February 12, 1994, PECO Energy made a four-hour report to the NRC pursuant to 10 CFR 50.72, concerning the 1B RHR shutdown cooling return valve (HV-051-1F015B) receiving an isolation signal on low reactor vessel water level. That event is discussed in Section 3.1 of this report.

On January 13, 1994, plant personnel made a four-hour report to the NRC concerning a spurious reactor enclosure HVAC isolation signal (see NRC Combined Inspection Report Nos. 50-352/93-33 and 50-353/93-33). During this inspection period, plant personnel determined that the event was not required to be reported, and retracted the notification. Prior to generation of the ESF signal, the safety function had already occurred, in that the valves that were required to close were already closed. 10 CFR 50.72 (b) (ii) (B) (2) specifically exempts this from being reported since the actuation was invalid, and occurred after the safety function had already been completed. The inspectors reviewed this event with plant personnel and concluded that the notification was appropriately retracted.

1.3 Delay of Unit 1 Shutdown

On January 26, 1994, PECO Energy management announced that the start of the Unit 1 refueling outage, 1R05, would be delayed one week. This decision was made by PECO Energy in consultation with PJM, after reviewing available generating capacity and anticipated load, and forecasted weather conditions for the area. This review concluded that the Unit 1 generating capacity was required to ensure reliable electric service throughout the area. During the last week in January, demand was high due to very low temperatures, and a number of regional plants went out of service unexpectedly.

The inspectors reviewed the impact of the delay and discussed related issues with plant management; of particular concern was the impact this delay would have on any required surveillances that must be performed with the unit shut down. The inspectors concluded that plant management was very concerned about the delay and its impact on surveillances. A comprehensive review was conducted which concluded that no required surveillance intervals would be exceeded; however, it was important that the plant be shut down on February 4, 1994, as planned, to avoid any surveillance problems.

On February 4, 1994, the inspectors observed, from the control room, the shutdown of the Unit 1 reactor for commencement of a refueling outage. In accordance with GP-3, Normal Plant Shutdown, the reactor was scrammed at 1:00 PM and the mode switch locked in the shutdown position. The operators then entered their normal post-scram procedures to prepare the plant for cooldown.

The inspectors concluded that the shutdown evolution was properly controlled and executed by the licensed operators.

1.4 Loss of Shutdown Cooling

On February 6, 1994, Unit 1 had been shut down approximately 2 days; the 1B loop of RHR was in service providing the primary means of shutdown cooling for the coolant system. The 0B RHR service water (RHRSW) pump was in service as the ultimate heat sink for the 1B loop of RHR. Unit 2 was operating at approximately full power, and the 2A loop of RHR was in service for suppression pool cooling; the 0A RHRSW pump was in service as the ultimate heat sink for the 2A loop of RHR. At 5:07 PM, a licensed operator inadvertently isolated the ultimate heat sink from the 1B RHR heat exchanger, by stopping the 0B RHRSW pump and closing the associated heat exchanger outlet and inlet valves. The operator had intended to shut down the Unit 2 RHR loop, providing suppression pool cooling, and its associated RHRSW loop. The operator thought he had performed the task correctly and notified the Unit 2 plant operator to lay up the 2A RHR heat exchanger with demineralized water by procedure. Followup for this failure to stop the correct pump is included in NRC Special Inspection Report 50-352, 353/94-09.

After the 0B RHRSW loop was secured, the Unit 1 operator noticed an increase in coolant temperature; in response, he increased RHR flow through the heat exchanger. The operator was monitoring the RHR inlet temperature to the heat exchanger approximately every 15 minutes, and during the afternoon had made several adjustments to RHR flow through the heat exchanger to maintain coolant temperature constant. The temperature increase did not at first appear unusual to the operator. However, the next time he observed coolant temperature, he noticed an unanticipated further increase in temperature; this was approximately 36 minutes after the 0B RHRSW loop was secured. During the Unit 1 operator's investigation into the unanticipated coolant temperature increase, he noticed that the 0B RHRSW loop was no longer in operation as required to support the shutdown cooling mode of operation of RHR. The 0D RHRSW loop was immediately placed in service to the 1B RHR heat exchanger in the shutdown cooling mode.

