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REGION I

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EXECUTIVE SUMMARY
Limerick Generating Station
Report No. 96-01 & 96-01

Plant Operations

On February 5, 1996, control room operators shut down Unit 1 for its sixth refueling outage. Operators exhibited very good three part communications and coordination of the activities with the various work groups involved. Additionally, good management oversight was observed by the inspectors. The Unit 1 startup was conducted on February 28, 1996, following the refueling outage. Shift management exercised positive control of control room traffic with the use of signs and rope barriers in and out of the control room. Only necessary personnel were permitted to be in the control room during the startup. Additional control room operators ensured that the operator withdrawing the control rods was not disturbed by any other control room activities (section 1.3). A hydrostatic test was performed on the Unit 1 reactor vessel and required boundaries to the power rerate pressure of 1045 psig, in order to perform necessary tests and inspections prior to operation. This hydrostatic test contained the 10 year ASME Section XI inspections, which included all ASME III, Class 1 piping and components, and required a four hour hold at rated pressure prior to the inspection of insulated components. The test was well controlled with excellent coordination between shift management and the operators. The hydrostatic test was satisfactorily completed, including the 10 year ASME inspections (section 1.5).

During a walkdown of the Unit 1 main control board on February 22, 1996, the inspectors identified that the operators were preparing to drain down the reactor cavity, with only the A loop of shutdown cooling (SDC) operable. At the time, the A and C residual heat removal (RHR) pumps were operable, and the A RHR heat exchanger was operable. The B and D RHR pumps were inoperable and the B heat exchanger was inoperable, all three due to testing of components in the system. Operators indicated that the A and C RHR pumps, with the one heat exchanger, were credited as the two operable loops of SDC for meeting the technical specification requirement. The failure to meet the technical specification action statement of verifying at least one alternate method capable of decay heat removal for the inoperable SDC mode loop within one hour, when the reactor cavity was drained so that the water level was less than 22 feet above the top of the reactor pressure vessel flange, constitutes a violation of TS 3.9.11.2. The NRC understands that plant management and the operations staff believed that the LCO was being met, so they did not believe it necessary that the Action statement be met. This violation has been categorized at Severity Level IV (50-352/96-01-01) (section 1.7).

Maintenance

The inspector observed activities associated with the steam separator latching on Unit 1. Good coordination was noted between the refuel floor technicians, the technicians doing the work from the refueling bridge, and the health physics personnel responsible for refuel floor activities. Radio headsets and

remote video monitors were very helpful in the control of this work. Observations of the Unit 1 HPCI Overspeed Trip Test indicated that in spite of several aborted attempts, good overall teamwork during this test allowed problems to be identified and corrected in a timely manner (section 2.1). Activities associated with refueling operations, in general, progressed smoothly, and no major problems were encountered. The personnel moving the fuel exhibited excellent three part communications, especially noted during the verification processes. Activities were coordinated very well with the main control room personnel, and all activities observed were conducted efficiently, safely and effectively (section 2.2). Plant management had placed a high priority on correcting main control room deficiencies (MCRDs) at the start of the Unit 1 outage. At the onset of the outage, there were approximately 39 MCRDs that required an outage to effect repairs. With the plant returned to power, all but one of the deficiencies were corrected including proper PMTs. Proper emphasis was placed on the repair of outage related MCRDs, and every effort was made to correct these problems during the outage. Excellent cooperation between various work groups was demonstrated during this undertaking (section 2.3). Observations of the Unit 1 CRD replacement work indicated that the entire maintenance procedure was conducted in a professional manner with excellent safety practices (section 2.4).

Surveillance

The Unit 1 refueling outage afforded the inspectors with many opportunities to observe surveillances both in the control room and in the field. The activities observed by the inspectors were well controlled evolutions which adhered to PECO Energy's procedures. Most of the surveillances observed were executed without problem and the applicable technical specifications were met. On a few occasions PECO Energy staff members were forced to delay in-progress tests (i.e. D14 Loss of Offsite Power, D24 slow start) due to abnormal system responses; however, the individuals responded quickly and decisively to these issues which is indicative of strong training and job ownership at Limerick (section 3.1).

Engineering

Prior to the offload of spent fuel from the Unit 1 reactor, the inspectors reviewed the spent fuel pool system to determine its capability to receive the spent fuel. Complete core offloads are not done at Limerick, are not planned at any time, and for this outage just under one half of the core was removed. Engineering personnel performed an evaluation, specifically for the present Unit 1 spent fuel pool, and concluded that no design limits specified in the UFSAR would be exceeded. Plant management indicated that they plan to perform a unit specific analysis prior to each refueling outage to verify that no limits are exceeded (section 4.1). Early in the Unit 1 refueling outage the inspectors became aware that QA personnel found a support for the A recirculation system suction piping broken in the drywell. The support had failed at a weld, which connected a nut to a spring hanger. The failure was consistent with a high cycle, low stress axial fatigue failure propagating from the root of the weld outward toward the outer diameter. All other

recirculation system supports were inspected; no other deficiencies were identified. The support was replaced prior to startup, and an engineering evaluation was completed which concluded that the system was operable without taking any credit for the support (section 4.2).

During the Unit 1 refueling outage several entries were made into Technical Specification (TS) 3.0.3, as a result of inoperable main control room emergency fresh air supply (CREFAS) system trains of ventilation. In all cases, immediate corrective actions returned the main control room HVAC, and thus CREFAS, to an operable status. During the investigation into these events, engineering personnel determined that the HVAC system was not within the design basis of the plant. If the running main control room HVAC subsystem failed, the standby subsystem was not capable of automatically starting. HVAC engineering personnel were separated into a new branch, and a multi-disciplinary team of individuals was formed to address the HVAC issues. This concern with the operability, and reliability, of the CREFAS and main control room HVAC systems will remain unresolved pending NRC review of the root causes and corrective actions taken concerning this issue. (URI 50-352/96-01-02 and 50-353/96-01-02) (section 4.4).

Additionally, during the outage, plant personnel tested several safety-related valves under dynamic flow conditions for the first time. Of particular note was that the B&C LPCI injection valves (17B, 17C) failed to fully close when demanded; the valves subsequently closed when the pressure differential across the valves was reduced. The interim corrective actions included: changing operations procedures for both units; issuing an operations shift training bulletin; and placing operator aid tags on the main control board, next to the valve switches, for both units. The procedure changes entailed directing the operator to stop the associated RHR pump(s) and reclose the valve, in the event that the valve does not fully close. The long term solution for this problem involves a modification, which needs to be properly planned and scheduled (section 4.5).

On January 24, 1996, the Chief of the Boiler Section, Bureau of Occupational and Industrial Safety, Commonwealth of Pennsylvania, notified the licensee that a National Board of Boiler and Pressure Vessels resurvey of a licensee's vendor found that vessel N331, manufactured for the Limerick Generating Station, had "possible doubtful construction." (This vessel is installed in Limerick Generating Station (LGS) Unit I, as residual heat removal (RHR) heat exchanger number 1.) In response an NRC region-based inspector reviewed the reports of the 18 quality control inspections conducted by a licensee contractor who was independent of the manufacturing vendor and its various subcontractors. These reports covered inspection of the various aspects of the heat exchanger fabrication. A matrix of all materials used in the fabrication of the heat exchanger that identified manufacturer, heat number, and testing to which the material was subjected, was also reviewed. Based on the above, the inspector concluded that the licensee's determination of the operability of the vessel is valid (section 4.6).

Plant Support

Although high radiation area access controls were generally very good, two instances of improper opening and blocking open of a locked high radiation area access door were identified. The two instances represent a failure to adhere to locked high radiation area access control requirements described in Technical Specification 6.12.2. The violation was reviewed against the criteria for exercise of discretion outlined in the NRC Enforcement Policy. Though unable to identify the responsible person(s) and take appropriate disciplinary action, the licensee's efforts to do so were extensive and thorough; the seriousness with which this event was regarded was communicated to the staff and was sufficient to create a deterrent effect; the immediate corrective actions were reasonable for the circumstance; and timely corrective measures were taken to prevent recurrence. In accordance with Section VII B.1. of the Enforcement Policy, this violation is non-cited (section 5.1.1).

An announced inspection of the radiation controls program during outage conditions was conducted from February 12-20, 1996. Overall radiological safety performance was good. Electronic dosimetry alarm set point practices and procedures for high radiation area access controls were not always implemented in a manner that assured or promoted adequate personnel exposure control. One non-cited violation was identified with respect to workers not following a work order. The workers did not contact HP prior to breaching a highly contaminated system. There was no unnecessary exposure associated with the event, and effective corrective actions were taken by the licensee.

External exposures were tracking below the goal of 218 person-rem for the outage and internal exposures totalled 13 mrem. Limerick's personnel exposures are very low. Radiological safety problems identified by the licensee were few and were promptly resolved by the licensee (section 5.1.2).

Selected aspects of the fire protection program were reviewed including verification of proper procedure implementation associated with the control of combustible materials, hot work, impairments, and of housekeeping and material conditions of fire protection equipment. Walkways, stairways, and equipment access pathways were generally free from obstructions. PECO Energy appropriately maintained combustible-free zones, fire brigade equipment including bunker gear and self-contained breathing apparatus, and fire doors. The material condition of fire equipment including the fire pumps and controller, electric fire pump batteries, system header piping and associated valves was acceptable (section 5.3).

Safety Assessment/Quality Verification

The inspectors attended three Plant Operations Review Committee (PORC) meetings during the inspection period. In two of these meetings, the inspectors found the reviews to be adequate for meeting the technical specification requirements. A third meeting, held to review the disposition of two RHR valves which failed dynamic testing, was found to be particularly indepth and comprehensive. Engineering personnel were thoroughly questioned

concerning the issues and the proposed corrective actions, by a very diverse PORC membership. A good initiative was taken by inviting a licensed operator to the meeting to give a different perspective (section 6.1). During the Unit 1 refueling outage, the inspectors reviewed the implementation of foreign material exclusion (FME) controls. These controls were implemented in the suppression pool, in the condenser, on the refueling bridge, and on the turbine deck. Overall, the inspectors found that the FME controls were adequately implemented and followed by personnel, with one identified exception. Near the end of the outage, plant personnel identified foreign material (tools and rags) that were left in the C condensate drain cooler. This appeared to be an isolated instance, and was found prior to returning the system to service (section 6.2).

Miscellaneous

An unresolved item (URI 50-353/95-06-01) was closed concerning PECO Energy's justification for concluding that certain dead bus relay failures, which resulted in failures of the emergency diesel generator (EDG) to start, did not constitute valid tests or failures. Plant personnel concluded that the relays are located on the busses, and are not considered part of the EDG system. Therefore, plant management put in place a plan to address the relay failures alone. This included testing of all of the other EDG bus relays, and continuing to test these relays periodically; this testing is accomplished without the need to start and run the EDGs. The inspectors concluded that the actions taken were appropriate and had no further concerns.

An unresolved item (URI 50-353/95-21-01) was closed concerning an instances where a locked high radiation door was found propped open. This item is closed, based on the documentation of the event as a non-cited violation, as discussed in section 5.1 of this inspection report.

