UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD.
KING OF PRUSSIA, PA 19406-2713

May 12, 2016

EA-16-057

Mr. Bryan Hanson
Senior Vice President, Exelon Generation
President and Chief Nuclear Officer, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: OYSTER CREEK NUCLEAR GENERATING STATION - INTEGRATED INSPECTION REPORTS 05000219/2016001, 05000219/2016009, AND PRELIMINARY WHITE FINDING

Dear Mr. Hanson:

On March 31, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Oyster Creek Nuclear Generating Station. The enclosed inspection report documents the inspection results, which were discussed on April 7, 2016, with Mr. M. Gillin, Plant Manager, and on April 29, 2016, with Mr. G. Stathes, Site Vice President, and other members of your staff.

NRC inspectors 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.

The enclosed inspection report discusses a finding that the NRC has preliminarily determined to be White, a finding of low to moderate safety significance. As described in Section 4OA2 of the enclosed report, the finding is associated with an apparent violation of Title 10 of the *Code of Federal Regulations* (CFR), Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because Exelon did not appropriately prescribe instructions or procedures for maintenance on the emergency diesel generator (EDG) cooling water system to ensure the EDG cooling flexible coupling hose was maintained to support the EDG safety function. As a result, the flexible coupling hose was in service for approximately 22 years and subjected to thermal degradation and aging that eventually led to failure of EDG No. 1 during operating conditions on January 4, 2016. As a consequence, Exelon also violated Technical Specification 3.7.C, since EDG No. 1 was determined to be inoperable for greater than the technical specification allowed outage time. The finding was assessed based on the best available information, using Inspection Manual Chapter (IMC) 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," issued June 19, 2012. The basis for the NRC's preliminary significance determination is described in the enclosed report.

As an apparent violation of NRC requirements, this finding is being considered for escalated enforcement action in accordance with the Enforcement Policy, which appears on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html. The NRC will inform you, in writing, when the final significance has been determined. We intend to complete and issue our final safety significance determination within 90 days from the date of this letter. The NRC's SDP is designed to encourage an open dialogue between your staff and the NRC; however, the dialogue should not affect the timeliness of our final determination.

We believe that we have sufficient information to make a final significance determination. However, before we make a final decision, we are providing you an opportunity to provide your perspective on this matter, including the significance, causes, and corrective actions, as well as any other information that you believe the NRC should take into consideration. Accordingly, you may notify us of your decision within 10 days to: (1) request a regulatory conference to meet with the NRC and provide your views in person, (2) submit your position on the finding in writing, or (3) accept the finding as characterized in the enclosed inspection report.

If you choose to request a regulatory conference, the meeting should be held in the NRC Region I office within 40 days of the date of this letter, and will be open for public observation. The NRC will issue a public meeting notice and a press release to announce the date and time of the conference. 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 you choose to provide a written response, it should be sent to the NRC within 30 days of the date of this letter. You should clearly mark the response as "Response to Preliminary White Finding in Inspection Report No. 05000219/2016001; EA-16-057," and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, Region I, and a copy to the NRC Senior Resident Inspector at the Oyster Creek Nuclear Generating Station.

You may also elect to accept the finding as characterized in this letter and the inspection report, in which case the NRC will proceed with its regulatory decision. However, if you choose not to request a regulatory conference or to submit a written response, you will not be allowed to appeal the NRC's final significance determination.

Please contact Silas Kennedy at (610) 337-5046 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.

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 violation may change based on further NRC review. The final resolution of this matter will be conveyed in separate correspondence.

The inspectors also documented two violations of NRC requirements, both of which were of very low safety significance (Green), in this report. Additionally, a licensee-identified violation, which was determined to be of very low safety significance, is listed in this report. Because of the very low safety significance, and because the violations have been entered into your corrective action program, the NRC is treating these findings as non-cited violations, consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the non-cited violations 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 Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Oyster Creek Nuclear Generating Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding, 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 Resident Inspector at Oyster Creek Nuclear Generating Station.

In accordance with Title 10 of the *Code of Federal Regulations* (CFR) 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's Public Document Room or from the Publicly Available Records component of the NRC's Agencywide Documents Access Management 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/

Michael L. Scott, Director
Division of Reactor Projects

Docket No. 50-219
License No. DPR-16

Enclosure:
Inspection Report 05000219/2016001
and 05000219/2016009
Attachment 1: Detailed Risk Evaluation
Attachment 2: Supplementary Information

cc w/encl: Distribution via ListServ

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Sincerely,
/RA/
Michael L. Scott, Director
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Docket No. 50-219
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Inspection Report 05000219/2016001
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Attachment 1: Detailed Risk Significance Evaluation
Attachment 2: Supplementary Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-219
License No.	DPR-16
Report No.	05000219/2016001; 05000219/2016009
Licensee:	Exelon Nuclear
Facility:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Dates:	January 1, 2016 – March 31, 2016
Inspectors:	A. Patel, Senior Resident Inspector E. Andrews, Resident Inspector F. Arner, Senior Reactor Analyst W. Cook, Senior Reactor Analyst B. Dionne, Health Physicist E. DiPaolo, Senior Reactor Inspector N. Floyd, Reactor Inspector J. Furia, Senior Health Physicist M. Henrion, Project Engineer P. Kaufman, Senior Reactor Inspector D. Orr, Senior Reactor Inspector
Approved By:	Silas R. Kennedy, Chief Reactor Projects Branch 6 Division of Reactor Projects

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SUMMARY

IR 05000219/2016001 and 05000219/2016009; 01/01/2016 – 03/31/2016; Exelon Energy Company, LLC, Oyster Creek Nuclear Generating Station; Operability Determinations and Functionality Assessments; Radiological Hazard Assessment and Exposure Controls; and Problem Identification and Resolution Annual Sample.

This report covered a three-month period of inspection by resident inspectors and announced baseline inspections performed by regional inspectors. Inspectors identified one apparent violation of low to moderate safety significance (White). The inspectors also identified two non-cited violations (NCVs), both of which were of very low safety significance (Green and/or Severity Level IV). The significance of most findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process”, dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, “Aspects Within Cross-Cutting Areas,” dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC’s Enforcement Policy, dated February 4, 2015. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 5.

Cornerstone: Mitigating Systems

- Preliminary White. The inspectors identified a preliminary White finding and associated apparent violation of Title 10 of the *Code of Federal Regulations* (CFR), Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” because Exelon did not appropriately prescribe instructions or procedures for maintenance on the emergency diesel generator (EDG) No. 1 cooling water system to ensure the EDG cooling flexible coupling hose was maintained to support the EDG safety function. Specifically, Exelon did not have appropriate work instructions to replace the EDG cooling flexible coupling hoses every 12 years as specified by Exelon’s procedure and vendor information. As a result, the flexible coupling hose was in service for approximately 22 years and subjected to thermal degradation and aging that eventually led to the failure of EDG No. 1 during operation on January 4, 2016. As a consequence of this inappropriate work instruction issue, Exelon violated Technical Specification 3.7.C because EDG No. 1 was determined to be inoperable for greater than the technical specification allowed outage time of seven days. Exelon’s immediate corrective actions included entering the issue into their corrective action program (issue reports 2607247 and 2610027), replacing of the EDG No. 1 and No. 2 flexible coupling hoses, and initiating a failure analysis to determine the causes of the failed flexible coupling hose.

  This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the ruptured flexible coupling hose caused the failure of EDG No. 1 to perform its safety function. In accordance with IMC 0609.04, “Initial Characterization of Findings,” and Exhibit 2 of IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” this finding required a detailed risk evaluation (DRE) because EDG No. 1 was inoperable for greater than the technical specification allowed outage time. The DRE estimated the increase in core damage frequency was 7E-6, or White (low to moderate safety significance) for this

finding. This finding does not have an associated cross-cutting aspect because the performance deficiency occurred in 2005 and is not reflective of present performance. (Section 4OA2.5.b)

- Green. The inspectors identified an NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," because Exelon did not promptly identify and correct a condition adverse to quality. Specifically, Exelon did not identify that the scram time test result for control rod drive 18-47 was beyond the analyzed scram time, which resulted in a degraded control rod drive. Exelon entered this issue into their corrective action program. Immediate corrective actions included fully inserting the control rod drive and developing a casual analysis to determine the degraded condition.

  The performance deficiency is more than minor because it is associated with the configuration control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency affected the reliability of control rod drive 18-47 to perform its safety function due to a slower than normal scram time. The inspectors evaluated the finding using IMC 0609, Attachment 4, "Initial Screening and Characterization of Findings." The inspectors determined that this finding is a deficiency that affected the design or qualification of a mitigating structure, system, or component (SSC), when the SSC maintained its operability or functionality. Therefore, the inspectors determined the finding to be of very low safety significance (Green). The finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Identification, because Exelon did not identify issues completely, accurately, and in a timely manner in accordance with the program. Specifically, Exelon did not identify that the actual scram time of control rod drive 18-47 was beyond the analyzed scram time, resulting in a degraded control rod drive. [P.1] (Section 1R15)

Cornerstone: Occupational/Public Radiation Safety

- Green. A self-revealing NCV of Technical Specification 6.8.1, "Procedures and Programs" was identified for Exelon's failure to use respiratory protection, as required in the radiation work permit (RWP)/as low as reasonably achievable (ALARA) plan 14-406 for drywell head reassembly work on October 2, 2014. The radiation protection (RP) supervisor overseeing this work removed the respiratory protection requirement for this work contrary to the RWP/ALARA requirement and without engineering approval. As a result, two workers received an unplanned intake of radioactive material that resulted in unintended internal dose. Upon identification of the intake, Exelon stopped work on this task and subsequently reinstituted the respiratory protection requirements to complete the remaining work and entered this event into their corrective action program as issue report 2390111.

  This finding is more than minor because it is associated with the Occupational Radiation Safety cornerstone to ensure adequate protection of the worker from radiation exposure. Specifically, without the use of respiratory protection two workers received unintended internal dose. The inspectors evaluated the finding using inspection manual chapter 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process." The inspectors determined that this finding is of very low safety significance (Green), because it did not result in an overexposure as defined by 10 CFR 20.1201, there was no substantial potential for an overexposure, and the ability to assess dose was not compromised. This finding has a cross-cutting aspect in Human Performance, Procedural Adherence, because Exelon did not follow procedures and work instructions. Specifically, RP supervision

instructed the workers that respiratory protection was not required contrary to the applicable RWP/ALARA plan. [H.8] (Section 2RS1)

Other Findings

A violation of very low safety significance 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 numbers are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status

Oyster Creek began the inspection period at 100 percent power. Operators lowered power to 95 percent on February 2, 2016, to perform maintenance on the feedwater system and returned to full power later the same day. On March 4 operators lowered power to 95 percent to perform turbine valve surveillances. Operators returned the unit to 100 percent power the following day. On March 11, operators lowered power to 70 percent for a rod pattern adjustment and scram time testing. Operators returned the unit to 100 percent power the following day. On March 18, operators lowered power to 90 percent to perform scram time testing and returned to full power later the same day. Oyster Creek 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 – 1 sample)

.1 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors reviewed Exelon's preparations for a winter storm warning issued for the period of January 19-22, 2016. The inspectors reviewed the implementation of adverse weather preparation procedures before the onset of and during this adverse weather condition. The inspectors walked down the EDGs and emergency service water to ensure system availability. The inspectors verified that operator actions defined in Exelon's adverse weather procedure maintained the readiness of essential systems. The inspectors discussed readiness and staff availability for adverse weather response with operations and work control personnel. Documents reviewed for each section of this inspection report are listed in Attachment 2.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns (71111.04Q – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Standby gas treatment system I while standby gas treatment system II was out of service on January 27, 2016
- Containment spray system I while containment spray system II was out of service on February 1, 2016
- Reactor building closed cooling water system on February 17, 2016
- Control rod drive system on February 22, 2016

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 Updated Final Safety Analysis Report (UFSAR), technical specifications, work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted system's performance of its 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.

.2 Full System Walkdown (71111.04S – 1 sample)

a. Inspection Scope

On January 12-14, 2016, the inspectors performed a complete system walkdown of accessible portions of the emergency service water system I to verify the existing equipment lineup was correct. The inspectors reviewed operating procedures, surveillance tests, drawings, equipment line-up check-off lists, and the UFSAR to verify the system was aligned to perform its required safety functions. The inspectors also reviewed electrical power availability, component lubrication and equipment cooling, hangar and support functionality, and operability of support systems. The inspectors performed field walkdowns of accessible portions of the systems to verify as-built system configuration matched plant documentation, and that system components and support equipment remained operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. Additionally, the inspectors reviewed a sample of related condition reports and work orders to ensure Exelon appropriately evaluated and resolved any deficiencies.

b. Findings

No findings were identified.

1R05 Fire Protection

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.