The 0B RHRSW loop was determined to be out of service for 38 minutes. During this time period, the coolant temperature increased approximately 10 degrees from 100 to 110 degrees F. Approximately 23 minutes after the 0B RHRSW loop was secured, operators began flooding up the vessel and cavity from a level at approximately the vessel flange to a level approximately 2 feet above the seal plate, in order to perform a leak check. This flooding operation was completed at 5:57 PM. Additionally, during the time that the 0B RHRSW loop was not in operation, the reactor water cleanup system was in operation, which will remove some decay heat, and the other RHR heat exchanger was available for decay heat removal, as required by technical specifications.

The inspectors discovered that the event had occurred during a review of control room logs on February 7, 1994. The inspectors were initially concerned because the 6:30 AM outage meeting and the 7:15 AM operations shift briefing did not mention the event, and the plant manager was not aware of the event until notified by the inspectors. The inspectors initially considered the event to be significant because at the time of the event, the cavity was not yet flooded up, so coolant inventory was relatively low, and decay heat was relatively high, since it was approximately 2 days after Unit 1 was shut down. The inspectors also noted that no apparent additional corrective actions had been taken to ensure that the RHRSW system was clearly identified as a system required for operation in support of the RHR system running in the shutdown cooling mode of operation. Immediate corrective actions taken had included counselling of the operator who made the mistake, and reminding control room operators of the need to perform adequate self checking.

PECO calculations showed that for the above situation, boiling of the coolant would conservatively have occurred after 4-5 hours if operators took no actions, that is if RHRSW had not been restored and the cavity had not been flooded up. The inspectors agreed that the calculations were conservative since reactor water cleanup was running and therefore this system removed some heat during this time, and the RHR system was operating and recirculating the coolant system. However, even with these systems in operation, residual heat generated in the vessel was not being adequately removed during the 38 minutes. Without operator action, coolant boiling would have occurred since none of the systems available to adequately remove the residual heat generated will automatically actuate. Additionally, had the coolant temperature increase gone unnoticed for an additional hour and a half, beyond the 36 minutes, an unanticipated mode change would have occurred at 140 degrees F.

PECO management concluded that significance for the event was low, since, although the RHRSW system was not in operation, the system was fully operable and available, and the other RHR heat exchanger was also operable and available during the event. Additionally, management found the actions taken by the operators in discovering the loss of RHRSW and fully restoring shutdown cooling, to be expected as part of routine monitoring of the coolant temperature. PECO management also stated that systems that can redundantly supply shutdown cooling capability are maintained available as part of the overall shutdown risk planning for the refueling outage.

The inspectors concluded that the event had significance because the loss of RHRSW was not known to anyone for approximately 36 minutes, and operator action was required to identify the loss of the primary means of removing residual heat and to fully restore shutdown cooling operation. Additionally, the inspectors observed an immoderate amount of time to implement comprehensive corrective actions. For instance, later on February 7, 1994, plastic caps were placed over the control switches for the RHRSW loop in operation, supporting the shutdown cooling mode of RHR, clearly marking the system as important. Additionally, notices were published in the outage night orders and the operations shift night orders reinforcing the importance of systems in service for residual heat removal.

The inspectors reviewed the guidance provided to control room operators concerning making required notifications to the NRC, and concluded that weaknesses may exist. For instance, using the guidance provided, four-hour notifications are not required if redundant, equipment in the system is capable of performing the safety function. No consideration is provided regarding an operator inadvertently securing a safety system. The inspectors noted that this guidance could potentially lead operators to conclude that other related events are not reportable, when in fact they may be reportable.

For instance, using the guidance provided, four-hour notifications are not required if redundant equipment in the system is capable of performing the safety function. No consideration is provided regarding operator error inadvertently securing a safety system.