An unresolved item (URI 50-352, 353/95-10-01) was updated concerning the proper storage of emergency diesel generators EGB mechanical governors, as well as, PECO Energy's review of the generic concerns dealing with the storage of replacement components. The 1989 EGB governor was sent back to the vendor to be inspected, refurbished, and returned to Limerick. The inspection indicated that there were no rubber or elastomer parts, bushings or seals found which showed any signs of degradation. Additionally, there were no visible signs of corrosion on the inside of the unit. The EGB governor was filled with oil and placed back in storage and corrective actions were taken to prevent recurrence. The inspectors had no further questions concerning this aspect of the unresolved item. The generic concerns dealing with the storage of replacement components are still under review by PECO Energy and will be reviewed when completed.

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DETAILS

1.0 PLANT OPERATIONS (71707, 93702)[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 responded properly to annunciators and plant conditions. Operators adhered to approved procedures and understood the reasons for lighted annunciators. The inspectors reviewed control room logs 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 January 15, 21, February 3, 5, 10, 11, 17, 18, 19, 24, 25, 27, and March 3, 1996.

1.1 Operational Overview

At the beginning of the inspection period, Unit 1 was operating at 90% power in end of cycle coastdown for the refueling outage. On February 2, 1996, power was reduced to approximately 22%, the drywell was purged, and the main turbine was tripped, in preparation for the scheduled refueling outage. At this point the outage was postponed by PECO Energy senior management, due to a predicted shortfall of power production capability caused by projected abnormally cold weather for the next several days. The main generator was resynchronized to the grid later that day, and power was restored to approximately 87%. The unit was shut down for the start of the sixth refueling outage on February 5, 1996. At the conclusion of the outage, the reactor was taken critical on February 28, 1996, and the main turbine generator was synchronized to the grid on March 1, 1996. At the end of the inspection period, Unit 1 was operating at 100% power.

Unit 2 was being restored to full power at the beginning of the inspection period, after completing hydraulic control unit (HCU) maintenance. Unit 2 remained at full power for the remainder of the inspection period, with minor exceptions for main turbine testing and control rod pattern adjustment.

1.2 Event Reports

There were seven event reports during this inspection period.

On January 11, 1996, an automatic Engineered Safety Feature (ESF) actuation occurred on Unit 1 during performance of a routine surveillance test, due to inadequate communications between technicians who were inadvertently performing different test procedures simultaneously. This resulted in an

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

automatic isolation of the reactor core isolation cooling (RCIC) system, an ESF actuation. The surveillance tests were suspended, and the RCIC system was restored within one hour.

On January 18, 1996, plant personnel reported the identification of a deficiency in the core thermal power calculation, revealing that the licensed maximum power level of 3293 MWT for Unit 1 and 3458 MWT for Unit 2 may have been exceeded by up to 0.45 MWT. This was due to the failure to account for approximately 3 gpm flow from the control rod drive (CRD) system to the reactor recirculation pumps in the heat balance and plant core thermal power calculations. The heat balances for both units have been adjusted to correct for the CRD flow.

On February 4, 1996, Unit 1 experienced a loss of the A RPS/UPS power to a distribution panel when an underfrequency signal caused a breaker to open. This resulted in an A side half scram signal and various primary containment isolations. The isolations were bypassed or reset and the systems were restored by operations personnel. The cause of the event was determined to be a spurious actuation of the underfrequency relay, which was replaced.

A reactor scram signal and primary containment isolation actuation signals were generated on February 6, 1996, on Unit 1. The control rods were already fully inserted and the isolation valves were already closed due to Unit 1 being in a refueling outage at the time. These ESF actuations occurred when the vessel level was inadvertently allowed to decrease to 12.5 inches, due to operator error. Vessel level was restored to its normal level, and the actuation signals were reset without further incident.

On February 27. 1996, plant personnel reported a condition where it was determined that the plants had operated outside their design bases. Engineering personnel identified that the backup main control room HVAC subsystem would not automatically start in the event of a failure of the primary subsystem. This HVAC system is needed to support the operability of the control room emergency fresh air supply (CREFAS) system, which is required to be operable per technical specifications. The Limerick Updated Final Safety Analysis Report (UFSAR) states that the CREFAS and the main control room HVAC systems active components are designed to meet the single failure criteria. The start failure is believed to be the result of an inappropriate duct flow sensor setpoint. The setpoints and feeder thermal overloads were adjusted and the subsystem was tested satisfactorily. The testing confirmed that each HVAC subsystem is capable of automatically starting to support the operability of the CREFAS (section 4.4).

On February 29, 1996, plant personnel reported an identified condition that alone could have prevented the fulfillment of a safety function of systems needed to remove residual heat. On February 22, 1996, the Unit 1 fuel pool cooling system tripped resulting in the temporary loss of heat removal from the reactor cavity and fuel pool. The A residual heat removal (RHR) system was being restored to the shutdown cooling mode of operation and was being flushed, which resulted in the lowering of the reactor cavity level by approximately 1 inch. This caused a reduction in flow to the fuel pool skimmer surge tank. The fuel pool cooling system was taking suction from the

skimmer surge tank and the tank level dropped below the pump trip level. Operators returned the fuel pool cooling system to service within one hour without further incident.

During testing of the Unit 1 high pressure coolant injection (HPCI) system on March 3, 1996, an inadvertent outboard primary containment valve isolation occurred. This resulted in rendering the HPCI system inoperable, so this event was reported as an ESF actuation and the loss of a single train system that performs a safety function. The testing was suspended, the isolation logic was reset, and the system was restored to an operable status in just over one hour. At the end of the inspection period, the root cause of the isolation had not been determined. This event will be reviewed after the Licensee Event Report (LER) is issued, as part of the normal inspection process.

1.3 Unit 1 Shutdown and Startup Operations

On February 5, 1996, control room operators shut down Unit 1 for its sixth refueling outage. Prior to shutdown, the shift supervisor clearly defined shift responsibilities for each crew member. The reactor was manually scrammed from the main control room. The inspectors observed the scram, and the subsequent actions taken to ensure that the plant was in a stable configuration. Control room operators exhibited very good three part communications and coordination of the activities with the various work groups involved. Additionally, good management oversight was observed by the inspectors.

The Unit 1 plant startup was conducted on February 23, 1996, following the refueling outage. At the onset of the startup, the operators determined that the rod worth minimizer was inoperable. A control rod block was received while attempting to withdraw the first control rod. It appeared that the rod worth minimizer was not correctly enforcing the control rod withdrawal sequence. Technical Specification 3.1.4.1, requires the rod worth minimizer to be operable in Operational Conditions 1 and 2, when thermal power is less than or equal to 10% of rated. However, action statement 3.1.4.1.b, states that one startup per calendar year may be performed with the rod worth minimizer bypassed provided that control rod movement and compliance with the prescribed control rod pattern are verified by a second licensed operator or technically qualified member of the unit technical staff. Plant management decided to conduct the startup with the rod worth minimizer bypassed, in accordance with the action statement above.

The inspectors observed the startup from the main control room. Shift management exercised positive control of control room traffic with the use of signs and rope barriers in and out of the control room. Only necessary personnel were permitted to be in the control room during the startup. The inspectors noted that this policy was strictly enforced. Double verification of the rod withdrawal sequence was accomplished using a second licensed operator and a reactor engineer overseeing the activities. The startup was conducted in a very controlled orderly fashion. Additional control room operators ensured that the operator withdrawing the control rods was not disturbed by any other control room activities.

1.4 Unit 1 Cavity Draindown Activities

On February 22, 1996, the reactor cavity was drained in accordance with GP-6.1, Shutdown Operations - Refueling; Core Alteration and Core Off-Loading, Revision 20. Communications were established with the refuel floor, and a video monitor in the control room provided a visual indication of cavity water level via a camera on the refuel floor. The cavity water was drained to the suppression pool using the residual heat removal shutdown cooling valve lineup. The actual draining was completed in a well controlled manner, in approximately one hour. Reactor water level was stabilized just below the reactor vessel flange at a level of 210 inches on the shutdown range. The operators maintained a positive control of level throughout the evolution. The video monitor proved extremely helpful to the operators in the coordination of this activity. The Shift Manager was very instrumental in minimizing control room distractions, including temporarily suspending a surveillance test until the draining activity was completed.

1.5 Unit 1 Operational Hydrostatic Test

On February 24, 1996, a hydrostatic test was performed on the Unit 1 reactor vessel in accordance with GP-10, Operational Hydrostatic Test, Revision 22. The test pressurized the vessel and required boundaries to the power rerate pressure of 1045 psig, in order to perform necessary tests and inspections prior to operation. This hydrostatic test contained the 10 year ASME Section XI inspections, which included all ASME III, Class 1 piping and components, and required a four hour hold at rated pressure prior to the inspection of insulated components.

Prior to the test, the operators were given an extensive briefing that included among other things, the test objectives, termination criteria, past industry events, and a written summary of the test procedure. Temporary operator aids were also placed at the reactor water cleanup (RWCU) control panel, CRD control panel, and adjacent to the plant monitoring system display. These operator aids provided the actions to be taken in the event of a loss of pressure control, as well as, the abort criteria for the test. Additionally, the operators used a data table derived from the technical specifications (TS) temperature/pressure curves, which provided more accurate indication to ensure the plant was operated within the temperature/pressure TS limitations. The test was well controlled with excellent coordination between shift management and the operators. The hydrostatic test was satisfactorily completed, including the 10 year ASME inspections.

1.6 Unit 1 Drywell Closeout

Near the end of the Unit 1 refueling outage, on February 24 and 25, 1996, the inspector toured the drywell just prior to the plant management closeout inspection. The inspector observed general conditions in the drywell, including storage of components, housekeeping, and conditions of equipment. In general components were stored properly, housekeeping was excellent, and equipment condition was good. A few minor discrepancies were identified which

were adequately resolved prior to drywell closeout. The inspector found the conditions in the drywell this year to be better than observed at the end of previous outages.

1.7 Unit 1 Residual Heat Removal Shutdown Cooling Mode Operability During Draindown

During a walkdown of the Unit 1 main control board on February 22, 1996, the inspectors identified that the operators were preparing to drain down the reactor cavity, with only the A loop of shutdown cooling (SDC) operable. This was identified at approximately 7:00 a.m., and was immediately brought to the attention of the control room operators, including shift and operations management. At the time, the A and C residual heat removal (RHR) pumps were operable, and the A RHR heat exchanger was operable. The B and D RHR pumps were inoperable and the B heat exchanger was inoperable, all three due to testing of components in the system. Operators indicated that the A and C RHR pumps, with the one heat exchanger were credited as the two operable loops of SDC for meeting the technical specification requirement. Technical specifications require two operable loops when the cavity is drained down.

The main control room operators showed the inspectors OSG-117, Guideline For Outage Planning and Risk Management, step 4.15, which defined a SDC loop as consisting of one RHR pump and an associated heat exchanger; an operable heat exchanger with both associated pumps operable constitutes 2 operable SDC loops. The step referenced a safety evaluation for the four loop SDC interpretation. Control room personnel did not have a copy of the safety evaluation. At approximately 7:30 a.m., the inspectors notified plant management that they believed that if the reactor cavity was drained down in the current configuration, that they would be in violation of the technical specifications. Plant management indicated that they would get the appropriate information, including the safety evaluation, to the inspectors. Approximately two hours later, the inspectors were notified by telephone that a 10 CFR 50.59 determination had been completed and reviewed by the Plant Operations Review Committee (PORC) in October 1993, which addressed the interpretation of the definition of what constitutes operable loops of SDC. The inspectors were informed that two RHR pumps with one common heat exchanger would constitute two loops of SDC. This was based on the fact that technical specifications (TS) did not require "independent" loops, and that NUREG 1433, Improved Standard TS, supported this interpretation. The inspectors noted that Limerick Unit 1 does not have the Improved Standard TS currently, and does not at this time intend to pursue changing to the Improved Standard TSs. The inspectors requested copies of the 10 CFR 50.59 determination and the applicable pages from NUREG 1433.