- Reactor building 23' elevation on February 1, 2016
- 'A' and 'B' battery room on February 16, 2016
- Control room on February 18, 2016
- EDG fuel oil storage area on February 29, 2016
- 'A' 480v switchgear room on March 9, 2016
- 'B' 480v switchgear room on March 9, 2016

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 – 1 sample)

Internal Flooding Review

a. Inspection Scope

The inspectors reviewed the UFSAR, the site flooding analysis, and plant procedures to identify internal flooding susceptibilities for the site. The inspectors review focused on A' and B' battery room area. It verified the adequacy of equipment seals located below the flood line, floor and water penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, control circuits, and temporary or removable flood barriers. It assessed the adequacy of operator actions that Exelon had identified as necessary to cope with flooding in this area and also reviewed the corrective action program to determine if Exelon was identifying and correcting problems associated with both flood mitigation features and site procedures for responding to flooding.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11 – 3 samples)

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on January 5, 2016, which included a feedwater heater trip, anticipated transient without scram and an isolation condenser steam leak. 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.

.2 Quarterly Review of Licensed Operator Performance in the Main Control Room

a. Inspection Scope

The inspectors observed control room operator performance after receiving half scram signals on the reactor protection system channel II on February 25, 2016. The inspectors also observed control room operator performance during a scheduled downpower for scram time testing on March 11, 2016. The inspectors observed infrequently performed test or evolution briefings, shift turnover briefings, and alarm response. Additionally, the inspectors observed control room operator performance to verify that procedure use, crew communications, and coordination of activities between work groups similarly met established expectations and standards. This paragraph represents two samples.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12 – 5 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on 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 a SSC classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return the SSC 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.

- Reactor building ventilation on February 10, 2016
- Augmented offgas system on February 24, 2016
- Condensate transfer system on March 4, 2016
- Control rod drive mechanism leakage on March 12, 2016
- Periodic 10 CFR 50.65(a)(3) evaluation on March 16, 2016

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 5 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 50.65(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 Exelon's 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.

- EDG No. 1 out of service for emergent maintenance on January 4, 2016
- EDG No. 2 out of service for planned maintenance on January 11, 2016
- Instrument air compressor 1-2 and containment spray system II out of service for planned maintenance on January 15, 2016
- Containment spray and emergency service water system II out of service for planned maintenance on February 1, 2016
- Containment spray system II out of service for emergent maintenance on February 9, 2016

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 5 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions based on the risk significance of the associated components and systems:

- EDG No. 2 after EDG No. 1 failed due to a flexible cooling water hose failure on January 5, 2016
- Containment spray system II loss of control power on February 9, 2016
- Control rod drive mechanism seal leakage causing increase in unidentified leakage on March 11, 2016
- Standby liquid tank level near minimum water level on March 21, 2016

- Control rod drive increase in insertion time due to control rod drive mechanism high temperature on March 18, 2016

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. The inspectors confirmed, where appropriate, compliance with bounding limitations associated with the evaluations. 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.

b. Findings

Introduction. The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," because Exelon did not promptly identify and correct a condition adverse to quality. Specifically, Exelon did not identify the scram time test result for control rod drive 18-47 was beyond the analyzed scram time, which resulted in a degraded control rod drive. As a result, Exelon fully inserting the control rod drive.

Description. Oyster Creek's control rod drive system has 137 control rod drives, which are mounted below the reactor vessel. The control rod drives position the control rods in the reactor core and are capable of inserting or withdrawing the rod at a slow, controlled rate as well as providing rapid insertion in an emergency.

Exelon's operating history indicates that increases in unidentified leakage rate could be attributed to control rod drive mechanism (CRDM) housing to flange mechanical joint seal leakage (see 4OA2 for inspection related to the increase in unidentified leakage and CRDM seal leakage). Exelon determined that isolating cooling water to the control rod drives would limit the leakage through the CRDM seals and therefore lower the unidentified leakage. As a consequence of isolating cooling water, control rod drive temperatures increase and a delay in scram time could occur due to two phase flow resistance. Exelon procedure, 617.4.003, "Control Rod Scram Insertion Time Test and Valve IST Test," states in part, "until actual scram time data is obtained, control rods with high operating temperatures of greater than 350ºF should have a scram time penalty applied to account for potential slowing of the scram speed as a result of two-phase hydraulic fluid (water) flow resistance." The procedure also references General Electric (GE) services information letter (SIL) 173, Supplement 1, Revision 1, "Control Rod Drive High Operating Temperature," as the basis for applying the penalty. Per GE SIL 173, at the 90 percent insertion point, the approximate scram time increase for a control rod drive at 500ºF is 0.7 seconds.

To limit the increase in unidentified leakage, Exelon isolated cooling to control rod drive 18-47 on March 31, 2015, and control rod drive 42-27 on March 5, 2016. Exelon maintains records of scram times for all 137 control rod drives on a control rod scram time data sheet, NF-OC-721-1101. As a result of isolating cooling water to the respective control rod drives, the temperature of those control rod drives increased to above 500ºF. Therefore, Exelon applied a scram time penalty of 0.7 seconds to control rod drives 18-47 and 42-27, per the GE SIL guidance. The 90 percent insertion point scram times for control rod drive 18-47 and control rod drive 42-27 recorded on the

scram time data sheet, dated March 12, 2016, were approximately 3.6 and 3.1 seconds, respectively. The recorded scram data for control rod drive 18-47, 3.6 seconds, was based on scram time data before cooling water was isolated (~2.9 seconds) and the application of the additional scram time penalty of 0.7 seconds.

Technical Specification 4.2.C.2 states in part, “For specifically affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods, the individual control rods shall be scram time tested at greater than 800 psig reactor control pressure.” On March 16, 2016, inspectors questioned Exelon’s compliance to Technical Specification 4.2.C.2 since two control rod drives, 18-47 and 42-27, had their respective cooling water isolated. The inspectors determined that isolating cooling water constituted a modification to the control rod drive system that could affect the scram time of those control rods. As a result, per technical specification, scram time testing of those rods should have been completed. Exelon entered this issue into their corrective action program as issue report 2641454 to evaluate technical specification compliance.

During discussions with Exelon about the technical specification compliance, Exelon stated that they followed their process and the GE SIL 173 guidance by applying penalties to account for the increase in control rod drive temperatures. The inspectors then reviewed the GE SIL 173 and applicable Exelon procedures to verify Exelon’s application of GE SIL 173 and the scram time penalties. The most recent full scram occurred at Oyster Creek in May 2015. The inspectors reviewed the scram time data from that scram and noted that control rod drive 18-47 had a scram time of 5.5 seconds at the 90 percent insertion point. The inspectors determined that Exelon did not identify that the actual scram time data of 5.5 seconds was greater than the 3.6 second value that was recorded on the scram time data sheet. Also, the inspectors identified that the increase in scram time of 2.6 seconds (5.5 seconds – 2.9 seconds) was beyond the maximum 0.7 second penalty referenced in GE SIL 173. As a result, a degraded condition was unknown to Exelon until identified by NRC inspectors. Based on this data, the inspectors had a reasonable doubt of operability for the control rods that had control rod drives greater than 500ºF. Subsequently, on March 18, 2016, Exelon performed scram time testing on the control rods that had increased temperatures. The control rod drive 42-27 scram time test result was within the GE SIL 173 scram time penalty. The control rod drive 18-47 scram time test result was 6.5 seconds at the 90 percent insertion point, which indicated further degradation from the May scram time data of 5.5 seconds. As a result of an unknown degradation mechanism to control rod 18-47, operations fully inserted the control rod. Although, control rod drive 18-47 scram time was degraded, technical specification operability was maintained since the average of the three fastest 2x2 array control rods and average of all control rod insertion times were within technical specification scram time allowances.

The inspectors also reviewed Exelon’s procedures that incorporate the guidance recommended in GE SIL 173. The inspectors noted that GE SIL 173 recommended testing for the control rods operating at high temperatures at the next opportunity. The inspectors determined that Exelon did not perform scram time testing of the control rod drives with high temperatures. The inspectors also noted Exelon procedures do not specifically state to include those control rods in the next set of control rod drives to be scram time tested. Exelon entered this issue into their corrective action program as issue report 2643603.

Corrective actions included inserting control rod drive 18-47 fully into the reactor core, replacing the control rod drives with high temperature, developing a casual analysis of the degraded control rod drive, submitting a licensee event report to discuss technical specification compliance, and revising station procedures to fully align with GE SIL 173 recommendations.

Analysis. The inspectors determined that Exelon's failure to identify a condition adverse to quality, in accordance with 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," was a performance deficiency that was within Exelon's ability to foresee and correct. The performance deficiency is more than minor because it is associated with the configuration control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency affected the reliability of control rod drive 18-47 to perform its safety function due to a slower than normal scram time.

The inspectors evaluated the finding using IMC 0609, Attachment 4, "Initial Screening and Characterization of Findings," and IMC 0609, Appendix A, Exhibit 2, "Mitigating System Screening Questions." The inspectors determined that this finding is a deficiency that affected the design or qualification of a mitigating SSC, when the SSC maintained its operability or functionality. Therefore, the inspectors determined the finding to be of very low safety significance (Green).

The finding has a cross-cutting aspect in the area of Problem Identification and Resolution, Identification, because Exelon did not identify issues completely, accurately, and in a timely manner in accordance with the program. Specifically, Exelon did not identify that the actual scram time of control rod 18-47 was beyond the analyzed scram time resulting in a degraded control rod drive. (P.1)

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," states in part, conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, are promptly identified and corrected. Contrary to the above, prior to March 17, 2016, Exelon did not identify a deficient control rod drive (18-47) in which the actual scram time for the control rod was greater than previously analyzed. Specifically, Exelon's scram time from the May 2015 scram for control rod drive 18-47 (~5.5 seconds) was greater than the analyzed scram time data of approximately 3.6 seconds. Additionally, the March 2016 scram time testing data (6.5 seconds) showed further degradation for control rod drive 18-47. Exelon's immediate corrective actions included fully inserting control rod 18-47 into the reactor core, developing a casual analysis of the degraded control rod, and revising station procedure changes to incorporate high temperature control rod drives into the next selection of control rod drive scram time testing. Because the violation was of very low safety significance (Green) and has been entered into the corrective action program as issue report 2642325, this violation is being treated as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy. (**NCV 05000219/2016001-01, Failure to Identify a Slower than Normal Scram Time of a Control Rod Drive**)

1R18 Plant Modifications (71111.18 – 2 samples)

.1 Temporary Modifications

a. Inspection Scope

The inspectors reviewed the temporary modifications listed below to determine whether the modifications affected the safety functions of systems that are important to safety. The inspectors reviewed 10 CFR 50.59 documentation and post-modification testing results, and conducted field walkdowns of the modifications to verify that the temporary modifications did not degrade the design bases, licensing bases, and performance capability of the affected systems.

- Temporary change to the augmented off gas system usage requirements on January 31, 2016
- Engineering Change Request 16-00096 – Temporary change to the main steam isolation valve limit switch input to the reactor protection system 2 on February 26, 2016

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 5 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure were consistent with the information in the applicable licensing basis and/or design basis documents, and that the test results were properly reviewed and accepted and problems were appropriately documented. The inspectors also walked down the affected job site, observed the pre-job brief and post-job critique where possible, confirmed work site cleanliness was maintained, and witnessed the test or reviewed test data to verify quality control hold point were performed and checked, and that results adequately demonstrated restoration of the affected safety functions.

- EDG No. 1 following flexible coupling replacement on January 5, 2016
- EDG No. 2 following flexible coupling replacement on January 12, 2016
- Standby gas treatment system II following system valve actuator maintenance (V-28-30) on January 26, 2016
- Containment spray system II following fuse replacement on February 9, 2016
- Main steam isolation valve 5 percent closure test following limit switch replacements on February 26, 2016

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 7 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:

- Containment spray and emergency service water system I pump operability test on February 1, 2016 (in-service test)
- Core spray system II pump operability test on February 10, 2016
- Unidentified reactor coolant system leak rate verification on February 18, 2016 (reactor coolant system leakage)
- Torus to drywell vacuum breaker operability and in-service test on February 20, 2016
- Main station battery surveillance on February 23, 2016
- EDG No. 1 fast start test on February 29, 2016
- EDG No. 2 load test on March 7, 2016

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 – 1 sample)

.1 Training Observations

a. Inspection Scope

The inspectors observed a simulator training evolution for licensed operators on January 5, 2016, which required emergency plan implementation by an operations crew. Exelon planned for this evolution to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that Exelon evaluators noted the same issues and entered them into the corrective action program.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Occupational/Public Radiation Safety (PS)

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01 – 1 sample)

a. Inspection Scope

The inspectors reviewed Exelon's performance in assessing and controlling radiological hazards in the workplace. The inspectors used the requirements contained in 10 CFR 20, technical specifications, applicable regulatory guides, and the procedures required by technical specifications as criteria for determining compliance.

b. Findings

Introduction. A self-revealing Green NCV of Technical Specification 6.8.1, "Procedures and Programs" was identified for Exelon's failure to use respiratory protection, as required in the RWP/ ALARA plan 14-406 for drywell head reassembly work on October 2, 2014. The RP supervisor overseeing this work removed the respiratory protection requirement for this work contrary to the RWP/ALARA requirement and without engineering approval. As a result, two workers received an unplanned intake of radioactive material that resulted in unintended internal dose.

