PUBLIC

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 546

In the Matter of		
Application by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities	))))))	TESTIMONY OF DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff representing the using and consuming public.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are outlined in detail in Appendix A of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to: (1) present the results of the Public Staff's investigation of the application filed by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company) in this docket on August 23, 2017; (2) present the results of its investigation into test year (July 1, 2016 – June 30, 2017) power plant performance and make recommendations regarding any resulting adjustments; and (3) present the results of its investigation into outages at Surry Unit 1 (July 11 - 22, 2015), Surry Unit 1 (October 13 - November 18, 2015), Surry Unit 2 (July 13 - 22, 2015), and Surry Unit 2 (December 4 - 11, 2015) and make recommendations regarding any resulting adjustments.[1]

My testimony is organized as follows:

Section 1: Overall Review of Docket No. E-22, Sub 546 (Sub 546)

Section 2: Detailed Review of Plant Performance in Sub 546

Section 3: Detailed Review of Plant Performance in Docket No. E-22, Sub 534 (Sub 534)

Section 4: Proposed Fuel and Fuel Related Cost Factors

Section 5: Forced Outage Allowance

Section 6: Recommendations of the Public Staff

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR INVESTIGATION AND YOUR RECOMMENDATIONS.

- Section 1: For the test year, the Company met the standards of Commission Rule R8-55, including its determination and calculation of proposed Rider A, the base proposed system average fuel factor for the billing period.

[1] In Docket No. E-22, Sub 534, the Public Staff reserved the right to continue its review of and make a recommendation on four nuclear forced outage events in this proceeding.

- Section 2: In regard to test year plant performance (July 1, 2016-June 30, 2017), I recommend that the Commission find that had North Anna Unit 2 and Surry Unit 2 been prudently managed in the test year, the outages at North Anna Unit 2 from July 30, 2016, through August 3, 2016, and at Surry Unit 2 from October 9, 2016, through October 13, 2016, could have been avoided. Therefore, I recommend that replacement power costs associated with these outages and allocated to North Carolina retail of $232,474 (excluding interest) be excluded from test year costs.

- Section 3: In regard to plant performance during the period of July 1, 2015, through June 30, 2016, I recommend that the Commission find that had Surry Units 1 and 2 been prudently managed, the outages at Surry Unit 1 from July 11 - 22, 2015 and October 13 - November 18, 2015, and at Surry Unit 2 from July 13 - 22, 2015, and December 4 - 11, 2015, could have been avoided. Therefore, I recommend that replacement power costs associated with these outages and allocated to North Carolina retail of $1,575,422 (excluding interest) be excluded from the experience modification factor (EMF) costs.

- Section 4: I present the results of my recommended adjustments into the proposed fuel and fuel related costs to be effective January 1, 2018.

- Section 5: I recommend that the Commission reject the Company's current methodology of utilizing a forced outage allowance in its calculation of incurred replacement power costs.

- Section 6: I present other recommendations of the Public Staff.

SECTION 1: OVERALL REVIEW OF DOCKET NO. E-22, SUB 546

Q. DID THE COMPANY MEET THE STANDARDS OF COMMISSION RULE R8-55(K) FOR THE TEST YEAR?

A**.** For the test year, the Company met the standards of Commission Rule R8-55(k) with an actual system-wide nuclear capacity factor that exceeded the NERC (North American Electric Reliability Corporation) weighted average nuclear capacity factor. Additionally, the Company's two-year simple average of its system-wide nuclear capacity factor exceeded the NERC weighted average nuclear capacity factor. Had the utility not meet at least one of these standards, a rebuttable presumption would have been created that the utility imprudently incurred the increased fuel costs during the test year.

Q. DO YOU AGREE WITH THE COMPANY'S DETERMINATION AND CALCULATION OF RIDERA?

A. I agree with the Company's determination and calculation of proposed Rider A, the base proposed system average fuel factor for the billing period. However, I am making recommendations regarding the replacement power costs for certain outages, discussed in more detail below. Rider B will need to be adjusted to account for these changes, which I provided to Public Staff witness Sonja R. Johnson for incorporation into her testimony and exhibit. The result of my changes to Rider B can be found in Section 4 of my testimony.