The cavity was drained down at 9:42 a.m. Approximately one hour later, the inspectors received the requested information. The determination concluded that a safety evaluation was not necessary and a new interpretation of the definition of SDC loops was made. The review credited the common RHR heat exchangers and discharge piping as being allowed to be shared between the associated, paired RHR pumps for purposes of operability determination in Operational Conditions 4 and 5. Therefore, four loops of SDC were possible, and for the instance on February 22, 1996, the two operable loops of SDC were

defined as the A RHR pump with the A RHR heat exchanger, and the C RHR pump also with the A RHR heat exchanger. The determination stated that this interpretation was supported by the regulatory guidance available in NUREG 1433, and was not in conflict with existing statements in the TSs or the UFSAR.

Technical Specification (TS) 3.9.11.2 requires, in part, that two shutdown cooling mode loops of the RHR system shall be operable and at least one loop shall be in operation, with each loop consisting of at least: (a) one operable RHR pump, and (b) one operable RHR heat exchanger, in operational condition 5 when irradiated fuel is in the reactor vessel and the water level is less than 22 feet above the top of the reactor pressure vessel flange. At the time that the inspectors identified that only one loop of RHR was operable for the SDC mode of operation, the cavity was filled to greater than 22 feet above the top of the reactor pressure vessel flange. For this condition, TSs require that only one SDC mode loop of the RHR system shall be operable and in operation.

The inspectors reviewed the UFSAR, section 5.4.7.1.1.5, which states, "Two separate shutdown cooling pump and heat exchanger loops are provided," and, "Inter-ties are provided between the suction and discharge lines of the RHR pump in the direct injection LPCI loop (C and D pumps) and the associated RHR pump in the heat exchanger loop (A and B pumps, respectively) to allow use of the C and D pumps in the shutdown cooling mode, thus providing greater maintenance flexibility." Through discussions with NRC Region I and NRC NRR personnel, the inspectors concluded that the current Limerick Generating Station (LGS) interpretation of the SDC loops was incorrect in that only two loops, vice four, were possible. After discussions with NRC Region I management, plant management agreed to enter the appropriate TS action statement. Action (a) for TS 3.9.11.2 states that with less than the required shutdown cooling mode loops of the RHR system operable, within one hour and at least once per 24 hours thereafter, verify the availability of at least one alternate method capable of decay heat removal for each inoperable RHR shutdown cooling mode loop. On the evening of February 22, 1996, plant management devised an acceptable alternate method capable of decay heat removal, which involved the use of two reactor water cleanup (RWCU) system pumps and heat exchangers (being cooled by drywell chilled water), along with a plan to enter Operational Condition 4 in a expeditious and safe manner. In this method, the RWCU system would be fully capable of removing all of the decay heat from the vessel. This alternate method of decay heat removal would be communicated to the control room personnel.

On the morning of February 23, 1996, the inspectors noted that there was no record of entry into the limiting condition for operation action statement for TS 3.9.11.2. When the operations shift management was questioned, they indicated that the TS 3.9.11.2 action statement had not been entered, and that the alternate method of decay heat removal was the C RHR pump with the A RHR heat exchanger; the primary method of decay heat removal was the A RHR pump with the A RHR heat exchanger. At approximately 7:30 a.m., the inspectors verified with plant management that Unit 1 should be in the TS LCO action statement, and informed plant management that the on-shift operations management was not aware of this. The inspectors further noted that the TS LCO action statement was not entered by main control room personnel until 9:00

a.m. that morning. The log entry noted it as a late entry, with an entered date and time of February 22, 1996, 19:50.

The failure to verify at least one alternate method capable of decay heat removal for the inoperable SDC mode loop within one hour, on February 22, 1996, when the reactor cavity was drained so that the water level was less than 22 feet above the top of the reactor pressure vessel flange, constitutes a violation of TS 3.9.11.2. The NRC understands that plant management and the operations staff believed that the LCO was being met, so they did not believe it necessary that the action statement be met. Therefore, the availability of at least one alternate method capable of decay heat removal for the inoperable RHR SDC mode loop was not verified within 1 hour. Additionally, the reactor water cleanup (RWCU) system was available to remove decay heat, and the vessel was in the process of being reassembled at the time of the draindown activities. The NRC is concerned that although plant management was aware that the NRC resident staff believed that TS would be violated, the draindown was completed prior to resolving the issue with the inspectors. This violation has been categorized at Severity Level IV. (50-352/96-01-01)

Although plant management agreed to enter the action statement and comply with it on the evening of February 22, the main control room operators were apparently not aware of this, and when questioned on the morning of February 23, believed that they were not in an action statement. In fact, an entry was not entered in the main control room log until one and one half hours after the inspectors notified plant management of this discrepancy. The inspectors did note however, that the operators were clearly aware that the RWCU system was available to remove decay heat from the vessel, and they would maximize its decay heat removal capabilities if needed. They were also aware that the RWCU system was not fully capable of removing the decay heat present, and maintaining the temperature below 140°F. On the evening of February 22, 1996, engineering personnel had calculated that the RWCU system was conservatively capable of removing enough decay heat to maintain the coolant temperature below 150°F. After the conclusion of the inspection period, the inspectors were informed that a formal entry was not made in the main control room logs or in the LCO log on the evening of February 22, 1996, because operations management did not understand that plant management had committed to doing so. However, operations management indicated that the RWCU system was verified as available as an alternate method of decay heat removal on the evening of February 22, 1996.

1.8 Suppression Pool Closeout Inspection

Following the completion of activities in the Unit 1 suppression pool, a closeout inspection was conducted by the plant manager and a health physics supervisor, as directed by procedure GP-2, Appendix 2, Drywell/Suppression Pool Closeout and Inspections, Revision 10. Prior to that inspection, the inspector, accompanied by the health physics supervisor, conducted an independent suppression pool closeout inspection. This inspection was performed to ensure that all grating was properly installed, scaffolding was removed, no foreign material was present, and general cleanliness was acceptable. The inspector identified one discrepancy, red danger tags adjacent to the equipment/floor drain tanks, which were promptly removed.

Overall, the inspector determined that cleanliness in the suppression pool was very good. Personnel conducting the cleanup activities were thorough and effective.

2.0 MAINTENANCE (60710, 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.

The following maintenance activities were reviewed:

- M-041-400, Reactor Pressure Vessel Reassembly, Revision 1, performed February 21, 1996.

The inspector observed activities associated with the steam separator latching on Unit 1, performed in accordance with maintenance procedure M-041-400, Reactor Pressure Vessel Reassembly, Revision 1. The latching of the separator shroud head bolts is accomplished by lowering a wrench assembly, releasing a retainer and engaging the head bolt. After the head bolt is hand tight, the wrench assembly is removed and the spring loaded retainer re-engages the nut. At the time of the inspector's observation, 39 of the 48 shroud head bolts were properly latched with the retainers engaged. Nine bolts were properly latched but the retainers were not engaged. The technicians were in the process of making a second pass with the wrench assembly to re-engage the remaining nine retainers. They were not successful, in that the retainers would not spring back into place.

It was determined that a new tool would have to be fabricated in order to engage the retainers. Engineering and maintenance, working together, were able to fabricate a fork-like tool in a short period of time, that proved effective in re-engaging all but one of the retainers. The occasional failure of a retainer to spring up and re-engage has occurred at both Limerick and Peach Bottom in the past. In response to this problem, engineering personnel performed an evaluation (A/R 0765610), in conjunction with General Electric (documented in calculation LS-148), and determined that at Limerick four shroud head bolts out of the 48 bolts were allowed to be less than fully engaged and still provide an adequate latching of the two components.

During this activity the inspector noted good coordination between the refuel floor technicians, the technicians doing the work from the refueling bridge, and the health physics personnel responsible for refuel floor activities. Radio headsets and remote video monitors were very helpful in the control of this work.

- M-055-003, HPCI Overspeed Trip Test, Revision 0, performed February 14, 1996.

The inspector observed the performance of maintenance procedure M-055-003, HPCI Overspeed Trip Test, Revision 0, which verified the proper operation of the Unit 1 HPCI turbine mechanical overspeed trip. The test involved an uncoupled run of the turbine, with a turbine side coupling gag installed, using auxiliary steam. Maintenance, health physics, and system engineering personnel were present, and communications with the control room were established prior to the start of the test. Soon after steam was admitted to the turbine, water and steam began to spray out of the drain pot vent valve upstream of the turbine steam supply isolation valve (F-001). The vent valve was properly clearance tagged open; however, the isolation valve F-001, which was gagged in the closed position, was leaking. The system manager immediately contacted the control room to verify the system lineup and determine if it was possible to move the clearance boundary and close the vent valve. During that time maintenance personnel, exercising good judgement, aborted the test when they determined that the leak was getting worse. The turbine was tripped and the auxiliary steam isolated. Health physics technicians assisted in the cleanup effort since the water had drained in and out of a posted contaminated area of the HPCI room. Contamination levels were minimal and the water was quickly cleaned up.

Following the repositioning of the clearance tags, the test was run a second time and aborted when bearing vibration approached the predetermined limit of 4.3 mils. The vibration problems were attributed to an off-center coupling gag and water in the turbine casing. Both of these problems were subsequently corrected and the test was completed satisfactorily. The inspector noted good overall teamwork during this test, which allowed problems to be identified and corrected in a timely manner.

- Action Request A0986880, Valve Leaking By The Seat, performed February 14, 1996.

This maintenance activity was to cap the vent line, which was leaking, for alternate rod insertion (ARI) valve SV-047-2F162A. The Fix It Now (FIN) team performed this activity under the direction of the FIN team SRO. The activity was coordinated very well with the control room, and personnel showed a good appreciation of the system vulnerabilities.

- M-C-747-011, Control Rod Drive Exchange Using NES Machine, Revision 7, performed February 14, 1996.

The inspector observed the health physics pre-brief for the maintenance procedure and interviewed personnel to assess the understanding of the information provided in the brief. The inspector observed the control rod drive (CRD) replacement from a control booth outside the drywell, which had several cameras in order to provide a clear picture of the activity. Despite the cumbersome bubble suits the maintenance workers were required to wear, the removal and replacement of the CRDs went smoothly. The communication between the worker in the control booth reading the procedure and the workers under the vessel was good. Each step of the procedure was read for each CRD that

was replaced, and the workers under vessel repeated back the appropriate step to confirm the action. The CRDs were removed from the vessel and their rebuilt counterparts were installed in a safe and efficient manner. The maintenance team members responsible for packaging the CRDs and transporting them to storage took time to thoroughly survey the area as the CRDs came out of the vessel. Although, the initial CRD packaging and storage took a long time, the Nuclear Maintenance Division manager provided the additional guidance needed to complete the task in a timely manner. The entire maintenance procedure was conducted in a professional manner with excellent safety practices.

- M-400-020, Preventive Maintenance Procedure For Q-listed Anchor-Darling Bolted Bonnet Globe, Globe Stops & Globe Stop Check Valve; Examination and Repair, Revision 1, performed February 24, 1996.

This maintenance activity was performed to repair an emergency service water check valve (HV-11-133D) that was found to be sticking closed during emergency diesel generator testing. The inspector observed the reassembly of the valve, and discussed the operation of the valve with the maintenance workers and the system manager. Personnel were found to be very knowledgeable concerning the activity and the operation of the valve. The activity was well coordinated between the system manager and the maintenance workers.