Description. On October 2, 2014, a team of five Exelon refueling services workers entered the refueling floor to begin work on positioning and tensioning the bolts/nuts on the drywell head. The RP supervisor for the refueling floor activities informed these workers that respiratory protection was not required while performing the work on the highly contaminated drywell head bolts/nuts in the reactor cavity. As the work in the reactor cavity commenced, due to deteriorating airborne radiological conditions, RP supervision suspended work and evacuated workers from the reactor cavity. Workers were checked for radioactive contamination on the refuel floor and were found to be contaminated. When exiting the radiological controlled area from the plant, two workers alarmed the personnel contamination monitor, had detectable facial/nasal contamination, and required personnel decontamination. Follow-up investigations, including multiple whole body counts over a four day period revealed that these two workers had intakes of radioactive material that resulted in unintended internal doses of 6.64 millirem and 8.18 millirem. Exelon entered this issue into their corrective action program as issue report 2390111. The casual analysis determined Exelon did not follow procedure RP-AA-403, "Administration of the Radiation Work Permit Program," which requires approval of engineering for RWP changes that alters the controls specified in the ALARA plan, such as respiratory protection requirements. Exelon's corrective actions included stopping work on this task and subsequently reinstituted the respiratory protection requirements to complete the remaining drywell head installation work.

Analysis. The inspectors determined that Exelon's failure to use respiratory protection during positioning and installing the bolts/nuts for the drywell head as required by Exelon's RWP 14-406, was a performance deficiency that was within Exelon's ability to foresee and correct. The performance deficiency is more than minor because it is associated with the Occupational Radiation Safety Cornerstone to ensure adequate protection of the worker from radiation exposure. Specifically, without the use of respiratory protection, two workers received unintended internal dose.

The inspectors evaluated the finding using IMC 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process." The inspectors determined that this finding is of very low safety significance (Green) because it did not result in an overexposure as defined by 10 CFR 20.1201, there was no substantial potential for an overexposure, and the ability to assess dose was not compromised.

This finding has a cross-cutting aspect in Human Performance, Procedural Adherence, because Exelon did not follow procedures and work instructions. Specifically, the RP supervision instructed the workers that respiratory protection was not required contrary to the applicable RWP/ALARA plan. (H.8)

Enforcement. Technical Specifications 6.8.1 requires, in part, that written procedures shall be established, implemented and maintained in accordance with Appendix A of Regulatory Guide 1.33. Regulatory Guide 1.33, Appendix A, Section 7, "Procedures for Control of Radioactivity," states that radiation protection procedures should be established. Radiation protection procedure, RP-AA-403, "Administration of the Radiation Work Permit Program," requires, that workers adhere to the requirements of the RWP/ALARA Plan, and that an individual obtain approval of engineering to allow deviation from a requirement in the RWP/ALARA Plan. RWP/ALARA plan 14-406 for drywell head reassembly, required respiratory protection. Contrary to the above, on October 2, 2014, the RP department specified that respiratory protection was not required in the refueling cavity during drywell head bolts/nuts installation activities and failed to obtain prior approval of engineering prior to removing the requirement for respiratory protection for this job activity. Immediate corrective actions included stopping work on this task and reinstituting respiratory protection requirements prior to completion of the drywell head installation work. Because this performance deficiency was of very low safety significance (Green) and was entered into the corrective action program as issue report 2390111, this finding is being treated as a NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 5000219/2016001-02, Failure to Use Respiratory Protection as Required in RWP/ALARA Plan for Drywell Head Reassembly)**

2RS8 Radioactive Solid Waste Processing and Radioactive Material Handling, Storage, and Transportation (71124.08 – 6 samples)

a. Inspection Scope

The inspectors verified the effectiveness of Exelon's programs for processing, handling, storage, and transportation of radioactive material. The inspectors used the requirements of 49 CFR 170-177; 10 CFR 20, 37, 61, and 71; applicable industry standards; regulatory guides, and procedures required by technical specifications as criteria for determining compliance.

Inspection Planning

The inspectors conducted an in-office review of the solid radioactive waste system description in the UFSAR, the process control program, and the recent radiological effluent release report for information on the types, amounts, and processing of radioactive waste disposed. The inspectors reviewed the scope of quality assurance audits performed for this area since the last inspection.

Radioactive Material Storage

The inspectors observed radioactive waste container storage areas and verified that Exelon had established a process for monitoring the impact of long-term storage of the waste.

Radioactive Waste System Walk-down

The inspectors walked down the following items and areas:

- Accessible portions of liquid and solid radioactive waste processing systems to verify current system alignment and material condition
- Abandoned in place radioactive waste processing equipment to review the controls in place to ensure protection of personnel
- Changes made to the radioactive waste processing systems since the last inspection
- Processes for transferring radioactive waste resin and/or sludge discharges into shipping/disposal containers
- Current methods and procedures for dewatering waste

Waste Characterization and Classification

The inspectors identified radioactive waste streams and reviewed radiochemical sample analysis results to support radioactive waste characterization. The inspectors reviewed the use of scaling factors and calculations to account for difficult-to-measure radionuclides.

Shipment Preparation

The inspectors reviewed the records of shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and Exelon verification of shipment readiness.

Shipping Records

The inspectors reviewed selected non-excepted package shipment records.

Identification and Resolution of Problems

The inspectors assessed whether problems associated with radioactive waste processing, handling, storage, and transportation, were identified at an appropriate threshold and properly addressed in Exelon's corrective action program.

b. Findings

One finding was identified by Exelon and is described in Section 4OA7.

4. OTHER ACTIVITIES

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 condition report screening meetings.

b. Findings

No findings were identified.

.2 Annual Sample: Core Spray Main Pump B Wire Failure

a. Inspection Scope

The inspectors performed an in-depth review of Exelon's apparent cause evaluation and corrective actions associated with issue report 2388760 related to a core spray main pump 'B' (NZ01B) surveillance test failure. During the performance of 610.3.215, "Core Spray System 2 Instrument Channel and Level Bistable Calibration and Test and System Operability," instrumentation and controls technicians identified that the expected response was not obtained at step 6.4.7.1 when low voltage, 5 volt direct current (Vdc), was identified at test terminal AA-146. The expected voltage was approximately 60Vdc. The surveillance test was performed on September 30, 2014, during the 1R24 Oyster Creek refueling outage. During subsequent troubleshooting performed on October 1, 2014, in accordance with work order M2364333, instrumentation and controls technicians identified that wire 1F-970 in cable 24-41 had failed (high conductivity at 4,000 ohms and low insulation resistance). The insulation resistance was meggered at 42Vdc and resulted in 20 ohms. Cable 24-41 was a rated 600Vdc nine conductor cable manufactured by General Electric with a Vulkene cross-linked polyethylene insulation. Wire 1F-970 was in the 125 Vdc control circuit for NZ01-B. Engineering change request OC 14-00471 001, "Core Spray Pump NZ01B Wire Change," was promptly initiated and swapped the faulty wire with a spare conductor in a like-for-like adjacent cable. Surveillance procedure 610.3.215, "Core Spray 2 Instrument Channel and Level Bistable Calibration and Test and System Operability," was satisfactorily completed on October 4, 2014, as a post-modification test and the NZ01B was declared operable.

The inspectors assessed Exelon's problem identification threshold, causal analyses, technical analyses, extent of condition reviews, and the prioritization and timeliness of corrective actions to determine whether Exelon was appropriately identifying, characterizing, and correcting problems associated with this issue. The inspectors reviewed the circumstances of this wire failure issue to ascertain the appropriateness of corrective actions. The inspectors also assessed Exelon's corrective actions to prevent recurrence. The inspectors compared the actions taken to the requirements of Exelon's corrective action program and 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action." In addition, the inspectors reviewed documentation associated with this issue, including condition reports, and interviewed engineering personnel to assess the effectiveness of the planned and implemented corrective actions.

b. Findings

No findings were identified.

Observations

After the faulty wire 1F-970 was identified and replaced, Exelon completed an equipment apparent cause evaluation on November 7, 2014. The inspectors noted that Exelon documented in the apparent cause evaluation that cable 24-41 was previously identified as having two faulty conductors prior to 2011. No additional information was provided to the circumstances of the faulty conductors or when the faults were identified. The faulty conductors were not being used and were documented on an as-built drawing updated in 2011. The inspectors inquired of design engineers when and how the faulty conductors were identified. The engineers determined the faulty wires were spared in 2008 after a conductor associated with the annunciator circuit for NZ01B overload and breaker permissive caused anomalous alarms in the main control room. The apparent cause evaluation noted that three of nine conductors in cable 24-41 were faulted and corrective actions were planned to complete diagnostic testing of the remaining and used six conductors in the upcoming Fall 2016 refueling outage 1R25. The alarm anomalies were documented in issue reports 711138 and 756372 initiated on December 13, 2007, and March 29, 2008, respectively.

The inspectors noted that the development, administrative review and processing of apparent cause evaluation (issue report 2388760) were opportunities to have assessed the operability of the remaining six conductors within cable 24-41. Exelon’s procedure OP-AA-108-115, Operability Determinations, has defined a degraded condition in part as a condition in which the qualification of a SSC or its functional capability is reduced. Examples provided of degraded conditions are failures, reduced reliability, malfunctions, deficiencies, deviations, and defective material and equipment. Cable 24-41 was a degraded condition because three of its nine conductors failed and the potential exists that the remaining conductors in this cable could be susceptible to similar degradation mechanisms. Step 4.1.5 of OP-AA-108-115 required operability to be determined immediately upon discovery that a system structure or component subject to technical specification is in a degraded or nonconforming condition.

Exelon promptly entered this issue into its corrective action program as issue report 2624299. Operations shift management determined the cable is operable but degraded and is only associated with NZ01B. The determination considered that previous surveillance testing demonstrated NZ01B would perform its function, therefore the issue is considered minor.

.3 Annual Sample: Corrosion Rate Change for Pipe Integrity Program

a. Inspection Scope

The inspectors performed an in-depth review of the Exelon staff‘s identification, evaluation and corrective actions associated with issue report 1490523, which was initiated to document the corrosion rate change for the Oyster Creek Pipe Integrity Inspection Program. Based on Exelon’s lab report, OYS-33725, the corrosion rate related to specific flow-related corrosion on two in-service emergency service water piping components ES0106 and ES0112 required a change from the general corrosion rate of 0.02 inches/year to a corrosion rate of 0.037 inches/year. The function of the line containing these degraded emergency service water components is to supply cooling water from the canal via the emergency service water pumps to the containment spray heat exchangers.

The inspectors assessed the problem identification threshold, extent of condition reviews, and the prioritization and timeliness of corrective actions to determine whether Exelon personnel were appropriately identifying, characterizing, and correcting problems associated with the increase corrosion rate due to internal coating failures of the emergency service water piping located under the Oyster Creek intake structure deck and whether the planned and completed corrective actions were appropriate.

The inspectors reviewed a sample of relevant corrective action documents, condition reports, work orders, procedures, ultrasonic testing thickness examination records, and technical evaluations noted in the Attachment to this report. The inspectors compared the actions taken to the requirements of Exelon's corrective action program procedure, 10 CFR 50, Appendix B, and American Nuclear Standards Institute (ANSI) B31.1-1983 through winter 1984 Addenda, and supplemental criteria. The supplemental criteria are identified in the design code reconciliation report, MPR-1938. These supplemental criteria are exceptions to the requirements of ANSI B31.1-1983 through winter 1984 Addenda that are necessary to maintain compliance with American Standards Association B31.1, 1955 with supplements, addenda and code cases through 1966.

b. Findings

No findings were identified.

Observations

Exelon's inspection of the emergency service water 1-4, 14"x14"x10", welded pipe tee (ES0112), that was cut-out and removed from under the deck of the Oyster Creek intake structure, north bay, system 1, had measurements documented in ultrasonic testing thickness examination report BOP-UT-2015-009, September 17, 2015. Results of the ultrasonic testing thickness measurements indicated that there had been some measurable corrosion of the wall thickness since the previous ultrasonic testing thickness measurements taken during the 1R24 refueling outage in October 2012. One of the 40 spot ultrasonic testing thickness measurements taken on the emergency service water 1-4, (ES0112) pipe tee shows a minimum wall thickness of 0.104 inches at a localized area of the pipe tee that was slightly below the calculated wall thickness value of 0.145 inches documented in technical evaluation A2210238-44.