Q. HOW DOES POWER PLANT PERFORMANCE FACTOR INTO THIS PROCEEDING?

A. When a generating plant goes off-line or experiences an outage, the Company may need to generate or purchase more expensive power to replace the power that the offline plant would have generated. The Company includes these replacement power costs in test year fuel costs. Thus, it is necessary to investigate the facts and circumstances surrounding generating plant outages to determine whether the replacement power costs were reasonably and prudently incurred. In Sub 534, I completed my investigation of plant performance except for the review of four nuclear plant outages that occurred during the test period ended June 30, 2016.

Q. PLEASE EXPLAIN THE DIFFERENT TYPES OF OUTAGES.

A. Generally speaking, outages can be separated into three categories (planned, maintenance, and forced). These three categories are not nuclear generation plant specific, but are applicable to all types of generating plants.

A planned outage is just as stated - planned. For a nuclear power plant, planned outages typically occur for nuclear refueling. A company can determine the expected consumption rate of the nuclear fuel and schedule outages to replace the depleted or used nuclear fuel. Planned outages can also incorporate known large plant upgrades or repairs that may need to take place. In summary, a planned outage is an outage of which the plant owner knows in advance. Planned outages can range in duration, but typically last from a few weeks to months.

A maintenance outage occurs outside of a planned outage and is required to perform maintenance or repair. Under NERC definitions, a maintenance outage can be deferred beyond the next weekend, but cannot wait until the next planned outage.[2]

A forced (unplanned) outage requires immediate shutdown of the plant. Forced outages typically occur when there is a severe failure that disables or hampers the plant from operating per its safety or design/technical specifications.

The nature of an outage may change over time. For example, a generating plant may enter a maintenance outage due to a suspected leak in the cooling system. If the initial leak did not completely disable the plant, the company could elect to reduce power while the issue is investigated. If the investigation revealed the leak to be more severe than initially thought, the plant could go into a forced outage

Q. HOW DO YOU DETERMINE WHICH POWER PLANTS, OR EVEN WHICH POWER PLANT OUTAGES, TO INVESTIGATE?

A. Throughout the year, I track the Company's monthly filed Baseload Power Plant Performance Reports.[3] I also review the United States Nuclear Regulatory Commission (NRC) Reactor Status Report,

[2] http://www.nerc.com/files/Section_3_Event_Reporting.pdf

[3] The reports utilized for the four nuclear outages from the Sub 534 proceeding addressed in this case were filed in Docket No. E-22, Subs 520 (2015) and 531 (2016).

NRC Reactor Event Notifications, the Reserve Situation Report generated weekly by the Public Staff, and other sources of industry data such as SNL.[4] The Public Staff contacts the Company regarding specific outages, as well as the overall operation of the generation fleet.

SECTION 2: DETAILED REVIEW OF PLANT PERFORMANCE IN DOCKET NO. E-22, SUB 546

Q. HOW MANY OUTAGES DID THE COMPANY REPORT?

A. The Company reported **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** outages in the Sub 546 test period.

Q. HOW MANY OUTAGES DID YOU REVIEW?

A. I requested more details on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** outages. After receiving a data response from the Company, I determined that two of the outages should receive further scrutiny.

[4] SNL is a subscription service of S&P Global Market Intelligence.

Q. ARE THERE ANY OUTAGES YOU BELIEVE WERE WITHIN OR AT LEAST PARTIALLY WITHIN THE COMPANY'S CONTROL AND FOR WHICH THERE WERE REPLACEMENT POWER COSTS?

A. Yes. There were two outages that I believe were within the Company's control and for which there were replacement power costs: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In order to start the review process of these outages, the Public Staff requested Root Cause Evaluation (RCE) reports from the Company. RCEs are documents prepared by the Company to investigate the causes of, and contributing factors to, a specific outage and determine corrective actions.

Based on RCEs reviewed by the Public Staff, it appears that the Company's RCE investigations **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

<u>SUB 546 OUTAGE 1</u>

Q. PLEASE DESCRIBE THE EVENTS THAT CONTRIBUTED TO THE JULY/AUGUST 2016 FORCED OUTAGE FOR NORTH ANNA UNIT 2.

A. The Company indicated that the outage resulted from **[BEGIN CONFIDENTIAL]** [redacted]

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[5] Response to Public Staff Data Request No. 8-2.b.

