UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

November 4, 2011

EA 2011-221

Mr. Michael J. Pacilio
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Officer, Exelon Nuclear
4300 Winfield Rd.
Warrenville, IL 60555

SUBJECT: LIMERICK GENERATING STATION, UNITS 1 AND 2 - NRC INTEGRATED INSPECTION REPORT 05000352/2011004 AND 05000353/2011004; AND PRELIMINARY WHITE FINDING

Dear Mr. Pacilio:

On September 30, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Limerick Generating Station Units 1 and 2. The enclosed integrated inspection report documents the inspection results, which were discussed on October 7, 2011, with Mr. W. Maguire, Limerick Site Vice President, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, a Technical Specification violation was identified which, using the applicable Significance Determination Process (SDP), has preliminarily been determined to be of low to moderate safety significance and may require additional NRC Inspection (White). As described in Section 4OA2.2 of this report, the inspectors determined that the failure by Exelon to ensure sufficient technical guidance was contained in operating procedures to: 1) ensure that a Main Feedwater system (FW) motor-operated valve (MOV) could close against expected system differential pressures and 2) prevent operators from attempting to close FW MOVs out of sequence resulting in differential pressures for which they are not designed; is a performance deficiency. This resulted in the Reactor Core Isolation Cooling system (RCIC) and a Primary Containment Isolation Valve (PCIV) being inoperable from April 23 to May 23, 2011, when FW MOVs HV-041-209B and HV-041-210 failed to fully shut. As a result, both safety-related systems were inoperable for greater than their Technical Specification allowed outage times. Upon identification, Limerick operations staff fully closed the valves restoring RCIC and PCIV operability, entered the issue into the Corrective Action Program (CAP) as issue report (IR) 1219476 and conducted a cause evaluation. Subsequent corrective actions included an extent-of-condition review, revisions to the operating procedures, and revisions to the maintenance and testing procedures.

The finding also involves apparent violations of NRC requirements that are being considered for escalated enforcement action in accordance with the Enforcement Policy, which can be found on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html. Because the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violations described in the enclosed inspection report may change as a result of further NRC review.

In accordance with NRC Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)," we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of the date of this letter. The SDP encourages an open dialogue between the NRC staff and the licensee; however, the dialogue should not impact the timeliness of the staff's final determination.

Before we make a final decision on this matter, we are providing you with an opportunity to (1) attend a Regulatory Conference where you can present to the NRC your perspective on the facts and assumptions the NRC used to arrive at the finding and assess its significance, or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of your receipt of this letter and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of your receipt of this letter. If you decline to request a Regulatory Conference or submit a written response, you relinquish your right to appeal the final SDP determination, in that by not doing either, you fail to meet the appeal requirements stated in IMC 0609, Attachment 2, Section 2, "Prerequisites," and Section 3, "Limitations."

Please contact Mr. Paul Krohn at 610-337-5120 and in writing within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision. The final resolution of this matter will be conveyed in separate correspondence.

In addition, this report documents two self-revealing findings of very low safety significance (Green). One of the findings was determined to involve a violation of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and because they are entered into your CAP, the NRC is treating these violations as non-cited violations (NCVs), consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Limerick facility. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I and the NRC Senior Resident Inspector at the Limerick facility.

In accordance with 10 Code of Federal Regulations (CFR) Part 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available

electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

Darrell J. Roberts, Director
Division of Reactor Projects

Docket Nos: 50-352, 50-353
License Nos: NPF-39, NPF-85

Enclosure: Inspection Report 05000352/2011004 and 05000353/2011004
w/Attachment: Supplemental Information

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the basis for your disagreement, to the Regional Administrator, Region I and the NRC Senior Resident Inspector at the Limerick facility.

In accordance with 10 Code of Federal Regulations (CFR) Part 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/
Darrell J. Roberts, Director
Division of Reactor Projects

Docket Nos: 50-352, 50-353
License Nos: NPF-39, NPF-85

Enclosure: Inspection Report 05000352/2011004 and 05000353/2011004
w/Attachment: Supplemental Information

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REGION I

Docket Nos.:	50-352, 50-353
License Nos.:	NPF-39, NPF-85
Report No.:	05000352/2011004 and 05000353/2011004
Licensee:	Exelon Generation Company, LLC
Facility:	Limerick Generating Station, Units 1 & 2
Location:	Sanatoga, PA 19464
Dates:	July 1, 2011 through September 30, 2011
Inspectors:	E. DiPaolo, Senior Resident Inspector J. Ambrosini, Acting Senior Resident Inspector N. Sieller, Resident Inspector J. Kulp, Senior Resident Inspector, Oyster Creek S. Hammann, Senior Health Physicist K. Mangan, Senior Reactor Inspector T. Moslak, Senior Health Physicist A. Rosebrook, Senior Project Engineer A. Ziedonis, Resident Inspector, Peach Bottom J. Lilliendahl, Reactor Inspector J. Nicholson, Health Physicist T. O'Hara, Reactor Inspector E. Miller, Project Engineer
Approved By:	Darrell J. Roberts, Director Reactor Projects Branch 4 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS 3

REPORT DETAILS 6

1. REACTOR SAFETY 6

1R01 Adverse Weather Protection 6
1R04 Equipment Alignment 7
1R05 Fire Protection 7
1R06 Flood Protection Measures 9
1R07 Heat Sink Performance 9
1R11 Licensed Operator Requalification Program 11
1R12 Maintenance Effectiveness 12
1R13 Maintenance Risk Assessments and Emergent Work Control 12
1R15 Operability Determinations and Functionality Assessments 13
1R18 Plant Modifications 13
1R19 Post-Maintenance Testing 14
1R22 Surveillance Testing 14
1EP6 Drill Evaluation 15

2. RADIATION SAFETY 15

2RS07 Radiological Environmental Monitoring Program (REMP) 15

4. OTHER ACTIVITIES 16

4OA1 Performance Indicator (PI) Verification 16
4OA2 Problem Identification and Resolution 18
4OA3 Follow-Up of Events and Notices of Enforcement Discretion 28
4OA5 Other Activities 35
4OA6 Meetings, Including Exit 37
4OA7 Licensee-Identified Violations 38

ATTACHMENT: SUPPLEMENTARY INFORMATION 38

SUPPLEMENTARY INFORMATION A-1

KEY POINTS OF CONTACT A-1

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED A-2

LIST OF DOCUMENTS REVIEWED A-3

LIST OF ACRONYMS A-16

SUMMARY OF FINDINGS

IR 05000352/2011004; 05000353/2011004; 07/01/2011-09/30/2011; Limerick Generating Station, Units 1 and 2; Problem Identification and Resolution; Follow-Up of Events and Notices of Enforcement Discretion

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. There was one finding and apparent violation (AV) that has been preliminarily determined to be of low to moderate safety significance (White) and two findings of very low safety significance (Green), one of which was also a non-cited violation (NCV). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using NRC Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). The cross-cutting aspects for the findings were determined using IMC 0310, "Components Within Cross-Cutting Areas." Findings for which the SDP does not apply may be Green, or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

Cornerstone: Mitigating Systems

- AV. A self-revealing preliminary white finding and apparent violation of Technical Specification (TS) 3.7.3, "Reactor Core Isolation Cooling System and TS 3.6.3, "Primary Containment Isolation Valves," was identified. The inspectors determined that the failure by Exelon to ensure sufficient technical guidance was contained in operating procedures to: 1) ensure that a Main Feedwater system (FW) motor-operated valve (MOV) could close against expected system differential pressures and 2) prevent operators from attempting to close FW MOVs out of sequence resulting in differential pressures for which they are not designed; is a performance deficiency. This resulted in the Reactor Core Isolation Cooling system (RCIC) and a Primary Containment Isolation Valve (PCIV) being inoperable from April 23 to May 23, 2011, due to FW MOVs HV-041-209B and HV-041-210 failing to fully shut. As a result, both safety related systems were inoperable for greater than their Technical Specification allowed outage times. Specifically, operations procedures did not contain adequate technical guidance to ensure that operations personnel operated HV-041-209 A&B and HV-041-210 in the proper sequence to remain within valve design limitations. This resulted in the HV-041-209B and HV-041-210 valves failing to fully close on April 22, 2011, although they indicated closed in the Main Control Room. Upon identification, Limerick operations staff fully closed the valves restoring RCIC and PCIV operability, entered the issue into the CAP as issue report (IR) 1219476 and conducted a cause evaluation. Subsequent corrective actions included an extent-of-condition review, revisions to the operating procedure, and revisions to maintenance and testing procedures.

  The inspectors determined that this finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, operating procedures, maintenance and testing were not adequately implemented to ensure that the design capability of HV-041-209B and HV-041-210 to close against expected system differential pressures was maintained. The finding was evaluated using NRC Inspection Manual Chapter 0609 Appendix A, "User Guidance for Significance Determination of Reactor Inspection Findings for At-Power Situations." Phase I, II, and III evaluations were conducted. The NRC total estimated ΔCDF in this preliminary assessment is Low E-6/yr

(WHITE) and the NRC total estimated Large Early Release Frequency (ΔLERF) in this preliminary assessment is 3.6E-9/yr (GREEN). The inspectors also determined that this issue has a cross-cutting aspect in the area of Human Performance, Resources, because Exelon did not ensure long term plant safety by maintaining design margins and minimizing preventive maintenance deferrals [H.2. (a)]. Specifically, design limitations of the HV-041-209 A & B valves were not adequately captured in the procedural guidance, which contributed to the operators continuing on in the procedures for securing the FW long path recirculation line up when problems with the HV-041-210 valve were encountered. Additionally preventive maintenance activities which could potentially have prevented this issue were deferred without an appropriate evaluation. (Section 4OA2.2)

- Green. A Green, self-revealing finding was identified because Exelon did not provide adequate instructions for restoration of the Limerick Unit 2 number three turbine control valve (CV #3) following maintenance. During a fill and vent activity of the electro-hydraulic control (EHC) supply line for CV #3, a void in the system piping resulted in a low pressure condition at the next-in-series control valve, CV #1. The pressure drop actuated a relayed emergency trip system (RETS) pressure switch, generating a reactor protection system (RPS) 'B' side half scram signal. Combined with an 'A' side half scram signal that was previously inserted into RPS due to the CV #3 being maintained closed, an automatic reactor scram resulted.

  The inspectors determined that Exelon's failure to provide adequate instructions for restoration of CV #3 from maintenance was a performance deficiency. The issue was more than minor because it was associated with the Procedure Quality attribute of the Initiating Events cornerstone, and it affected the cornerstone objective of limiting the likelihood of events that upset plant stability. Specifically, on May 29, 2011, Limerick Unit 2 experienced an automatic reactor scram during restoration of turbine CV #3 from maintenance. The restoration instructions in the work order (WO) did not provide sufficient guidance to address the presence of a large air void in the EHC system that had the potential to cause EHC pressure fluctuations and resulted in a reactor scram. The finding was determined to be of very low safety significance (Green) in accordance with IMC 0609 Attachment 4, "Phase 1-Initial Screen and Characterization of Findings," because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding had a cross-cutting aspect in the area of Human Performance, Decision-Making, because Exelon did not use a systematic process to make a risk-significant decision when faced with uncertain or unexpected plant conditions. Specifically, Exelon did not recognize the potential risk of the CV #3 EHC fill and vent restoration activity, and they failed to conduct a thorough technical review of the restoration plan. [H.1.(a)] (Section 4OA3.3)

- Green. A Green, self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," occurred when Exelon did not adequately assess the potential impacts of test equipment on turbine trip circuitry. This resulted in an automatic reactor scram of Unit 1 when the main turbine high reactor water level trip relay inadvertently energized during a surveillance test on June 3, 2011. This test is a quarterly surveillance, designed to verify proper operation of the Digital Feed Water Level Control System (DFWLCS) which initiates a turbine trip on high reactor level. The DFWLCS has a 1 out of 2 twice logic to energize the trip relay, so each channel is tested separately to eliminate the possibility of inadvertent actuation. As an additional precaution, the surveillance procedure contains steps for the technician to verify the other channels are free of closed trip contacts prior to beginning the test. Exelon used a Simpson 260 Volt/Ohm Meter (VOM) to perform this verification by demonstrating a nominal voltage difference between each side of the contact and station

ground. During this verification step, Exelon inadvertently established a direct current loop from station ground, to the floating battery ground from the 125V power supply, to the trip circuit. This completed the circuit, energized the main turbine high reactor water level trip relay, which tripped the main turbine and caused the reactor to scram. Exelon revised the test procedure to change the requirements for test instrumentation to prevent this from recurring and entered the issue into the corrective action program as IR 1224283.

The inspectors determined that the performance deficiency was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," because it was associated with the Equipment Performance attribute of the Initiating Events cornerstone and affected the objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operation. Specifically, by not considering the impact of maintenance and test equipment (M&TE) during multiple revisions of the surveillance procedure, Exelon failed to recognize a vulnerability which could lead to a plant transient. In accordance with IMC 0609, Attachment 4, "Phase 1 - Initial Screen and Characterization of Findings," the finding was determined to be of very low safety significance (Green) because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. The inspectors determined that this performance deficiency did not reflect current performance, as the last revision to the surveillance procedure that affected M&TE requirements was greater than three years ago. As a result, the inspectors did not assign a cross-cutting aspect to this finding. (Section 4OA3.5)

Other Findings

A violation of very low safety significance that was identified by Exelon was reviewed by the inspectors. Corrective actions taken or planned by Exelon have been entered into Exelon's corrective action program. This violation and corrective action tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power. During the inspection period, Unit 1 power was reduced several times for short durations as a result of high condensate temperatures, due to environmental conditions (i.e. hot outside temperatures). On September 2, operators reduced power to 65 percent to facilitate turbine valve testing, scram time testing, control rod pattern adjustment, and condenser tube leak repairs. The unit was returned to 100 percent power on September 4. On September 11, operators reduced power to 90 percent to perform a follow-up control rod pattern adjustment. The unit returned to full power later that same day. The unit remained at or near 100 percent power for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent power. During the inspection period, Unit 2 power was reduced several times for short durations as a result of high condensate temperatures, due to environmental conditions (i.e. hot outside temperatures). On September 9, operators reduced power to 65 percent to facilitate turbine valve testing, scram time testing, control rod pattern adjustment, and condenser tube leak repairs. The unit was returned to 100 percent power on September 11. On September 15, operators reduced power to 90 percent to perform a follow-up control rod pattern adjustment. The unit returned to full power on September 16. The unit remained at or near 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 2 samples)

.1 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors performed a review of Exelon's readiness for the onset of seasonal high temperatures. The review focused on the spray pond pump house and high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) for Units 1 and 2. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), technical specifications, control room logs, and the corrective action program to determine what temperatures or other seasonal weather could challenge these systems, and to ensure Exelon personnel had adequately prepared for these challenges. The inspectors reviewed station procedures, including Exelon's seasonal weather preparation procedure and applicable operating procedures. The inspectors performed walkdowns of the selected systems to ensure station personnel identified issues that could challenge the operability of the systems during hot weather conditions. Documents reviewed for each section of this inspection report are listed in the Attachment.

b. Findings

No findings were identified.

.2 Site Imminent Weather Conditions

a. Inspection Scope

On August 25, the inspectors reviewed Exelon's preparations in advance of Hurricane Irene. The inspectors performed walkdowns of areas that could be potentially impacted by the weather conditions, such as the diesel structure and transformers, and verified that station personnel secured loose materials staged for outside work prior to the forecast high winds. The inspectors verified that Exelon monitored the approach of the storm according to applicable procedures and took appropriate actions as required.

b. Findings

No findings were identified.