The inspectors reviewed Exelon's corrective actions to ensure timely identification and resolution of non-conforming conditions. The inspectors determined that procedures and processes were in place to address the emergency service water pipe wall thinning isssue. Specifically, the inspectors reviewed action tracking items 01477443-21 and 01477443-22 and determined that the ultrasonic testing thickness examination results of the emergency service water piping tee identified on September 17, 2015, and the planned inspections and replacement of emergency service water system 1 pipe spool ES0106 per action request number A2327285 during the 1R26 refueling outage tracked actions for evaluation of the previously calculated corrosion rate of 0.037 inches/year. The evaluations would involve appropriate revisions considering the localized corrosion rate of 0.052 inches/year documented in technical evaluation 02621492-02. Based on these action tracking items, the inspectors determined Exelon staff planned to update Technical Data Report 829, "Pipe Integrity Inspection Program," and update Topical Report 140, "Emergency Service Water and Service Water System Piping," based on the ultrasonic testing thickness examination results from operating cycle 25 and refueling outage 1R26.

The inspectors determined that while the emergency service water 14 inch, ES0112, pipe tee was replaced as part of Exelon's corrective actions to address emergency service water localized corrosion problems, one location of the replaced tee was measured to be lower than the calculated minimum wall thickness and actions were not completed to evaluate this condition. The inspectors determined that Exelon did not perform a technical evaluation to compare the degraded localized as-found condition against the computed minimum pipe wall value to ensure operability of the emergency service water system piping component. The inspectors considered this to be a past operability concern of the emergency service water system piping component that was removed from the plant in September 2015, and had no impact on any existing plant systems, structures, or components. Subsequently, Exelon performed technical evaluation issue report 2621492-02 to verify past operability and structural integrity of the emergency service water system piping tee component. The inspectors reviewed the technical evaluation and verified that structural integrity was maintained and the emergency service water system piping would have been able to perform its intended design basis function. Therefore, not initially performing a past operability review was a minor issue.

.4 Annual Sample: Increased Unidentified Leak Rate Due to Control Rod Drive Mechanism O-rings

a. Inspection Scope

The inspectors performed an in-depth review of Exelon's evaluation and corrective actions associated with issue report 2475490 for an increase in Oyster Creek's unidentified leak rate following the start-up from a forced outage in March 2015. Specifically, the unidentified leak rate increased from 0.6 gallons per minute (gpm) (pre-outage) to 0.84 gpm (post-outage) and continued to slowly increase to a maximum leak rate of 2.62 gpm. The plant's technical specification requires the unidentified leak rate to be tracked and limits the quantity of unidentified leakage to a maximum rate of 5 gpm.

The inspectors assessed Exelon's problem identification threshold, cause analyses, compensatory actions, and the prioritization and timeliness of Exelon's corrective actions to determine whether Exelon staff were properly identifying, characterizing, and correcting problems associated with this issue and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to Exelon's corrective action program and the requirements of 10 CFR 50, Appendix B. The inspectors reviewed documentation from past maintenance activities and interviewed engineering personnel to discuss the results of the cause evaluation and to assess the effectiveness of the implemented corrective actions.

b. Findings and Observations

No findings were identified.

Exelon staff determined the cause of the increased unidentified leak rate was due to leakage past the CRDM housing to flange mechanical joint, which is sealed using O-rings, based on indications from available plant parameters, chemistry samples, and past operational experience. Exelon staff also determined that the modified CRDM seal design, which was installed in a select number of CRDMs in 2010, was not effective in

reducing the leakage. Specifically, a previous corrective action implemented a modification to the seals by replacing the original CRDM housing to flange O-ring with a C-Ring design; however, a majority of the C-rings have developed leaks in addition to the O-rings. The inspectors noted that Exelon staff planned to replace all of the remaining C-rings with the original O-ring design during the next refueling outage.

The inspectors concluded that Exelon staff conducted an appropriate review to identify the likely causes of the increased unidentified leakage. Following identification of a leaking CRDM seal through troubleshooting, immediate corrective action was to isolate the cooling water to the CRDM. Exelon staff further implemented an adverse condition monitoring plan as a corrective action, which included increased monitoring frequencies of plant parameters and actions to complete when established parameters were exceeded. The inspectors noted that Exelon staff were in the process of evaluating additional corrective actions in consultation with the CRDM maintenance vendor related to O-ring installation enhancements and CRDM flange dimensional measurements.

The inspectors reviewed Exelon's troubleshooting plan and procedure ER-AB-331-1006, "BWR Reactor Coolant System Leakage Monitoring and Action Plan," to verify that the primary source of the unidentified leakage was appropriately determined to be from the CRDM mechanical joints. The inspectors reviewed the adverse condition monitoring plan and the results of control rod drive exercising to ensure that prescribed actions were being implemented. The inspectors also reviewed the master work order for CRDM replacements during the last refueling outage to verify that maintenance was conducted at the required intervals and in accordance with site procedures, and that the results did not identify any degraded conditions. The inspectors determined Exelon's overall response to the issue was commensurate with the safety significance, was timely, and included appropriate compensatory actions.

.5 Annual Sample: Root Cause – EDG Cooling Flexible Coupling Hose Failure

a. Inspection Scope

The inspectors conducted an in-depth review of Exelon's root cause analysis and corrective actions associated with the coolant leak on EDG No. 1 (issue report 2610027). Specifically, on January 4, 2016, the EDG No. 1 cooling flexible coupling hose ruptured during a bi-weekly surveillance test, which resulted in low coolant pressure and subsequent inoperability of EDG No. 1.

The inspectors assessed Exelon's problem identification threshold, cause analyses, extent of condition reviews, and the prioritization and timeliness of Exelon's corrective actions to determine whether Exelon was appropriately identifying, characterizing, and correcting problems associated with this issue and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to Exelon's corrective action program and the requirements of 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

Introduction. The inspectors identified a preliminary White finding and associated apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because Exelon did not provide appropriate maintenance instructions to

ensure the EDG cooling flexible coupling hose was maintained to ensure adequate cooling to support the EDG No. 1 safety function.

Description. On January 4, 2016, EDG No. 1 was operated for its bi-weekly load surveillance test when alarms “EDG 1 LOW COOLANT PRESSURE” and “EDG 1 DISABLE” were received. Following automatic shutdown of the EDG unit, Exelon staff discovered that the flexible coupling hose had ruptured, which allowed engine coolant to escape through the ruptured hose. This resulted in low cooling water pressure and the actuation of the engine shutdown protective features and alarms. Exelon’s immediate corrective actions consisted of replacing EDG No. 1 and EDG No. 2 flexible coupling hoses and initiating a root cause evaluation to investigate and identify the causes of the flexible coupling hose failure.

Oyster Creek is equipped with two identical EDG units, which were manufactured by Electro-Motive Division (EMD). The function of the EDGs is to provide alternating current (AC) power to the safety-related class 1E busses upon a loss of off-site power. The EDG cooling water system for each diesel consists of engine driven cylinder bank pumps that supply cooling to the engine. Heated water from the discharge manifold flows through two forced air cooled radiators through a lube oil cooler and back again to the pumps. The EDG cooling water system includes a temperature control manifold, water tank, piping, and instrumentation. The water tank stores the cooling water and allows expansion of the fluid and allows refilling of the system. The water tank has two connections on the bottom of the tank that are connected to the suction of the two cylinder bank pumps. The piping from the tank to the suction piping of the two cylinder bank pumps is connected via two separate flexible coupling hoses. These flexible coupling hoses are composed of a nitrile rubber material. Exelon last replaced these hoses in 1994 as a corrective action for a leak on one of the hoses.

As part of their investigation, Exelon staff sent parts of the flexible coupling hose to Exelon PowerLabs for failure analysis. Exelon PowerLabs concluded that the hose failure was caused by thermal degradation and aging. Based on the laboratory failure results, Exelon concluded that EDG No. 1 could have met its mission time (run continuously for 24 hours) any time prior to approximately 17.8 days before the actual hose failure on January 4, 2016. Exelon engineering staff concluded that vibration and pressure effects were negligible and therefore did not factor them into their evaluation.

The inspectors reviewed Exelon’s analysis and determined that while temperature degradation was the primary factor of degradation, vibration and pressure effects also contributed to degradation. The inspectors noted that EDG No. 1 failed during a surveillance test and not during a standby condition. In addition, the hose degradation rate was accelerated during EDG operation due to increased cooling water temperature. Using the accumulated EDG No. 1 run times from past surveillance testing, the inspectors concluded that a more realistic estimate of EDG No. 1 functionality was that the EDG could have met its mission time (run continuously for 24 hours) approximately 168 days prior to the hose failure on January 4, 2016.

Exelon’s root cause evaluation, issue report 2610027, determined, “the site implementation of Exelon’s Electro-Motive Division Diesel Generator performance centered maintenance (PCM) Template did not include making preventative maintenances (PM) for the ‘Miscellaneous – Non-metallic flexible hose replacement

12 year frequency template line item while performing the corrective action to preclude recurrence captured under Root Cause corrective action program O2004-1184 – Loose EDG-1 Pillow Block Fan Shaft Bearing."

The inspectors reviewed the root cause evaluation and supporting failure analysis report, and performed independent reviews of the flexible coupling hose service life based on thermal degradation and aging. The inspectors determined that the age of the hose beyond vendor manufacturing recommendations and the operating temperature of the hose resulted in thermal degradation and aging greater than the limit of the flexible coupling hose material. Specifically, the service life (approximately 22 years) and subsequent thermal degradation likely caused the flexible coupling hose to deteriorate the hose material which eventually caused a failure.

The inspectors reviewed the EDG maintenance history to evaluate Exelon's performance. Prior to January 2005, Exelon staff followed the instructions in Exelon procedure 636.1.010, "Diesel Generator Inspection (24 Month)," for performing EDG maintenance which included the diesel cooling water system. As part of a corrective action (O2004-1184) for the EDG pillow block issue that occurred on May 17, 2004, the diesel generator inspection procedure was changed and individual work orders were established for PM tasks specified in that procedure and the Exelon EDG PCM template. At the time of work order establishment in 2005, the vendor manual, EMD user's group, and Exelon's PCM template, all of which specified replacement of the flexible coupling hoses, were available to be reviewed. Specifically, the vendor manual, VM-OC-0096, "Engine Maintenance Manual 645E4 Turbo Charger Engine," cooling water section stated to replace flexible coupling seals every 12 years. The EMD owners group recommended maintenance program, section 8.1, "Cooling," stated to replace rubber seals in cooling system (applies to flexible pipe couplings) every 12 years. Also, Exelon's EMD PCM template directed replacement of non-metallic flexible hoses every 12 years. As mentioned above, the inspectors determined, that Exelon last replaced these hoses in 1994 as a corrective action for a leak on one of the hoses.

In addition, Exelon's procedure 636.1.010, "Diesel Generator Inspection (24 Month)," Appendix 1, "Component Replacement Schedule," stated to replace "water system seals" every 10 years and specifically in 18R/19R (refueling cycle numbers) which was from years 2000 – 2004. Water system seals would include the flexible coupling hoses as it is part of the cooling water system as specified in the vendor manual and the EMD owner's group maintenance program. Exelon implemented revision 21 to the Diesel Generator Inspection (24 Month) in 2002 which changed the Appendix 1 to that procedure by adding "if leaking" as a comment to the water system seals section. The inspectors noted that the Exelon procedure change request form did not document or reference an evaluation that described the reason for this addition.

As stated above, on May 17, 2004, EDG No. 1 failed due to a pillow block issue. Licensee event report, 2004-001-00, was issued. As a corrective action (O2004-1184) for this issue, Exelon engineering staff were directed to, "evaluate and create PM tasks for the 24-month diesel inspection, including the specific tasks identified in the 'Component Replacement Schedule' (Appendix 1) of ST 636.1.010." The completed corrective actions stated, in part, that PM tasks for items in the diesel generator inspection procedure (24 month) and Exelon's PCM template were reviewed and separate work orders were established for those items. The inspectors reviewed, work order A2106558, which evaluated the cooling water system replacement schedule and it stated, in part, "add PM task to perform cooling system – rubber seals in cooling system,

replace." Work order R2166216, "Replace Engine Water Inlet Elbow Seal," was created as the work order to replace the rubber seals in the cooling system. The inspectors reviewed the work order and other PM task directed work orders that could be related to the cooling water system and determined they did not include replacing the flexible coupling hoses as directed by corrective actions for the May 2004 No.1 EDG failure, O2004-1184.

The inspectors concluded that Exelon had the above two opportunities to identify that the maintenance work instructions and procedures but did not establish a replacement periodicity for the flexible coupling hoses as recommended by the Exelon PCM template, vendor manual, EMD owners group, and the original 24 month diesel inspection procedure. This led to those flexible coupling hoses being in service longer than manufactured recommendations and ultimately failure of one flexible coupling hose on EDG No. 1 on January 4, 2016.

Analysis. The inspectors determined that Exelon's failure to maintain appropriate maintenance instruction to ensure the EDG cooling flexible coupling hoses were maintained to support the EDG safety function, in accordance with 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was a performance deficiency because it was reasonably within Exelon's ability to foresee and correct and should have been prevented.