[redacted] **[END CONFIDENTIAL]**

Q. WHAT CAUSED THE UNIT TO TRIP OR GO OFFLINE?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** the Company elected to take the unit offline to fix the issue.

Q. WOULD YOU PLEASE EXPLAIN THE DIRECT CAUSE STATED EARLIER IN YOUR TESTIMONY?

A. Yes, a **[BEGIN CONFIDENTIAL]** [redacted]

[6] *Id.*

[redacted] **[END CONFIDENTIAL]** and ultimately required that the unit be taken offline.

Q. HAD THE COMPANY PERFORMED WORK ON THE [BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted]

[7] Kewaunee Power Station was closed in 2013.

[8] DR 14-3.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[9] Response to Public Staff Data Request 14.2.i.

[10] RCE CA3037190 pg. 17.

[11] *Id.*

[redacted]

[12] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** RCE CA3037190 pg. 19.

[13] RCE CA3037190 pg. 17.

[redacted]

[redacted]

[redacted]

[14] The RCE states **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** *Id*.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[15] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** RCE CA3037190, pg. 16.

[16] *Id.*

[17] Public Staff Data Request 14-29.a.

[redacted] **[END CONFIDENTIAL]**

Q. PLEASE DISCUSS A MODIFICATION BOUNDARY.

A. The modification boundary is used to determine project scope. The project scope is used for project planning, budgeting, labor, materials, dose rates, etc. The modification boundary should be identified in relation to the overall project and its risks. It appears that the modification boundary **[BEGIN CONFIDENTIAL]** [redacted]

[18] Public Staff Data Request 14-45.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[19] **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** RCE 3037190 pg. 13.

[redacted] **[END CONFIDENTIAL]** I believe that all of these errors were within the Company's control and were reasonably avoidable. But for these errors, I do not believe this outage would have occurred.

Q. WHAT IS THE NORTH CAROLINA RETAIL PORTION OF THE REPLACEMENT POWER COSTS FOR THIS OUTAGE?

A. The North Carolina retail portion of the replacement power costs for this outage is approximately $113,645.

SUB 546 OUTAGE NO. 2

Q. PLEASE DESCRIBE THE EVENTS THAT CONTRIBUTED TO THE OCTOBER 2016 FORCED OUTAGE FOR SURRY UNIT 2.

A. **[BEGIN CONFIDENTIAL]** [redacted]

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[20] Public Staff Data Request No. 8-2.

[redacted]

[END CONFIDENTIAL]

Q. HOW DO THE SST AND IPDB CONNECT?

A. The IPBD is an enclosed sealed bus system (bus bar to allow electrical connection) from the main generator to the SST and Main Transformer. When the IPBD transitions to the SST, a transformer leads termination enclosure (Lead Box or Termination Enclosure) holds all of the electrical connection of the components.

Q. WHERE ARE THE IPBD AND SST LOCATED AT THE SITE?

A. The IPBD, SST, and Lead Box are located outside and are subject to weather events. *See* Exhibit 7: IPDB and SST Location.[22]

Q. ARE THESE SYSTEMS DESIGNED TO WITHSTAND WEATHER EVENTS SINCE THEY ARE INSTALLED OUTSIDE?

A. **[BEGIN CONFIDENTIAL]** [redacted]

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[21] *Id*.

[22] Public Staff Data Request No. 15-4.

[23] RCE CA 3042011 pg. 9 of 42.

[redacted] **[END CONFIDENTIAL]**

Q. HAVE ANY REACTOR TRIPS OCCURRED PRIOR TO THIS FROM WATER INTRUSION IN THESE DEVICES AT SURRY?

A. No, the components in question never caused a reactor trip.[26]

Q. PLEASE EXPLAIN HOW [BEGIN CONFIDENTIAL] [redacted]

[24] "System" refers to both the IPBD and the SST as it is an inline component.

[25] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** RCE CA3042011 pg. 9 of 42.

[26] Public Staff Data Request 15-7.