2.2 Unit 1 Refueling Activities

During the Unit 1 refueling outage, the inspectors observed activities associated with refueling operations. In particular, the inspectors spent time on the refueling bridge observing the movement of fuel assemblies to and from the reactor vessel. In general, activities progressed smoothly, and no major problems were encountered. The personnel moving the fuel exhibited excellent three part communications, especially noted during the verification processes. Activities were coordinated very well with the main control room personnel, and all activities observed were conducted efficiently, safely and effectively. Additionally, the workers were found to be very knowledgeable and professional.

2.3 Main Control Room Deficiencies

At the onset of the Unit 1 refueling outage, there were approximately 39 main control room deficiencies (MCRD) that required an outage to effect repairs. Prior to the Unit 1 startup, the inspector discussed the status of these deficiencies with the responsible system manager. Plant management had placed a high priority on correcting these deficiencies at the start of the outage. A review of the MCRDs prior to startup provided an indication of how effective plant personnel were at correcting the problems.

There were 12 outstanding MCRDs remaining prior to startup. These MCRDs were repaired, but were waiting for a satisfactory post maintenance test (PMT) to bring the status of the items to completion. These PMTs were performed as systems were placed in service as a part of the plant's return to full power operations. With the plant operating at 100% rated power, a review of the MCRDs indicated that all but one of the 12 deficiencies were corrected

including proper PMTs. The deficiency that remained was associated with the lack of proper indication for HV-051-1F050A, RHR shutdown cooling check valve. The valve disc indicates full open with shutdown cooling out of service. A special test was performed to verify that the valve was closed. This indication problem will be addressed at the next available opportunity. The inspector concluded that proper emphasis was placed on the repair of outage related MCRDs, and appropriate efforts were made to correct these problems during the outage. Excellent cooperation between various work groups was demonstrated during this undertaking.

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 surveillances were reviewed:

- ST-6-055-230-2, HPCI Pump, Valve and Flow Test, Revision 21

The inspector attended the pre-brief and observed the HPCI pump, valve and flow test from the control room. The HP technician reviewed the appropriate Radiation Work Permit (RWP) and discussed the additional radiological postings with the equipment operators. The RO also discussed previous difficulties with the barometric condenser vacuum pump and the possibility of steam leakage into the room. The HP technician provided the appropriate guidance for this scenario and the EOs were dispatched. The EOs located the equipment specified in the procedure and verified the system lineup and "as found" condition as required in the procedure. Communication between the control room and the HPCI pump room was established and the surveillance test was started. The test met the prerequisites of the procedure and was completed in a timely manner in accordance with the procedure and the technical specifications (TS). (TS: 4.05, 4.5.1.b.3, 4.6.2.1.b.1)

- ST-6-092-314-2, D24 Diesel Generator Slow Start Operability Test, Revision 22, performed January 24, 1996

The inspector observed the D24 slow start surveillance test conducted in accordance with TS 4.8.1.1.2. The diesel started and came up to rated voltage. It was synchronized to the grid and the test was performed in accordance with the guidance in the procedure. However, an alarm came in (Generator Loss of Excitation) before the test was complete. The EO notified the I&C technicians and the system engineer, and simultaneously began following the procedures outlined in the Alarm Response Card (ARC). The diesel surveillance was terminated and the engine was shut down and declared inoperable in order to troubleshoot the problem.

I&C technicians determined that the relay associated with the alarm was out of calibration and decided to replace the relay the following day. The new relay was initially calibrated in the I&C lab and brought out to the diesel room where it was calibrated to the panel for a finer tuned setpoint. The diesel surveillance was completed on January 25, 1996.

- ST-6-048-320-1, Standby Liquid Control (SLC) Operability Verification and Valve Test, performed February 7, 1996.

The surveillance was observed by the inspector locally at the SLC system. The EOs performing this surveillance established good communications with the control room and performed a thorough walkdown of the system prior to the actuation. The C squib valve fired without incident and the system performed as expected. Once the pump reached a steady state operating condition the operator performed a walkdown of the system piping per the procedure, to ensure no degraded conditions existed in the piping. The surveillance was completed in accordance with the procedures and satisfied the requirements in TS 4.1.5.d.1.

- ST-1-092-114-1, D14 Diesel Generator 4KV SFGD Loss of Power LSF/SAA and Outage Testing, Revision 15, performed February 23, 1996.

Portions of this surveillance were observed by the inspectors from the main control room. The inspector observed a very good pre-job briefing, and found personnel conducting the surveillance very knowledgeable concerning the test. During the testing, an operator at the diesel engine noted that the jacket water temperature was increasing unexpectedly. He immediately notified control room personnel, and tripped the engine. The high temperature was a result of a stuck emergency service water check valve, which limited cooling water flow to the heat exchanger. This valve was subsequently repaired. The inspector concluded that actions taken by operations personnel were appropriate to ensure that the diesel engine was not inappropriately challenged. However, the inspector noted that an equipment trouble tag (ETT) was hanging on the check valve, which indicated that the valve did not open with flow. The tag was dated from June 8, 1995, and the inspector determined that the activity was rejected in June, due to the valve operating correctly at the time. Apparently the ETT was not removed in June when the activity was rejected. The inspector expressed concern that personnel might see an ETT on the equipment and, believing that the problem was being tracked in the appropriate system, not initiate an ETT, potentially resulting in a problem not being corrected in a timely manner. Plant management indicated that in mid-March, plant walkdowns of both units would be conducted, by assigned housekeeping areas, specifically looking for ETTs which are old and should be removed.

- ST-6-092-315-2, Emergency Diesel Generator (EDG #21) "Fast Start", Revision 9 performed February 29, 1996.
  ST-6-020-231-2, D21 Diesel Generator Fuel Oil Transfer Pump, Valve and Flow, Revision 11, performed February 29, 1996.
  ST-6-020-811-2, D21 Diesel Generator Fuel Oil Analysis, Revision 9, performed February 29, 1996.

The inspector observed the EDG surveillance locally at the diesel generator. The EOs followed the appropriate procedures and performed a thorough walkdown of the diesel prior to initiating the test. The diesel engine performed as prescribed in the procedure coming up to rated voltage and frequency in the allowable time frame. The EOs continued to verify the performance parameters of the engine and noted the appropriate indications on the local alarm panel. The surveillances were performed in accordance with PECO Energy's procedures and met all of the applicable TS.

- ST-6-049-230-1, Reactor Core Isolation Cooling (RCIC) Pump, Valve and Flow Test, Revision 1, performed March 1, 1996.

The RCIC operability test was performed in conjunction with special procedure (SP)-146, Unit 1 RCIC Operability Verification for Power Rerate and Modification P00210, Revision 1. This test was performed at 960 psig reactor pressure after the startup as required by Technical Specification 4.7.3.b. The acceptance criteria for the ST was that the RCIC pump develop a flow greater than 600 gpm in a test flow path when steam is supplied to the turbine at a pressure of 1040 + 13, -120 psig. Additionally, SP-146 required the operators to verify that the time to reach rated flow was less than 55 seconds. The RCIC turbine was placed in service and the steam admission valve functioned as expected and maintained a smooth ramp rate for turbine speed. The rated flow was reached in 19.5 seconds, the turbine reached the required flow of 600 gpm, and the discharge pressure of the pump with flow at 600 gpm reached 1250 psig, which is well above the required pressure of 70 psig above reactor pressure. A Temporary Change Control Form was added to the procedure to allow for dynamic VOTES testing on the HV-050-1F045 steam admission valve. The communication between the RO, RCIC system manager and the VOTES testing crew was good prior to the initiation of the test and before tripping the turbine which enabled the VOTES engineers to obtain new dynamic data on the valve. The inspector concluded that the 1040 psig RCIC testing was well controlled with good shift management oversight. Following the completion of the test the inspector reviewed the test package. The test package was complete and properly filled out with all the appropriate entries and initials.

- ST-6-050-760-1, ADS Valve Exercising, Revision 15, performed February 29, 1996

The inspectors observed the pre-test brief for the stroking of the ADS valves. All prerequisites were addressed and the operators were clear on the specific actions to take for the evolution. Two operators exercised the valves. One operator initiated the opening of the valve and verified the time to open requirement prescribed in the procedure, the second operator verified the closing of the main steam bypass valves as the SRVs opened. Midway through the test, the M ADS valve indication malfunctioned. The operator reacted quickly and closed the valve, when the M valve indicated closed before he manually initiated the action. The operators and the engineering staff actively began troubleshooting this incident and developing a plan to retest the M valve. The operators continued on with the test in order to finish the other ADS valves. The troubleshooting efforts revealed a defective acoustic monitor active channel (ZE-041-115M-1) which indicated a closed signal with

the SRV open. Since each SRV has two acoustic monitor channels, the immediate resolution included replacing the active channel with the passive channel (ZE-041-115M-2) and performing the test on the M valve a second time. The test was successful and met the requirements of the procedure. Plant staff also generated an Action Request (AR) to enter the drywell at the next available opportunity and replace/repair the active channel. The inspectors concluded that the ADS surveillance was conducted in accordance with procedures, and the operators response to the abnormality in the valve response was swift and decisive.

After the ADS stroke test was complete, the inspectors began tracking the SRV tailpipe temperatures to determine if any SRVs were leaking. The E, D, and N SRVs had higher than normal temperature indications. This issue is currently being monitored by plant personnel and the inspectors.

4.0 ENGINEERING (37551)

4.1 Spent Fuel Pool Design Commitments

Prior to the offload of spent fuel from the Unit 1 reactor, the inspectors reviewed the spent fuel pool system to determine its capability to receive the spent fuel. Of concern was: would spent fuel be moved into the pool earlier than analyzed for, and would the number of fuel bundles in the spent fuel pool exceed the maximum allowed at any time. Complete core offloads are not done at Limerick, are not planned at any time, and for this outage just under one half of the core was removed. This was largely due to the unit being rerated, and the unit being on a two year cycle, whereas it was on a one and one half year cycle in the past.

The inspectors reviewed technical specifications and the Updated Final Safety Analysis Report (UFSAR) to determine if there were inconsistencies. The UFSAR analysis for decay heat removal from the spent fuel pool assumes that the unit is offloading one third of the core, and that the unit is on a one and one half year cycle. However, both plants are on two year cycles and typically more than one third of the core is changed out. Plant personnel indicated that the UFSAR has not yet been updated to reflect the changes. The inspectors asked how soon fuel could be moved into the spent fuel pool, and at any time would a configuration arise where the spent fuel pool cooling system would not be capable of adequately removing the decay heat present.

Engineering personnel determined that the maximum number of assemblies in the Unit 1 spent fuel pool during the outage was approximately 1800, which is well below the technical specification limit. Additionally, prior to fuel movement, engineering personnel performed an evaluation, specifically for the present Unit 1 spent fuel pool, and concluded that no design limits specified in the UFSAR would be exceeded as long as fuel was not moved from the reactor vessel to the spent fuel pool before 72 hours after shutdown. The inspectors verified that fuel was not moved prior to the 72 hour limit. Plant management indicated that they plan to perform a unit specific analysis prior to each refueling outage to verify that no limits are exceeded.