This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the ruptured flexible coupling hose caused the failure of EDG No. 1 to perform its safety function. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," the inspectors screened the finding for safety significance and determined that a DRE was required based on EDG No. 1 being inoperable for greater than the technical specification allowed outage time of 7 days.

A Region I Senior Reactor Analyst (SRA) completed a DRE using the Oyster Creek Standardized Plant Analysis Risk (SPAR) model, Version 8.22 and Systems Analysis Programs for Hands-On Integrated Reliability Evaluations (SAPHIRE). Based upon the DRE, the estimated increase in core damage frequency for this issue was 7E-6, or low to moderate safety significance (White). The dominant internal core damage sequences involved various loss-of-offsite-power (LOOP) initiating events with failure of both EDGs, failure of the combustion turbines, and failure to recover an EDG or offsite power. The dominant external event core damage sequences involved office building roof fires leading to loss of condenser heat sink, failure of the 1B2 electrical bus, failure of the 'A' startup transformer (SUT) and subsequent failure to control the isolation condensers without direct current (DC) power. The actual run times that EDG No. 1 was available and demonstrated functionality prior to failure on January 4, was credited in the risk evaluation and provided operators more time for recovery of offsite power and lowered the risk of this issue. Also, diverse make-up sources to the isolation condenser and availability of the Forked River combustion turbine generators provided additional risk mitigation. The SRA used an exposure time of 168.75 days (168 days plus repair time) for the time the EDG would have been challenged to meet its 24-hour mission time.

The DRE is enclosed as Attachment 1 to this report. This finding does not have an associated cross-cutting aspect because the performance deficiency occurred in 2005 and is not reflective of present performance.

Enforcement. 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that "activities affecting quality shall be prescribed by documented instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings."

Contrary to the above, since 2002, Exelon did not appropriately prescribe instructions or procedures for maintenance on the EDG cooling water system to ensure the EDG cooling flexible coupling hose was maintained to support the EDG safety function. Specifically, Exelon did not have appropriate work instructions to replace the EDG cooling flexible coupling hoses every 12 years as specified by Exelon's procedure and vendor information. As a result, the flexible coupling hose was in service for approximately 22 years and subjected to thermal degradation and aging that eventually led to EDG No. 1 failure on January 4, 2016. As a consequence of this inappropriate work instruction issue, Exelon also violated Technical Specification 3.7.C, because EDG No. 1 was determined to be inoperable for greater than the technical specification allowed outage time of seven days. Exelon's immediate corrective actions included entering the issue into their corrective action program (issue reports 2607247 and 2610027), replacing the EDG No. 1 and No. 2 flexible coupling hoses, and initiating a failure analysis to determine the causes of the failed flexible coupling hose. This issue is being characterized as an apparent violation (AV) in accordance with the NRC's Enforcement Policy, and its final significance will be dispositioned in separate future correspondence. **(AV 05000219/2016009-01, Inadequate Instructions for the Flexible Coupling Hose Preventative Maintenance Resulting in an Inoperable Emergency Diesel Generator)**

c. Observations

The inspectors concluded that Exelon staff conducted an appropriate technical review in sufficient detail to identify the likely causes of the flexible coupling hose failure. Their review included an examination performed by a laboratory (Exelon PowerLabs) and an estimated evaluation of exposure time (when EDG No. 1 could have performed its 24 hour mission time) performed by a third party contractor. The inspectors also concluded that Exelon staff identified the extent of condition which was limited to the one redundant EDG unit. Corrective actions included replacement of the failed EDG No. 1 and EDG No. 2 flexible coupling hoses and reviewing other potentially missed PMs.

Exelon staff documented in their analysis that the flexible coupling hose failure occurred via thermal degradation and aging. While the inspectors agreed that thermal degradation and aging was a dominant factor, the vibration and pressure effects could not be ignored. The inspectors also noted that the degradation rate was accelerated during EDG operation due to increased cooling water temperature and other synergistic effects discussed in Attachment 1 to this report. The inspectors recognized the difficulty in determining an exposure time due to various uncertainties involved. Therefore an exposure time methodology was applied using Section 2.5 of the Risk Assessment of Operational Events (RASP) Volume 1 – Internal Events, Revision 2.0, when evaluating the risk increase of the issue. The risk evaluation was based on the proven cumulative

run time (factual evidence) and used a 24 hour mission time when calculating the exposure time of 168 days. Additionally, as a sensitivity run, this time was divided by 2, but did not result in a change in the overall risk determination.

The inspectors determined Exelon's overall response to the issue was commensurate with the safety significance, was timely, and included appropriate compensatory actions. The inspectors concluded that actions completed to replace the flexible coupling hoses on EDG No. 1 and EDG No. 2 were reasonable to correct the problem and prevent reoccurrence.

4OA6 Meetings, Including Exit

On April 7, 2016, the inspectors presented the inspection results to Mr. M. Gillin, Plant Manager, and other members of the Oyster Creek staff. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

On April 29, 2016, the inspectors presented the inspection results of the EDG cooling flexible coupling hose failure inspection to Mr. G. Stathes, Site Vice President, and other members of the Oyster Creek Nuclear Generating Station staff. The inspectors verified that no proprietary information was retained by the inspectors or 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 a non-cited violation:

From 2010 to 2014, Oyster Creek made a total of four shipments of radioactive material which contained category 2 quantities of radioactive material. Oyster Creek did not implement a transportation security plan for any of these shipments, which is contrary to the requirements of 49 CFR 172, Subpart I, "Safety and Security Plans." This performance deficiency adversely affected the Public Radiation Safety cornerstone attribute of Program and Process based on inadequate procedures associated with the transportation of radioactive materials. The finding was determined to be of very low safety significance (Green) because the transportation of radioactive material issue did not involve: (1) a radiation limit that was exceeded; (2) a breach of package during transport; (3) a certificate of compliance issue; (4) a low level burial ground nonconformance; or (5) a failure to make notifications or provide emergency information. This issue was documented in the Exelon's corrective action program as IR 2484646. Corrective actions included contracting with a vendor to receive regular, prompt notifications of potentially applicable rule changes in the Federal Register.

ATTACHMENT 1: DETAILED RISK EVALUATION

ATTACHMENT 2: SUPPLEMENTARY INFORMATION

ATTACHMENT 1: DETAILED RISK EVALUATION
Oyster Creek Nuclear Generating Station
Failure of Emergency Diesel Generator (EDG) No. 1 Flexible Coupling Hose

Screening Logic

The inspectors evaluated the finding in accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," for the mitigating systems cornerstone. The finding screened to a DRE because EDG No. 1 was inoperable (not capable of running for the 24-hour mission time) for a period of time greater than Technical Specification 3.7.C allowed outage time of 7 days.

Detailed Risk Evaluation

The SRAs evaluated the finding using the Oyster Creek SPAR model version 8.22, and SAPHIRE version 8.1.3.

Internal Events Risk Contribution

Key Assumptions:

Exposure Time

The SRA reviewed Exelon PowerLabs' Report summarizing the results of the flexible coupling hose failure investigation. The failed hose (Nitrile rubber composition), inner layer was hardened and cracked throughout the inside diameter surface. There was no elasticity or flexibility of the rubber material in the vicinity of the rupture location. Additionally, significant cracking was localized to the area under the edges of the clamps where there would be areas of higher stress. The outer layer was also hardened with slight flexibility remaining. The observations were consistent with degradation due to thermal degradation and aging. Beneath the inner layer was a center layer of woven fabric reinforcement which was significantly weakened in all locations. Also, deposits (likely iron oxides) were observed in the area of the hose that was in contact with the piping and on portions of the inner layer in the location of the rupture.

A significant difference in hardness was detected between an un-used and the as-found EDG No. 1 ruptured flexible coupling. The un-used coupling had an average durometer (hardness) value of 70 A (Shore A). The failed coupling rubber produced a durometer value greater than 90 A. According to the Powerlabs findings and American Society for Testing and Materials (ASTM) D2240, durometer readings above 90 A are not considered to be reliable. However, the difference indicated significant embrittlement of the ruptured coupling inner layer. Additionally, EDG No. 2 left and right bank flexible coupling rubber inner layer generated average values of 85 durometer 'A' (both exhibiting much higher inner layer hardness than the un-used coupling hardness). According to Exelon document, "Elastomer Evaluation Guide," the service life of nitrile rubber at 182ºF is 1.2 years and 14.8 years at 122ºF, the standby temperature. Exelon's technical evaluation used an Arrhenius model method that predicted the actual life of the hose at a temperature of 125ºF to be greater than 18 years (end of life represents 50 percent material property degradation). The Arrhenius model also predicted a nominal one-year life based on continuous operation at a temperatures of 179ºF.

Both Oyster Creek EDGs are run for about 1.5 hours every 14 days. The failure on January 4, 2016, occurred within the first half hour of operating at the elevated coolant water temperature (180ºF) compared to the previous 336 hours of standby coolant water temperature of 125ºF (since the last completed surveillance test). While the period of time in standby temperature conditions contributes to the nitrile rubber degradation, the elevated operating temperature significantly contributes more to the degradation rate of the nitrile rubber coupling hose.

Based upon these operating times and temperatures, Exelon completed a sensitivity analysis that estimated the exposure time (period of time the EDG would not have been capable of fulfilling its mission time) using the Arrhenius method to be 17.8 days. The inspectors acknowledge that the Arrhenius model is a widely accepted method for predicting expected service life. However, the inspectors concluded that using this method to reverse engineer an exposure period for a service life failure (beyond the 50 percent degradation state), was non-conservative because it is solely dependent upon time at a specific temperature. The uncertainties introduced by this specific application (operating pressure, water chemistry affects, installation stresses and vibration) are not accounted for in the Arrhenius model and therefore make this exposure time prediction highly uncertain.

Exelon's preferred exposure time for this issue was based upon T/2 methodology. Time (T) representing the time period between the last successful surveillance test on December 21, 2015 and the test failure on January 4, 2016, (14 days). Exelon concluded that T/2 or 7 days best represented the presumed exposure period because the actual time that the EDG would not have been capable of fulfilling its complete 24-hour mission time is unknown. Acknowledging that the precise time that EDG No. 1 was no longer capable of meeting its 24-hour mission time is indeterminate, the SRAs concluded that the most appropriate and conservative method, prescribed by the RASP, is to account for the observed cumulative EDG runtimes. Using the guidance in Section 2.5 of the RASP Handbook, Revision 2.0, the SRA estimated the time and temperature dependent exposure period was 168 days (refer to Table 1 below for details).

SPAR Model Modifications

Consistent with RASP guidance for run time dependent failure risk evaluations, the SRA modified the SPAR model to account for the successful EDG run times by revising the failure to recover offsite power probabilities. The method used to adjust the probabilities for non-recovery of offsite power was developed in consultation with Idaho National Labs. This method involves convolution and maintains the potential for random EDG failures during the 24-hour mission time.

Model adjustments were made to account for diminished decay heat following successful EDG operation. With decay heat rates lowering with time after shutdown, as well as reduced reactor pressure, the impact and potential for recirculation pumps seal leakage is reduced over time. To account for this condition, SPAR model post processing rules were written for each interval between surveillance test runs. The rules were invoked for the dominant sequences which included offsite power non-recovery events (OEP) at 30 minutes, 1 hour, 4 hours and 10 hours.

Sample interval 1 from Table 1's exposure period was from December 21, 2015 to January 4, 2016. In this interval for modeling purposes (new basic events), EDG No. 1 was considered to fail after 1 hour of operation due to the performance deficiency. The exposure time for this period was 14 days. Details about EDG No. 1 operating history are provided in Table 1 below. In order to model the run failure at one hour, recovery rules and model logic changes were required.

The 30 M (minute) offsite power non-recovery dominant cutsets were only associated with recirculation pump seal failures regardless of isolation condenser success or failure. Therefore, for the first interval, only 15 minutes was credited to add to this 30 minute LOOP sequence. This also ensured that convolution rules were still applied by adjusting to non-recovery of offsite power to 90 minutes vice 75 minutes as convolution had a 90 minute basic event.

The EDG run was assumed to be 45 minutes prior to failure (30 minutes before hose failure with an assumed additional 15 minutes before machine failure due to lack of cooling).

<u>Example of First interval adjustments to OEP recoveries</u>

OEP 30M = EDG1 (45 minutes) + OEP 30M + 15M = 45M + 45M (minutes) = 90 Minutes. Therefore OEP30M changed to 90M OEP 1HR = EDG1 (45Minutes) + OEP 1 HR + 30M = 2.25 Hours. Because 1 HR dominant cutsets are associated with isolation condenser failures any fractions were rounded down in this case to 2 hours because of the loss of decay heat removal function. So OEP-NR01HR = OEP-NR2HR OEP 4HR is always associated with success of the isolation condensers, without recirculation pump seal failures. This would allow added time when station blackout conditions would occur due to batteries allowing isolation condensers to continue to remove decay heat until depletion. Therefore, any fractions were rounded up. OEP 4HR = EDG1 (45 minutes) + OEP 4HR + 30M = 5.25HR rounded to 6HR for use in post processing rule. OEP10HR simply used the credited EDG run time which was added to the 10 hours.