1.5 Fire Protection Issues

The inspectors reviewed PECO Energy's controls on ignition sources and fire watches/patrols, with particular emphasis on activities in Unit 1 during the refueling outage, and assessed that for the most part, activities were being conducted in accordance with the appropriate administrative procedures. However, exceptions, as described below, were noted.

The inspectors reviewed Administrative procedures (A)-12, Revision 5, Ignition Source Control Procedure, and A-12.1, Revision 4, Control of Technical Specification Continuous Firewatches and Hourly Firewatch Patrols, to determine the requirements that apply at Limerick Generating Station. The inspectors also held discussions with personnel from the fire protection group. Lastly, outage activities were observed at various times and adherence to the requirements of A-12 and A-12.1 was assessed.

1.5.1 Ignition Source Control Concerns

For the majority of activities observed, the inspectors concluded that the requirements of A-12 were being met for jobs where ignition sources were in use. The appropriate paperwork was properly filled out, fire watches were present and knowledgeable of their duties and responsibilities, and compensatory measures were in effect to contain sparks/molten metal generated by the ignition source activity. However, the inspectors observed the following non-compliances with the provisions of A-12:

1. The inspectors observed an individual on a platform performing a grinding operation (ignition source activity per step 4.2 of A-12) on February 10, 1994, without a dedicated fire watch present. This was contrary to the requirement of A-12, section 7.2.3, which states that minimum fire watch requirements are one dedicated individual for each ignition source operation. This requirement was discussed with PECO Energy fire protection personnel, and it was determined that a fire watch may observe more than one ignition source activity provided both activities are within the fire watch's line-of-sight. However, while there was another ignition source activity

nearby, with its own fire watch, the inspectors determined that the fire watch for that activity did not have line-of-sight of the grinding operation. Therefore, the grinding operation was performed without the required fire watch present.

2. An unattended welding machine was found energized and no personnel were in the area on February 18, 1994. A-12, step 7.4.1, states in part that the ignition source worker shall insure that at the completion of the portion of the job that uses the ignition source, that the ignition source is removed or made passive. In the case of a welding machine, this can be achieved by turning it off or disconnecting the welding lead sets. However, none of these actions had been carried out for the unattended, energized welding machine.

3. The inspectors observed simultaneous grinding operations performed in the upper level of the Unit 1 RHR heat exchanger room on February 17, 1994. The grinding operations were carried out over open grating with combustibles and electrical equipment located below the grating. Although a fire watch was present, no effort was made to contain the grinding sparks in the areas adjacent to or underneath the ignition source activity. This was contrary to the requirement of A-12, Appendix A, Precaution Check List items 3.b and c, which states in part that electrical equipment and combustible materials below or within about 35 feet of the ignition source are protected (or removed in the case of combustibles) by fireproof material between the ignition source and the electrical equipment or combustible material. Fireproof material was not used until the inspectors questioned the fire watch about this requirement and the fact that no effort was being made to contain sparks that were falling down through the open grating to the other elevations of the RHR heat exchanger room where there were combustibles and electrical equipment.

4. During questioning of a fire watch on February 18, 1994, assigned to observe a welding activity on an elevated platform, it was apparent that the fire watch was not knowledgeable of the location of the nearest phone and pager. However, A-12, Appendix B, Dedicated Firewatch Instructions, step 10 states in part that the fire watch shall know the location of the nearest phone and pager as listed on the ignition source control checklist.

These four examples are a violation of a PECO Energy administrative procedure required by TS 6.8.1. (50-352/94-02-01)

The inspectors were concerned that since these four examples all involved contracted workers, control of contractors for fire watch training and implementation may be weak. The above items were discussed with individuals from PECO Energy's fire protection group. The inspectors assessed that these individuals were quite knowledgeable of fire protection requirements, responsive in investigating the inspector's concerns, and were seen frequently in the field observing work activities. On February 18, 1994, the inspector was accompanied by two of these individuals into the Unit 1 reactor building for a tour of ignition source activities and to discuss some of the inspector's previous concerns. During this tour, items 2 and 4 above were noted by the PECO Energy personnel and the inspector.