1R04 Equipment Alignment

Partial System Walkdowns (71111.04Q – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Unit Common residual heat removal service water (RHRSW) system (Spray Pond Pump House and reactor building pipe tunnel components) on July 1
- B.5.b portable fire pump on July 5
- Unit 1 RCIC on August 2
- Unit 1 'D' residual heat removal (RHR) system on August 18

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the UFSAR, technical specifications, work orders, condition reports (CRs), and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted system performance of their intended safety functions. The inspectors also performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors also reviewed whether Exelon staff had properly identified equipment issues and entered them into the corrective action program for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Resident Inspector Quarterly Walkdowns (71111.05Q – 6 samples)

a. Inspection Scope

The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that Exelon controlled combustible materials and ignition sources in accordance with administrative procedures. The inspectors verified that fire protection and suppression equipment was available for use as specified in the area pre-fire plan, and passive fire barriers were maintained in good material condition. The inspectors also verified that station personnel implemented compensatory measures for out-of-service, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

- Unit 1, RCIC Room (F-R-108)
- Unit 1, Reactor Feed Pump Lube Oil Areas (EL 200) (F-T-252)
- Unit 1, Class 1E Battery Room (EL217) (F-A-323)
- D12 Diesel Generator Room and Fuel Oil and Lube Oil Tank Room (F-D-311B)
- Common, 13.2 KV Switchgear Room 336, (F-A-336)
- Common, Unit 1 D12 Emergency 4KV Switchgear Room 433 (EL239) (F-A-433)

b. Findings

No findings were identified.

.2 Fire Protection – Drill Observation (71111.05A – 1 sample)

a. Inspection Scope

The inspectors observed Fire Drill Scenario F-T-252, "Unit 1 Reactor Feed Pump Turbine Lube Oil Conditioner." The drill was conducted on September 19 and involved a fire in the turbine building near the reactor feed pump lube oil areas. The inspectors evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that Exelon personnel identified deficiencies, openly discussed them in a self-critical manner at the post drill debrief, and took appropriate corrective actions as required. The inspectors evaluated specific attributes as follows:

- Proper wearing of turnout gear and self-contained breathing apparatus
- Proper use and layout of fire hoses
- Employment of appropriate fire-fighting techniques
- Sufficient fire-fighting equipment brought to the scene
- Effectiveness of command and control
- Search for victims and propagation of the fire into other plant areas
- Smoke removal operations
- Utilization of pre-planned strategies
- Adherence to the pre-planned drill scenario
- Drill objectives met

The inspectors also evaluated the fire brigade's actions to determine whether these actions were in accordance with Exelon's fire-fighting strategies.

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 – 2 samples)

.1 Internal Flooding Review

a. Inspection Scope

The inspectors reviewed the Unit 2 'B' and 'D' RHR room to assess susceptibilities involving internal flooding. The inspectors reviewed the UFSAR, the site flooding analysis, and plant procedures to determine the design basis of the room and ensure operator actions for coping with flooding were adequate. The inspectors verified the adequacy of floor and wall penetration seals, watertight door seals, common drain lines and sumps, level alarms, control circuits, and temporary or removable flood barriers. The inspectors specifically focused on the adequacy of Exelon's procedural guidance for establishing compensatory measures when the RHR room floor plugs were removed for maintenance.

b. Findings

No findings were identified.

.2 Annual Review of Cables Located in Underground Bunkers/Manholes (MH)

a. Inspection Scope

The inspectors conducted an inspection of underground bunkers/manholes subject to flooding that contain cables whose failure could disable risk-significant equipment. The inspectors reviewed records for safety-related cables contained in manholes MH 101 through MH 110, which service emergency service water (ESW) and RHRSW pumps, to verify that the cables were not submerged in water, that cables and/or splices appeared intact, and to note the condition of cable support structures. When applicable, the inspectors verified proper sump pump operation and verified level alarm circuits were set in accordance with station procedures and calculations to ensure that the cables will not be submerged. The inspectors also ensured that drainage was provided and functioning properly in areas where dewatering devices were not installed.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07T - 3 samples)

a. Inspection Scope

Based on a plant specific risk assessment, past inspection results, recent operational experience, and resident inspector input, the inspectors selected and completed the following heat sink and heat exchanger (HX) samples:

Heat Sink Sample

The inspectors conducted a walkdown of the Unit 1 and Unit 2 common spray pond structure and associated equipment. The spray pond serves as the ultimate heat sink

for both Unit 1 and Unit 2. The inspectors also reviewed a recent survey of spray pond silt accumulation and a recent structural inspection report of the condition of the embankments of the spray pond.

The inspectors observed the conditions outside and inside the spray pond pump house and the associated piping and pumps of the ESW and the RHRSW systems. Also, the inspectors observed the operation of the spray manifolds located above the surface of the spray pond. The inspectors reviewed the licensee's calculation which demonstrates that the spray pond has sufficient heat removal capacity to carry out the safety-related functions described in the Unit 1 and Unit 2 UFSAR.

The inspectors reviewed the original construction records for the spray pond and reviewed the licensee's recent structural inspections of the overflow weir and the embankments of the pond. The inspectors also reviewed the periodic surveillance procedures performed to check the chemical treatments performed on the spray pond and associated water systems to prevent degradation of the spray pond structures.

The inspectors verified that the licensee conducts inspections of buried piping associated with the Unit 1 and Unit 2 Spray Pond and associated systems. The inspectors reviewed the operation and maintenance records for the Cathodic Protection System which is used to prevent degradation of all buried, safety-related piping systems at Limerick Unit 1 and Unit 2. Also, the inspectors reviewed the results of the American Society of Mechanical Engineers (ASME), Section XI, Subsection IWA 5244 testing completed on buried piping connected to the Spray Pond.

ESW Heat Exchanger Sample

The inspectors conducted a walkdown of accessible equipment and structures of the ESW system and associated safety-related HXs.

In emergency situations the ESW system can cool all of the safety-related HXs from both Limerick Units. The inspectors conducted a walkdown of the ESW safety-related HXs and the associated structural supports. The inspectors also interviewed the responsible system engineering manager about system operation, past piping leaks, and future, planned piping repairs and upgrades. Also, the inspectors reviewed recent ESW system health reports, and reviewed recent system heat removal capacity test reports.

The inspectors verified, through review of design records, that the safety-related HXs for Unit 1 and Unit 2 have been designed to minimize the potential for water hammer and that operational flow values have been chosen to minimize the potential for flow induced vibration effects from occurring in the HXs served by the system. Additionally, there are no tubes plugged in the safety-related systems served by the ESW system.

The inspectors reviewed Exelon's test and inspection, maintenance, chemical control, and performance monitoring methods for the ESW system to determine whether potential deficiencies could mask degraded performance, and to assess the capability of the systems to perform their design functions. In addition, the inspectors evaluated whether any potential common cause heat sink performance problems could affect multiple HXs or heat removal paths in mitigating systems or could result in an initiating event.

Exelon verified in their 60 day Response to NRC Generic Letter 88-04 that Limerick Service Water systems were not subject to pump to pump interactions.

The inspectors reviewed a sample of Action Reports related to the Spray Pond, Unit 1 and Unit 2 Cooling Towers, the ESW System and the RHRSW System to verify that Exelon was appropriately identifying, characterizing, and correcting problems related to these systems and components, and that the planned or completed corrective actions for the reported issues were appropriate.

Unit-2 RHR Pump Motor Oil Cooler Sample

The inspectors performed a walkdown of the Unit 2 RHR pump motor oil cooler and the associated piping, pump, and motor. The inspectors reviewed surveillance test records which verified the ability of the HX to remove sufficient heat to support operation of the motor and support the HX's design function. The inspectors also reviewed the licensee's calculations showing that the HX was not susceptible to water hammer damage or to flow induced vibration damage if operated within the correct fluid flow velocity ranges. The inspectors also verified that the licensee conducts periodic tests to ensure that HX flow remains within the design limits.

The inspectors reviewed the periodic surveillance test results which monitor the chemical environment intended to prevent corrosion of the system piping, valves, and HXs. The Unit 2 RHR motor oil cooler is a single, wound coil type HX which has no blockage in the single tube provided that sufficient flow is measured. Eddy current testing is not performed on this HX.

The Action Reports reviewed are listed in Attachment 1.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11Q – 1 sample)

a. Inspection Scope

On August 17, the inspectors observed a licensed operator requalification simulator training session. The simulator scenario tested the operators' ability to respond to operating equipment failures, a RHR pipe rupture, and an anticipated transient without a scram. The inspectors evaluated operator performance during the simulated event and verified completion of risk significant operator actions, including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. The inspectors verified the accuracy and timeliness of the emergency classification made by the shift manager and the technical specification action statements entered by the shift technical advisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q – 2 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on systems, structures, and components (SSC) performance and reliability. The inspectors reviewed system health reports, corrective action program documents, maintenance work orders, and maintenance rule basis documents to ensure that Exelon was identifying and properly evaluating performance problems within the scope of the maintenance rule. For each sample selected, the inspectors verified that the SSC was properly scoped into the maintenance rule in accordance with 10 CFR 50.65 and verified that the (a)(2) performance criteria established by Exelon staff was reasonable. As applicable, for SSCs classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return these SSCs to (a)(2). Additionally, the inspectors ensured that Exelon staff was identifying and addressing common cause failures that occurred within and across maintenance rule system boundaries.

- Seismic Monitoring, system 365
- IR 1222301, Unit 2 Manual Scram due to 2A/2B recirculation pump trips

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 3 samples)

a. Inspection Scope

The inspectors reviewed station evaluation and management of plant risk for the maintenance and emergent work activities listed below to verify that Exelon performed the appropriate risk assessments prior to removing equipment for work. The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that Exelon personnel performed risk assessments as required by 10 CFR 60.65(a)(4) and that the assessments were accurate and complete. When Exelon performed emergent work, the inspectors verified that operations personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work and discussed the results of the assessment with the station's probabilistic risk analyst to verify plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

- IR 1238767, Emergency diesel generator (EDG) D24 unplanned unavailability due to standby alternating current power system out-of service alarm on July 11
- Unit 2 Yellow Risk Profile due to HPCI planned outage on July 26-30
- Unit 2 Risk Profile during RCIC Pump Valve and Flow, ST-6-049-230-2, on September 8

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 6 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions:

- IR 1239365, EDG D23 return to service following failure to start on July 13 during monthly testing
- IR 1245734, RCIC valve LV-049-1F054 packing leak
- IR 1246836, EDG D11 fuel oil strainer high differential pressure
- IR 1254061, Part 21 Seismic impact on channel distortion
- IR 1260638, Unit 2 Division 2 redundant reactivity control system out of service
- IR 1262728, Small amount of clear reflective material found in EDG D13 fuel oil pump

The inspectors selected these issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the operability determinations to assess whether technical specification operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the technical specifications and UFSAR to Exelon's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled by Exelon. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 – 1 sample)

a. Inspection Scope

The inspectors reviewed the modifications for ECR 11-00354, "New Power Supply Board in STS535 Controller," to determine whether the changes adversely affected the safety functions of systems that are important to safety. The inspectors reviewed 10 CFR 50.59 documentation and post-modification testing results to verify that the modifications did not degrade the design bases, licensing bases, or performance capability of the affected systems.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 3 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed the test procedure to verify that the procedure adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure was consistent with the information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed test data to verify that the test results adequately demonstrated restoration of the affected safety functions.

- A1815583, EDG D24 inoperable due to defective control circuit Bussman fuse
- C0238920, Troubleshoot and repair EDG D23
- C0239277, Replace Packing for RCIC valve LV-049-1F054 due to packing steam

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 6 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant SSCs to assess whether test results satisfied technical specifications, the UFSAR, and Exelon procedure requirements. The inspectors verified that test acceptance criteria were clear, tests demonstrated operational readiness and were consistent with design documentation, test instrumentation had current calibrations and the range and accuracy for the application, tests were performed as written, and applicable test prerequisites were satisfied. Upon test completion, the inspectors considered whether the test results supported that equipment was capable of performing the required safety functions. The inspectors reviewed the following surveillance tests:

- ST-6-012-231-0, 'A' LOOP RHR Service Water Pump, Valve and Flow Test
- ST-6-092-112-1, D12 Diesel Generator 24 Hour Endurance Test
- ST-6-092-311-1, D11 Diesel Generator Slow Start Test
- ST-2-051-802-2, Division 2 LPCI System Response Time Testing
- ST-6-107-596-1, Drywell Floor Drain Sump 1 Equipment Drain Tank Surveillance Log 1 Operational Condition 1, 2, 3
- ST-6-001-660-2, Main Turbine Control Intercept Valves, Stop Valve, and End of Cycle-Recirculation Pump Trip Channel Functional Test

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 – 2 samples)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of two routine Exelon emergency drills on July 20 and August 17 to identify any weaknesses and deficiencies in the classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator and technical support center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the station drill critique to compare inspector observations with those identified by Exelon staff in order to evaluate Exelon's critique and to verify whether the Exelon staff was properly identifying weaknesses and entering them into the corrective action program.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety

2RS07 Radiological Environmental Monitoring Program (REMP) (71124.07 - 1 sample)

a. Inspection Scope

During the period September 26 - 30, 2011, the inspectors conducted the following activities to verify that the licensee implemented the radiological environmental monitoring program (REMP) consistent with the Site Technical Specifications and the Off-Site Dose Calculation Manual (ODCM) to validate that radioactive effluent releases met the design objectives of Appendix I to 10 CFR Part 50.

REMP Inspection:

The inspectors reviewed the 2009 and 2010 Annual Radiological Environmental Operating Reports and the 2010 Land Use Census Report to verify that the environmental monitoring programs were implemented as required by the ODCM (Revision 24).

The inspectors walked down five (of 6) air particulate/iodine sampling stations (Nos. 10S3, 11S1, 11S2, 13C1, and 14S1), four (of 4) drinking water stations (Nos. 15F4, 15F7, 16C2, and 28F3), two (of 2) surface water sampling stations (24S1, 13B1), and the associated thermoluminescence dosimeter (TLD) monitoring stations. The inspectors evaluated the sampling equipment material condition and determined if sampling locations were as described in the ODCM. The inspectors confirmed that the air sampling locations were in areas having the highest X/Q and D/Q wind sectors, and the TLDs were located in areas with the highest potential for public exposure.

As part of the walkdown, the inspectors observed a technician collect and prepare for analysis water and air samples. The inspectors verified that sampling techniques were performed in accordance with procedures. During walkdowns, the inspectors had the technician demonstrate that the air and water sampling equipment was properly operating. Subsequently, the inspectors reviewed maintenance records and calibration records for the air sampling equipment.

Based on direct observation and review of records, the inspectors verified that the meteorological instrumentation was operable, calibrated, and maintained in accordance with the guidance contained in the UFSAR, NRC Safety Guide 23, and the licensee/vendor procedures. The inspectors verified that the meteorological data readout and recording instruments in the control room and at the primary tower was operable for wind direction, wind speed, temperature, and delta temperature. The inspectors confirmed that redundant instrumentation was operable and that the annualized recovery rate for meteorological data was greater than 90 percent.

The inspectors reviewed Issue Reports, Nuclear Oversight Audit/Assessment Reports, management observations of sample collection, REMP contractor audits, and departmental self-assessment reports, relevant to the ODCM requirements, to evaluate the threshold for which issues are entered into the corrective action program, the adequacy of subsequent evaluations, and the effectiveness of the resolution.

The inspectors reviewed the results of the licensee's quarterly laboratory cross-check program to verify the accuracy of the licensee's environmental air filter, charcoal cartridge, water, biota, and milk sample analyses.