These rules were adjusted for all the different intervals based on the EDG accumulated and credited run time. These rules in essence give credit for the additional time EDG No. 1 had proven run time and would have supported the removal of decay heat and ability to maintain normal reactor vessel water levels. The new rule finds the cutsets with failure to recover offsite power and the EDG No. 1 failure to run and deletes the OEP recovery term and adds another OEP recovery term to best represent the condition. This rule section was added before the convolution rules section.

The EDG No. 1 surveillance tests completed prior to January 4, 2016, were broken into exposure time intervals. These intervals were then added up until the 24-hour mission time was met. Separate delta core damage frequency risk calculations were performed for all of the 14 intervals, comprising the cumulative exposure time back to when EDG No. 1 had proved based on run time to complete any required 24-hour mission time (July 20, 2015). As mentioned, each of these exposure intervals had revised basic events and post-processing rules written to reflect adjustments to offsite power recovery and fault tree revisions.

<u>Common Cause Assumption</u>

The two Oyster Creek EDGs are similar in all respects. As previously stated, the Powerlabs report identified increased hardness on the EDG No. 2 flexible coupling internal surfaces well above normal ranges. Therefore, no changes to the model were made to account for this two

component common cause group. The SRA set the EDG No. 1 failure to run basic event (EPS-DGN-FR-DG1) to TRUE in the conditional case evaluations to ensure the common cause basic event is revised to reflect this coupling mechanism.

TABLE 1
Internal Event EDG Run Times for calculated 24 hour mission

Interva l	Dates	Duration (days)	Runtime (hours)	Cumulative Run Time (hours)	EDG Run Time (hours) *****
1	12-21-15 to1-4-16	14	1	1	1
2	12-7 to 12-21	14	1.639	2.639	3
3	11-30 to 12-7	7	2.039	4.678	5
4	11-23 to 11-30	7	1.534	6.212	6.5
5	11-10 to 11-23	13	1.779	7.991	8.25
6	10-26 to 11-10	15	1.569	9.56	10
7	10-18 to 10-26	8	1.615	11.175	11.5
8	10-12 to 10-18	6	1.639	12.814	13
9	9-28 to 10-12	14	1.925	14.739	15
10	9-11 to 9-28	17	1.347	16.086	16.25
11	8-31 to 9-11	11	1.708	17.794	18
12	8-16 to 8-31	15	1.495	19.289	19.5
13	8-4 to 8-16	12	1.506	20.795	21
14	7-20 to 8-4	15	1.378	22.173	22.5
15	7-6 to 7-20	14	1.547	23.72	24

Notes:

On July 20, 2015, the EDG No. 1 cumulative run time capability of 24 hours was observed. For each exposure interval, the delta core damage frequency (CDF) contribution was calculated and summed to obtain the overall risk increase. Two very short runs were grouped together into the intervals and accounted for as there was some thermal cycling involved.

***** For each exposure interval, 15 minutes was added to the observed run time value to account for an assumed 15 minutes of EDG operation without cooling before EDG failure.

Internal Risk Calculation

Interval	Cumulative Run Time	Cond Case (yr)	Base Case (yr)	Delta CDF (yr)	Exposure days	Delta CDF
1	1	1.31E-5	1.11E-6	1.2E-5	14	4.60E-7
2	3	8.81E-6	1.11E-6	7.7E-6	14	2.95E-7
3	5	7.16E-6	1.11E-6	6.05E-6	7	1.16E-7
4	6.5 *	6.61E-6	1.11E-6	5.50E-6	7	1.06E-7
5	8.25 *	5.95E-6	1.11E-6	4.84E-6	13	1.724E-7
6	10	5.71E-6	1.11E-6	4.6E-6	15	1.89E-7
7	11.5 *	5.37E-6	1.11E-6	4.26E-6	8	9.34E-8
8	13	5.26E-6	1.11E-6	4.15E-6	6	6.82E-8
9	15	5.09E-6	1.11E-6	3.98E-6	14	1.53E-7
10	16.25 *	4.96E-6	1.11E-6	3.85E-6	17	1.79E-7
11	18	4.94E-6	1.11E-6	3.83E-6	11	1.15E-7
12	19.5 *	4.88E-6	1.11E-6	3.77E-6	15	1.54E-7
13	21	4.82E-6	1.11E-6	3.71E-6	12	1.22E-7
14	22.5	4.82E-6	1.11E-6	3.71E-6	15	1.52E-7

*EDG run times were rounded down for fractions for ease of modeling and conservatism when determining adjustments to offsite power non-recovery probabilities

Internal Delta CDF for 168 days Exposure Time

The CDF increase for LOOP internal events with applied common cause potential, for the cumulative 24-hour run time exposure period (168 days) is 2.38E-6/yr.

The transient and loss of feedwater control events were noted to have a combined increase in CDF of 3.74E-7/yr. The analyst implemented post processing rules to delete conservative core damage cutsets such as test and maintenance on both trains of SUT breakers and test and maintenance on 4 kilovolt (kV) safeguards bus at power. Dominant cutsets for these events were associated with the failure of both SUT breakers to close with failure of EDG No. 2 to run and failure to control the isolation condensers without DC power.

Analysis of Dominant Cutsets

For internal event consideration, the dominant accident sequence cut-sets involved loss-of-offsite-power (LOOP) events with failure of both EDGs, failure of the combustion turbines to supply power to the safety busses, with failure to recover an EDG and subsequent failure to recover offsite power, leading to core damage.

Repair Interval Risk

EDG No. 1 was unavailable and not recoverable from the time it automatically shutdown until maintenance personnel replaced the flexible coupling and operations removed the clearance to enable standby capability.

EDG No. 1 was unavailable for 18 hours after the failure.

For the conditional case, a change set was used to set basic event EPS-DGN-FR-DG1 to TRUE, to account for increase in common cause failure until EDG No. 2 was inspected. No rules were required to account for failure to recover offsite power events because EDG No. 1 was unavailable during the time of maintenance.

Condition case (2.27E-5/yr) – Base case (6.9E-7/yr) = 2.20E-5/yr

2.20E-5/yr X Exposure time (18/8760 hours) = 4.52E-8/yr

The increase in CDF due to the repair interval was 4.5E-8/year

Uncertainty and Sensitivity Analysis

The analyst performed several uncertainty and sensitivity analyses as shown below. As previously discussed, one of the most significant aspect of the risk evaluation was exposure time. Sensitivity analyses were performed for different exposure times to confirm the recommended White finding:

Mission time 24 hour run (168 days)

Delta CDF = Internal Events 2.75E-6/yr + Repair 4.52E-8/yr + Fire 4.48E-6/yr + Seismic 1.41E-7/yr = 7.42E-6/yr

Mission Time 24 hour run (T=168 days) divided by 2 or 84 days

Delta CDF (Overall time divided by 2 to reflect uncertainty of when coupling would fail)
Internal Events 1.69E-6/yr + Repair 4.52E-8/yr + Fire 2.25E-6/yr + Seismic 7.11E-8/yr
= 4.05E-6/yr

Internal Event method used for LOOP events sensitivity analysis

The analyst reviewed the effect of adjusting offsite power recovery probabilities to reflect the duration of successful EDG operation and associated decay heat reduction. This involved model changes for each interval between surveillance test runs and applying post processing rules for changing non-recovery probabilities for offsite power. This method resulted in a calculated decrease in the risk estimation of 69 percent for the 3rd interval that was sampled. This indicates the significant effect that this method has on calculating a best estimate risk increase due to an EDG failure to run event.

Contributions and Risk Estimates from External Events

Fire

The SPAR model for Oyster Creek does not include fire (external) events. In response to this condition, Exelon developed an application specific model (ASM) for their fire probabilistic risk assessment (PRA) for the EDG No. 1 fail to run SDP risk evaluation. The analyst reviewed the ASM, OC-ASM-04, revision 0, notebook which represented refinements to the Oyster Creek fire model OC108AF0. The model included several revisions to remove conservatisms identified

when evaluating the failure of EDG No. 1 to run. The previous revision of the fire model had the dominant fire areas as Startup Transformer catastrophic fires given a condition of an EDG fail to run. Based on the revisions to the model the dominant fire areas became the office building roof and the 1D switchgear area.

The analyst performed a sensitivity check on the two new dominant fire scenarios using the SPAR model internal events as a surrogate for the events.

Fire Office Building Roof

This bounding scenario includes all ignition frequencies for fan motors and transformers located on the office building roof. The sequence results in a unit trip with the loss of condenser vacuum due to the loss of the 1A 4kV bus. The 1B 480V load center switchgear room and battery room ventilation fans fail due to the fire. The USS 1B2 bus is assumed lost due to the fire.

The analyst created two change sets for use in the SPAR model and used the loss of condenser heat sink (LOCHS) as a surrogate internal event to determine the change in risk. A base case change set was created with IE-LOCHS set to a failure probability of 1.0, the 1B2 Bus set to a failure probability of 1.0, and the failure to control the isolation condenser without DC power late failure was set to 0.1. The conditional case change set for the EDG No. 1 failure to run was created using the above changes for the base case along with the EDG No. 1 failure to run basic event set to TRUE. The conditional core damage probability (CCDP) for the base case was 5.3E-5 and the CCDP for the condition case was 4.77E-4. This resulted in a delta CCDP of 4.24E-4. The fire model ignition frequency was then applied to determine the increase in CDF/yr.

OB Roof 4.33E-3/yr x 4.24E-4 (delta CCDP) = 1.84E-6/yr.

The dominant cutsets consisted of the loss of the condenser heat sink with loss of 1B2 bus and failure of the ‘A’ SUT circuit breaker to close with failure to control the isolation condensers without DC power.

The analyst compared this to the Oyster Creek revised fire model application for the EDG No. 1 failure to run annual change in CDF of 9.7E-6/yr. The fire office building roof contribution to the total increase in risk due to the EDG No. 1 failure to run compared favorably to what Exelon had calculated in their revised fire model. (18.7 percent)

Fire in 4kV Switchgear 1D

The analyst noted from the Exelon’s fire PRA information that a second dominant fire scenario was associated with the 1D switchgear Bus. This scenario would represent the loss of the 1D switchgear.

The analyst substituted the Oyster Creek fire PRA ignition frequency value for the fire area and applied it to the internal events (event tree) for the initiating event Loss of 1D bus. The analyst created a change set for both a base case and condition case. Post processing rules were written to delete cutsets which contained the 1A or 1C 4kV switchgear out for test and maintenance at power conditions to reflect a best estimate risk calculation. For both the base case and conditional case the IE-LO1D probability was set to 1.0. The conditional case set the EDG No. 1 failure to run event to TRUE. The delta CCDP was 2.42E-3. This was multiplied by

the ignition frequency for the area of 7.87E-4/yr to get a change in CDF of 1.9E-6/yr. The analyst noted the resulting contribution was close to the Exelon's revised Fire PRA estimate for the increase in contribution due to this Fire scenario. The dominant core damage cutsets consisted of the loss of the 1D switchgear with the 'A' SUT offsite circuit breaker failing to close and failure to control the isolation condensers without DC power.

Based on the above sensitivity reviews the analyst considered the use of Exelon's calculated annual change in CDF given the EDG No. 1 failure to represent an adequate representation of the fire risk. The annual change in CDF calculated by Exelon with their revised fire model was 9.7E-6/yr for the EDG No. 1 failure.

Total Estimated Risk From Fires

The fire risk determined from the revised Exelon's fire model was calculated to be 9.7E-6/yr x (168.75/365). This included the repair time for the EDG. The result for the 168 day exposure time and repair time was 4.48E-6/yr.

Flooding

The analyst reviewed the Oyster Creek's Individual Plant Examination External Events (IPEEE) and did not consider flooding to be a significant risk contributor for this particular performance deficiency.

Seismic

The primary effect of seismic was determined to be a sustained LOOP. The earthquakes of concern were those that would cause a loss of offsite power, but not cause a loss of the EDGs. Based on the IPEEE, the average acceleration to cause a loss of the EDGs was a nominal 0.5g. Average acceleration to cause a loss of offsite power was 0.3g. Based on NUREG-1488, "Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains," the earthquake frequencies were determined to be 0.45E-4/yr for 0.3g and 0.15E-4/yr for 0.5 g. The analyst confirmed these numbers using the seismic hazard vectors for Oyster Creek contained in Table 4A-1 of Volume 2- External Events of the Risk Assessment of Operational Events Handbook.