4.2 Unit 1 A Recirculation Support Failure

Early in the Unit 1 refueling outage the inspectors became aware that QA personnel found a support for the A recirculation system suction piping broken in the drywell. The support had failed at a weld, which connected a nut to a spring hanger. Engineering personnel had the hanger pieces sent out for analysis, which concluded that the failure was consistent with a high cycle, low stress axial fatigue failure propagating from the root of the weld outward toward the outer diameter. They concluded that the weld exhibited poor surface preparation and poor root penetration. All other recirculation system supports were inspected and no other deficiencies were identified. The support was replaced prior to startup, and an engineering evaluation was completed which concluded that the system was operable without taking any credit for the support.

The inspectors observed the support before, during, and after replacement. Additionally, the inspectors discussed the failure with engineering personnel, and reviewed the results of the engineering evaluation. The inspectors concluded that the failed support received proper management attention and was properly dispositioned.

4.3 Unit 1 Core Shroud Inspection Results

During the Unit 1 refueling outage, plant personnel performed an inspection of the core shroud welds to determine the amount of cracking present. The inspectors reviewed the results of the inspection by attending a PORC meeting, where the results were discussed, and by discussing the results with the appropriate engineering personnel. They indicated that only five minor indications were identified. Cracking was present in the H3 weld only. A detailed report concerning the inspection will be sent to the NRC.

4.4 Control Room Emergency Fresh Air Supply System

On February 7, 1996, during EDG Bus testing, a total main control room HVAC shutdown occurred, resulting in both trains of Control Room Emergency Fresh Air Supply (CREFAS) system being declared inoperable and entry into Technical Specification (TS) 3.0.3 on Unit 2; this was not applicable for Unit 1 since it was shutdown at the time. Technical Specification 3.0.3 was entered a second time on February 7, during EDG LOCA/LOOP testing, when a supply fan failed to automatically start. On February 18, 1996, TS 3.0.3 was entered again when both trains of CREFAS were rendered inoperable, after a main control room supply fan tripped unexpectedly, while the other train of HVAC was out of service. On February 23, 1996, both trains of main control room HVAC were declared inoperable when problems were encountered during a transfer from one train to the other, thus requiring entry into TS 3.0.3. In all cases, immediate corrective actions returned the main control room HVAC and thus CREFAS to an operable status. Additionally, during the investigation into these events, engineering personnel determined that the HVAC system was not within the design basis of the plant. If the operating main control room HVAC subsystem failed, the standby subsystem was not capable of automatically starting, due to a coordination problem in the starting of the supply and

return fans. This condition has apparently existed since startup of the plant, and was not identified earlier due to inadequate startup testing of the system.

Station personnel tested the system after corrective actions were taken, and management concluded that the system was fully operable. However, plant management concluded that the HVAC systems in general need further, more indepth review. Therefore, the HVAC engineering personnel formed a new branch, and a multi-disciplinary team of individuals was formed to address the HVAC issues. The team is expected to address the more immediate concerns during a one month period, and the HVAC branch is expected to remain as a separate group for several months. Additionally, an LER with updates will report the overall root causes and corrective actions. This concern with the operability, and reliability, of the CREFAS and main control room HVAC systems will remain unresolved pending NRC review of the root causes and corrective actions taken concerning this issue. (URI 50-352/96-01-02 and 50-353/96-01-02).

4.5 Unit 1 RHR LPCI Valves

During the Unit 1 refueling outage, plant personnel tested several safety-related valves under dynamic flow conditions for the first time. Of particular note was that the B LPCI injection valve (17B) failed to fully close when demanded; the valve subsequently closed when the pressure differential across the valve was reduced. Because of a potential generic concern, all other Unit 1 LPCI injection valves were dynamically VOTES tested. One (17C) of the other three failed similarly to 17B. Plant engineering personnel reviewed the situation, and presented conclusions and corrective actions to plant management at a PORC meeting, on February 27, 1996 (section 6.1). Engineering personnel concluded that the valve failed to close completely due to disc tilting caused by the flow. The long term solution for this problem involves a modification, which needs to be planned and scheduled. This process will be completed within the next two years, or PORC will review the issue again.

In the interim, operations procedures for both units were changed, an operations shift training bulletin was issued, and operator aid tags were placed on the main control board next to the valve switches for both units. The procedure changes entailed directing the operator to stop the associated RHR pump(s) and reclose the valve in the event that the valve does not fully close. The inspectors, along with NRC Region I management, reviewed the corrective actions and concluded that they were acceptable.

4.6 Review of Unit I Residual Heat Removal Heat Exchanger Fabrication Question

On January 24, 1996, the Chief of the Boiler Section, Bureau of Occupational and Industrial Safety, Commonwealth of Pennsylvania, notified PECO Energy that a National Board of Boiler and Pressure Vessels resurvey of a vendor found that vessel N331, manufactured for the Limerick Generating Station, had "possible doubtful construction." This vessel is installed in Limerick Generating Station (LGS) Unit 1, as the residual heat removal (RHR) heat

exchanger. In response to being notified by PECO Energy, a region-based inspector visited the plant on February 8 to review records and interview personnel associated with the matter.

The inspector reviewed the reports of the 18 quality control inspections conducted by a contractor who was independent of the manufacturing vendor and its various subcontractors. These reports covered inspection of the various aspects of the heat exchanger fabrication. The inspector verified that all reports of nonconformance identified in these reports had been satisfactorily resolved.

The inspector also reviewed a matrix of all materials used in the fabrication of the heat exchanger that identified manufacturer, heat number, testing to which the material was subjected, etc. Interviews with the metallurgical engineer indicated that material data and test reports were available and provided assurance that the materials used in the fabrication of the vessel met the purchase specifications. Checks by the inspector of random records verified this information.

On March 1, the inspector received and conducted an in-office review of Engineering Change Request (ECR) number LG 96-00518 000. This ECR provides the basis for an interim disposition for continued use. This disposition is interim only in that the possible code noncompliances had not been specifically determined. While there is no specific information that would implicate the LGS RHR heat exchanger, the possible noncompliances appear to be related to the vendor's procedural control of activities allowing use of material supplied by non-certified suppliers.

Based on the above, the inspector concluded that the determination of the operability of the vessel is valid.

PLANT SUPPORT (64704, 71707, 71750, 83750, 93702)

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. People working in RWP areas were observed as meeting the applicable requirements.

5.1.1 Review of Unauthorized Opening and Blocking Open of High Radiation Area Access Door

Background and Description of Circumstances

On December 4, 1995, an equipment operator (EO), passing door No. 392 (a normally locked high radiation area access door located in the Unit 2 Turbine Building at elevation 239') noted at 1:45 p.m. that the door was blocked open with a flashlight. The door was posted with a sign indicating radiation work permit (RWP) and radiation protection briefing needed for entry. A second, highly-visible posting on the door indicated that the door was a locked high radiation area and that personnel needed to ensure the door was locked upon entry and exit. The door provided access to general areas within the Unit 2 moisture separator area, some of which exhibited accessible radiation exposure dose rates greater than 1,000 mR/hr (maximum approximately 2,000 mR/hr). Access to such areas is required to be positively controlled to prevent unauthorized entries in accordance with the licensee's technical specifications.

The EO immediately contacted the radiation protection organization via a local telephone while maintaining positive access control to the area. A radiation protection representative directed the operator to kick the flashlight into the room and pull the door closed. The door could be opened from the inside and would not preclude egress from the area. The radiation protection organization initiated an investigation as to the circumstances surrounding the event.

At 7:50 p.m. that same day, a radiation protection (RP) technician, performing normal daily high radiation area access door surveillance, identified the same door blocked open with a wrench. The RP technician immediately informed his supervisors who initiated additional reviews of the events. The RP technician maintained positive access control to the area.

Licensee Corrective Actions and Investigation Results

The inspector noted that the licensee initiated a number of reviews and corrective actions subsequent to the discovery of door No. 392 found blocked open. The reviews and corrective actions were as follows.

Event 1 Licensee Corrective Actions/Reviews (Door Found Blocked Open at 1:45 p.m. on December 4, 1995)

- The EO immediately notified radiation protection personnel, who directed that the EO close the door. The door was closed.

- A radiation protection technician was immediately dispatched to review the status of all access doors (five total) to the Unit 2 moisture separator area and verify access door key inventory.

- A radiation protection supervisor initiated key inventory and control checks, including inventory and sign-out of high radiation area keys located in the main Control Room (2:50 p.m.). The key inventory

indicated all keys were present and accounted for and no one had recently entered the area under an approved RWP. Radiation protection personnel concluded that the opening of the door was not in accordance with procedure requirements.

- An RP technician was directed (3:20 p.m.) to enter the area afforded access by the door and review the area for the presence of personnel. No personnel were identified within the area.

- An internal event notice/evaluation was initiated (5:00 p.m.).

- The RP technician, who last performed the high radiation area door surveillance, was interviewed by radiation protection personnel (6:15 p.m.). The technician indicated the door was previously found closed during the last daily high radiation area door surveillance.

- An RP supervisor directed (7:05 p.m.) that a complete high radiation area door surveillance be performed. Such a surveillance is normally done weekly. During performance of the surveillance, the same door (door No. 392) was again found (7:50 p.m.) to be blocked open, this time, by use of a wrench.

Event 2 Licensee Corrective Actions/Reviews (Door Found Blocked Open Again at 7:50 p.m. on December 4, 1995)

- The RP technician, who identified the blocked open door, maintained positive access control to the area.

- An RP supervisor went to the area and informed (9:20 p.m.) the main control room of the second occurrence. The operations floor supervisor also went to the door location.

- A radiation protection technician entered the area afforded access by the door (9:20 p.m.) and determined that no individuals were in the area.

- Security personnel were informed (9:20 p.m.) of the event and initiated an investigation.

- The RP supervisor directed (10:00 p.m.) that the lock cores for the five doors providing access to the area be changed. The lock cores were changed on the evening of December 4, 1995, as a conservative action in the event that an uncontrolled key was being used.

- The RP supervisor changed (10:00 p.m.) the frequency of complete high radiation area door surveillance from weekly to daily. The licensee continued performance of the complete surveillance of all high radiation area access doors (as of January 26, 1996). (Note that the licensee normally performs a daily high radiation area access door surveillance only for doors whose keys had been signed out that day. The licensee

also performs a complete surveillance weekly for all high radiation area access doors whether or not their key was signed out.) No other doors were found blocked open or unlocked.

- The RP personnel requested that security personnel provide enhanced surveillance of the affected door. Enhanced security surveillance was initiated on the evening of December 4, 1995, and continued through the end of December 1995. The surveillance involved visiting the area three-four times per day, as compared to once per day. The surveillance was discontinued due to the lack of any additional findings.

Additional Corrective Actions Following the Second Event

- The licensee initiated an extensive security investigation to determine who had blocked open the doors. They were not able (as of January 24, 1996) to determine who blocked open the door and concluded that the door was improperly opened and the individual or individuals, who opened the door, disregarded posted special instructions for access control.

- The event was discussed at a station Plant Operations Review Committee (PORC) meeting on December 7, 1995, and was also discussed at a station ALARA council meeting on December 15, 1995.

- The licensee performed an evaluation of all high radiation area access doors during the week of December 11, 1995. Of 89 high radiation area access doors, three doors were found to be of similar design to the door No. 392. One of the three doors was found to be not as tamper-resistant as the others, though still reasonably able to prevent unauthorized access.

- On January 3, 1996, the RP personnel initiated a work request to place a metal guard over the door lock area to enhance the tamper-resistance of the doors. However, since the doors were fire doors, an engineering evaluation was initiated (January 4, 1996) to evaluate placement of metal guards over the door lock area.