1.5.2 Technical Specification Fire Watch Concerns

The inspectors reviewed work activities against the requirements of A-12.1, which controls the implementation of fire watches or patrols when required by the technical specifications. The inspectors reviewed fire watch inspection sheets posted in the field and several work packages, past and present, to ensure that the appropriate technical specifications (TS) compensatory measures were implemented. The inspectors identified the following concerns:

1. While reviewing several work packages from a fire protection system outage conducted in December of 1993, the inspectors noted that one activity, C0149139, disabled the fire sprinkler for all four Unit 1 emergency diesel generator (EDG) rooms. In accordance with TS 3.7.6.2, Action a., a continuous fire watch shall be posted for each affected area in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol. PECO Energy's fire protection group has interpreted this to mean that a continuous fire watch would be needed for each area, in this case, one for each of the 4 EDG cells.

   The inspectors noted that the instructions section of clearance number 93006880, which established the isolation for the repair activity, stated: "This clearance removes all 4 U/1 D/G pre-action sprinkler systems from service. Ensure Tech Spec fire watch in place before applying. Will require 1 fire watch, and 1 security guard to open all 4 D/G doors for F/W." Through discussions with fire protection personnel, the inspectors determined that the intent of this instruction was to have all 4 EDG room doors open with a fire watch present in the common hallway to act as a continuous watch, rather than have one fire watch assigned per EDG room. The security guard would be posted as all four EDG room doors would be open, and the guard would control access to the Unit 1 EDG hallway.

   The inspectors discussed the security aspect of this situation with the security manager to determine how this activity was controlled. The manager stated that he would not allow all four doors to be opened simultaneously. Further, he stated that on the day of this activity, December 21, 1993, the security computer was down, which prevented personnel access to the rooms with key cards, and a guard had been dispatched to the area with a security key for the EDG rooms. Rather than have all four doors open, the guard opened the doors one at a time so that the fire watch could enter the rooms on a rotating basis. Without all four doors open simultaneously, it appeared that the TS requirement for a continuous fire watch for each area was not met; rather, a roving watch was put in place.

The inspectors determined that it was the fire protection group's intent to have all four EDG doors open with one fire watch (this same methodology had been used in August of 1993) and that they had approved this configuration when reviewing the work package for the activity and the work instructions for the clearance . However, they were not consulted about the change in the field that occurred as a result of the security computer being down. The inspectors were concerned that the fire protection group was not consulted about this change, and that as a result, TS may have been violated.

In further discussions, the fire protection group stated that even though a continuous watch was not present in each EDG room, the roving watch satisfied the intent of a continuous watch as procedure A-12.1 states that a continuous watch should be in or near the affected area. In this case, the roving watch was inspecting each EDG cell on a 2 to 3 minute interval, and was always near the other EDG cells. Whether A-12 is correct or consistent with NRC policy on continuous fire watch requirements was not determined prior to the end of the report period. Also, it was not clear to the inspector whether a continuous watch in each EDG room was actually required per TS 3.7.6.2 as it is not clear how the statement concerning redundant systems or components should be applied to the EDG cells. Although the fire protection group has interpreted (in the past) this to mean a continuous watch should be established when suppression is taken out of service in an EDG cell, this interpretation may be overly conservative. These issues remain unresolved pending further review and resolution by the NRC and PECO Energy. (50-352/353/94-02-02)

2. While touring Unit 1 on February 21, 1994, the inspectors noted an A-12.1 fire watch sign-in sheet posted at door number 199. The inspectors noted that two of the hourly fire watch signoffs were missing on sign off sheets for previous days, and that no sign offs had been made since February 18, 1994, even though the A-12.1 posting was still active. The inspectors discussed this concern with the fire protection group. It was determined that none of the required hourly inspections had been missed as responsibility for the hourly inspection had been informally transferred (by agreement between the contractor initially performing the watch and security) to the security group who was already performing hourly inspections in the area.