The analyst used the internal event LOOP weather related as a surrogate for the seismic evaluation. The base case was set with a LOOP weather related probability set to 1.0. Additionally, offsite power recovery was failed and the combustion turbine fail to start probabilities were increased an order of magnitude to 0.156. This increase was performed due to the assumption that the natural gas supply would not be available reducing the redundancy for the combustion turbine with reliance on fuel oil.

The base case CCDP was 4.74E-4. The conditional case with EDG No. 1 set Fail to Run TRUE was 1.07E-2. The Delta CCDP was 1.02E-2. Delta CCDP x (.45E-4/yr – 0.15E-4/yr) = 3.06E-7/yr

The annualized delta CDF x exposure time of 168.75/365 = 1.41E-7/yr. For an exposure time of 84 days (T mission time 168 days/2), including repair time, this would equate to 7.11E-8/yr.

Total External Risk

The total external events delta CDF/yr is the sum of fire and seismic risk and for the 24-hour run exposure time (168.75 days) would be 4.62E-6/yr.

For an exposure time of 84 days including repair time, this would equate to 2.32E-6/yr.

Large Early Release Frequency (LERF)

The SRA used insights from IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," to evaluate the estimated change in LERF associated with this finding. The failure of EDG No. 1 to meet its 24-hour mission time was classified a Type A finding per Appendix H. Based upon review of station Emergency Operating Procedures, operators are directed to flood the drywell floor for accident scenarios potentially leading to reactor vessel breach and a drywell overpressure condition. Flooding the drywell minimizes the potential for an atmospheric release (large early release pathway). Consequently, with operator procedure credit, a LERF factor of 0.1 (vice 1.0) is appropriate. Additionally, the SRA screened out EDG operating time intervals where EDG No. 1 runtimes of 8 hours or more were achieved. Any runtimes of less than 8 hours were conservatively retained in the LERF evaluation to account for potential scenarios where a large early release may occur and the near-in population could not be sheltered or evacuated in time.

The SRA determined that Exelon uses a similar LERF factor value of 8E-2. This value takes into consideration operator action for those relevant high-pressure vessel breach scenarios (namely, fuel-coolant interaction, liner-melt-through, and direct containment heating).

LERF FACTOR	Delta CDF/yr *	Delta LERF
8E-2 (licensee)	2.23E-6	1.78E-7
0.1 (NRC drywell flooded)	2.23E-6	2.23E-7

Internal risk for 42 days LOOP events 9.76E-7/yr +other internal contribution (Transient/Loss of Feed control) 9.37E-8/yr = 1.07E-6/yr.

* Estimated using an internal event contribution (EDG ran <8 hours, 42-day exposure time) of 1.07E-6/yr, plus external fire contribution (42-day exposure time) of 1.12E-6 + Seismic 42 days, 3.52E-8/yr = 2.23E-6 total risk relative to LERF.

The SRA used the more conservative NRC value for the final change in LERF estimate.

Total Estimated Increase in Risk

Delta CDF = 7.42E-6/yr using the 24 hour run time method (White)
The total change is the sum of internal, repair and external risk.
Note: The above is a bounding value, which may not adequately account for aging effects in the last months of exposure time. However, this exposure time was considered to be the best estimate (based on factual evidence of run time) given the uncertainties involved with determining the exposure period.

The change in LERF estimate was consistent with the delta CDF White significance discussed above.

Licensee's Risk Evaluation

Exelon initially performed their risk evaluation using two separate cases or assumptions for exposure time.

The first case used a T/2 exposure time from the last surveillance test including repair time of 7.75 days. Exelon determined this to be the correct approach as their technical analysis has shown EDG No. 1 would have operated for its full internal event PRA mission time (6 hours) up until its last test on December 21, 2015. Additionally, it was assumed the hose failure could have occurred any time between the test and the date EDG No. 1 failed. The internal and external increase in CDF was calculated to be 7.64E-7/yr.

The second case used a technical evaluation to establish the exposure time by relating the difference in the thermal degradation rates for the hose during EDG No. 1 standby and operating conditions to the mission time for the EDGs. This Arrhenius model method was used in predicting the exposure time for the EDG No. 1 six hour internal event mission time and 24 hour external event mission time. The increase in CDF was calculated to be 8.67E-7/yr. Dominant internal event scenarios are LOOP with loss of EDG No. 2 with unavailability of combustion turbines and isolation condenser shell makeup from fire protection not available. This contributes to 50 percent of internal risk. The delta CDF for LOOP events is dominated by weather related events.

The delta LERF for internal events was calculated to be 4.52E-8/yr for the T/2 exposure and 3.03E-8/yr for the 5.19 day exposure which equates to their 6 hour mission time. The impact on delta LERF from fire was qualitatively determined to be of no larger than the delta CDF risk impact due to a significant portion of cutsets being long term station blackout sequences (i.e. core damage greater than 4 hours)

The Oyster Creek PRA fire PRA internal event model of record uses a 6-hour mission time for the EDGs as a surrogate for an equivalent 24-hour mission time. The method as listed in attachment 1 of OC-SDP-004, Mission Time, is based on convolution and multiple discrete LOOP initiating events.

The major difference in outcomes is tied to the difference in exposure time assumed. Exelon is using a T/2 approach or 7.75 days with repair time factored in. This is based on the technical analysis, using Arrhenius model prediction that the EDG would have run successfully for its full 6 hour mission time up until the last test December 21, 2015.

The fire PRA ASM OC108AF2 was created to address some of the conservatisms not addressed in a previous version. These included updating fire ignition frequencies to the latest industry data (NUREG-2169), and crediting the deluge system for the main transformer catastrophic fire scenarios.

Subsequently, Exelon performed two more cases using an internal event mission time of 24 hours and using the binning process similar to that applied in the NRC's risk assessment (revising OEP probabilities based on predicted Arrhenius equation EDG No. 1 run times). The first case came up with a value in the very low E-6 range (low to moderate safety significance).

A fourth case used average coolant temperatures for LOOP conditions, vice the maximum observed. Using the same binning process and adjustments to offsite power non recovery, the risk was estimated in the upper 9E-7 range. The NRC SRA noted the use of average temperatures did not appear to factor in uncertainty with the measurements or the ability of operators to increase load by starting equipment well after the initial event as any procedures may allow.

Summary of Results and Impact

The NRC's quantitative risk assessment (internal and external delta CDF contributions) for this finding was determined to be 7.42E-6/year, or of low to moderate safety significance (White). Sensitivity analyses demonstrate a high confidence in this quantitative risk estimate. Exelon values were calculated to be within the range of 7.64E-7/yr (very low safety significance) to 1.06E-6/yr (low to moderate safety significance) depending on various assumptions and the use of an Arrhenius method (temperature based approach). The SRA based the final risk evaluation on the proven cumulative EDG run time for its 24 hour mission time. This was determined to provide a more credible estimate of the increase in risk given the uncertainties involved with using the Arrhenius equation to back-calculate an exposure time for a component severely degraded with high uncertainty regarding effects of service conditions.

ATTACHMENT 2: SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Exelon Personnel

G. Stathes, Site Vice-President
M. Gillin, Plant Manager
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L. Dormann, Electrical Design Engineer
R. Dutes, Regulatory Assurance Specialist
R. Francis, System Manager
G. Harttraft, Program Engineer
T. Keenan, Manager, Site Security
T. Nickerson, Design Engineer
J. McCarthy, Senior Radiological Engineer
M. McKenna, Manager, Regulatory Assurance
H. Ray, Senior Manager, Design Engineering
J. Renda, Manager, Environmental/Chemistry
J. Stanley, Director, Engineering
H. Tritt, Electrical Design Engineering Manager
E. Swain, Shift Operations Superintendent
C. Symonds, Director, Training
K. Wolf, Radiation Protection Manager

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened/Closed

05000219/2016001-01	NCV	Failure to Identify a Slower than Normal Scram Time of a Control Rod Drive (Section 1R15)
05000219/2016001-02	NCV	Failure to Use Respiratory Protection as Required in RWP/ALARA Plan for Drywell Head Reassembly (Section 2RS1)
05000219/2016001-03	AV	Inadequate Instructions for the Flexible Coupling Hose Preventative Maintenance Resulting in an Inoperable Emergency Diesel Generator (Section 4OA2.5)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
ABN-32, Abnormal Intake Level, Revision 24
ABN-31, High Winds, Revision 19
OP-OC-108-109-1001, Severe Weather Preparation T&RM for Oyster Creek, Revision 30
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 12
OP-OC-108-109-1002, Cold Weather Freeze Inspections, Revision 4
ABN-60, Grid Emergency, Revision 15

Drawings
3E-168-02-001, General Arrangement Intake Structure Plan and Sections, Revision 10

Section 1R04: Equipment Alignment

Procedures
330, Standby Gas Treatment System, Revision 57
310, Containment Spray System Operation, Revision 113
309.2, Reactor Building Closed Cooling Water System, Revision 95
CC-AA-309-1001, Guidelines for Preparation and Processing Design Analysis, Revision 4
ABN 29, RBCCW Failure Response, Revision 10
ABN 54 DC Bus B and Panel MCC Failures, Revision 7
ABN 55 DC Bus C and Panel MCC Failures, Revision 9
RAP-10F3F, RBCCW Rad Hi, Revision 3
302.1, Control Rod Drive System, Revision 116

Condition Reports

2344248	2617718	2624596	1434655	1688085	2573567
2611531	2448596	2461906	2480745	2480746	2484130
2492094	2504823	2504825	2528626	2528627	2538914
2541934	2561508	2566183	2580964	2603717	2616011
2628842	2627246				

Drawings
GE 148F740, Containment Spray System Flow Diagram, Revision 44
BR 2005, Emergency Service Water System, Revision 86
BR 2006, Reactor Building Closed Cooling Water System, Sheet 1, Revision 79
BR 2005, Emergency Service Water System Flow Diagram, Sheet 4, Revision 88
GE 237E487, Control Rod System Flow Diagram, Sheet 1, Revision 70

Miscellaneous
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 9.2, Water Systems, Revision 18
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 6.2, Containment Systems, Revision 18
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 3.9, Mechanical Systems and Components, Revision 17

Oyster Creek Generating Station Technical Specifications, Section 3.4, Emergency Cooling, Amendment 247
Oyster Creek Generating Station Technical Specifications, Section 3.2, Reactivity Control, Amendment 178
SBDB-OC-532, Design Basis Document for Emergency Service Water System, Revision 2

Calculations
EXOC005-CALC-002, Sys. #241, 532 System Acceptance Criteria for Containment Spray and ESW Flow Rates, Revision 1

Section 1R05: Fire Protection

Procedures
ER-AA-600-1069, High Risk Fire Area Identification, Revision 1
FSP-OB5A, Fire Support Procedure for Control Rm Complex, Revision 0
FSP-OB6A, Fire Support Procedure for A 480v SWGR RM, Revision 9
FSP-OB6B, Fire Support Procedure for B 480v SWGR RM, Revision 7
OP-OC-201-008-1005, Reactor Building (23' Elevation), Revision 2
OP-OC-201-008-1015, "A" and "B" Battery Room, Electric Tray Room, Revision 1
OP-OC-201-008-1018, Control Room, Revision 1
OP-OC-201-008-1037, Emergency Diesel Generator Fuel Storage Area, Revision 1
OP-OC-201-008-1022, 480v Switchgear Room "A", Revision 2
OP-OC-201-008-1023, 480v Switchgear Room "B", Revision 2
ABN 30, Control Room Evacuation, Revision 27
645.6.034, Fire Detection System Alarm Circuitry Test for 480v Switchgear Rooms, A/B Battery. Room, Mechanical Equipment Room, and M/G Set Room, Revision 15
645.6.214, Fire Suppression System Halon Cylinder Check 480v SW/GR Room, Revision 0

Section 1R06: Flood Protection Measures

Procedures
OP-AA-108-115, Operability Determinations, Revision 16
OP-AA-108-115-1002, Supplemental Consideration for On-Shift Immediate Operability Determinations, Revision 3
101.2, Oyster Creek Site Fire Protection Program, Revision 73

Miscellaneous
OC-PSA-012, Internal Flood Evaluation Summary Notebook, Revision 1

Section 1R11: Licensed Operator Requalification Program

Procedures
HU-AA-101, Human Performance Tools and Verification Practices, Revision 9
TQ-AA-150, Operator Training Programs, Revision 11
TQ-AA-155, Conduct of Simulator Training and Evaluation, Revision 5
RAP-G1c, Scram Contactor Open, Revision 4
NF-AB-720-F-1, Control Rod Sequence Review and Approval Sheet, Revision 1

Condition Reports

2609982	2620417	2631588	2631824	2639650	2639642
2639556	2639395	2639390	2639359	2639356	2639337
2639336					