The inspectors reviewed any significant changes made by the licensee to the ODCM as a result of changes to the land use census or sampler station modifications since the last inspection. The inspectors also reviewed technical justifications for any change in sampling location or analytical parameter, and verified the licensee performed the reviews required to ensure that the changes did not affect its ability to adequately monitor the radiological condition of the environment.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151-7 samples)

.1 Mitigating Systems Performance Index (2 samples)

a. Inspection Scope

The inspectors reviewed Exelon's submittal of the Mitigating Systems Performance Index for Unit 1 and Unit 2 RHR systems for the period of July 1, 2010 through June 30, 2011. To determine the accuracy of the PI data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors also reviewed Exelon's operator narrative logs, CRs, mitigating

systems performance index derivation reports, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

.2 Unplanned Scrams per 7000 Critical Hours (2 samples)

a. Inspection Scope

The inspectors reviewed Exelon's submittals for the Unplanned Scrams per 7000 Critical Hours PI for both Unit 1 and Unit 2 for the period of July 1, 2010, through June 30, 2011. To determine the accuracy of the PI data reported during those periods, inspectors used definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 10 CFR 50.73." The inspectors reviewed Exelon's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, CRs, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

.3 Unplanned Scrams with Complications (2 samples)

a. Inspection Scope

The inspectors reviewed Exelon's submittals for the Unplanned Scrams with Complications PI for both Unit 1 and Unit 2 for the period of July 1, 2010, through June 30, 2011. To determine the accuracy of the PI data reported during those periods, inspectors used definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 10 CFR 50.73." The inspectors reviewed Exelon's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, CRs, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Inspection Findings

No findings were identified.

.4 RETS/ODCM Radiological Effluent Occurrences (1 sample)

a. Inspection Scope

The inspectors reviewed relevant effluent release reports for the period August 2010 through August 2011, for issues related to the public radiation safety performance indicator as specified in NEI 99-02. The NEI criteria for reporting the performance indicator includes radiological effluent release occurrences that exceed 1.5 mrem/qtr

whole body or 5.0 mrem/qtr organ dose for liquid effluents; 5mrads/qtr gamma air dose, 10 mrad/qtr beta air dose, and 7.5 mrads/qtr for organ dose for gaseous effluents.

Included in this review were the following documents to ensure the licensee met all requirements of the performance indicator.

- Monthly projected dose assessment results due to radioactive liquid and gaseous effluent releases
- Quarterly projected dose assessment results due to radioactive liquid and gaseous effluent releases
- Dose assessment procedures

b. Inspection Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 3 samples)

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, "Problem Identification and Resolution," the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that Exelon entered issues into the corrective action program at an appropriate threshold, gave adequate attention to timely corrective actions, and identified and addressed adverse trends. In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the corrective action program and periodically attended CR screening meetings.

b. Findings

No findings were identified.

.2 Annual Sample: Failure of motor-operated valves to isolate Unit 2 long-path FW system recirculation flow path resulting in loss of RCIC and PCIV safety functions

a. Inspection Scope

The inspectors performed an in-depth review of Exelon's root cause analysis and corrective actions associated with CR 1219476, failure of two motor-operated valves (MOVs) to isolate Unit 2 long-path FW system recirculation flow path. This resulted in loss of RCIC and PCIV safety functions. Specifically, operations procedures did not contain adequate technical guidance to ensure that operations personnel operated HV-041-209 A&B and HV-041-210 in the proper sequence to remain within valve design limitations, which resulted in the RCIC and PCIV system being inoperable from April 23 to May 23 when the MOVs failed to fully close.

The inspectors assessed Exelon's problem identification threshold, cause analyses, extent-of-condition reviews, compensatory actions, and the prioritization and timeliness of Exelon's corrective actions to determine whether they were appropriate. The

inspectors compared the actions taken to the requirements of Exelon's corrective action program and 10 CFR 50, Appendix B. In addition, the inspectors performed field walkdowns and interviewed engineering personnel to assess the effectiveness of the implemented corrective actions.

b. Findings and Observations

Introduction. A self-revealing preliminary white finding and apparent violation of TS 3.7.3, "Reactor Core Isolation Cooling System," and TS 3.6.3, "Primary Containment Isolation Valves," was identified. The inspectors determined that the failure by Exelon to ensure sufficient technical guidance was contained in operating procedures to: 1) ensure that a FW MOV could close against expected system differential pressures and 2) prevent operators from attempting to close FW MOVs out of sequence resulting in differential pressures for which they are not designed; is a performance deficiency. This resulted in the RCIC system and a PCIV being inoperable from April 23 to May 23, 2011, due to FW valves HV-041-209B and HV-041-210 failing to fully shut. As a result, both safety-related systems were inoperable for greater than their Technical Specification allowed outage times. Specifically, operations procedures did not contain adequate technical guidance to ensure that operations personnel operated HV-041-209 A&B and HV-041-210 in the proper sequence to remain within valve design limitations. .

Description.

Discovery and System Configuration

On April 23, 2011, after restarting from a scheduled refueling outage, Limerick staff identified that Unit 2's electrical output was less than it should have been. On May 23, 2011, while troubleshooting this lost electrical capacity, Limerick staff identified valve seat leakage on two FW long path flush MOVs. The 16-inch globe valves (HV-041-209B and HV-041-210) were found to be off their closed seats which was allowing 570 gpm to leak from the 'B' FW header to the main condenser. Limerick operators closed the valves, and main generator load increased by approximately 20 MWe. Through its subsequent investigation, Limerick determined that the valves had failed to fully close when long path flushing was secured on April 22, 2011.

The FW long path flush line is used during refuel outage restart evolutions at Limerick to clean the condensate and FW lines and to clean the hotwell until reactor water chemistry goals are achieved. The 'A' and 'B' FW headers are each equipped with a 16-inch diameter, long-path flush line near the FW line penetrations into primary containment. Each flush line is equipped with a 16-inch MOV (HV-041-209A & B). The two flush lines merge into a single 16-inch line which returns to the main condenser. The single line is also equipped with a 16-inch MOV (HV-041-210).

On April 22, 2011, when securing FW long path flushing, Limerick operators identified that HV-041-210 failed to fully close, which they recognized due to both indicating lights (red and green) remaining illuminated. In order to secure the flushing and enable troubleshooting of the HV-041-210 valve, Limerick operators closed the upstream HV-041-209 A & B valves. However, these valves are not designed to close against a differential pressure, which they experienced since HV-041-210 was not fully closed. While HV-041-209A fully closed (even against the differential pressure), HV-041-209B did not. Instead, HV-041-209B's torque switch activated prior to the valve fully seating, causing the valve to not fully seat, even though its indicating light showed that the valve

was closed. Note that it is normal for an MOV's red indicating light to extinguish as the valve enters the seat just prior to actuation of the torque switch which terminates the valve motion. If the torque switch actuates before the valve is fully seated the red light may be extinguished with the valve slightly open.

The operators, not recognizing that HV-041-209B had not fully seated, again attempted to shut HV-041-210, and this time, the green open light extinguished. However, as with HV-041-209B, the torque switch actuated before the valve was fully seated. HV-041-210 is designed to close against a differential pressure; however, as was later identified by Limerick staff, the valve was degraded resulting in its failure to fully close.

Maintenance History

In 2007 preventive maintenance (PM) recurring task PM391081 was developed for non NRC Generic Letter 89-10 program MOVs with a 12-year periodicity. The initial performance of the PM for HV-041-209 A & B and HV-041-210 was deferred from the Spring 2011 refueling outage (2R11) to Spring 2013 refueling outage (2R12) via work order action items A16113875, A16113876, and A16113877, even though these valves have received minimal maintenance since 1991. These valves previously had a PM which was deactivated in 1994. The evaluations performed by Exelon to support deferring maintenance on these valves did not take into account the fact that it had been 20 years since maintenance was last performed or consider the impacts of the valves failing on other safety-related equipment/systems. Post failure review determined the MOV thermal overloads for HV-041-210 tripped due to valve internal degradation or stem lube degradation. The PM task may have mitigated the stem lube degradation, and may have provided an opportunity to identify other potential failure mechanisms.

Procedure Limitations and RCIC Impact

Limerick Generating Station procedures GP-2, "Normal Plant Startup," Rev. 141 and S06.5.A, "Long Path Recirculation and Feedwater System Flushing," Rev. 35., contain the direction and requirements for securing the FW long-path flush, which includes direction for operating the PCIVs HV-041-209A and HV-041-209B. However, these procedures did not provide adequate direction for operating PCIVs HV-041-209A and HV-041-209B. Specifically, when licensee operators could not secure the flush by closing the HV-041-210 valve, they attempted to secure it by closing the upstream HV-041-209A and HV-041-209B valves, even though they were subject to full FW system differential pressure as a result of the HV-041-210 valve not being fully seated. Plant procedures did not prohibit or otherwise instruct the operators that valves HV-041-209 A&B are not designed to be closed against full FW system differential pressure. Since valves HV-041-209 A&B are credited as PCIVs, the operators' decision to continue was reasonable given the guidance they and Engineering personnel had available at the time. As a result, the HV-041-209B valve did not fully seat. This condition, together with the failure of the licensee to fully close the HV-041-210 valve discussed above, allowed leakage back to the main condenser at a flow rate of approximately 570 gpm between April 23, 2011, and May 23, 2011.

The Limerick RCIC system discharges to the reactor via the 'B' FW header, thus with HV-041-209B and HV-041-210 cracked open, a flow path existed for RCIC to flow from the 'B' FW header thru HV-041-209B and HV-041-210 to the main condenser vice discharging to the reactor via the 'B' FW header as designed. RCIC is a 600 gpm system; therefore, RCIC would not have been able to supply design flow to the reactor in

this configuration, and its safety function would have been lost. RCIC is required to be operable in Modes 1, 2, and 3 when steam dome pressure is greater than 150 psig. Thus, RCIC was inoperable from April 23, 2011 until May 23, 2011 (30 days.) Technical Specification (TS) 3.7.3, "Reactor Core Isolation Cooling System," allowed outage time for RCIC is 14 days.

PCIV Impact

In addition, HV-041-0209B is a PCIV. TS 3.6.3, "Primary Containment Isolation Valves," requires each PCIV to be operable in Modes 1, 2, and 3. With one or more of the PCIVs inoperable, Limerick must maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours either:

1. Restore the inoperable valve(s) to OPERABLE status, or
2. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position, or
3. Isolate each affected penetration by use of at least one closed manual valve or blind flange.

Otherwise, the TS requires the plant to be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

HV-041-0209B is normally shut, locked, and de-energized. Thus, it only functions as a passive boundary valve with no active isolation functions being credited. Since the valve was out of its credited safety function position of fully closed in Modes 1 & 2, HV-041-0209B was also inoperable as a PCIV from April 23, 2011 until May 23, 2011 as this valve was not in its required position to perform its safety function, and the required four hour action statement to isolate the affected penetration was not met.

Troubleshooting Efforts and Corrective Actions

Limerick staff had been troubleshooting the lost electrical generation output since it was identified on April 26, 2011. A troubleshooting plan was developed which identified approximately 200 total steam and FW flow paths as potential causes. However, the HV-041-209 A&B/HV-041-210 FW flow path was one of the last flow paths to be fully resolved by the troubleshooting plan. Given the known issue with HV-041-210 on April 22, 2011, which had been documented in the CAP, and the fact that two safety-related functions may have been adversely affected by this flow path, it is reasonable that this flow path should have been given a higher priority. If this had been done, the issue may have been discovered earlier and the exposure time and plant risk from this configuration may have been reduced.

Immediate corrective actions implemented on May 23, 2011, involved restoring HV-041-209B and HV-041-210 to the full closed position, which restored the safety function and operability of RCIC and the PCIV. Long term corrective actions planned involve valve in-body maintenance, diagnostic testing, a preventive maintenance scope revision, and long-path recirculation operating procedure revision. Exelon also issued Licensee Event Report (LER) 05000353/2011-003-00 on July 21, 2011 for operation with two conditions prohibited by TS.

Analysis. The inspectors determined that the failure by Exelon to ensure sufficient technical guidance was contained in operating procedures to: 1) ensure that a Main

Feedwater system (FW) motor-operated valve (MOV) could close against expected system differential pressures and 2) prevent operators from attempting to close FW MOVs out of sequence resulting in differential pressures for which they are not designed; is a performance deficiency. Specifically, operations procedures did not contain adequate technical guidance to ensure that operations personnel operated HV-041-209 A&B and HV-041-210 in the proper sequence to remain within valve design limitations; is a performance deficiency. The condition was corrected by the licensee, so there were no remaining safety concerns.

The inspectors determined that this finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, operating procedures, maintenance, and testing were not adequately implemented to ensure that the design capability of HV-041-209 B and HV-041-210 to close against expected system differential pressures was maintained. These deficiencies resulted in Unit 2 RCIC being inoperable for greater than the TS 3.7.3 allowed outage time. In accordance with in accordance with IMC 0609 Attachment 4, "Phase 1 - Initial Screen and Characterization of Findings," Phase 1 screening worksheets, a Phase 2 risk analysis was required because the finding represents an actual loss of safety function of a single train for greater than the TS allowed outage time of 14 days.

Phase 2 Risk Evaluation

The Phase 2 risk evaluation was performed in accordance with IMC 0609, Appendix A, Attachment 1, "User Guidance for Significance Determination of Reactor Inspection Findings for At-Power Situations." The total exposure period for the degraded condition was approximately 30 days. Using Limerick's Phase 2 SDP notebook, pre-solved worksheets, and an initiating event likelihood of 3-30 days, the inspector identified that this finding is of Low to Moderate Safety Significance (White) for ΔCDF. The dominant sequence was a transient with loss of power conversion combined with a failure of high pressure injection and a failure of the operators to depressurize the reactor.

Phase 3 Analysis

The Senior Risk Analyst (SRA) used Limerick's Standardized Plant Analysis Risk (SPAR) model, version 8.16, in conjunction with the System Analysis Programs for Hands-On Integrated Reliability Evaluations, version 8.0.7.17, dated May 18, 2011, to estimate the internal risk contribution of the Phase 3 risk assessment.

Influential Assumptions

The following assumptions were used for this assessment:

- To closely approximate the type of failure exhibited by RCIC, the SRA used the RCIC failure-to-run event <RCI-TDP-FR-TRAIN> and changed its failure probability to True, representing a 100 percent failure-to-run condition;

The exposure time for this condition was 30 days. Based upon the nature of the failure, no adjustments were made to the nominal operator recovery credit;

- No adjustments were made to human error probabilities (HEPs) to account for the

small flow permitted by RCIC or for low power operation at the beginning of the exposure period
- All remaining events were left at their nominal failure probabilities
- Cut-set probability calculation truncation was set at 1E-13

Analysis of Dominant Cut-sets/Sequences

Based on the above assumptions, the ΔCDF was calculated at 8.3E-7. The dominant internal event sequences involved:

1. Loss of condenser heat sink with a failure of high pressure injection and a failure to successfully depressurize the reactor.
2. Loss of main feedwater with a failure of high pressure injection and a failure to successfully depressurize the reactor.
3. Loss of off site power with a failure of high and low pressure injection and a failure of alternate low pressure injection.

Uncertainty and Sensitivity Analysis

The failure to depressurize the reactor is the dominant basic event with a base case probability of 5E-4. If the available time is changed from nominal to extra time the conditional probability is 5E-5. The effect of this modification is to increase the importance of LOOP events and results in an overall lower change of ΔCDF of 2.5E-7. Although, some additional flow may be available to allow more time to depressurize, the SRA concluded that the increase in system and operator dependencies would offset the benefit of additional time. Exposure time is well established therefore no additional sensitivity analysis was conducted.