[redacted]

[27] RCE CA3042011 pg. 10 of 42.

[28] *Id*.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[29] *Id.*

[30] RCE CA 3042011 pp. 12-13 of 42.

[redacted]

[redacted]

[31] RCE CA3042011 pg. 11 of 42.

[32] *Id*. At pp. 13 and 14.

[redacted]

[END CONFIDENTIAL] I believe that these errors, as discussed above, were within the Company's control and were reasonably avoidable. But for these errors, I do not believe this outage would have occurred.

Q. WHAT IS THE NORTH CAROLINA RETAIL PORTION OF THE REPLACEMENT POWER COSTS FOR THIS OUTAGE?

A. The North Carolina retail portion of the replacement power costs for this outage is approximately $118,829.

<u>SECTION 3: DETAILED REVIEW OF PLANT PERFORMANCE IN SUB 534</u>

Q. PLEASE EXPLAIN WHY YOU ARE REVIEWING PERFORMANCE OF CERTAIN NUCLEAR PLANTS DURING THE TEST YEAR FOR THE 2016 FUEL PROCEEDING, DOCKET NO. E-22, SUB 534.

A. As indicated in my testimony filed on October 24, 2016, in Docket No. E-22, Sub 534 (Sub 534), the Public Staff was unable to complete its review of plant performance for the test period ended June 30, 2016. I further stated that the Public Staff intended to complete its review and make any recommendations in the 2017 fuel adjustment proceeding. The Company agreed to this approach. The Commission approved this approach in its December 22, 2016 Order Approving Fuel Charge Adjustment in Sub 534.[33]

Q. HOW MANY GENERATING UNIT OUTAGES DID THE COMPANY REPORT FOR THE SUB 534 TEST YEAR?

A. In response to a Public Staff data request, the Company reported approximately 79 nonnuclear and five nuclear outages.

Q. DID YOU INVESTIGATE EACH OF THESE OUTAGES?

A. No, I did not. The vast majority of these outages appeared to be routine in nature and common for the Company's fleet of generating units. For example: on April 4, 2016, Possum Point 6, a natural gas-fired combined cycle plant, entered a planned outage for a routine steam turbine valve inspection; on December 3, 2016, Warren County Power Station (Warren County), also a natural gas-fired combined cycle plant, entered an outage for excessive vibration of

[33] See Evidence and Conclusions for Findings of Fact Nos. 6-7.

a low pressure bearing. In the Possum Point instance, this type of outage is part of normal equipment preventative maintenance. In the Warren County instance, the Company elected to enter an outage and made the necessary adjustments as per the original equipment manufacturer (OEM) specifications to correct the issue before vibration levels reached a predetermined trip set point.[34] In my estimation, neither outage warranted further investigation.

Q. HOW MANY OUTAGES DID THE PUBLIC STAFF BELIEVE WARRANTED ADDITIONAL INVESTIGATION?

A. The Public Staff requested additional details on the outages from the Company and then reviewed 15 outages that occurred during the Sub 534 test year. These outages occurred at the Mount Storm (three unit coal-fired plant), Surry (two-unit nuclear plant), and North Anna (two unit nuclear plant) Power Stations.

Mount Storm Unit 1 experienced three outages, two of which were planned outages, and one of which was a maintenance outage. Mount Storm Unit 2 experienced four outages, which appear to be two planned outages, and two of which were maintenance outages. Mount Storm Unit 3 experienced three outages, two planned outages, and one maintenance outage. Based on my review, it

[34] Public Staff Data Request No. 2-1.

does not appear that any of these outages could have been prevented under prudent management.

There were five outages at DENC's nuclear facilities during the test year. Two were planned refueling outages, one of which was extended because of issues pertaining to a prior forced outage. The remaining three outages consisted of one forced outage and two planned outages occurring outside the planned refueling outage timeframe. Based upon my review as detailed below, I recommend that the Commission find that two of these five nuclear outages, along with the nuclear outage extension resulting from one of the forced outages, were avoidable. As a result, I believe an adjustment is appropriate to account for the replacement power costs associated with the outages that were avoidable in the Company's proposed EMF.