The security personnel perform their rounds in accordance with SOP 20, Revision 4, Security Fire Patrol Duties. This is a self-contained and comprehensive procedure that provides specific instructions for the security force when performing fire patrols. SOP-20 also has sign-off sheets for documenting inspection of required areas. The inspectors were satisfied that the hourly TS inspections had indeed been performed and documented on the security rounds sheets. However, the hourly fire watch was initially implemented per A-12.1, but A-12.1 does not recognize the use of SOP-20 to perform this function. The inspectors were concerned that the informal turnover of fire watch responsibilities to the security force without some method of formally documenting the exchange on the A-12.1 forms could result in missed watches. This concern was discussed with individuals from the fire protection group who agreed to review A-12.1 for enhancement in this area.

2.0 MAINTENANCE (62703)

2.1 Maintenance Observations

The inspectors reviewed the following safety-related maintenance activities to verify that repairs were made in accordance with approved procedures and in compliance with NRC regulations and recognized codes and standards. The inspectors also verified that the replacement parts and quality control used on the repairs were in compliance with PECO Energy's Quality Assurance (QA) program.

Portions of the following maintenance activities were reviewed:

- 1A RHR heat exchanger replacement

  The inspectors observed the installation of the new heat exchanger, and removal of the old one. Good health physics support was observed. Weaknesses observed in the fire protection area are discussed in Section 1.5.1.

- installation of RHRSW and ESW valves

  The inspectors observed the monitoring of the freeze seals for these activities, and discussed the activities with the appropriate system manager. Activities appeared to be well controlled and monitored. In particular, the inspectors noted good, continuous monitoring of the freeze seals, as required.

- main feedwater check valve inspection and seat work

  The inspectors observed these activities in the drywell, and observed good management involvement. Additionally, there was good coordination of the activities with health physics personnel.

- jet pump beam replacement

  This activity is discussed in Section 4.0.

- refueling activities

  These activities are discussed in Section 2.3.

The above maintenance activities were performed adequately by knowledgeable workers, with good supervisory oversight and good coordination with health physics personnel.

2.2 D24 Coolant Leak

On February 10, 1994, the inspectors were made aware, during a review of the control room logs, that a coolant leak was identified on the D24 emergency diesel generator (EDG). The inspectors observed the leak, at the number 8 cylinder, and became concerned about how this might affect EDG operability. Through discussions with the system manager, the inspectors concluded that the leak had been properly identified and evaluated for its affect on diesel operability. The leak was determined to be from a gasket for the number 8 cylinder relief adapter assembly. The leak was such that it would not be into the cylinder, which might affect EDG operability.

2.3 Refueling Operations

The inspectors observed refueling operations and assessed that they were performed in a controlled and safe manner. Personnel required by the TS were present, refueling procedures were present and in use, and proper shift turnovers performed. The inspectors noted that the refueling mast was modified to add an underwater camera near the grapple assembly, and that proper engineering review was performed to assess the hydrodynamic effects of this modification on the mast's structure. The inspectors assessed that addition of the camera as an aid to the operators during refueling operations was a good initiative.

One instance was noted where a fuel bundle being lowered into the core was inadvertently lowered onto the upper core support plate. This instance will be discussed in NRC special inspection report 50-352, 353/94-01.

3.0 SURVEILLANCE (61726)

3.1 Surveillance Observations

During this inspection period, the inspectors reviewed in-progress surveillance testing and completed surveillance packages. The inspectors verified that the surveillances were completed according to PECO Energy approved procedures and plant technical specification requirements. The inspectors also verified that the instruments used were within calibration tolerance and that qualified technicians performed the surveillances.