Section 1R12: Maintenance Effectiveness

Procedures
ER-AA-310, Implementation of the Maintenance Rule, Revision 9
ER-AA-310-1001, Maintenance Rule – Scoping, Revision 4
ER-AA 310-1004, Maintenance Rule – Performance Monitoring, Revision 13
329, Reactor Building Heating, Cooling and Ventilation System, Revision 63
ABN 35, Loss of Instrument Air, Revision 13
ABN 22, AOG Building Loss of Power, Revision 9
ABN 25, Offgas Degragation, Revision 8
317.4, Feedwater Hydrogen Injection, Revision 56
350.1, Augmented Offgas System Operation, Revision 98
RAP-10XF1C, H2 Hi-Hi, Revision 1
RAP-10XF2C, H2 Hi, Revision 1
NF-OC-721-1101, Control Rod Scram Time Data Sheet, Revision 34
617.4.003, Control Rod Scram Insertion Time Test and Valve IST Test, Revision 54
RAP-H5c, CRD Temp Hi, Revision 6

Condition Reports

2624285	2436965	2444765	2450579	2473665	2508785
2532365	2568372	2582212	2428084	2628386	1462325
2431996	2463085	2431996	2455449	2463085	2468683
2507088	2519097	2572662	2620914	2451879	2559734
1547241	1657604	2559831	2559706	2559713	2452411
2645104	2474405	2644517	2644512	2642334	2642346
2642317	2643603	2474409	2499188	2641454	2642390
2642325	2390658	2476241	2477387	2493018	2390667
2550508	2529739	2513954	2511400	2496606	

Drawings
BR 2011, Reactor Building Ventilation Flow Diagram, Sheet 2, Revision 63
BR M608, Augmented Off-Gas System Flow Diagram, Sheet 1, Revision 34
BR M608, Augmented Off-Gas System Flow Diagram, Sheet 2, Revision 30

Maintenance Orders/Work Orders

C2034015	R2249085	R2247701

Miscellaneous
Oyster Creek Maintenance Rule Database, updated January 31, 2016
Oyster Creek Generating Station Maintenance Rule Periodic (a)(3) Assessment for July 1, 2013-June 30, 2015, dated September 29, 2015
Oyster Creek Generating Station Technical Specifications Section 3.1, Protective Instrumentation, Amendment 208
Oyster Creek Generating Station Technical Specifications Section 3.5, Containment, Amendment 168
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 6.2, Containment Systems, Revision 18
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 9.4, Heating, Ventilation and Air Conditioning Systems, Revision 14
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 11.3, Gaseous Waste Management Systems, Revision 18
SP-1302-52-108, Specification for Inspection of Tanks, Revision 3

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
WC-AA-101, Online Work Control Process, Revision 25
WC-AA-101-1001, Online Risk Management and Assessment, Revision 19
WC-AA-104, Integrated Risk Management, Revision 23
ER-AA-600-1042, Online Risk Management, Revision 9
OP-AA-108-117, Protected Equipment Program, Revision 4
OP-OC-201-012-1001, Online Fire Risk Management, Revision 4
341, Emergency Diesel Generator Operation, Revision 110
RAP-T4b, EDG 1 Disabled, Revision 36
RAP-B1b, DW Press Lo, Revision 2
RAP-B3b, Cntrl Pwr 2 Lost, Revision 3
607.4.016, Containment Spray and Emergency Service Water System I Pump Operability and Quarterly Inservice Test, Revision 41
334, Instrument and Service Air System, Revision 133

Condition Reports
2623460

Maintenance Orders/Work Orders
C2035049 R2147320 M2397900

Miscellaneous
Oyster Creek Generating Station Technical Specifications Section 3.7, Auxiliary Electrical Power, Amendment 256
Oyster Creek Generating Station Technical Specifications Section 3.4, Emergency Cooling, Amendment 247
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 8.3, Onsite Power Systems, Revision 18
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 6.2, Containment Systems, Revision 18

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
RAP-B1b, DW Press Lo, Revision 2
RAP-B3b, Cntrl Pwr 2 Lost, Revision 3
RAP-G4b, Tank Level Hi/Lo, Revision 3
310, Containment Spray System Operation, Revision 113
612.3.006, Standby Liquid Control Tank Level Sensor Calibration, Revision 14
OP-AA-108-101, Control of Equipment and System Status, Revision 12
NF-OC-721-1101, Control Rod Scram Time Data Sheet, Revision 34
617.4.003, Control Rod Scram Insertion Time Test and Valve IST Test, Revision 54
RAP-H5c, CRD Temp Hi, Revision 6

Calculations
C-1302-213-5370-009, SLCS Modification using Enriched Boron-10, Revision 4

Condition Reports

2623460	2607247	2610027	2625012	2624649	2624662
2624831	2624838	0650654	1659962	2607288	2609397
2420196	2607691	2645104	2474405	2644517	2644512
2642334	2642346	2642317	2643603	2474409	2499188
2641454	2642390	2642325	2390658	2476241	2477387
2493018	2390667	2550508	2529739	2513954	2511400
2496606					

Drawings

GE 237E901, Containment Spray Logic Electrical Elementary Diagram for Containment Spray System II, Sheet 2, Revision 21

Miscellaneous

Oyster Creek Generating Station Technical Specifications Section 3.4, Emergency Cooling, Amendment 247

Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 6.2, Containment Systems, Revision 18

Prompt Investigation for Containment Spray System II Unexpected Alarms, Revision 1

Oyster Creek Generating Station Technical Specifications 3.2, Reactivity Control, Amendment 262

Oyster Creek Generating Station Technical Specifications 4.0, Surveillance Requirements, Amendment 241

Oyster Creek Generating Station Technical Specifications 4.2, Reactivity Control, Amendment 276

Section 1R18: Plant Modifications

Procedures

LS-AA-104-1000, 50.59 Resource Manual, Revision 9

LS-AA-104, Exelon 50.59 Review Process, Revision 10

LS-AA-104-1003, 50.59 Screening Form, Revision 4

HU-AA-1212, Technical Task Risk/Rigor Assessment, Pre-Job Brief, Independent Third Party Review, and Post-Job Review, Revision 7

350.1, Augmented Offgas System Operation, Revision 98

420, Instrumentation Setpoints, Revision 17

602.4.004, Main Steam Isolation Valve 10% Closure Test, Revision 27

RAP-10XF1c, H2 Hi-Hi, Revision 1

RAP-10XF2c, H2 Hi, Revision 1

RAP-G1c, Scram Contactor Open, Revision 4

RAP-J2a, MSIV Closed II, Revision 5

Condition Reports

2631588	2631588	2635236	2635239

Drawings
BR M608, Augmented Off-Gas System Flow Diagram, Sheet 1, Revision 34
BR M608, Augmented Off-Gas System Flow Diagram, Sheet 2, Revision 30
GE 237E566, Reactor Protection System Electrical Elementary Diagram – Channel 2, Sheet 6, Revision 39
GE 237E566, Reactor Protection System Electrical Elementary Diagram – Channel 2, Sheet 7, Revision 8

Maintenance Orders/Work Orders
R2247701 C2035838

Miscellaneous
OYS-0-2015-0697, Rx Internals Mitigation Strategy, Revision 1
OC-10-00504, TCCP for MSIV Limit Switch Input to RPS Sys 2, Revision 0
OC 16-00096, TCCP for MSIV Limit Switch Input to RPS Sys 2, Revision 0
OC-2016-S-0018, 50.59 Review for TCCP for MSIV Limit Switch Input to RPS Sys 2, Revision 0, dated February 26, 2016
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 5.2, Integrity of Reactor Coolant Pressure Boundary, Revision 17
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 11.3, Gaseous Waste Management Systems, Revision 18
Oyster Creek Generating Station Technical Specifications Section 3.1, Protective Instrumentation, Amendment 208
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 5.4, Component and Subsystem Design, Revision 18
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 7.3, Engineered Safety Feature Systems, Revision 15

Section 1R19: Post-Maintenance Testing

Procedures
OP-AA-106-101, Significant Event Reporting, Revision 17
MA-AA-716-012, Post Maintenance Testing, Revision 20
WC-AA-101, On-Line Work Control Process, Revision 24
MA-AA-716-011, Work Execution & Close Out, Revision 19
651.4.003, Standby Gas Treatment 15-minute Run-System 2, Revision 15
310, Containment Spray System Operation, Revision 113
341, Emergency Diesel Generator Operation, Revision 111
636.4.003, Diesel Generator #1 Load Test, Revision 101
636.4.013, Diesel Generator #2 Load Test, Revision 49
RAP-T4b, EDG 1 Disabled, Revision 3
420, Instrumentation Setpoints, Revision 17
602.4.004, Main Steam Isolation Valve 10% Closure Test, Revision 27

Condition Reports

2631588	2631824	2607247	2607288	2610027	2607639
2607534	2607291	2616773			

Drawings

GE 237E901, Containment Spray Logic Electrical Elementary Diagram for Containment Spray System II, Sheet 2, Revision 21

3E-861-21-1001, Emer Diesel Gen Water Cooling System Flow Diagram, Sheet 1, Revision 12

GE 237E566, Reactor Protection System Electrical Elementary Diagram – Channel 2, Sheet 6, Revision 39

GE 237E566, Reactor Protection System Electrical Elementary Diagram – Channel 2, Sheet 7, Revision 8

Maintenance Orders/Work Orders

R21119263 M2397900 C2035838 C2035542

Miscellaneous

Oyster Creek Generating Station Technical Specifications Section 3.1, Protective Instrumentation, Amendment 208

Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 5.4, Component and Subsystem Design, Revision 18

Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 7.3, Engineered Safety Feature Systems, Revision 15

Oyster Creek Generating Station Technical Specifications Section 3.7, Auxiliary Electrical Power, Amendment 278

Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Section 8.3, Onsite Power Systems, Revision 18

Section 1R22: Surveillance Testing

Procedures

607.4.016, Containment Spray and Emergency Service Water System I Pump Operability and Quarterly Inservice Test, Revision 41

610.4.022, Core Spray System 2 Pump Operability and Quarterly Inservice Test, Revision 29

ER-AB-331-1006, BWR Reactor Coolant System Leakage Monitoring and Action Plan, Revision 2

302.2, Control Rod Drive Manual Control System, Revision 63

312.9, Primary Containment Control, Revision 58

340.1, 125VDC Distribution Systems A & B, Revision 70

340.33, 125 Volt DC Distribution System C, Revision 41

ABN 53, DC Bus A and Panel Failures, Revision 12

ABN 54, DC Bus B and Panel MCC Failures, Revision 7

ABN 55, DC Bus C and Panel/MCC Failures, Revision 9

604.4.016, Torus to Drywell Vacuum Breaker Operability and In-Service Test, Revision 37

312.11, Nitrogen System and Containment Atmosphere Control, Revision 46

341, Emergency Diesel Generator Operation, Revision 111

636.4.003, Diesel Generator #1 Load Test, Revision 101

636.4.013, Diesel Generator #2 Load Test, Revision 49

Calculations

C-1302-241-5360-004, Containment Spray/Emergency Service Water System Performance, Revision 0

C-1302-735-E320-044, OC 125V DC Voltage Drop, Revision 2B

C-1302-735-E320-047, Oyster Creek Station Battery B and C Capacity for SBO, Revision 1A

C-1302-735-E320-049, Oyster Creek 'B' and 'C' Station Battery Sizing Calculation, Revision 1
C-1302-243-5310-047, OCNGS 18" Torus-to-Drywell Vacuum Breaker – Verification of Test Proc #604.4.015, Revision 0

Condition Reports

2620225	2475490	2477387	2475490	2636430	2628842
2628826	2628798	2628796	2637618	2506746	1585214
1585222	1585224	1585230	1585233	1619219	1619220
1619223	1619308	1619327	1619343	1619352	2629316
2629318	2629319	2629320	2409678	2499141	2409670
2450954	2616439				

Drawings
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LIST OF ACRONYMS

AC	alternating current
ADAMS	Agencywide Documents Access and Management System
ALARA	As Low As is Reasonably Achievable
ANSI	American Nuclear Standards Institute
ASM	application specific model
AV	apparent violaton
CCDP	conditional core damage probability
CDF	core damage frequency
CFR	Code of Federal Regulations
CRDM	control rod drive mechanism
DC	direct current
DRE	detailed risk evaluation
EDG	emergency diesel generator
EMD	Electro-Motive Division
GE	General Electric
gpm	gallons per minute
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination External Events
kV	kilovolt
LERF	large early release frequency
LOCHS	loss of condenser heat sink
LOOP	loss-of-offsite power
M	minute
NCV	non-cited violation
NRC	Nuclear Regulatory Commission
OEP	offsite power non-recovery events
PCM	performance centered maintenance
PM	preventative maintenance
PRA	probabilistic risk assessment
RASP	Risk Assessment of Operational Events
RP	radiation protection
RWP	radiation work permit
SAPHIRE	Systems Analysis Programs for Hands-On Integrated Reliability Evaluations
SDP	significance determination process
SIL	services information letter
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SSC	structure, system, or component
SUT	startup transformer
UFSAR	Updated Final Safety Analysis Report
Vdc	volts direct current