Contributions and Risk Estimate from External Events

The SRA evaluated the external events contribution using the External Initiators Risk-Informed Inspection Notebook for Limerick Units 1 and 2 (Revision 1). Evaluating that RCIC failed for a 30 day period, the SRA determined that the external events contribution was in the low 1E-6 range. The dominant scenarios were for fires in Fire Group A (table 3.3.1), Fire Group B (table 3.3.2) and Fire Group N (table 3.3.14). The specific dominant sequences were:

1. Fire in Fire Group A with a failure of high pressure injection and a failure to successfully depressurize the reactor.
2. Fire in Fire Group B with a failure of high pressure injection and a failure to successfully depressurize the reactor.
3. Fire in Fire Group N with a failure of control room habitability, shutdown path A and shutdown path B.

The failure to depressurize the reactor is the dominant basic event. A review of the fire scenarios determined that no modification for the mitigation or recovery credit was warranted. Additionally, the exposure period of 3-30 days does not add additional conservatism to the outcome since the exposure period was 30 days.

The licensee has updated their risk analysis with respect to flooding. As a result the information provided in the notebook has become outdated. The licensee's flooding

analysis is contained in their internal events assessment. The SRA reviewed the contribution from flooding and found them to be negligible.

The contribution from seismic event was considered to be low, in the 1E-8 range.

Potential Risk Contribution Due to LERF

The SRAs used IMC 0609 Appendix H, "Containment Integrity Significance Determination Process," and NUREG-1765, "Basis Document for Large Early Release Frequency (LERF) SDP," to determine the potential risk contribution due to LERF. Applying the factors for the Phase 2 SDP notebook, for a Mk II containment, resulted in a potentially substantial safety significance (Yellow) for ΔLERF. Since these results are highly conservative, the SRA also reviewed the licensee model which indicated a ΔLERF of 6.3E-9. The SRA reviewed these results and found them to be reasonable.

The finding also presented the possibility for a release due to containment bypass. Specifically, the bypass would result from fission products released to the suppression pool, then pumped through RCIC to the hotwell after swap-over to suppression pool from the condensate storage tank. The SRA also conducted a qualitative assessment of this condition. Thermo-hydraulic modeling performed by the licensee indicated that for the given conditions, the predicted core damage would be relatively small with almost 100% of the cesium and iodine being retained in the reactor vessel. Any release to the suppression pool would have some degree of scrubbing. The transport rate of fission products out of the suppression pool would be small considering the large size of the pool (~1 million gallons) vs the flow rate (~500gpm). The volume of the condensate storage tank available prior to swap over would provide ~ 2.5 hrs of flow also delaying onset of fission product transfer to the hotwell. As a result the SRA concluded that LERF contributions from this path are small given that any release out of the vessel to the hotwell would be small, it would occur several hours after core damage and the transport rate would be low.

Licensee's Risk Evaluation

The licensee evaluated 3 separate cases. Specifically:

Case 1:

This was an internal events assessment for a RCIC failure given a 30 day exposure with no other adjustment made. The ΔCDF was 6E-7 with good sequence alignment with the SPAR results. One difference noted was that the licensee's initiating event frequency for loss of condenser heat sink was approximately half that of the SPAR value. Other dominant probabilities and frequencies were reasonably close.

Case 2:

This was an internal events assessment for a RCIC failure given a 30 day exposure with adjustments made to the HEP for manual depressurization of the reactor. Specifically, the licensee evaluated the impact on available time given that approximately 56 gpm of RCIC flow combined with maximizing CRD (~113 gpm) and initiation of SLC (86 gpm for 45 minutes) would be available. In addition makeup to the CST from the RWST would be credited, with some limits

on loss of off-site power sequences. Given these adjustments the licensee estimated that the time available would be extended from ~40 minutes to 84 minutes. Applying this to the relevant sequences and applying a success of 90% for the dependent equipment (RCIC, initiation of SLC, maximizing CRD, and refilling the CST) the HEP was modified from 3.6E-4 to 1.2E-4 (66% reduction). The resulting ΔCDF was 2.83E-7.

Case 3:

This was an internal events condition assessment for a RCIC failure given a 30 day exposure with adjustments made to account for lower decay heat loading, which would account for more favorable success criteria, in the early stage of the exposure period. This resulted in a ΔCDP of 1.8E-7.

External Events

The licensee estimated the contribution from external events of ~7E-7.

Summary of Licensee Assessment

An evaluation of the licensee's assessments determined that Case 1 is the most accurate representation of the actual conditions. The change in risk, accounting for both internal and external events, would produce a ΔCDF of low E-6. Although some additional time would be allotted due to some RCIC flow in case 2, the resulting equipment and operator dependencies would likely not have a significant impact on the depressurization HEP. Case 3, is not considered since the SDP evaluates nominal conditions.

The NRC total estimated ΔCDF is Low E-6/yr (WHITE).

The NRC total estimated ΔLERF is 3.6E-9/yr (GREEN).

Cross-Cutting Aspect

The inspectors determined that this issue has a cross-cutting aspect in the area of Human Performance, Resources, because Exelon did not ensure long term plant safety by maintaining design margins and minimizing preventive maintenance deferrals [H.2.(a)] Specifically, design limitations of the HV-041-209 A & B valves were not adequately captured in the procedural guidance, which contributed to the operators continuing on in the procedure for securing the FW long path recirculation line up when problems with the HV-041-210 valve were encountered. Since valves HV-041-209 A&B are credited as PCIVs, the operators' decision to continue was reasonable. Operation's staff requested support from Limerick Engineering staff who also supported the decision to proceed. This indicates a lack of understanding of the design features of safety-related plant equipment and is indicative of current performance. Additionally preventive maintenance activities which may have prevented this issue were deferred without an appropriate evaluation. This was also considered to be indicative of current performance.

Enforcement.

A. Technical Specification (TS) 6.8, "Procedures and Programs," Section 6.8.1, requires that written procedures be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide (RG) 1.33, Revision 2, February 1978.

RG 1.33, Revision 2, 1978, Appendix A, Section 4.0, "Procedures for Startup, Operation, and Shutdown of Safety-Related BWR Systems," states, in part, that instructions should be prepared for the feedwater system.

Limerick Generating Station procedures GP-2, "Normal Plant Startup," Rev. 141 and S06.5.A, "Long Path Recirculation and Feedwater System Flushing," Rev. 35., contain the direction and requirements for securing the feedwater long-path flush, which includes direction for operating the PCIVs HV-041-209A and HV-041-209B.

Contrary to the above, on April 23, 2011, Limerick Generating Station implemented a procedure to secure feedwater long path flushing that did not provide adequate direction for operating PCIVs HV-041-209A and HV-041-209B. Specifically, when licensee operators could not secure the flush by closing the HV-041-210 valve, they attempted to secure it by closing the upstream HV-041-209A and HV-041-209B valves, even though they were subject to differential pressure as a result of the 210 valve not being fully seated. Procedures GP-2, "Normal Plant Startup," Rev. 141 and S06.5.A, "Long Path Recirculation and Feedwater System Flushing," Rev. 35, did not prohibit or otherwise instruct the operators that these valves are not designed to be closed at differential pressure. As a result, the HV-041-209B valve did not fully seat. This condition, together with the failure of the licensee to fully close the HV-041-210 valve, allowed leakage back to the main condenser at a flow rate of approximately 570 gpm between April 23, 2011, and May 23, 2011.

B. TS Limiting Condition for Operation 3.7.3 requires, in part, that the RCIC system be operable in Modes 1, 2, and 3. With RCIC inoperable, operation may continue for 14 days, provided the HPCI system is operable. Otherwise, be in at least hot shutdown within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 psig within the following 24 hours.

TS Limiting Condition for Operation 3.6.3, "Primary Containment Isolation Valves," requires, in part, that each PCIV be operable in Modes 1, 2, and 3. With one or more PCIVs inoperable, at least one isolation valve must be maintained operable in each affected penetration that is open and within 4 hours either the inoperable valve(s) must be restored, to operable status or the affected penetration must be isolated. Otherwise, be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

Contrary to the above, between April 23, 2011, and May 23, 2011, Limerick Generating Station Unit 2 operated in Modes 1, 2, and 3 with a primary containment isolation valve (HV-041-209B) inoperable and the affected penetration unisolated. Additionally, because neither the HV-041-209B nor the HV-041-210 valve were fully seated, Limerick Generating Station Unit 2 operated for a period of time greater than 14 days in Modes 1, 2, and 3 with the RCIC system inoperable and the plant was not taken to hot shutdown within the next 12 hours and reactor steam dome pressure was not reduced to less than or equal to 150 psig within the following 24 hours. **(AV 05000353/2011-04-01, Failure of FW MOVs Resulting in RCIC and PCIV Inoperability for Longer than Allowed by Technical Specifications).**

.3 <u>Annual Sample: Limerick Second Quarter 2011 Multiple Scrams</u>

a. Inspection Scope

The inspectors performed an in-depth review of Exelon's CAP investigations for the three scrams that occurred in May and June 2011. The IRs reviewed included:

- 1223645, U2 Automatic Scram During Restoration of Control Valve #3 (May 29)
- 1222301, U2 Manual Scram due to 2A and 2B Recirculation Pump Trip (May 30)
- 1224283, U1 Automatic Scram due to Main Turbine Trip (June 3)

The inspectors reviewed each root cause report or apparent cause report to assess the causes identified by Exelon and ensure corrective actions were adequate for the identified causes. Due to the close timing of the scrams to each other, the inspectors also reviewed the three events for potential common causes.

b. Findings and Observations

The inspectors did not identify any commonality between the three events. Each event was determined to be separate and unique. However, one minor issue and two findings of significance were identified.

The first scram, IR 1223645, was the result of an inadequate fill and vent activity during restoration of a turbine control valve. This resulted in a void in the EHC system, which actuated a low EHC pressure switch and resulted in a Unit 2 reactor scram from 75 percent power. The full event details were discussed by Exelon in LER 05000353/2011-004-00. The inspectors identified one finding for Exelon's failure to provide adequate fill and vent restoration instructions. The enforcement aspects of this finding, along with the inspectors' review of Exelon's LER, are discussed in Section 4OA3.3 of this report.

The second scram, IR 1222301, was a Unit 2 manual scram initiated by control room operators as the result of a dual recirculation pump trip. The plant was in the Startup mode at the time (zero percent power). The recirculation pumps tripped due to the failure of the main turbine first stage pressure trip unit. The full event details were discussed by Exelon in LER 05000353/2011-005-00. The inspectors identified a minor performance deficiency regarding the performance of preventive maintenance for the trip unit. This performance deficiency, along with the inspectors' review of the LER, is discussed in Section 4OA3.4 of this report.

The third scram, IR 1224283, was caused by improper test equipment being used during a surveillance test of turbine trip circuitry. The test equipment caused the main turbine high reactor water level trip relay to inadvertently energize, which resulted in a main turbine trip and a Unit 1 reactor scram from 100 percent power. The full event details were discussed by Exelon in LER 05000352/2011-002-00. The inspectors identified one finding regarding Exelon's failure to assess the potential impacts of test equipment on turbine trip circuitry. The enforcement aspects of this finding, along with the inspectors' review of Exelon's LER, are discussed in Section 4OA3.6 of this report.

.4 Annual Sample: Unit 1 High Pressure Coolant Injection (HPCI) Control Valve Failure

a. Inspection Scope

The inspectors performed an in-depth review of Exelon's equipment apparent cause evaluation (EACE) associated with IR 1231487, "Unit 1 HPCI Turbine Control Valve Failure." Specifically, the HPCI control valve number one poppet was found to be binding, causing the turbine control valve to not fully seat. Exelon determined that the Unit 1 HPCI system safety function could not be assured with this condition. (See Section 4OA3.7 for the inspectors' review of Exelon's LER, including a more detailed event description.)

The inspectors reviewed Exelon's EACE to assess the causes identified by Exelon, ensure corrective actions were adequate for the identified causes, and verify that extent of condition was adequately addressed.

b. Findings and Observations

No findings were identified.

Exelon determined the number one poppet was binding due to a failed anti-rotation pin between the control valve lifting beam and the number one poppet stem. The failed pin allowed the number one poppet valve assembly to rotate, which caused accelerated wear of the valve assembly parts. Over time, this led to intermittent binding of the poppet valve and eventually fatigue failure of the valve stem.

Exelon attributed the broken pin to an inadequate inspection procedure, because Limerick's HPCI maintenance procedure did not require technicians to conduct a visual inspection of the pin. Rather, the procedure tested for functionality of the pin by directing technicians to attempt to rotate the valve assembly. As such, the procedure would not identify a degraded pin until it completely failed. Exelon instituted several corrective actions including revising the inspection procedure, increasing the frequency of inspections, and performing an extent of condition inspection on Unit 2.

The inspectors reviewed Exelon's EACE and corrective actions and did not identify any performance deficiencies. Although Exelon's procedure was not adequate to detect degradation of the pin before failure, the inspectors confirmed that the procedure was consistent with vendor guidance and accepted industry standards. Additionally, the frequency of Exelon's HPCI inspection was consistent with vendor guidance and accepted industry standards. The inspectors verified that Exelon appropriately shared the information regarding their HPCI control valve failure with the rest of the industry. The inspectors determined that Exelon's corrective actions were thorough and appropriate to address the identified condition.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 - 9 samples)

.1 Plant Events (3 samples)

a. Inspection Scope

For the plant events listed below, the inspectors reviewed and/or observed plant parameters, reviewed personnel performance, and evaluated performance of mitigating systems. The inspectors communicated the plant events to appropriate regional personnel, and compared the event details with criteria contained in IMC 0309, "Reactive Inspection Decision Basis for Reactors," for consideration of potential reactive inspection activities. As applicable, the inspectors verified that Exelon made appropriate emergency classification assessments and properly reported the event in accordance

with 10 CFR Parts 50.72 and 50.73. The inspectors reviewed Exelon's follow-up actions related to the events to assure that Exelon implemented appropriate corrective actions commensurate with their safety significance.

- IR 1239365, EDG D23 failure to start on July 13, 2011 during surveillance testing
- IR 1254561, Unusual Event Declared Due to Earthquake on August 23
- IR 1269903, Unusual Event Declared Due to Sodium Hypochlorite Spill on September 29

b. Findings

No findings were identified.

.2 (Closed) LER 05000352/2011-001-00: 1B Reactor Enclosure Recirculation System Charcoal Sample Analysis Results Exceeded TS Limit

On May 9, 2011, Exelon received laboratory results for a 1B Reactor Enclosure Recirculation System (RERS) charcoal sample that had been taken on April 15, 2011. The results indicated that the methyl iodide penetration for the charcoal sample was 7.25 percent. This exceeded the TS required limit of 2.5 percent. Exelon declared the 1B RERS subsystem inoperable on May 9 and entered TS 3.6.5.4 Action 'a', which required Exelon to restore the inoperable RERS subsystem within seven days. Exelon replaced the 1B charcoal bed and returned the subsystem to operable status on May 14, 2011. Because the charcoal sample was taken on April 15, Exelon determined that the 1B RERS subsystem had been inoperable from April 15 until May 14, 2011. This period exceeded the TS allowed outage time of seven days, and as such was reportable under 10CFR50.73(a)(2)(i)(B) as a condition prohibited by TS. Limerick submitted LER 05000352/2011-001-00 to document this condition. The issue was also entered into Exelon's CAP as IRs 1214119, 1250820, and 1256023.

The inspectors reviewed LER 05000352/2011-001 and determined that there was no performance deficiency associated with this issue. Specifically, the Limerick TS allowed up to 31 days to receive the results of the charcoal sample, and Exelon received the results within 24 days. Additionally, Limerick entered TS 3.6.5.4 immediately upon receiving the failed test results and replaced the charcoal within the seven day allowed outage time. Therefore, this LER is closed.