The following surveillance was reviewed:

On February 5, 1994, during performance of ST-1-092-114-1, D14 Diesel Generator 4 KV Sfgd Loss of Power LSF/SAA and Outage Testing, Revision 12, the inspectors, along with the personnel performing the test, observed that output voltage failed to automatically come up to 4285 VAC (3865 - 4705), after the emergency diesel generator was started; voltage stabilized at approximately 3400 VAC. The cause was determined to be that the voltage regulator was not properly returned to service after maintenance was performed on February 4, 1994, in that a motor operated control (MOC-1) was not run to the RUN BACK position. Plant personnel determined that this step of the procedure was not performed due to a procedural weakness where an earlier step incorrectly directed the person performing the procedure to bypass the appropriate steps. As corrective actions, the procedure was reviewed and revised to give proper direction. The procedure was determined to be weak due to it being a Testing and Laboratories Division procedure, which had not received the same level of attention as plant procedures. These procedures are in the process of being converted to plant procedures. For this procedure, it will be converted to an Instrumentation and Controls procedure. The inspectors reviewed the procedure, discussed the event with plant personnel, and concluded that the procedural weakness was properly identified and enhanced.

During the performance of a surveillance test (ST) on February 12, 1994, the 1B RHR shutdown cooling return valve (HV-051-1F015B) received an isolation signal on low reactor vessel water level. The isolation signal closed the HV-051-1F015B valve, which resulted in the 1B RHR pump running without a flow path until discovered by operations approximately 18 minutes later. During that time reactor vessel water temperature increased from 79 to 81 degrees F. At the time of the event the reactor vessel head was removed, the reactor cavity was flooded up, and fuel movements were in progress. The fuel pool cooling system was also in service removing decay heat.

I&C technicians were performing ST-2-036-704-1, Excess Flow Check Valve Functional Test, Revision 1, to verify excess flow check valve operability once per 18 months. The initial steps of this procedure require the I&C technicians to take actions to prevent inadvertent isolations that could occur during the performance of the test. Step 6.1.2 directs operations personnel to open the breaker for the HV-51-1F008, shutdown cooling suction isolation valve, which ensures the valve remains open for RHR pump protection (in the shutdown cooling mode of RHR that was then in service) should an inadvertent isolation signal be received. Like the HV-51-1F015B valve, HV-51-1F008 receives a close signal on low reactor vessel water level. The next step of the procedure, 6.1.3, directs the I&C technicians to simulate signals to three master trip units to prevent isolation signals. While attempting to simulate a signal on the first trip unit the I&C technician noted that a TRIP LED was energized, at a step that required him to verify the TRIP LED was off. He immediately notified his supervisor of a condition not addressed in the ST and requested further guidance before proceeding. The supervisor was aware that an ongoing Routine Test procedure (RT)-2-042-622-1, Unit 1 Division 3 Logic and 10C005 Rack Outage Procedure, required the use of jumpers to prevent spurious isolation signals, and thought that this may be affecting the performance of the ST. The supervisor then contacted an I&C foreman at home with knowledge of both the RT and ST procedures, and established a three way telephone conversation between himself, the foreman and the technician in the field. During the approximately two minute conversation, the foreman stated that in order for the TRIP LED to be off, the STABLE CURRENT adjustment would have to be positioned fully clockwise. Following the telephone conservation, the technician resumed the performance of the ST and adjusted the STABLE CURRENT to the fully clockwise position, which extinguished the TRIP LED.

At the time, the technician did not recognize that three steps prior to verifying the off condition of the TRIP LED, step 6.1.3.2.D required the following: Rotate the STABLE CURRENT adjustment fully clockwise. Apparently, when the technician came to this step of the procedure he verified the adjustment fully counter clockwise, as he would have done in other ST's performed during power operation. The technician continued to make the same error with the next two trip units and corrected his actions, as instructed by the foreman, each time he observed the TRIP LED energized.