- On January 11, 1996, the Vice President, Limerick Station, issued a memorandum to all station supervisors (which detailed this event and the seriousness with which it was regarded), directing them to discuss this event with their staffs and reinforce the policy of compliance with posted instructions, and indicate that willful failure to comply would result in termination of employment.

  In following up on communication of this memorandum on January 24, 1996, the inspector found that two contractors (who had recently arrived on site) were not aware of this specific occurrence. When brought to the licensee's attention, management committed to verify that all appropriate personnel were aware of this event, the seriousness with which it was regarded, and the consequences for willful violation of

procedures and requirements (as expressed in the January 11, 1996, memorandum from the Vice President, Limerick Station) by the start of the Unit 2 outage (February 2, 1996).

- The RP personnel received the engineering evaluation response on January 22, 1996, which indicated that the door hardware should be tightened to remove any slack, thereby preventing the potential for tampering. The affected doors were subsequently adjusted on January 31, 1996, including adjustment of the interlock mechanism on door No. 392.

As of February 2, 1996, the licensee had not identified any further occurrences.

NRC Review and Evaluation

The inspector reviewed the circumstances surrounding the discovery, on December 4, 1995, of the blocked open high radiation area access door, the evaluations of the event, and corrective actions. The review was against requirements contained in applicable licensee procedures, the technical specifications, 10 CFR Part 19, and 10 CFR Part 20.

High Radiation Area Access Controls

The inspector toured the Unit 2 turbine building and reviewed access points to the Unit 2 moisture separator area, a locked high radiation area. The inspector also toured Unit 1 and reviewed similar doors and access points. The inspector also reviewed high radiation area access point key control and evaluated the adequacy of the high radiation area access controls. The inspector concluded that high radiation area access doors were locked and well identified by clearly visible postings. Keys were administratively controlled in accordance with the requirements of the technical specifications and procedures. The inspector considered the normal high radiation area access controls to be very good.

Though not a specific requirement, the inspector noted that the high radiation area control procedure (HP-C-202, Revision 3) did not provide guidance as to actions to be taken when it was discovered that the integrity of a locked high radiation area door may have been compromised. The Radiation Protection Manager indicated on February 2, 1996, that the procedure would be reviewed and revised, as appropriate, by May 31, 1996, to address this contingency.

The inspector noted that Technical Specification (TS) 6.12.2 requires, in part, that areas accessible to personnel with radiation levels such that a major portion of the body could receive in one hour a dose greater than 1000 mrems shall be provided with locked doors to prevent unauthorized entry and the keys shall be maintained under the administrative control of shift supervision on duty and/or the health physics supervision. Further, TS 6.12.2 requires that the doors shall remain locked, except during periods of access by personnel under an approved RWP. The inspector also noted that TS 6.11 requires adherence to radiation protection procedures. Radiation Protection

Procedure A-C-100, Revision 0, Radiation Protection Program, requires, in Section 5.4.2, that plant workers obey posted, oral, and written radiological control instructions and procedures.

Door No. 392 was opened by an unauthorized person or persons on two occasions on December 4, 1995; the door was posted, indicating that an HP briefing and RWP 30 were required to support entry to the area. The door also had a clearly-visible posting, which provided special instructions for the control of the door. The special instructions indicated that the area was a locked high radiation area and that personnel needed to ensure the door was locked after entry or exit. The inspector noted that, on December 4, 1995, the licensee discovered the door blocked open at 1:45 p.m and again at 7:50 p.m. and: (1) no individual(s) had signed out the keys for the area at the time the doors were found open, (2) no individual(s) had signed in on RWP 30 for the area at the times the door was found blocked open, (3) the individual(s) improperly gained access through the door failed to adhere to the licensees procedures and instructions that were in effect relative to access to the high radiation area controlled by Door No. 392, (4) the individual(s) improperly gained access through the door and did not ensure the area was locked after exiting the area, and (5) the licensee was unable to ascertain the identity of the individual(s) responsible for the unauthorized entry. Consequently, the inspector considered that these two instances, of failure to maintain door No. 392 locked, except during access by personnel under an approved RWP, to be a violation of TS 6.12.2.

The inspector reviewed the violation against the criteria for exercise of enforcement discretion outlined in the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. Regarding the criteria, the inspector noted that the violation was licensee identified and would normally be regarded as a Severity Level IV violation (in this circumstance), did not appear to be a violation that could reasonably have been expected to have been prevented by corrective actions for a previous violation, and reasonable immediate corrective actions and other appropriate corrective measures were taken in a timely manner to prevent recurrence. Since willfulness on the part of an individual(s) is suspected, information on this matter was promptly provided to the NRC. Further: (1) there is no evidence to support that the offense was committed by a licensee official; (2) the action appears to be isolated, without management involvement, and not due to lack of management oversight; and (3) the licensee initiated significant remedial action commensurate with the circumstances that communicated the seriousness of the violation sufficient to create an apparent deterrent effect in the organization. Though the licensee was unable to determine the identity of the responsible individual(s), the investigative effort appeared to be extremely thorough and extensive, further demonstrating the regard for the seriousness of this event in the organization. In accordance with Section VII. B.1. of the Enforcement Policy, this violation is non-cited.

Potential For Unplanned Exposures or Overexposures

The inspector reviewed and evaluated the potential for unplanned radiation exposures, including potential overexposures. The inspector reviewed radiation, contamination, and airborne radioactivity survey data for areas

afforded access by the blocked open door. The inspector concluded that the areas afforded access by the blocked open door were not very high radiation areas, indicated generally low levels of contamination and appeared to exhibit low levels of airborne radioactivity. Maximum accessible radiation exposure dose rates (in isolated areas) were about 2,000 mR/hr. The inspector noted, although areas within the moisture separator area were not individually posted, radiation levels were generally not excessive and personnel normally would wear an alarming dosimetry set at 100 mR integrated exposure and 100 mR/hr maximum allowable radiation exposure dose rate. The inspector concluded that there was limited apparent potential for an unplanned exposure, including an overexposure.

Review of Dosimetry Results

The inspector reviewed dosimetry results for personnel who may have entered the area afforded access by the blocked open doors. The inspector did not identify any apparent significant dosimetry anomalies for the individuals identified by the security group as an individual(s) who may have potentially entered the areas controlled by the normally-locked, high radiation area access door. The inspector did note that the selection of individuals was based on the assumption that the same individual(s) opened the door on both occasions. This population numbered 47 individuals. It appeared only 44 of those individuals had been checked by the dosimetry group for dosimetry anomalies. The licensee subsequently provided dosimetry results for the remaining three individuals, which did not indicate any apparent anomalies.

The inspector requested data on the total number of individuals who may have entered the area. The licensee had identified 300 individuals who could have been in the vicinity of the door. The licensee compared the year-end dosimetry anomaly summary to the individuals who could have been in the vicinity of the door. Three individuals, who may have been in the vicinity of the door, were identified with anomalies (alarming electronic dosimeter results did not match personnel TLD results). The anomalies did not appear to be significant and had been initially identified via the normal electronic dosimeter/TLD intercomparison evaluations. The licensee initiated a review of the anomalies and did not identify any concerns. The individuals were verified to have been working in other locations of the station and/or under routine observation by radiation protection personnel.

Worker Training

The inspector reviewed the adequacy of training provided to workers relative to high radiation area access requirements and adherence to postings. The inspector also interviewed selected station personnel during tours of the station to ascertain their knowledge of high radiation area access control requirements. The inspector concluded adequate training was provided workers relative to high radiation area access controls and that workers interviewed understood high radiation area access control requirements. Further, the inspector noted high radiation area access control doors, including the affected door, were visibly posted with special instructions regarding

provisions for entry and locking of the door. The training of radiation workers and the in-field information provided to them, relative to high radiation area access control requirements, were considered good.

5.1.2 Review of Radiological Safety Performance During the Unit 1 Outage

Performance Enhancement Program (PEP) Review

The inspector reviewed the PEP reports that document radiological incidents for 1996 to include the February outage. The PEP reports record the licensee's root cause determination and corrective action process. Five PEPs involving radiological incidents had been issued during 1996 and were reviewed by the inspector. These included inadvertent contamination spills, a shoe contamination, and an inadvertent feedwater system breach without appropriate radiation protection coverage. All of these represented low safety significance.

One other PEP (No. 5110) documented the cutting and removal of drain piping from the main steam isolation valve leakage control system without involvement of radiation protection personnel on February 8, 1996. The piping system breach involved significant contamination inside the piping and therefore, had potential safety significance. No actual contamination of personnel occurred. The radiation protection staff determined that the workers had not complied with the work package requirements to notify radiation protection (RP) personnel prior to beginning work and did not obtain a radiological survey. In addition, the RP staff also indicated the possibility of miscommunication of radiological requirements due to wording in the work package. The subject work package specified health physics (HP) survey prior to work and in fact, a survey of external pipe contamination had been performed earlier that day and was available for use. Corrective actions taken by the licensee are listed below.

- Outage work activities were temporarily stopped until the Plant Manager could meet with representatives from each organization to reaffirm expectations to follow HP instructions.

- All work packages were pulled back from the field. HP signoffs were added to work packages prior to the start of radiological work.

- Copies of the HP instructions contained in work packages would be distributed on a timely basis to the appropriate HP control points.

Based on the inspector's review of the licensee-identified incident, the corrective actions specified, and the lack of actual exposure significance, the failure to follow HP instructions contained in the work package constitutes a violation of minor significance and is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy.

In summary, there were few radiological incidents recorded during January and February of 1996 indicating very good radiological work performance. Management oversight of the radiological incidents was of good quality.

Radiation Protection Staffing

The radiation protection organization was expanded by 59 temporary senior HP technicians. The inspector reviewed selected résumés and training qualifications and found that they met ANSI/ANS 3.1-1978 and station procedural requirements. Through in-plant observations by the inspector, no training or qualification weaknesses were observed. No discrepancies were noted.

External Exposure Control

The inspector toured each of the major work areas during the outage, interviewed workers and HP technicians, and made independent radiation field measurements in these locations. The inspector observed three instances where high radiation areas dose rates were greater than 1 R/hr at a distance of 30 centimeters from the source and were barricaded with yellow and magenta rope with a flashing light. Technical Specification 6.12.2 requires locking of these areas, but allows the use of a roped barricade and flashing light where no enclosure can be reasonably constructed to prevent access to the area. The inspector discussed with the licensee the practicality of locking these areas. The areas discussed were:

- the lower head drain line in the lower elevation of the drywell,
- the access ladder to the upper elevations of the drywell during fuel movement, and
- the suppression pool catwalk.

In response, the Radiation Protection Manager initiated the following to prevent access into these greater than 1 R/hr high radiation areas.

- The lower head drain line was shielded with lead blankets, which reduced the dose rates to less than 1 R/hr at 30 centimeters, and the shielding was secured with chain and a lock to prevent unauthorized removal of the shielding.
- Fuel movement had been completed, the access ladder to the upper elevations of the drywell was deposted, allowing access. Plans for fabricating a ladder lock for future outage requirements are being considered.
- A tube-block scaffold barricade was erected on the suppression pool catwalk.

The inspector determined that the licensee had effectively improved the controls to prevent access to the above-mentioned high radiation areas.