.3 (Closed) LER 05000353/2011-004-00: Automatic Actuation of the Reactor Protection System Due to Actuation of Turbine Control Valve Closure Logic

a. Inspection Scope

On May 29, 2011, Limerick Unit 2 experienced an automatic scram from 75 percent power during restoration of the number three turbine control valve (CV #3) from maintenance. The control valve had been taken out of service on May 28, after it had failed to re-open during performance of quarterly valve testing. Exelon placed the 'A1' RPS channel in the tripped condition to satisfy the requirements of TS 3.3.1 and commenced troubleshooting. Exelon replaced the fast acting solenoid valve and shutoff valve for CV #3, and upon completion of the maintenance, began restoring EHC oil to CV #3. As operators opened the EHC oil supply valve to CV #3, the EHC pressure switch for control valve number one actuated. This inserted a 'B1' half scram signal into RPS, which completed the logic for a turbine trip and reactor scram.

Exelon performed a root cause evaluation for this event under IR 1223645, and the inspectors reviewed Exelon's root cause and corrective actions as part of an annual problem identification and resolution (PI&R) sample (see Section 4OA2 for more details.) One finding of significance was identified and is described below. This LER is closed.

b. Findings

Introduction. A Green self revealing finding was identified because Exelon did not provide adequate instructions for restoration of the Limerick Unit 2 number three turbine control valve (CV #3) following maintenance. During a fill and vent activity of the EHC supply line for CV #3, a void in the system piping resulted in a low pressure condition at the next-in-series control valve, CV #1. The pressure drop actuated a relayed emergency trip system (RETS) pressure switch, generating a RPS 'B' side half scram signal. Combined with an 'A' side half scram signal that was previously inserted into RPS due to the CV #3 being maintained closed, an automatic reactor scram resulted.

Description. On May 28, 2011, during quarterly turbine valve testing on Limerick Unit 2, CV #3 failed to reopen when the test push button was released. Operators declared CV #3 inoperable and inserted an 'A1' half scram into RPS in accordance with Technical Specification (TS) 3.3.1, Action 'b'. Exelon's troubleshooting identified that the CV #3 Shutoff valve and Fast Acting Solenoid valve needed to be replaced. WO C0238390 was developed to perform the repair, which required isolating CV #3 from the EHC system by closing EHC isolation valves 031-2013 and 031-2014. The work was completed on May 29, and the station began restoring the system in accordance with the WO instructions.

The restoration instructions contained in the WO cautioned that reopening the EHC isolation valves could result in an EHC pressure fluctuation. The WO specified that both EHC isolation valves were to be opened "very slowly," but did not contain any other specific guidance to ensure a potential void in the system would not cause pressure fluctuations. When the equipment operator opened valve 031-2013 from 20 percent to 30 percent open, Limerick Unit 2 automatically scrammed. Exelon's review of RPS data indicated that a pressure drop occurred in the EHC RETS supply line to the next valve in series on the RETS supply header, CV #1. This caused the RETS pressure switch on CV #1 to trip, which inserted a 'B1' half scram signal into RPS. Combined with the 'A1' half scram that had previously been manually inserted per TS due to CV #3 being closed, this resulted in a full scram signal and an automatic reactor scram.

Exelon conducted a root cause investigation (IR 1221783) and confirmed that the cause of the event was an unrecognized void in the CV #3 RETS supply line, which caused a perturbation at the CV #1 RETS pressure switch during restoration. The station identified several contributing causes to the event; namely that they had failed to recognize the risk of the fill and vent restoration activity, and they did not conduct a thorough technical review of the restoration plan. Exelon's review of industry operating experience identified that other Exelon plants had developed detailed procedural guidance on how to restore turbine control valves from maintenance. For instance, three other Exelon plants had procedures that directed operators to:

- Remove the half scram using a test box
- Cycle above seat drains after holding open for 45 minutes
- Slowly open the RETS and Fast Acting Solenoid valves

Had Limerick recognized the risk of the fill and vent restoration activity, and provided technical reviews of the restoration plan, the station would likely have identified the need for a more detailed restoration procedure, beyond the WO C0238390 instructions to open the valves "very slowly." Exelon's root cause investigation resulted in several corrective actions, including:

- Developing and implementing a procedure to provide specific direction for restoration steps for turbine control valves
- Revising Limerick work control procedures to provide specific guidance on how to properly assess the operational risk for emergent work issues
- Further investigating the human performance aspects of this event by including it as an example in the station's Human Performance Root Cause Investigation (IR 1213692), which focused on the trend of Limerick personnel proceeding towards task completion assuming too high a level of risk

Analysis. The inspectors determined that Exelon's failure to provide adequate instructions for restoration of CV #3 from maintenance was a performance deficiency. The issue was more than minor because it was associated with the Procedure Quality attribute of the Initiating Events cornerstone, and it affected the cornerstone objective of limiting the likelihood of events that upset plant stability. Specifically, on May 29, 2011, Limerick Unit 2 experienced an automatic reactor scram during restoration of turbine CV #3 from maintenance. The restoration instructions in the WO did not provide sufficient guidance to address the presence of a large air void in the EHC system that had the potential to cause EHC pressure fluctuations and result in a reactor scram. The finding was determined to be of very low safety significance (Green) in accordance with IMC 0609 Attachment 4, "Phase 1 - Initial Screen and Characterization of Findings," because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available.

The inspectors determined that this finding had a cross-cutting aspect in the area of Human Performance, Decision-Making, because Exelon did not use a systematic process to make a risk-significant decision when faced with uncertain or unexpected plant conditions. Specifically, Exelon did not recognize the risk of the CV #3 EHC fill and vent restoration activity, an evolution which is infrequently performed at power, and they failed to conduct a thorough technical review of the restoration plan or consider relevant corporate operating experience to provided adequate instructions to mitigate the risk of a plant transient. [H.1.(a)]

Enforcement. Enforcement action does not apply because the performance deficiency did not involve a violation of regulatory requirements. Specifically, Exelon's failure to provide adequate restoration instructions for CV #3 did not impact the ability of the turbine control valves or EHC RETS pressure switches to perform their safety functions. Because the finding does not involve a violation of regulatory requirements, was determined to be of very low safety significance, and was entered into the licensee's Corrective Action Program as IR 1221783, it is characterized as a finding. **(FIN 05000353/2011004-02, Failure to Provide Adequate Restoration Instructions for Turbine Control Valve Online Maintenance.)**

.4 (Closed) LER 05000353/2011-005-00: Manual Actuation of the Reactor Protection System Due to Both Recirculation Pumps Trip

On May 30, 2011, Limerick Unit 2 was in Operational Condition 2 (Startup) in support of a shutdown to perform maintenance on a main turbine control valve when both recirculation pumps tripped. Operators entered OT-112, "Recirculation Pump Trip" and inserted a manual scram as required by the procedure. Exelon determined the cause of this event was a failure of the main turbine first stage pressure trip unit. When this trip unit failed, it activated the logic which tripped the recirculation pump trip breakers as designed. This logic sequence is bypassed when power is greater than 29.5 percent, so this failure mechanism would not be present when the reactor is at power. Limerick submitted LER 05000353/2011-005-00 to document this condition. The issue was also entered into Exelon's CAP as IR 1222301.

The inspectors performed an in-depth review of this scram as part of an annual PI&R sample (see Section 4OA2 for more details). The inspectors identified a minor performance deficiency (PD) associated with the performance of preventive maintenance for the trip unit. Specifically, Exelon's preventive maintenance template recommended replacing this type of Rosemont trip unit every 10 years, but the trip unit that failed had been installed for 25 years. Exelon had identified the need to replace the trip unit, and other similar units, and had developed a replacement schedule in September 2010. However, the trip unit was not replaced in time to prevent its failure on May 3, 2011.

The inspectors determined that Exelon's failure to replace the trip unit before it failed was a PD. The PD was determined to be minor in accordance with NRC IMC 0612 Appendix B, "Issue Screening." Although the PD was associated with the Equipment Performance attribute of the Initiating Events cornerstone, the inspectors determined that the issue did not impact the cornerstone objective. Specifically, the plant was in the Startup mode (but not yet critical) with all rods inserted at the time of the trip unit failure. Operators responded appropriately in accordance with the plant procedure to the indications of the recirculation pump trip and manually inserted a scram. Although the event is reportable, it did not result in a plant transient, power excursion, upset plant stability, or challenge plant mitigating systems. Thus, the cornerstone objective was not impacted in this case and the issue was determined to be minor.

Because the PD was determined to be minor, it is not subject to enforcement action in accordance with the Enforcement Policy. However, Exelon entered the issue into their CAP (IR1222301), developed, and is implementing corrective actions to address this issue. This LER is closed.

.5 (Closed) Licensee Event Report 05000353/2011-003-00: Condition Prohibited by Technical Specifications due to Inoperable Reactor Core Isolation Cooling

a. Inspection Scope

On April 23, 2011, after restarting from a scheduled refueling outage for Unit 2, Limerick identified that its electrical output was less than it should have been. On May 23, 2011, while troubleshooting this lost electrical capacity, Limerick staff identified valve seat leakage on two FW long path flush MOVs. The 16-inch globe valves (HV-041-209B and HV-041-210) were found to be off their closed seat and allowing 570 gpm leak-by from the 'B' FW header to the main condenser. Limerick operators closed the valves, and main generator load increased by approximately 20 MWe. Through its subsequent investigation, Limerick staff determined that the valves had failed to fully close when long path flushing was secured on April 22, 2011.

Exelon submitted LER 05000353/2011-003 to document this condition. The issue was also entered into Exelon's CAP as IR 1219476. The inspectors reviewed this LER and identified one performance deficiency, described in Section 4OA2.2 of this report. This LER is closed.

b. Findings

Finding is described in Section 4OA2.2 of this report.

.6 (Closed) Licensee Event Report 05000352/2011-002-00: Automatic Actuation of the Reactor Protection System Due to a Main Turbine Trip

a. Inspection Scope

On June 3, 2011, Limerick Unit 1 received an automatic actuation of the reactor protection system due to a main turbine trip during surveillance testing. Exelon technicians performed surveillance test ST-2-042-634-1, "Feedwater/Main Turbine Trip System Actuation - Reactor Vessel Water Level - High Level 8; Channel B Functional Test". During the test, the main turbine high reactor water level trip relay inadvertently energized, which caused the main turbine to trip, which then resulted in an automatic reactor scram.

Exelon performed a root cause investigation for this event under IR 1224283. The inspectors reviewed the licensee's root cause and corrective actions as part of an annual PI&R sample (see Section 4OA2.3 for more details). The inspectors identified one finding, described below. This LER is closed.

b. Findings

Introduction. A Green, self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," occurred when Exelon did not adequately assess the potential impacts of maintenance and test equipment (M&TE) on turbine trip circuitry which resulted in an automatic reactor scram of Unit 1 when the main turbine high reactor water level trip relay inadvertently energized during a surveillance test.

Description. On June 3, 2011, Exelon technicians performed surveillance test ST-2-042-634-1, "Feedwater/Main Turbine Trip System Actuation - Reactor Vessel Water Level - High Level 8; Channel B Functional Test." During the test, the main turbine high reactor water level trip relay inadvertently energized, which caused the main turbine to trip, which then resulted in an automatic reactor scram.

ST-2-042-634-1 is a quarterly surveillance, designed to verify proper operation of the DFWLCS which initiates a turbine trip on high reactor level. The DFWLCS has a "one out of two – taken twice" logic to energize the trip relay. Thus, each channel is tested separately to eliminate the possibility of inadvertent actuation. As an additional precaution, the surveillance procedure contains steps for the technician to verify the other channels are free of closed trip contacts prior to beginning the test. Exelon used a Simpson 260 VOM to perform this verification by demonstrating a nominal voltage difference between each side of the contact and station ground. During this verification step, Exelon inadvertently established a direct current loop from station ground, to the floating battery ground from the 125V power supply, to the trip circuit. This completed

the circuit, energized the main turbine high reactor water level trip relay, which tripped the main turbine and caused the reactor to scram.

Exelon performed a root cause analysis of this event (IR 1224283) and determined the Simpson VOM had low input impedance and using this type of M&TE on such a sensitive circuit allowed a ground loop of enough magnitude to form and cause an inadvertent actuation. This had not happened during previous surveillance tests using this equipment because the ground parameters continuously vary. Both the potential difference between station ground and battery ground and the actual station ground magnitude and location change, and there needs to be a specific combination present to replicate the trip condition found on June 3.

This vulnerability existed since 2004 when Exelon implemented the DFWLCS modification without a review of potential interference from the M&TE used to perform surveillances. Exelon had an additional opportunity to recognize the potential M&TE effects during multiple revisions of the surveillance procedure, including a revision in 2004 which required the use of a digital voltmeter instead of the Simpson VOM. There was another revision in 2006 which did not contain a thorough review of M&TE effects. This revision changed the M&TE requirements back to the VOM due to a modification to the station ground detection system.

Analysis. Exelon's failure to assess the potential impacts of test equipment on turbine trip circuitry is a performance deficiency that was reasonably within Exelon's ability to foresee and prevent. The inspectors determined that the performance deficiency was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," because it was associated with the Equipment Performance attribute of the Initiating Events cornerstone and affected the objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operation. Specifically, by not considering the impact of M&TE during multiple revisions of the surveillance procedure, Exelon failed to recognize a vulnerability which resulted in a plant transient. In accordance with IMC 0609 Attachment 4, "Phase 1 - Initial Screen and Characterization of Findings," the finding was determined to be of very low safety significance (Green) because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available.

The inspectors determined that this performance deficiency did not reflect current performance, as the last revision to the surveillance procedure that affected M&TE requirements was greater than three years ago. As a result, the inspectors did not assign a cross-cutting aspect to this finding.

Enforcement. 10 CFR 50 Appendix B, Criterion XI, "Test Control," states, in part, that test procedures shall include provisions for assuring that adequate test instrumentation is available and used. Contrary to the above, Exelon failed to consider the potential adverse effects of M&TE used in a Technical Specification Surveillance would have on the logic system being tested and which resulted in an automatic scram on June 3, 2011, of Unit 1. Because this violation was of very low safety significance and it was entered into Exelon's corrective action program as IR 1224283, this violation is being treated as an NCV, consistent with the Enforcement Policy. **(NCV 05000352/2011-04-03, Test Equipment Interference Resulting in Reactor Scram).**

.7 (Closed) Licensee Event Report 05000352/2011-003-00: Condition That Could Have Prevented the Fulfillment of the High Pressure Coolant Injection System Safety Function

On June 19, 2011, Limerick removed the Unit 1 HPCI system from service for a planned system outage window. On June 22, Operators performed a scheduled ST of the Unit 1 HPCI pump. The ST was successfully completed, and all performance criteria were met. However, upon securing the auxiliary oil pump, operators noticed that the HPCI control valve did not return to the expected position of full closed. Subsequent inspection identified that one of five poppet valves in the control valve was binding and preventing the valve from fully closing. The excessive binding also caused the poppet's stem to crack. Exelon determined that the Unit 1 HPCI system safety function could not be assured with this condition. Exelon initiated repairs to the control valve, and returned the HPCI system to operable status on June 27, 2011. The Unit 1 HPCI system was out of service for eight days, less than its TS AOT of 14 days.

To provide for a detailed review of the failure mode and extent of condition, the inspectors reviewed this HPCI failure as a PI&R sample under Inspection Procedure 71152. No performance deficiencies were identified. For additional information, see section 4OA2.4 of this report. This LER is closed.