The actual isolation of HV-51-1F015B occurred when the second trip unit was actuated. The first and third trip units did not cause spurious isolations since jumpers were in place under RT-2-042-622-1, associated with Division 3 logic. The second trip unit was associated with Division 4 logic and therefore was not jumpered under the RT. Step 6.1.4 of the ST, then directed the technician to inform operations that they may reset any isolations that occur as a result of this testing as the isolations occur. At this point, the operators noted the HV-51-1F015B had closed and shutdown cooling was not in service. The operators also noted that at the time the valve closed, an RHR pump discharge Hi/Lo pressure alarm was received and acknowledged. Unfortunately, it was attributed to the performance of the ST. The performance of this particular ST does affect some 37 alarms and indications; however, RHR discharge Hi/Lo pressure was not one of them.

The inspectors are concerned with two aspects of this event. The first concern is that the I&C technician incorrectly performed step 6.1.3.2.D three times, by not making the proper adjustment to the STABLE CURRENT on the trip units. Followup for this incident is in NRC Special Inspection Report 50-352, 353/94-09. The second concern regards the I&C technicians performing a step, again on three occasions, that at the time was not recognized by him as part of the procedure. He apparently did not make any attempt to change the procedure or to determine what the problem was, but relied on the suggestion of the I&C foreman to correct the apparent procedure problem. The failure to execute a temporary change, or revise the procedure to correct the discrepant condition is a violation of PECO Energy administrative procedures required by Technical Specification Section 6.8.1. (50-352/94-02-03).

3.2 RPV Reference Leg Backfill System

In January 1994, the Peach Bottom Atomic Power Station (PBAPS) found that with the backfill system secured to a reactor vessel instrumentation reference leg, on Unit 2, a deviation of 3 inches occurred within 3 hours. This was determined to be due to the presence of a gas-bound (non-condensing) condensing chamber in conjunction with a reference leg leak. PBAPS has observed problems with the condensing chambers before, but the backfill system appears to have accelerated the gas binding. While Limerick historically has not observed either problem, a reference leg backfill system has been installed on Unit 1, in response to NRC Bulletin 93-03, Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs.

Once Limerick plant management became aware of the observed level indication problems at PBAPS, they took a proactive approach to the issue and developed a Special Procedure (SP)-131, RPV Reference Leg Backfill System Shutdown Monitoring. The purpose of the procedure was to monitor the effect of removing one reference leg backfill (the 1B reference leg) to determine the presence of a gas-bound condensing chamber along with reference leg leakage, as observed at PBAPS. The reference leg backfill was removed two days before the Unit 1 shutdown for the refueling outage, and remained out service until the unit was shut down and depressurized. The three narrow range level indications were acquired, once per hour during that time, using the plant process computer.

The inspectors reviewed the special procedure and the associated 10 CFR 50.59 Review Form. The procedure was well written and the inspectors agreed that a 50.59 safety evaluation was not required. Additionally, the procedure was reviewed and approved by PORC with the comment to provide automatic data acquisition via the process computer vise manually by the operators. The inspectors observed the shift briefing prior to the start of the test and noted that the abort criteria for the test (4 inch level deviation) was clearly pointed out to the operators. Following the performance of the test, the inspectors discussed the test results with the system manager. There was no evidence of the B narrow range level indication deviating while at power, and no indication of B level instrument notching during reactor vessel depressurization. At this time, it does not appear that Limerick is susceptible to the narrow range level indication drift, following a shut down of reference leg backfill, observed at PBAPS.

4.0 ENGINEERING

During the inspection period the inspectors witnessed portions of the jet pump hold down beam replacement modification. All 20 hold down beams were replaced to avoid potential inservice failure due to inter-granular stress corrosion cracking and ductile fracture. The weekly team meetings that were conducted prior to the 1R05 outage were instrumental in keeping the modification on schedule. All personnel on the refuel bridge were dressed in anti-contamination clothing as required, and there was good health physics coverage of the area. The operators carefully maneuvered the camera underwater in order to get a clear picture of the upper region of the jet pumps. Water clarity in the vessel was good such that the inspectors were able to see the jet pump inlet elbows and hold down beams. The inspectors found the jet pump hold down beam replacement activities to be well organized and carried out with high regard for safety.