According to data compiled by the radiation protection organization, maintenance work in the drywell accounts for approximately 60% of all refueling outage exposure. The inspector reviewed the licensee's efforts to reduce exposures in the drywell. Approximately 20,000 pounds of lead and

10,000 pounds of water shielding were applied in the Unit 1 drywell during this outage, based on information supplied by the Rad Engineering staff. The inspector toured the drywell and made independent radiological survey measurements to ascertain the effectiveness of the exposure reduction efforts. The inspector noted that, in general, good efforts were made to shield local work areas in the drywell. In addition, personnel transit areas were also shielded. However, significant lengths of recirculation piping were not shielded; and, consequently, general background dose rates in the drywell were not greatly affected by the local shielding efforts. Notwithstanding, the outage exposure goal of 218 person-rem was very low with respect to the industry BWRs, and outage exposures were tracking well with respect to this goal. Due to this level of performance, the levels of exposure reduction efforts were found to be very good.

The inspector observed work coverage by the radiation protection staff. The drywell effectively utilized intermittent coverage of all work by a "rover" radiation protection technician, who was available inside the drywell at all times. For drywell RWPs, the dose rate alarm was set at 900 mrem per hour while dose rate fields were typically 10-100 mrem per hour. Other than the relatively high electronic dosimeter alarm setpoints used by workers, the RP coverage of work in the drywell was very good.

The inspector reviewed each of the outage RWPs relative to the effectiveness of the electronic dosimeter setpoint. The radiation protection group established 47 RWPs for the outage based in part, on similarity of work and radiological hazards. For each RWP, electronic dosimeter alarm setpoints were established. The inspector reviewed the alarm setpoints relative to each RWP used during the outage and determined that the alarms ranged from total doses of 100-300 mrem and from dose rates of 93-9000 mrem per hour. In general, electronic dosimeter setpoints were found to be set higher than the dose rates or dose per entry would suggest. The Radiation Protection Manager stated that previous plant policy and current radiation worker training states that, when an electronic dosimeter alarms for any reason, the worker should exit the area. Therefore, for a worker to temporarily enter a higher dose rate area than expected, a temporarily alarming dosimeter would cause the worker to exit the area. The Radiation Protection Manager stated that the customized setting of electronic dosimeter alarm setpoints would be evaluated, and would entail revising radiation worker training, as appropriate.

In response to the inspector's observations, the radiation protection staff also reevaluated the work areas covered by RWP No. 16 (a generally high radiation area access RWP) and reduced the electronic dosimeter alarm setpoint down from 1500 mrem/hr to 516 mrem/hr. Also, the drywell electronic dosimeter alarm setpoint was lowered from 906 mrem/hr to 506 mrem/hr. The licensee agreed to evaluate the practices relative to use and application of electronic dosimeter alarm setpoints as a personnel reduction exposure control and reduction procedure.

The reactor water cleanup system work areas consisted of various locked rooms that were controlled through the reactor building 283-foot elevation control point. Six rooms were posted as locked high radiation areas, and two were posted as high radiation areas. One radiation work permit, Number 16, was

issued to support access for all of these areas. This RWP required positive HP coverage for these areas. The inspector discussed the applied controls with the HP technicians responsible for administering coverage for work under RWP No. 16. The technicians considered that positive control could be met by briefing workers on radiological conditions in the work area, unlocking the door to the posted locked high radiation area, and after the workers enter, ensuring the door is locked behind the workers in order to preclude anyone else from entering. The inspector observed an HP technician briefing workers on radiological conditions and asking the workers how long they would be working in the area, but no staytimes were provided to the workers. Technical Specification 6.12.2 specifies that, for entry into areas greater than 1000 mrem/hr, an approved RWP shall specify the dose rate levels in the immediate work area and either state the maximum allowable stay time or provide for continuous HP surveillance for individuals in the area. The inspector reviewed radiation surveys of the reactor water cleanup rooms and determined that at the time of the inspection, the areas accessed by RWP No. 16 did not contain areas where dose rates were greater than 1000 mrem/hr, although the rooms were posted as locked high radiation areas. The requirements of Technical Specification 6.12.2 did not apply. Therefore, there was no regulatory compliance issue in this case.

The inspector reviewed the potential for not complying with technical specifications for other posted, locked, high radiation areas where dose rates were greater than 1000 mrem/hr. For the reactor water cleanup areas, RWP No. 16 specified positive HP coverage for posted locked high radiation areas. The inspector reviewed Procedure HP-C-310, Rev. 2, "Access Control Program." Section 8.2.3 defines positive HP coverage: "Technician provides support for entry, maintaining positive control over activities in the area (e.g., HP briefs workers on area dose rates and monitors time spent in area)." The inspector informed the Radiation Protection Manager that positive HP coverage, as defined by Procedure HP-C-310, would not meet technical specification requirements for entry into high radiation areas greater than 1000 mrem/hr. The Radiation Protection Manager indicated that the procedure would be reviewed to assure that conformance to the technical specification was maintained.

In general, the inspector observed good radiation protection coverage and surveillance during this outage. However, alarm setpoint practices and procedures for high radiation area access controls were not always implemented in a manner that assured or promoted adequate personnel exposure control.

Internal Exposure

The inspector observed generally very good contamination control techniques and effective air sampling practices during tours of the outage work areas. The inspector determined that over a one week time period, approximately 81 air samples were taken each day. At the time of this inspection, the outage had shown only three air samples that were $\geq$ 0.3 derived air concentrations. Only one of these air samples represented worker's breathing air. For this case, two individuals performing RWCU valve work were documented in the area. The two individuals' records were reviewed by the inspector and found that the radiation protection staff had appropriately assigned 2.2 and 2.9 DAC-hours

for the time spent in the area, for a total of 13 mrem of internal exposure combined. The inspector found an *a priori* ALARA evaluation that estimated a maximum of 15 mrem of internal exposure per individual may occur due to the valve work and that respiratory equipment was not advised in the interest of ALARA. No other internal exposures were recorded for the outage at the time of this inspection. No discrepancies were noted.

Radwaste Equipment Material Condition Review

In response to a recent plant condition observed in a Region I nuclear plant involving degraded radwaste equipment (as documented in NRC Information Notice 96-14), the inspector reviewed the Limerick Station radwaste facilities to verify the physical condition of nonroutinely-visited areas. The inspector reviewed radwaste building floor elevation blueprints and discussed with the Radwaste System Engineer the areas of interest. The inspector accompanied by the Radwaste System Engineer toured the areas listed below.

162-foot elevation:	floor drain spent resin tank and pump (tank has contents), equipment drain spent resin tank and pump (empty)
191-foot elevation:	evaporator feed tank and pump (empty), evaporator distillate sample tank and pump (empty), radwaste evaporator storage tank and pump (tank contents undetermined), radwaste evaporator and condensers A & B (evaporator was never used, condenser contents undetermined)
217-foot elevation:	High integrity container fill and settling station
237-foot elevation:	radwaste centrifuges A & B, high integrity container sample station

In all cases, the tanks, valves, and piping systems were found to be leak-free, with no detectable corrosion or degradation of plant components. To prevent future degradation of components, several tanks were identified (as mentioned above) that either contained liquid contents or the tank level could not be determined based on a visual inspection outside of the tank. The Radwaste System Engineer stated that the indicated tanks would be evaluated to determine contents and that a disposition plan for those that contain contents would be developed.

Updated Final Safety Analysis Report (UFSAR) Review

The inspector reviewed the implementation of the Limerick radiation control program with respect to Section 12 of the Limerick UFSAR. Section 12.1.1.3 states that a formal ALARA review is conducted every three years by the Nuclear Review Board. By review of licensee records, the most recent formal ALARA review conducted by the Nuclear Review Board was dated October 26, 1992 (Audit No. A0662983). This ALARA review was conducted by the Limerick Nuclear Quality Assurance Group and reviewed by the Nuclear Review Board. The Limerick Nuclear Quality Assurance Group performed another ALARA program

review in March of 1994 (Audit No. A0811612). In the audit report introduction section, it states, "Health Physics Operations/ALARA is not a Tech. Spec. Assessment therefore NRB concurrence was not solicited." The inspector determined that the intent of UFSAR Section 12.1.1.3 had been met by performance of a biennial ALARA review; however, the perspective of the Nuclear Review Board was not obtained. The Rad Engineering staff wrote an action request to evaluate the appropriateness of the subject UFSAR requirement. Other UFSAR Sections that were reviewed against current plant practice included: 12.1.3.2, 12.1.3.3, and 12.5. No other discrepancies were noted. In general, the Limerick radiation control program is implemented in accordance with the Final Safety Analysis Report.

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.

5.3 Fire Protection

Selected aspects of the fire protection program were reviewed to ensure compliance with license conditions, PECO Energy commitments, and NRC regulations. This review included verification of proper procedure implementation associated with the control of combustible materials, hot work and impairments, and of housekeeping and material conditions of fire protection equipment.

On February 13, 1996, the inspector walked down selected Unit 1 plant areas within the turbine, auxiliary, and emergency diesel generator buildings, the refueling floor, and the fire alarm panels located within and directly outside the control room. The inspector found walkways, stairways, and equipment access pathways generally free from obstructions. PECO Energy appropriately maintained combustible-free zones, fire brigade equipment including bunker gear and self-contained breathing apparatus, and fire doors. Brigade equipment was in good condition and strategically located within the plant for good accessibility by the fire brigade. The inspector interviewed four roving and/or continuous firewatches encountered during the tour and verified their knowledge of PECO Energy's expectations and requirements regarding their duties and fire reporting. No problems were identified during these discussions or during review of roving patrol log data. However, through discussions with firewatch and industrial risk management (IRM) personnel responsible for the fire program, the inspector noted that firewatch personnel do not complete annual refresher training. The verification and acceptability of the lack to require annual refresher training for firewatch personnel will be reviewed during the upcoming fire protection program review. This programmatic review is required by NRC policy to be conducted prior to the close of PECO Energy's current systematic assessment period. At the time of this inspection, the period was scheduled to end on March 29, 1997.

The inspector observed hot work in progress in the pipe tunnel on the 198 ft. elevation of the reactor building and found work permits properly displayed, fire extinguishers appropriately present at the work site, and firewatches attentive and appropriately not assigned any other duties. The material condition of fire equipment including the fire pumps and controller, electric fire pump batteries, system header piping and associated valves was acceptable.

The inspector identified two emergency lighting units of thirteen sampled that failed to illuminate. PECO Energy took action to include 10-EL-071 and 10-EL-087 in their Fix It Now (FIN) maintenance program for restoring these lights to an operable status within the end of the work shift. During a subsequent telephone conversation with IRM group representatives, the inspector was informed that the two lighting units were repaired under the FIN program and that IRM had initiated a formal evaluation of the adequacy of preventive and corrective maintenance applied to emergency lights. IRM initiated this evaluation following a recent transfer of responsibility for emergency light testing and surveillance from the electrical maintenance department to IRM. The inspector stated that the emergency light testing and surveillance program, and operability of lights would also be reviewed during the upcoming fire protection program review.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707)

6.1 Plant Operations Review Committee Meetings

The inspectors attended three Plant Operations Review Committee (PORC) meetings during the inspection period. On February 14, 1996, a PORC meeting was held to review an activity which would remove an alternate rod insertion (ARI) scram solenoid valve from service, which was found to be leaking. Another PORC meeting was held on February 22, 1996, to review several engineering issues prior to the end of the Unit 1 outage. For both of these meetings, the inspectors found the reviews to be adequate for meeting the technical specification requirements. A third PORC meeting, on February 27, 1996, was held to review the disposition of two RHR valves which failed dynamic testing. The inspectors found that the review at this meeting was particularly indepth and comprehensive. Engineering personnel were thoroughly questioned concerning the issues and the proposed corrective actions, by a very diverse PORC membership. Additionally, a good initiative was taken by plant management, by inviting a licensed operator to the meeting to give a different perspective, which could be important since the licensed operators would be implementing the actions.