4OA5 Other Activities

.1 (Closed) NRC Temporary Instruction 2515/177 - Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems

a. Inspection Scope

The inspectors performed the inspection in accordance with Temporary Instruction (TI) 2515/177, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems." The NRC staff developed TI 2515/177 to support the NRC's confirmatory review of licensee responses to NRC Generic Letter (GL) 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems." Based on a review of Exelon's GL 2008-01 response letters, the Office of Nuclear Reactor Regulation staff provided additional plant specific guidance on inspection scope to the regional inspectors. The inspectors used this inspection guidance along with the TI to verify that Exelon implemented or was in the process of acceptably implementing the commitments, modifications, and programmatically controlled actions described in their GL 2008-01 response. The inspectors verified that the plant-specific information (including licensing basis documents and design information) was consistent with the information that Exelon submitted to the NRC in response to GL 2008-01.

The inspectors reviewed a sample of isometric drawings, and piping and instrument diagrams, and conducted selected system piping walkdowns to verify that Exelon's drawings reflected the subject system configurations and UFSAR descriptions. Specifically, the inspectors verified the following related to a sample of isometric drawings for the HPCI, core spray, and RHR systems:

- High point vents were identified
- High points that did not have vents were recognized and evaluated with respect to their potential for gas buildup
- Other areas where gas could accumulate and potentially impact subject system operability, such as orifices in horizontal pipes, isolated branch lines, HXs,

improperly sloped piping, and under closed valves, were acceptably evaluated in engineering reviews or had ultrasonic testing points which would reasonably detect void formation

- For piping segments reviewed, branch lines and fittings were clearly shown

The inspectors conducted walkdowns of portions of the above systems to evaluate the acceptability of Exelon's drawings utilized during their review of GL 2008-01. The inspectors verified that Exelon conducted walkdowns of the applicable systems to confirm that the combination of system orientation, vents, instructions and procedures, tests, and training would ensure that each system was sufficiently full of water to ensure operability. The inspectors reviewed Exelon's methodology used to determine system piping high points, identification of negative sloped piping, and calculations of void sizes based on ultrasonic testing (UT) equipment readings, to ensure the methods were reasonable. The inspectors also reviewed engineering analyses associated with the development of acceptance criteria for as-found voids. The review included engineering assumptions for void transport and acceptability of void fractions at the suction and discharge piping of the applicable system pumps. In addition, the inspectors verified that Exelon included all emergency core cooling systems, along with supporting systems, within scope of the GL.

The inspectors reviewed a sample of Exelon's procedures used for filling and venting the associated GL 2008-01 systems to verify that the procedures were effective in venting or reducing voiding to acceptable levels. The inspectors verified that Exelon's venting surveillance frequencies were consistent with Limerick's Technical Specifications and associated bases, and the UFSAR. The inspectors reviewed a sample of system venting surveillance results to ensure proper implementation of the surveillance program.

The inspectors reviewed CAP documents to verify that selected actions described in Exelon's nine-month and supplemental submittals were acceptably documented including completed actions, and implementation schedules for incomplete actions. The inspectors also verified that the NRC commitments in Exelon's submittals were included in the CAP. The inspectors specifically verified the installation of hardware vents, located in the core spray, high pressure coolant injection, and RHR discharge piping, as committed to in Exelon's GL response. Additionally, the inspectors reviewed evaluations and corrective actions for various issues Exelon identified during their GL 2008-01 review. The inspectors performed this review to ensure Exelon appropriately evaluated and adequately addressed any gas voiding concerns including the evaluation of operability for gas voids discovered in the field. Finally, the inspectors reviewed Exelon's training associated with gas accumulation to assess if appropriate training had been provided to the operations and engineering support staff to ensure appropriate awareness of the effects of gas voiding. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified. This completes the inspection requirements for TI 2515/177.

.2 Independent Spent Fuel Storage Installation (60855, 60855.1 – 2 samples)

a. Inspection Scope

The inspectors observed activities associated with the loading of a dry cask canister to ensure that Technical Specifications were met, equipment operated properly, and personnel were properly trained. The inspectors reviewed documents and records associated with the operation of the Limerick Generating Station Independent Spent Fuel Storage Installation (ISFSI). The inspectors met with reactor engineering personnel and reviewed the fuel selection process and associated documentation. The video recording of the fuel assemblies placed into the canister was reviewed to ensure that each fuel assembly was placed into the proper location. The inspectors observed work activities on the refuel floor associated with the fuel selection and loading of fuel assemblies into the cask. The inspectors also observed the setup and operation of the of the vacuum drying and helium backfilling systems. The inspectors reviewed dry cask loading records and met with representatives associated with the radiation protection, as low as reasonably achievable, and training groups. The inspectors went to the ISFSI pad to inspect the horizontal storage modules (HSMs) on the pad and observe the operation of the temperature monitoring system. The inspectors observed the lifting of the transfer cask and the loaded dry shielded canister (DSC) out of the spent fuel pool and the downloading of the transfer cask and the processed DSC from the refuel floor down to the transport trailer (TT) in the railroad bay. The inspectors observed the insertion of the DSC into the HSM.

The inspectors reviewed routine operations and monitoring of the ISFSI. The inspectors walked down the ISFSI to evaluate its material condition, performed independent dose rate measurements of the storage modules, and confirmed that module temperatures were within the required limits. The inspectors also reviewed plant equipment operator logs for ISFSI surveillances and environmental /radiation protection dosimetry (ISFSI-specific) records. Radiological control activities for the ISFSI were evaluated against 10 CFR Part 20, ISFSI Technical Specifications, and the licensee's procedures.

b. Findings and observations

No findings were identified.

The inspectors observed the insertion of the DSC into the HSM. After the DSC was inserted, the TT could not be moved out of the way to install the HSM door because of a hydraulic pressure issue with the TT outriggers. The issue was caused by a faulty hydraulic pump. A ring gasket in the pump failed.

This issue was resolved two days later when a replacement pump was installed. During the period that the trailer was not able to be moved and the HSM door could not be put in place a high radiation area was established between the end of the trailer and the HSM opening. Radiation protection personnel controlled access to the area per procedure. Temporary shielding was installed to maintain dose ALARA while repairs and troubleshooting were conducted. The outriggers were able to be lifted after the replacement pump was installed and the TT was moved away from the HSM and the HSM door was moved into place. The inspectors responded to the event, observed Exelon's response to this event, and determined that Exelon's actions were appropriate.

4OA6 Meetings, Including Exit

On October 7, the inspectors presented the inspection results to Mr. William Maguire, Site Vice President, Limerick Generating Station, and other members of Exelon staff. The inspectors reviewed proprietary information, which was returned to Exelon at the

end of the inspection. The inspectors verified that no proprietary information is documented in this report.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by Exelon and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for being dispositioned as an NCV.

- 10 CFR 50.54(q) requires, in part, that a power reactor licensee follow an emergency plan that meets the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50. Contrary to the above, Exelon did not make timely notification when the emergency action level threshold was met for HU5, "Natural and Destructive Phenomena Affecting the Protected Area." Specifically, Exelon operators did not declare an Unusual Event within the required fifteen minutes of the earthquake felt onsite on August 23. The actual declaration was nine minutes late. At 1:51 PM, control room operators received a "Seismic Monitor System Recording Activated" alarm coincident with reports of seismic activity felt by station personnel. The seismic monitoring system at Limerick had previously been declared inoperable due to problems with its power supply, so operators began the compensatory measures which directed the operators to contact the United States Geological Survey to confirm the epicenter and magnitude of the seismic event prior to event classification. The United States Geological Survey has a call queue system to answer inquiries in an orderly manner, and Exelon was on hold until 2:11 PM. Exelon declared the Unusual Event at 2:15 PM and made all appropriate state and local notifications. Exelon entered the untimely event declaration into their corrective action program as IR 1254845. The inspectors determined that the finding was of very low safety significance (Green) in accordance with NRC IMC 0609, Appendix B, "Emergency Preparedness Significance Determination Process," Sheet 2, because this was related to an actual event implementation problem for a Notice of Unusual Event.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel:
W. Maguire, Site Vice President
P. Gardner, Plant Manager
R. Kreider, Director of Maintenance
P. Colgan, Director of Work Management
C. Gerdes, Security Manager
R. Dickinson, Director of Training
D. Merchant, Radiation Protection Manager
J. Hunter, Manager, Regulatory Assurance
R. Harding, Regulatory Assurance Engineer
R. Rhode, Licensed Operator Requalification Training Supervisor
D. Doran, Director of Engineering
J. Commiskey, Radiological Engineer
C. Rich, Director of Operations
K. Kemper, Manager Nuclear Oversight
O. Becker, Projects
G. Schweiser, Projects
S. Dixson, Projects
N. Harmon, Dosimetry Physicist
D. Wahl, Effluent REMP Engineer
G. Snyder, Reactor Engineer
C. Cooney, Chemistry/Radwaste Manager
J. Davies, Environmental Technician, Normandeau Associates
M. Gillin, Sr. Manager Engineering Systems
R. Higgins, Environmental Engineer
R. Lance, Chemistry Programs Supervisor
B. Landis, Senior Radiation Protection Technician
G. Sprissler, Chemistry Department
T. Johnston, Mechanical Design Engineering
S. Luessenhop, Cathodic Protection System Engineer
T. Vodges, Unit 1 Cooling Tower, System Engineer
B. Tracy, Buried Piping Program Manager
J. Berg, Systems Engineering Manager

Other:

M. Murphy, Inspector, Commonwealth of Pennsylvania

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened

5000353/2011004-01	AV	Failure of Feedwater MOV Resulting in RCIC Inoperability for Longer than Allowed by Technical Specifications (Section 4OA2.2)

Opened/Closed

05000352/2011-001-00	LER	1B Reactor Enclosure Recirculation System Charcoal Sample Analysis Results Exceeded TS Limit (Section 4OA3.2)
05000352/2011-002-00	LER	Automatic Actuation of the Reactor Protection System Due to a Main Turbine Trip (Section 4OA3.6)
05000352/2011-003-00	LER	Condition That Could Have Prevented the Fulfillment of the High Pressure Coolant Injection System Safety Function (Section 4OA3.7)
05000353/2011-003-00	LER	Condition Prohibited by Technical Specifications due to Inoperable Reactor Core Isolation Cooling (Section 4OA3.5)
05000353/2011-004-00	LER	Automatic Actuation of the Reactor Protection System Due To Actuation of Turbine Control Valve Closure Logic (Section 4OA3.3)
05000353/2011-005-00	LER	Manual Actuation of the Reactor Protection System Due to Both Recirculation Pumps Trip (Section 4OA3.4)
05000353/2011004-02	FIN	Failure to Provide Adequate Restoration Instructions for Turbine Control Valve Online Maintenance (Section 4OA3.3)
05000352/2011004-03	NCV	Test Equipment Interference Resulting in Reactor Scram (Section 4OA3.6)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
SE-9, Preparation for Severe Weather, Revision 29
S 12.7.C, Once Through Operation of ESW/RHRSW, Revision 14
OP-AA-108-111-1001, Severe Weather Guidelines, Revision 6

Miscellaneous
UFSAR 3.4, Water Level (Flood) Design
UFSAR 3.5, Missile Protection

Section 1R04: Equipment Alignment

Procedures
RT-6-000-913-0, Inspection of B.5.b Security Order Equipment, Revision 7

Miscellaneous
Guest Trolling Series Battery Charger Owner's Manual

Section 1R05: Fire Protection

Procedures
SE-8, Fire, Revision 43
ST-6-022-551-0, Fire Drill, Revision 10
OP-AA-201-003, Fire Drill Performance, Revision 12

Miscellaneous
Limerick Generating Station Pre-Fire Plan F-D-311B, Unit 1 D12 Diesel Generator Room and Fuel Oil and Lube Oil Tank Room, Rooms 311B and 312B (EL 217), Revision 7
F-A-323, Revision 8
F-A-433, Revision 12
F-A-336, 13.2 KV Switchgear Room 336, Revision 13
F-T-252, Unit 1 Reactor Feed Pump Lube Oil Area, Revision 7

F-R-108, Unit 1 RCIC Pump Room 108, Revision 10

Section 1R06: Flood Protection Measures

Issue Reports
1056715 1084627 1164290 1173112 1208879

Procedures
ER-AA-3003, Cable Condition Monitoring Program, Revision 2

Miscellaneous:
Information Notice 2002-12, Submerged Safety-Related Electrical Cables
Generic Letter 2007-01, Inaccessible or Underground Power Cable Failures that disable Accident Mitigation System or Cause Plant Transients

Section 1R07: Heat Sink Performance

System Health Reports

Emergency Service Water System Health Report, [89] WHITE; 4/1/11 to 6/30/11
RHRSW, System Health Report, [86.25] WHITE; 4/1/11 to 6/30/11
1st Quarter 2011, Limerick BPRWCP Program (Buried Piping) Health Report
2nd Quarter 2011, Limerick BPRWCP Program (Buried Piping) Health Report

Self Assessments

FASA Self Assessment Report: Limerick GL 89-13 Program and Ultimate Heat Sink Inspection, FASA, 1138044-03

Drawings & Sketches

LEAKS 4-29-11.pdf, ESW/RHRSW Piping Flaw History
SIMM-M-0012, Sheet 1, Revision 9; Limerick Generating Station Unit 1 and 2, PECO Energy Company; Emergence Service Water/RHR Service Water Overview, Revision 8, 5/29/01
Limerick Generating Station, Exelon Nuclear Corporation; P&ID Emergence Service Water (Unit 1 and 2 and Common), Sheet 1, 8031-M-11, Revision 70, 10/8/10
Limerick Generating Station, Exelon Nuclear Corporation; P&ID Emergence Service Water (Unit 1 and 2 and Common), Sheet 2, 8031-M-11, Revision 86, 10/8/10
Limerick Generating Station, Exelon Nuclear Corporation; P&ID Emergence Service Water (Unit 1 and 2 and Common), Sheet 3, 8031-M-11, Revision 54, 11/13/09
Limerick Generating Station, Exelon Nuclear Corporation; P&ID Emergence Service Water (Unit 2), Sheet 4, 8031-M-11, Revision 53, 8/31/11
Limerick Generating Station, Exelon Nuclear Corporation; P&ID Emergence Service Water (Unit 2), Sheet 5, 8031-M-11, Revision 49, 11/12/10
Limerick Generating Station, Exelon Nuclear Corporation; P&ID Residual Heat Removal Service Water (Common), Sheet 1, 8031-M-12, Revision 70, 8/5/10
Limerick Generating Station, Exelon Nuclear Corporation; P&ID Residual Heat Removal Service Water (Unit 1), Sheet 2, 8031-M-12, Revision 7, 12/14/09
Bechtel dwg. A-801, Revision 1, 2/16/88; Limerick Generating Station Unit 1 & Unit 2, Spray Pond Pump House, Structures, Plans & Sections
Bechtel dwg. C-1107, Revision 1, 3/5/84; Limerick Generating Station Unit 1 & Unit 2; Yardwork Spray Pond, General Arrangement
Bechtel dwg. M-389, Revision 21, 1/22/08
Spray Pond Sediment Mapping Survey, Limerick, PA, sheet 1 of 7, 4/27/10, by Land & Sea Engineering, Ray Okuraski P.E.
Spray Pond Sediment Cross Sections, Limerick, PA, sheet 2 of 7, 4/27/10, by Land & Sea Engineering, Ray Okuraski P.E.
Spray Pond Sediment Cross Sections, Limerick, PA, sheet 3 of 7, 4/27/10, by Land & Sea Engineering, Ray Okuraski P.E.
Spray Pond Sediment Cross Sections, Limerick, PA, sheet 4 of 7, 4/27/10, by Land & Sea Engineering, Ray Okuraski P.E.
Spray Pond Sediment Cross Sections, Limerick, PA, sheet 5 of 7, 4/27/10, by Land & Sea Engineering, Ray Okuraski P.E.
Spray Pond Sediment Cross Sections, Limerick, PA, sheet 6 of 7, 4/27/10, by Land & Sea Engineering, Ray Okuraski P.E.
Spray Pond Sediment Cross Sections, Limerick, PA, sheet 7 of 7, 4/27/10, by Land & Sea

Engineering, Ray Okuraski P.E.