5.0 PLANT SUPPORT (71707)

5.1 Radiological Protection

During the inspection period, the inspectors examined work in progress in both units including health physics (HP) procedures and controls, ALARA implementation, dosimetry and badging, protective clothing use, adherence to radiation work permit (RWP) requirements, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials.

The inspectors observed individuals generally frisking in accordance with HP procedures. A sampling of high radiation area doors was verified to be locked as required. Compliance with RWP requirements was reviewed during plant tours. RWP line entries were reviewed to verify that personnel provided the required information and people working in RWP areas were observed as meeting the applicable requirements.

5.2 Security

Selected aspects of plant physical security were reviewed during regular and backshift hours, to verify that controls were in accordance with the security plan and approved procedures. This review included the following security measures: guard staffing, vital and protected area barrier integrity, and implementation of access controls including authorization, badging, escorting, and searches. The inspectors did not identify any deficiencies. They concluded that observed activites were conducted properly with good management involvement.

6.0 REVIEW OF LICENSEE EVENT AND ROUTINE REPORTS (90712, 90713)

6.1 Licensee Event Reports (LERs)

The inspectors routinely reviewed LERs and performed followup inspections to PECO Energy's actions regarding the disposition of corrective initiatives. The inspectors reviewed the following LERs and found that the events were described accurately, PECO Energy had identified the root causes, implemented appropriate corrective actions and made the required notifications.

LER/SPECIAL REPORT 1-93-013, LER and Special Report Concerning the Failure of the D14 Emergency Diesel Generator to Start During its Monthly Operability Test Run, Revision 01, Event Date: October 26, 1993, Report Date: February 14, 1994.

This event is discussed in NRC Inspection Report 50-352/93-30.

LER 1-93-018, Emergency Diesel Generator Fuel Oil Samples not analyzed within the Technical Specification specified time period. Event Date: December 6, 1993, Discovery Date: December 29, 1993, Report Date: January 27, 1994.

This event is discussed in NRC Inspection Report 50-352, 353/93-33.

LER 1-94-001, Manual actuation of the Reactor Protection System due to the unexpected failure of an indicating light bulb during reinstallation into its socket. Event Date: January 14, 1994, Report Date: February 14, 1994.

This event is discussed in NRC Inspection Report 50-352, 353/93-33.

LER 1-94-002, Manual isolation of the Reactor Enclosure Secondary Containment, an Engineered Safety Feature Actuation, due to equipment problems encountered with the Auxiliary Boiler system. Event Date: January 16, 1994, Report Date: February 09, 1994.

This event is discussed in NRC Inspection Report 50-352, 353/93-33.

The inspectors found that the LERs listed above met the requirements of 10 CFR 50.73 and had no further questions regarding these events.

6.2 Routine Reports

Routine reports submitted by PECO Energy were reviewed to verify the reported information. The following report was reviewed and satisfied the requirements for which it was reported.

Station Monthly Operating Report for January, dated February 11, 1994.

7.0 MANAGEMENT MEETINGS

7.1 Exit Interviews

The inspectors discussed the issues in this report with PECO Energy representatives throughout the inspection period, and summarized the findings at an exit meeting with the Vice President, Limerick Generating Station, Mr. D. Helwig, on February 24, 1994. No written inspection material was provided to licensee representatives during the inspection period.

7.2 Additional NRC Inspections this Period

Five Region-based inspections were conducted during this inspection period. Inspection results were discussed with senior plant management at the conclusion of the inspections.

Date	Subject	Inspection No.	Lead Inspector
01/31/94	Security	50-352/94-03 50-353/94-03	A. Della Ratta
01/31/94	Engineering	50-352/94-04 50-353/94-04	J. Carrasco
02/07/94	Inservice Inspection	50-352/94-05 50-353/94-05	C. Beardslee
02/14/94	Effluents Dose Assessment	50-352/94-06 50-353/94-06	J. Jang
02/15/94	Radiological Protection	50-352/94-07 50-353/94-07	R. Nimitz