6.2 Foreign Material Exclusion Controls

During the Unit 1 refueling outage, the inspectors reviewed how personnel were implementing foreign material exclusion (FME) controls. These controls were implemented in the suppression pool, in the condenser, on the refueling bridge, and on the turbine deck. The inspectors found the use of clearly marked bags covering equipment to be appropriate. All areas were clearly marked as FME areas, which required reading and signing a document prior to entry into the area. Overall, the inspectors found that the FME controls were

adequately implemented and adhered to by personnel, with one identified exception. Near the end of the outage, plant personnel identified foreign material (tools and rags) that were left in the C condensate drain cooler. This appeared to be an isolated instance, and was found prior to returning the system to service.

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

7.1 Licensee Event Reports (LERs)

The inspectors routinely reviewed LERs and performed follow-up 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 1-95-010, Manual U/1 Secondary Containment Isolation with Operation of the Common Plant SGTS & U/1 Reactor Enclosure Recirculation System, ESF Actuations, due to Equipment Problems. Event Date: December 23, 1995, Report Date: January 22, 1996.

This event was reviewed in NRC Combined Integrated Inspection Report Nos. 50-352/95-21 and 50-353/95-21.

LER 1-95-011, Engineered Safety Feature Actuation resulting from a Reactor Water Cleanup (RWCU) System Isolation, caused by High 'B' RWCU Pump Room Temperature after a Pump Seal Failed. Event Date: December 27, 1995, Report Date: January 25, 1996.

This event was reviewed in NRC Combined Integrated Inspection Report Nos. 50-352/95-21 and 50-353/95-21.

LER 1-96-001, Automatic Isolation of the Reactor Core Isolation Cooling System During Surveillance Testing Due to Less Than Adequate Attention to Detail. Event Date: January 11, 1996, Report Date: February 9, 1996.

This event is reviewed in section 1.2 of this inspection report.

LER 1-96-002, Operation in Excess of 100 Percent Rated Thermal Power due to Core Thermal Power Calculation Methodology Error. Event Date: January 18, 1996, Report Date: February 7, 1996.

This event is reviewed in section 1.2 of this inspection report.

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

7.2 Routine Reports

Routine reports submitted by PECO Energy were reviewed to verify the reported information. Station Monthly Operating Reports for December, dated January

11, 1996 and for January, dated February 8, 1996 were reviewed and satisfied the requirements for which they were reported.

8.0 FOLLOW-UP OF PREVIOUS INSPECTION FINDINGS (92903, 92904)

Closed (URI 50-353/95-06-01) This item was unresolved pending NRC review of PECO Energy's justification for concluding that certain dead bus relay failures, which resulted in failures of the EDG to start, did not constitute valid tests or failures. Plant personnel concluded that the relays are located on the busses, and are not considered part of the EDG system as described in Regulatory Guide 1.9; PECO Energy is committed to Regulatory Guide 1.108, and not to 1.9. However, Regulatory Guide 1.108 does not describe what constitutes the EDG system. Therefore, since these relay failures were outside of the EDG system, their failures did not count toward reportable EDG failures, and the EDGs could have been manually started at any time. Finally, plant personnel pointed out that not only were these relays not part of the EDG system, but if they got into a situation where more frequent EDG testing was required based on the number of failures, these relays would not be tested anyway. Therefore, plant management put in place a plan to specifically address the relay failures alone. This included testing of all of the other EDG bus relays, and continuing to test these relays periodically; this testing is accomplished without the need to start and run the EDGs. The inspectors concluded that the actions taken were appropriate and had no further concerns. This unresolved item is closed.

Closed (URI 50-353/95-21-01) This item was unresolved pending NRC review of two instances where a locked high radiation door was found propped open, including the results of PECO Energy's investigation. This item is closed, based on the documentation of the event as a non-cited violation, as discussed in section 5.1 of this inspection report.

Update (URI 50-352, 353/95-10-01) This item concerned the proper storage of emergency diesel generators EGB mechanical governors, as well as, PECO Energy's review of the generic concerns dealing with the storage of replacement components.

In June 1995, both the EGA and EGB governors were replaced on the D14 emergency diesel generator. Prior to the work, a maintenance technician identified that one of the two EGB governors in the store room was improperly stored without oil, as recommended in the vendor manual. The EGB stored without oil was date stamped 1989. This issue was brought to the attention of the engineering staff who performed an investigation and found that the root cause of the event was that standards, policies or administrative controls were less than adequate in that they were confusing or incomplete. Although the vendor storage recommendations called for oil, the inventory parts catalog did not have oil levels noted. At the end of that inspection period, the inspectors determined that based upon a vendor recommendation, the 1989 EGB governor was filled with oil and returned to storage. The inspectors requested a disposition on whether or not the 1989 EGB was suitable for use without being stored in oil for approximately six years. This issue was unresolved pending further review and resolution by PECO Energy.

The 1989 EGB governor was sent back to the vendor to be inspected, refurbished, and returned to Limerick. The Repair Report stated that this model unit was not as susceptible to corrosion damage resulting from dry storage as are other model governor actuators. The inspection indicated that there were no rubber or elastomer parts, bushings or seals found which showed any signs of degradation. Additionally, there were no visible signs of corrosion on the inside of the unit. Calibration testing was performed on the unit and the only out of specification reading was null voltage (.95 volts when the expected range was .7 to .9 volts), which was adjusted within specifications. The vendor report stated that the null voltage being slightly out of adjustment was insignificant. A null voltage of up to 1.5 volts would have been acceptable for this model unit. The EGB governor was filled with oil and placed back in storage. To prevent this event from recurring, the inventory parts catalog, stock code description for this part was updated to include a "Yes" in the maintenance required field. A note was also added that reads, "Important - Special Storage Instructions To Warehouse Stockperson," with an explanation of what those requirements are. The inspectors had no further questions concerning this aspect of the unresolved item. The generic concerns dealing with the storage of replacement components are still under review by PECO Energy and will be reviewed by the NRC when completed.

9.0 MANAGEMENT MEETINGS

9.1 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors. The UFSAR, section 5.4.7.1.1.5 states, "Two separate shutdown cooling pump and heat exchanger loops are provided," and, "Inter-ties are provided between the suction and discharge lines of the RHR pump in the direct injection LPCI loop (C and D pumps) and the associated RHR pump in the heat exchanger loop (A and B pumps, respectively) to allow use of the C and D pumps in the shutdown cooling mode, thus providing greater maintenance flexibility." Through discussions with NRC Region I and NRC NRR personnel, the inspectors concluded that the LGS interpretation of the SDC loops, with four possible, was incorrect in that only two loops, were possible.

9.2 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 Plant Manager, Mr. R. Boyce, on March 4, 1996. The Plant Manager expressed disagreement with the RHR shutdown cooling cited violation, stating that PECO Energy believes that their interpretation of the two loops of SDC (two pumps with a common heat exchanger) meets the intent of the technical specification. He additionally stated that the issue of not

logging the entry into the limiting condition for operation action statement, until the inspectors brought it to his attention, was an administrative issue only. Overall, he did not consider the event to be a safety issue. No written inspection material was provided to licensee representatives during the inspection period.

9.3 Plant Challenges/Focus on Excellence Meeting

On January 12, 1996, a meeting was held between NRC staff and PECO Energy representatives to discuss several plant events which occurred during the August and September 1995 time frame, and PECO Energy's Focus on Excellence program. The meeting was at the request of NRC Region I management in order for PECO Energy personnel to present the results of their analysis of the events as well as the highlights of the Focus on Excellence program. The meeting was open to public observation and was an informative type meeting. Attachment 1 contains PECO Energy handouts provided at the meeting.

9.4 Additional NRC Inspections this Period

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

Date	Subject	Inspection No.	Lead Inspector
2/12-15/96	Access Authorization	50-352/96-02 50-353/96-02	G. Smith

PECO ENERGY

Limerick Generating Station

Presentation to the NRC Plant Challenges / Focus on Excellence

January 12, 1996

USNRC, Region I

Agenda

❖ Introduction	Walt MacFarland, Site Vice President
❖ Plant Challenges	Bob Boyce, Plant Manager
❖ Focus on Excellence	Directors
❖ Summary	Walt MacFarland

Recent Plant Challenges

- 8/8/95 - Unit 2 Scram Due to Loss of FWLCS Power Supply
- 8/20/95 - Unit 2 EHC Malfunction & Scram
- 8/28/95 - Unit 1 Manual Scram Due to High Coolant System Leakage
- 9/11/95 - Unit 1 Manual Scram Resulting From Inadvertent SRV Opening
- Other Plant Challenges

Planned Reliability Outages

- 5/7/95 - Unit 1 Drain Cooler/Recirc Pump Seal
- 8/20/95 - Unit 1 Fuel Leak
- 11/22/95 - Unit 2 Stator Water Cooling Filters

Station Response

- Strong Management Focus
- Exceptional Level of Team Work, Skill, & Ownership by Workforce
- Strong Operations Performance
- Conservative Decisions
- Plant Responded as Designed
- No Threat to Public Health & Safety

Focus on Excellence

Through People

Area of Focus	Champion
❖ Safety	D. P. LeQuia
❖ Equipment Performance	M. P. Gallagher L. A. Hopkins
❖ Quality Execution	E. F. Sproat
❖ Change Management	J. T. Smugeresky

Sponsor: W. G. MacFarland
Co-Sponsor: R. W. Boyce

Safety

- Nuclear / Risk Minimization
- Radiological
- Industrial

Nuclear / Risk Minimization

- Conservative Decision Making
- Equipment Reliability Enhancement
- On-Line Maintenance Management
- Shutdown Risk Minimization
- Human Performance Enhancement

Radiological

- Radioactive Material Control
- Radiological Work Standards
- ARW Enhancements

Industrial

- Continued Focus on Basics
- Contractor Performance

Equipment Performance

- Standards of Excellence
- Industry Experience
- Key System Reliability

Standards of Excellence

- Deficiency Threshold
- Leak Identification Standards
- Operator Challenges & Workarounds
- Availability & Operability

Industry Experience

- Networking
- Prevention of Chronic Problems

Key System Reliability

- Feedwater Tiger Team
- Recirc & EHC Reliability
- Identify Other Systems

Quality of Execution

- Management Tear
- Individual Performance
- Station Assessment Processes
- Quaiity Improvement Initiatives

Management Team

- Reinforce Expectations
- Model Desired Behaviors
- Coaching

Individual Performance

- Personal Goals for All Workers
- Pinpointed Behaviors
- PECO ADVANTAGE

Station Assessment Processes

- Critical Process Assessments
- Root Cause Analysis
- Corrective Action Effectiveness

Quality Improvement Initiatives

- Foreign Material Exclusion Practices
- Plant Status Controls
- Material & Parts Control
- Modification/PMT Process
- Work Package Quality

Change Management

- Process Change
- Personnel Development

Process Change

- "Managed" Change
- Integrated Approach
- Impact Reviews
- Assessment of Change

Personnel Development

- Manager & Supervisory Skills
- Key Area Bench Strength
- Growth Opportunities in NGG

Summary

- ***Strong Performance in Many Areas***
- ***Strong Management/Workforce Team***
- ***Major Processes Fundamentally Sound***
- ***Learning Opportunities***
- ***Heightened Focus on Quality & Excellence***
- ***Continuous Self-Assessment***