Licensing and Design Basis Documents

Design Basis Document, Emergency Service Water System, L-S-02, Revision 14: Exelon Nuclear Limerick Generating Station, Units 1 and 2
Design Basis Document, Residual Heat Removal Service Water System, L-S-04, Revision 11; PECO Nuclear, Limerick Generating Station Units 1 and 2
Design Basis Document, Spray Pond, L-S-27, Revision 9; PECO Nuclear, Limerick Generating Station, Units 1 and 2
UFSAR Section 9.2.6.2.2. Spray Pond Descriptions
UFSAR Section 2.4.2.3.2. Drainage from Spray Pond Area
UFSAR Section 2.4.8.1 General Description of the Spray Pond
UFSAR Section 2.5.4.5.3. Spray Pond Excavation, Slope Protection and Liner Construction
UFSAR Section 2.5.4.6.1. Spray Pond Seepage Analysis
Cathodic Protection Systems, L-S-12, Revision 2: PECO Nuclear, Limerick Generating Station, Units 1 and 2; Design Basis Document

Engineering Calculations, Analyses, Specifications, and Design Changes

Calculation LM-383, Post LOCA Spray Pond Performance Analysis, 7/28/93
Calculation LM-382, 7/28/93; Code Verification and Validation of Spray Pond Performance, UHS Versions 3.3 and 3.4
Calculation M-12-28; Limerick Units 1 and 2, Transient Analysis Review of the Spray Pond Network, 1/17/89
Limerick Generating Station, Hydraulic Study for ESW/RHRSW System Modifications P-166 to P-168. Performed for PECO Energy Company by Bechtel Power Corporation, 7/15/94
Bechtel Letter 006441, 8/18/88; ESW/RHRSW Transient Testing Field Test/Studies – Final Report

Completed Tests, Surveillances, and Inspections

RT-1-01-390-0, ESW Room Cooler Heat Transfer Performance Calculation TEST, 3/16/10
RT-1-01-390-0, ESW Room Cooler Heat Transfer Performance Calculation TEST, 1/27/11
RT-1-01-390-0, ESW Room Cooler Heat Transfer Performance Calculation TEST, 4/25/11
RT-1-01-390-0, ESW Room Cooler Heat Transfer Performance Calculation TEST, 3/21/11
RT-1-01-390-0, ESW Room Cooler Heat Transfer Performance Calculation TEST,1/20/11
RT-2-011-398-1, Revision 9, 1C RHR Motor Oil Cooler Heat Transfer Test, 6/9/10
RT-2-011-398-1, Revision 9, 1C RHR, Motor Oil Cooler Heat Transfer Test, 9/10/10
RT-2-011-398-2, Revision 9, 1C RHR Motor Oil Cooler Heat Transfer Test, 7/13/09
RT-2-011-398-2, Revision 9, 1C RHR Motor Oil Cooler Heat Transfer Test 7/2/09
RT-6-011-601-0, Revision 17, 'A' LOOP ESW Flushing Biocide Procedure, 9/7/11
RT-6-011-602-0, Revision 20, 'B' LOOP ESW Flushing Biocide Procedure, 9/6/11
RT-6-012-602-0, Revision 7, 'B' LOOP RHRSW Biocide Treatment Procedure, 9/5/11
RT-6-012-602-0, Revision 6, Spray Pond Spray Nozzle Test
RT-6-012-601-0, Revision 7, 'A' LOOP RHRSW Biocide Treatment Procedure, 9/6/11

RT-1-012-390-0, Revision 7; RHR HX Heat Transfer Performance COMPUTATION TEST, 2/21/08
RT-1-012-390-0, Revision 8; RHR HX Heat Transfer Performance Computation Test, 2/8/10
RT-2-011-251-0, Revision 20; ESW LOOP 'A' Flow Balance, 8/6/10
RT-2-011-252-0, Revision 21; ESW LOOP 'B' Flow Balance, 11/13/10
ST-1-012-901-0, Revision 1; Spray Pond Structural Inspection, 10/16/1IMPRO Report: Long Range Guided Wave Ultrasonic Pipe Screening Results; Technical Report of Service Water Piping System Using GUL Wavemaker G-3 For Exelon Generating Company At Limerick Generating Station Units 1 and 2, 6/19/10
ST-4-011-954-0, Revision 6: ESW AND RHRSW LOOP 'B' BURIED PIPE FLOW TEST; completed on 2/27/09
ST-4-011-953-0, Revision 6: ESW AND RHRSW LOOP 'A' Buried Pipe flow Test, completed on 8/1/08
RT-2-011-398-2, Revision 9: UNIT '2C' RHR Motor Oil Cooler Heat Transfer Test; completed on 7/13/09, Post-clean
RT-2-011-398-2, Revision 9: UNIT '2C' RHR Motor Oil Cooler Heat Transfer Test; completed on 7/2/09, PRE-CLEAN
RT-1-011-390-0, Revision 7: ESW Room Cooler Heat Transfer Performance Calculation Test; completed on 3/6/10
RT-1-011-390-0, Revision 7: ESW Room Cooler Heat Transfer Performance Calculation Test; completed on 4/25/11
RT-2-011-398-1, Revision 9: UNIT '1C' RHR Motor Oil Cooler Heat Transfer Test; completed on 9/9/10, Post-Clean
RT-2-011-398-1, Revision 9: UNIT '1C' RHR Motor Oil Cooler Heat Transfer Test; completed on 6/9/10, Post-Clean
RT-1-011-390-0, Revision 7: ESW Motor Oil Cooler Heat Transfer Test; completed on 1/20/11
RT-1-011-390-0, Revision 7: ESW Room Cooler Heat Transfer Performance Calculation Test; completed on 3/21/11
RT-1-092-390-0, Revision 0: EDG HX Heat Transfer Performance Computation Test; completed on 6/3/11
RT-6-109-001-0, Revision 9, 8/19/11: Cathodic Protection Monthly inspection; completed on 8/20/11
Corpro Letter dated 3/23/2011, Subject: Cathodic Protection for Underground Piping Systems, Limerick Generating Station, Corpro Job No. 402475 (Annual Service)

Action Reports (AR)

00826190	00828566	00847711	00931079	00938131	00943744
00902357	00943744	00943738	00950695	01071641	01072638
00976111	00989858	01003884	01023033	01038249	01043444
01044341	01045990	01185972	01220882	01223566	01255136
01251770	01211070	01160934	01058112	01666331	01765141

* AR written as a result of this NRC inspection

Construction Specifications

Specification 8031-C-9, Installation and Testing of Underground Process Piping For The Limerick Generating Station Units 1 and 2, Philadelphia Electric Company; Bechtel Western Power Company, 4/20/88

Specification 8031-P-306, Materials For Coating and Wrapping Underground Piping and Piping Joints

Operability Determinations

OPE-11-004 (IR1242289) – HBC-245-01-ESW System Unit 2 'B' Loop piping (ESW supply to HPCI Coolers). Pipe repair planned under AR A1817107 (WW1229)
OPE-11-005 (IR1244448) – HBC-082-01-ESW System Common 'B' Loop Piping. Pipe repair planned under AR A1817887 (WWTBD)

Limerick Generating Station Program Documents

ER-RA-5400, Revision 4; Buried Piping and RAW Water Corrosion Program (BPRWCP) Guide.
Exelon Nuclear, Application of Quantitative Pipe Inspections to ASME Class 3 Service Water Pipe, 9/5/08
Exelon Nuclear Memorandum, Technical Position Paper on Use of Qualitative Pipe Inspection Techniques for Surveying ASME Class 3 Service Water Piping

Miscellaneous Documents

NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment, 7/18/89
PECO 60 day Response to GL 88-04, 6/30/88
ASME, Section XI, Subsection IWA 5244 Testing of buried components.
Exelon Memo dated 5/25/11; Re: Data Reduction and Results from Limerick D-22 EDG Heat Exchanger Performance Test of August 31, 2010 (IR1113353)

Section 1R12: Maintenance Effectiveness

Issue Reports:

1046068	1043637	1166215	1153880	941786	1174809
820196	1222301	1236407			

Procedure:
ER-LG-310-1010, Maintenance Rule Implementation, Revision 14
ST-2-036-600-0, Seismic Monitoring – Triaxial Time - History Accelerometer Records, Revision 17
ER-AA-310, Maintenance Rule – Performance Criteria Selection, Revision 3
ER-AA-310-1004, Performance Monitoring, Revision 8

Miscellaneous:
UFSAR 3.7.4 Seismic Monitoring Instrumentation
Maintenance Rule Expert Panel Meeting Minutes, May 3, 2011
Maintenance Rule Scoping and Performance Monitoring for System 0365
Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Issue Reports

1244462

Procedures
WC-LG-101-1001, Guideline for the Performance of On-Line work/On-Line System Outages, Revision 19

Section 1R15: Operability Evaluations

Issue Reports

1254061	1131380	1260638	1262728	1252971	0924068
1246836	1242478	1192548			

Procedures
RT-3-047-640-1, Fuel Channel Distortion Monitoring, Revision 15
ST-6-020-813-1, D13 Diesel Generator Fuel Oil Analysis, Revision 19

Miscellaneous
UFSAR 7.6.1.8, Redundant Reacting Control System – Instrumentation and Controls
DBD L-S-55, Redundant Reactivity Control System Design Basis Document, Revision 2
Regulatory Guide 1.6, Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems, Revision 0
Regulatory Guide 1.53, Application of the Single – Failure Criterion to Nuclear Power Plant Protection Systems, Revision 0
M-0020 Sheet 3-P&ID Fuel and Diesel oil Storage and Transfer, Revision 39
Powerlabs Evaluation of an EDG Fuel Pump Inlet Filter Strainer, dated August 31, 2011

Work Orders
A1824285 C0239898

Section 1R18: Plant Modifications

Issue Reports
1252971 1231352 1245713

Other
ECR 11-00354, Perform ARI Evaluation for new Power Supply Board in STS535 Controller

Section 1R19: Post-Maintenance Testing

Issue Reports
1238109

Miscellaneous
A1816016, Equivalency evaluation for EDG air start solenoid valve 092-2309
C0239277, Repack 1" RCIC AOV LV-049-1F054
MA-AA-716-012 Attachment 3, AOV Post Maintenance Test Matrix, Revision 14

Section 1R22: Surveillance Testing

Issue Reports

1238246	1249566	1249449	1258771	1261482	1230677

1219466

Work Orders
R1204075, Drywell Floor Drain Sump Surveillance Log, dated August 13, 2011
R1076828, ISI Pressure Test of RCIC Pump and Turbine Supply, dated March 21, 2008
R1045268, ISI Pressure Test of RCIC Pump and Turbine Supply, dated December 5, 2008

Miscellaneous
Test Results Evaluation for ST-6-001-660-2 performed September 10, 2011
ER-AB-331-1006, Reactor Coolant System Leakage Monitoring and Action Plan, Revision 2
LS-AA-2100, Monthly Data Elements for NRC RCS Leakage, Revision 5
Test Results Evaluation for ST-2-051-802-2, Division 2 LPCI System Response Time Testing, dated September 1, 2011
Temporary Change 11-0425-0
ASME OM Code-2004, Code for Operation and Maintenance of Nuclear Power Plants, January 31, 2005
NUREG-0696, Function Criteria for Emergency Response Facilities, February 1981
NUREG-0737, Clarification of TMI Action Plan Requirements, November 1980
Regulatory Guide 1.52, Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water Cooled Nuclear Power Plants, Revision 3
Regulatory Guide 1.140, Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmosphere Cleanup Systems in Light-Water Cooled Nuclear Power Plants, Revision 2

Section 1EP6: Drill Evaluation

Procedures
EP-AA-111, Emergency Classification and Protective Action Recommendations, Revision 16
TSC Actuation and Operation, Revision 7
Standardized Radiological Emergency Plan, Revision 20

Section 2RS07: Radiological Environmental Monitoring Program (REMP)

Procedures:
CY-AA-170-000, Radioactive Effluent and Environmental Monitoring Programs
CY-AA-170-100, Radiological Environmental Monitoring Program
CY-AA-170-210, Potentially Contaminated System Controls Program
CY-AA-170-1000, Radiological Environmental Monitoring Program and Meteorological Program Implementation
CY-AA-170-1100, Quality Assurance for Radiological Monitoring Programs
CY-LG-170-301, Offsite Dose Calculation Manual
ST-4-114-360-0, Independent Spent Fuel Storage Installation Technical Specification Testing
ST-6-107-590-0, Daily Surveillance Log/Common Plant At All Times
*ER – 5, Collection of Water Samples for Radiological Analysis
*ER – 8, Collection of Air Particulate and Air Iodine Samples for Radiological Analysis

*Normandeau Associates, Inc. Procedures

Sampling Sites:

Air Particulate/Iodine: 10S3, 11S1, 11S2, 13C1, 14S1, 22G1
Drinking Water: Nos.: 15F4, 15F7, 16C2, 28F3
Surface Water Nos.: 13B1, 24S1
Thermolumeniscent Dosimeters Nos.: 10S3, 11S1, 14S1, 15D2, 18S2, 21S2, 36S2

Nuclear Oversight Focus Area Self-Assessment Reports:
Self-Assessment 01137684, ISFSI Operations Inspection
Self-Assessment 01141545, REMP Inspection

Issue Reports:

01035179	01035185	01039780	01041671	01042024	01044041
01044045	01069156	01069160	01073556	01073563	01073567
01074042	01074049	01074058	01076290	01080488	01080499
01092994	01229501	01231609	01261873	01243200	

Miscellaneous Reports:
2010 Annual Radioactive Effluent Release Report, No. 36
2010 Annual Radiological Environmental Operating Report, No. 26
2009 Annual Radioactive Effluent Release Report, No. 35
2009 Annual Radiological Environmental Operating Report, No. 25
Air Particulate Monitoring System Maintenance/Calibration Records (Normandeau Associates, Inc)
Water Sampling Equipment Maintenance Logs
2010 Land Use Survey
Routine Groundwater and Surface Water Monitoring Program Results
P1009 Meteorological Monitoring Program, Equipment Servicing and Data Recovery Manual, Revision 26
Monthly Report on the Meteorological Monitoring Program
NUPIC Audit No. 22937, Teledyne Brown Engineering Environmental Services
NORMA – 2009-1, Audit report of Normandeau Associates by Environmental Inc. Midwest
ODCM Change Determination, No. 25
50.75 (g) Decommissioning Records

Section 4OA1: Performance Indicator Verification

Issue Reports

861177	1127483	1222301

Miscellaneous
NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 6
Reactor Oversight Program MSPI Basis Document, Limerick Generating Station, Revision 1
Unavailability Reports for Unit 1 and Unit 2 RHR, July 2010 – June 2011
LER 352-2011-002; 353-2011-004; 353-2011-005

Section 4OA2: Problem Identification and Resolution

Issue Reports

1222301	1219476	1207704	1223645	1222690	1222511
1222809	1222234	1222210	1221783	1231487	1244462

Procedures

GP-2, Preparation for Startup, Revision 139

Other
EP-AA-1008, Limerick Generating Station Emerging Plan Annex, Revision 20
Work Order R0992765, U2 HPCI Turbine Major Inspection
Work Order R08440377, U2 HPCI Turbine Major Inspection
GE PRC 93-04, HPCI Turbine Control Valve Assembly (Utility Report # SC93-07)

Section 4OA3: Followup of Events and Notices of Enforcement Discretion

Issue Reports
1254779 1254845 1254915 1254776 1254835 1254956
1222083 1245696

Procedures
SE-5, Earthquake, Revisions 30, 31, and 32

Other
Response Spectra Analysis for SSA-3 Recorder A dated August 23, 2011
Failure Analysis of the Limerick Unit 1 HPCI Turbine Control Valve No. 1 dated July 2, 2011

Section 4OA5: Other Activities

Calculations and Evaluations
757303-28, Technical Evaluation Air Identified in 'A' and 'B' RHR Discharge Line Upstream of HV-51-F016, dated 10/8/08
757303-29, Air Identified in 1A Core Spray Discharge Line, dated 10/08/08
757303-30, Engineering Technical Evaluation Air Identified in HPCI Suction and Discharge Lines, dated 10/08/08
757303-63, Technical Evaluation to Provide Technical Basis for Relaxing Periodic Air Accumulation UT Frequency, dated 9/30/10
ECR 09-00430, High Pressure Coolant Injection and Condensate Storage Tank High Point Vents, Revision 0

Completed Tests
RT-4-052-641-1, 1A Core Spray Air Accumulation Inspection (CM-1), performed 3/18/10, 4/26/10, 5/26/10, 6/30/10, 7/29/10, 8/26/10, 9/26/10, 11/23/10, 2/23/11, and 5/24/11
RT-4-052-641-2, 2A Core Spray Air Accumulation Inspection (CM-1), performed 3/19/10, 4/19/10, 5/15/10, 6/22/10, 7/21/10, 8/20/10, 9/17/10, 11/18/10, 2/22/11, and 5/26/11
RT-4-052-642-1, 1B Core Spray Air Accumulation Inspection (CM-1), performed 3/18/10, 4/26/10, 5/26/10, 6/30/10, 7/30/10, 8/26/10, 9/26/10, 11/23/10, 2/23/11, and 5/24/11
RT-4-052-642-2, 2B Core Spray Air Accumulation Inspection (CM-1), performed 3/19/10, 4/19/10, 5/17/10, 6/22/10, 7/21/10, 8/20/10, 9/17/10, 11/18/10, 2/22/11, and 5/26/11
S51.1.A, Set Up of RHR System for Automatic Operation in LPCI Mode, performed 4/2/11
S52.1.A, Core Spray Setup for Service Operation, performed 3/28/10, 8/16/10, 4/3/11, and 4/11/11
ST-6-107-370-1, Low Pressure ECCS Keep Fill System High Point Venting, performed 7/4/08, 1/2/09, 3/20/09, 7/3/09, 1/28/10, 3/19/10, 8/31/10, 1/7/11, 3/6/11, and 6/3/11
ST-6-107-370-2, Low Pressure ECCS Keep Fill System High Point Venting, performed 4/21/08, 2/17/09, 3/30/09, 4/8/09, 1/18/10, 5/18/10, 8/17/10, 4/11/11, 4/19/11, and 7/1/1

Corrective Action Documents
A1659520 A1683497 AR00751682 AR00757303 AR01054871

Issue Reports
00746424 00751484 00758962 01249916* 01249916* 01249931* 01249931*
* Identified during inspection

Design Change Packages
DCP LG 09-00430, HPCI/RCIC/CST System High Point Vents-Unit 1, Revision 1
LG-08-00457, Core Spray System High Point Vents-Unit 2, Revision 0
LG-09-00271, Core Spray System High Point Vents-Unit 1, Revision 1

Design & Licensing Bases
Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to USNRC, "Three Month Response to Generic Letter 2008-01," dated April 11, 2008
Letter from K. R. Jury (Exelon Generation Company, LLC/AmerGen Energy Company, LLC) to USNRC, "Supplemental Response to Generic Letter 2008-01," dated July 7, 2009
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Letter from Patrick R. Simpson (Exelon Generation Company, LLC) to USNRC, "Response to Request for Additional Information Regarding Generic Letter 2008-01," dated March 11, 2010
Limerick Generating Station – Technical Specifications, Amendment 186
Limerick Generating Station Updated Final Safety Analysis Report, Revision 15

Drawings
8031-M-51, Shts. 1, 2, 3, and 4, RHR (Unit 1), Revisions 65, 66, 67 and 66
8031-M-51, Shts. 5, 6, 7, and 8, RHR (Unit 2), Revisions 30, 23, 21 and 25
8031-M-52, Shts. 1 and 2, Core Spray (Unit 1), Revisions 50 and 46
8031-M-52, Shts. 3 and 4, Core Spray (Unit 2), Revisions 19 and 16
8031-M-55, Sht. 1, High Pressure Coolant Injection (Unit 1), Revision 57
8031-M-55, Sht. 2, High Pressure Coolant Injection (Unit 2), Revision 56
8031-M-56, Sht. 1, High Pressure Coolant Injection Pump/Turbine (Unit 1), Revision 40
8031-M-56, Sht. 2, High Pressure Coolant Injection Pump/Turbine (Unit 2), Revision 12
DCA-104-1, 2 and 4, Reactor Building, RHR (Unit 1), Revisions 13, 16 and 4
DCA-105-1 and 3, Reactor Building, RHR (Unit 1), Revisions 16 and 8
DCA-319-1, Reactor Building, Core Spray (Unit 1), Revision 16
DCA-320-1, Reactor Building, Core Spray (Unit 1), Revision 13
DCA-419-1, Reactor Building, Core Spray (Unit 2), Revision 12
DCA-420-1, Reactor Building, Core Spray (Unit 2), Revision 14

DLA-110-1, Reactor Building, Core Spray (Unit 1), Revision 22
DLA-111-1, Reactor Building, Core Spray (Unit 1), Revision 22
DLA-112-2, Reactor Building, RHR (Unit 1), Revision 16
DLA-210-1, Reactor Building, Core Spray (Unit 2), Revision 15
DLA-211-1, Reactor Building, Core Spray (Unit 2), Revision 17
EBB-129-1, 3, and 4, Reactor Bldg HPCI (Unit 1), Revsisions 22, 26, and 6
EBB-130-1, Reactor Bldg, HPCI (Unit 1), Revision 16
EBB-131-1, Reactor Building, Core Spray (Unit 1), Revision 26

EBB-132-1, Reactor Building, Core Spray (Unit 1), Revision 18
EBB-231-1, Reactor Building, Core Spray (Unit 2), Revision 9
EBB-232-1, Reactor Building, Core Spray (Unit 2), Revision 8
GBB-101-1, 2, and 4, Reactor Bldg, RHR (Unit 1), Revisions 26, 22, and 16
GBB-102-1, 2 and 6, Reactor Building, RHR (Unit 1), Revisions 25, 22 and 6
GBB-105-2, Reactor Building, RHR (Unit 1), Revision 12
GBB-107-2, Reactor Building, RHR (Unit 1), Revision 15
GBB-109-1, Reactor Building, RHR (Unit 1), Revision 27
GBB-110-1, Reactor Building, RHR (Unit 1), Revision 8
GBB-112-1, 2 and 3, Reactor Building, Core Spray (Unit 1), Revisions 15, 18, and 30
GBB-113-1, 2 and 3, Reactor Building, Core Spray (Unit 1), Revisions 20, 19, and 22
GBB-117-1 and 2, Reactor Building, RHR (Unit 1), Revisions 17 and 15
GBB-118-1 and 3, Reactor Building, RHR (Unit 1), Revisions 21 and 15
GBB-118-4, Reactor Building, RHR (Unit 1), Revision 24
GBB-119-1, 2, 3 and 11, Reactor Building, RHR (Unit 1), Revisions 10 17, 23 and 11
GBB-120-2, Reactor Building, RHR (Unit 1), Revision 8
GBB-212-1, 2 and 3, Reactor Building, Core Spray (Unit 2), Revisions 8, 10, and 13
GBB-213-1, 2 and 3, Reactor Building, Core Spray (Unit 2), Revisions 9, 8, and 18
HBB-109-2, Reactor Bldg, HPCI (Unit 1), Revision 15
HBB-110-1, Reactor Bldg, HPCI (Unit 1), Revision 20
HBB-117-1, Reactor Building, RHR (Unit 1), Revision 17
HBB-118-1, 2, 3 and 4, Reactor Building, RHR (Unit 1), Revisions 18, 15, 14 and 14
HBB-119-1, Reactor Building, RHR (Unit 1), Revision 14
HBB-120-1, 3, 5, and 7, Reactor Bldg, Core Spray (Unit 1), Revisions 22, 20, 21, and 22
HBB-209-1, Reactor Enclosure, HPCI (Unit 2), Revision 17,
HBB-210-1, Reactor Building, HPCI (Unit 2), Revision 16,
HBB-220-1, 2, 3 and 4, Reactor Building, Core Spray (Unit 2), Revisions 14, 9, 12, and 11
HCB-102-2, Reactor Bldg, Condensate and Refueling Water Storage (Unit 1), Revision 11
HCB-105-1, Reactor Bldg, Condensate and Refueling Water Storage (Unit 1), Revision 17
HCD-119-1, Yard Piping, Condensate Storage, (Units 1 & 2), Revision 2
HCD-119-2, Reactor Building, Condensate and Refueling Water Storage (Unit 1), Revision 2
HCD-219-1, Yard Piping, Condensate Storage Tank No. 2, Revision 14
S51.1.A, Set Up of RHR System for Automatic Operation in LPCI Mode, Revision 50
SP-EBB-129-4F, Reactor Bldg, Drain from 8" EBB-129 (Units 1 & 2), Revision 5
SP-EBB-130-1F, Reactor Bldg, Vent and Test Connection from 4" EBB-130-1, Revision 4
SP-EBB-134-1F, Reactor Encl, Vent from 4" EBB-134 to DRW (Units 1 & 2), Revision 5
SP-HBB-109-2F, Vent and Drain for HPCI – Reactor Building (Unit 1), Revision 2
SP-HBB-110-1F, Reactor Bldg, Inst and Drain from HBB-110 (Units 1 & 2), Revision 3
SP-HBB-209-1E, Reactor Building, HPCI Pump Suction Line Vent and Test Connections, Revision 2
SP-HBB-210-1E, Reactor Building, HPCI Pump Suction Line PSV, Revision 3
SP-HCB-105-1F, Instrument for Condensate and Refueling Water Storage, Reactor Building, Revision 7
SP-HCD-119-1F, Yard, High Point Vent from 20' HCD-119 (Units 1 & 2), Revision 1

Miscellaneous

N-LM-ENG-LECT-WG-0906, Basic Overview of Gas Accumulation, LEDM Work Group-Specific Continuing Training, Revision 0
NRC Generic Letter 2008-01: Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems, dated 1/11/08
System Health Report-Unit 1 Core Spray System, 1Q11 and 2Q11

System Health Report-Unit 2 Core Spray System, 1Q11 and 2Q11
Unit 1 RHR Loop Vent Trending Data, 3/18/10 – 5/24/11

Procedure
ER-AA-2009, Managing Gas Accumulation, Rev. 1
ER-AA-335-007, Ultrasonic Inspection for Determination of Sedimentation in Piping Systems or Components and Fluid Level Measurements, Revision 3
OP-AA-108-106, Equipment Return to Service, Revision 4
RT-4-052-641-1, '1A' Core Spray Air Accumulation Inspection (CM-1), Revision 2
RT-4-052-641-2, '2A' Core Spray Air Accumulation Inspection (CM-1), Revision 1
RT-4-052-642-1, '1B' Core Spray Air Accumulation Inspection (CM-1), Revision 2
RT-4-052-642-2, '2B' Core Spray Air Accumulation Inspection (CM-1), Revision 1
RT-4-055-641-1, HPCI Air Accumulation Inspection (CM-1), Revision 2
RT-4-055-641-2, HPCI Air Accumulation Inspection (CM-1), Revision 1
S52.1.A, Core Spray Setup for Service Operation, Revision 37
S55.3.A, HPCI Fill and Vent, Revision 27
ST-2-051-404-1, ECCS-LPCI Keep Filled System Injection Line A Calibration, Revision 10
ST-6-107-370-1, Low Pressure ECCS Keep Fill System High Point Venting, Revision 12
ST-6-107-370-2, Low Pressure ECCS Keep Fill System High Point Venting, Revision 8
ST-6-107-370-2, Low Pressure ECCS Keep Fill System High Point Venting, Revision 8
ST-6-107-371-1, HPCI Keep Fill System High Point Venting, Revision 9
ST-6-107-371-2, HPCI Keep Fill System High Point Venting, Revision 7

Other (60855/60855.1)
Corrective Action Documents
AR 00587910, LGS ISFSI Documentation, Evals, Decisions, & Lessons Learned
AR 01195668, Enhance Controls of ISFSI Pad

Calculations and Evaluations
ECR Number LG-00094, LGS ISFSI Project – UFSAR/Licensing Docs/DBD/Haul Path Eval

Procedure
LS-AA-126-1001, Attachment 2, FASA Self-Assessment Report, Revision 5
NF-AA-309, Special Nuclear Material and Core Component Move Sheet Development, Revision 3
NF-LG-310-2000, Special Nuclear Material and Core Component Movement, Revision 5
NF-LG-626, Fuel Loading/Unloading of a Dry Shielded Canister, Revision 1
NF-LG-638, Dry Storage Fuel Selection For DSC Loading, Revision 2
NF-LG-641, Transport and Loading of Transfer Cask and Dry Shielded Canister, Revision 11
RP-AA-210 Rev 0 Dosimetry Issue, Usage and Control
RP-AA-210-1001 Rev 5 Dosimetry Logs and Forms
Analysis No. HP-08-05 Rev 0 Expected Response of ASP-1/NDR and Harshaw TLD to Dry Fuel Storage Neutrons
Analysis N0. RP-08-07 Rev 1 Harshaw TLD Response to Limerick Dry Fuel Storage Neutron Spectra
RWP 11-73 2011 ISFSI Campaign
RP-AA-401 ALARA Plan 11-122 Limerick 2011 ISFSI Campaign
ST-4-114-360-0, ISFSI Technical Specification Testing

Miscellaneous

EXELON Radiation and Contamination Surveys 11-06754, 11-06737,11-06738, 11-06673, 11-06677, 11-06672 and 11-06678
Limerick Generating Station Offsite Dose Calculation Manual Revision 24
Limerick Generating Station Offsite Dose Calculation Manual Revision 24
2010 Annual Radioactive Effluent Release Report
2010 Annual Environmental Operating Report

LIST OF ACRONYMS

ADAMS	Agency wide Documents Access Management System
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CDF	Core Damage Frequency
CR	Condition Report
CFR	Code of Federal Regulations
DFWLCS	Digital Feed Water Level Control System
DSC	Dry Shielded Canister
EACE	Equipment Apparent Cause Evaluation
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
ESW	Emergency Service Water
GL	Generic Letter
HEP	Human Error Probability
HPCI	High Pressure Coolant Injection
HPI	High Pressure Injection
HSM	Horizontal Storage Modules
HX	Heat Exchanger
IMC	Inspection Manual Chapter
IR	Issue Report
ISFSI	Independent Spent Fuel Storage Installation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LPRM	Local Power Range Monitor
NCV	Non-Cited Violations
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PCIV	Primary Containment Isolation Valve
PD	Performance Deficiency
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PM	Preventative Maintenance
RCIC	Reactor Core Isolation Cooling
RERS	Reactor Enclosure Recirculation System
RG	Regulatory Guide
RETS	Relayed Emergency Trip System
RHR	Residual Heat Removal
RPS	Reactor Protection System
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SSC	Systems, Structures and Components
ST	Surveillance Test
TLD	Thermoluminescence Dosimeter
TS	Technical Specification
TT	Transport Trailer
UFSAR	Updated Final Safety Analysis Report
VOM	Volt/Ohm Meter
WO	Work Order