I provided the costs of these outages and their respective date of occurrence to Public Staff witness Johnson to determine the applicable interest component and impact to Rider B. Updated proposed fuel and fuel related costs factors can be found in Exhibit 4.

SUB 534 OUTAGE NO. 1

Q. BASED UPON THE PUBLIC STAFF'S INVESTIGATION, WERE THERE ANY OUTAGES THAT YOU BELIEVE TO HAVE BEEN OUTSIDE OF THE COMPANY'S CONTROL?

A. Yes. After investigation and review of supplemental supporting documentation from the Company, I believe that the July 2015 outage of Surry Unit 2 was outside of the Company's control.

I arrived at this conclusion because I learned that the OEM did not update its technical data sheets following an OEM change in manufacturing process for certain gaskets. Without notification from the OEM regarding this update to its technical data sheets, the Company would be unaware that an internal engineering judgement decision could result in a potential latent failure such as the one that occurred at Surry Unit 2 in July 2015.

Q. PLEASE DESCRIBE THE EVENTS THAT CONTRIBUTED TO THE JULY 2015 FORCED OUTAGE FOR SURRY UNIT 2.

A. The Company indicated that the outage resulted from a controlled shutdown with the direct cause being a failure of the gasket to adequately seal the pressurizer spray valve body to the bonnet extension joint, resulting in a leak at the joint.[35] The response further summarized the root cause as: "The procedure did not have sufficient detail and guidance to ensure the misalignment condition was resolved prior to placing the valve in service."[36]

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** Metal-to-metal contact surfaces often have natural contours and un-parallelism in machining,[37] causing misalignment and surface voids which may allow a fluid to escape. When the gasket is compressed, the OEM will provide a

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[35] Sub 534 Data Request No. 2-1.b.

[36] Sub 534 Data Request No. 2-6.b.

[37] When bolting two parts together, the area in which each part makes contact with one another may not be perfectly flat because the machined areas of the parts are made at different times or even on different metal cutting/forming processes.

specification as to how much area the gasket will be able to fill (i.e., the gasket will compress and expand into the voids ("crush") to a specification tolerance as described by the OEM).

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

[38] RCE 3002174 p. 4.

[39] Per the RCE**, [BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]**

[40] Rolled metal can occur near the edge of an object and/or angle and result in a raised edge. This edge, or point, is susceptible to becoming deflected when a force is applied to it.

[41] RCE 3002174, Attachment 7, log entry 5/13/2014, 05:01, page 35 of 57.

[42] RCE 3002174, Attachment 7, log entry 5/13/2014, 06:44, page 35 of 57.

[redacted]

[redacted]

[redacted]

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43 RCE 3002174 p. 36.

44 *Id.*

45 *Id.* at 38.

[redacted]

[redacted]

[redacted]

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[46] ETE-SU-2014-0047

[47] RCE 3002174, Attachment 7, log entry made on 5/14/2014 at 02:18, page 37 of 57. Note that the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** RCE 3002174, Attachment 7, page 36 of 57.

[48] RCE 3002174, Attachment 7, page 40 of 57.

[49] gallons per minute

[redacted]

[redacted]

[redacted]

[redacted]

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[50] RCE 3002174, Section 2.9 Extent of Cause, page 17 of 57; RCE 3002174, Attachment 7, 7/10/2015, 19:39, page 40 of 57.

[51] RCE 3002174, Attachment 7, 7/13/2015, 07:41, page 41 of 57.

[52] RCE 3002174, Attachment 3, page 30 of 57.

[53] RCE 3002174, Section 2.2.2 Pressurizer Spray Valve Body to Bonnet Leakage Event July 2015, page 8 of 57; RCE 3002174, Section 2.8 Operating Experience, page 15 of 57; Company Response to Public Staff Conference Call Data Request Q.14.

[redacted]

[redacted]

[redacted]

[54] A "Fit-up Check" simplified; one would put the required pieces together and see if they assemble together correctly with no interference. This process is often done in advance of the final installation to identify any potential issues that may arise.

[55] RCE 3002174 p. 9.

[56] RCE 3002174 Section 2.2.2 Pressurizer Spray Valve Body to Bonnet Leakage Event July 2015, page 9 of 57.

[redacted]

[redacted]

[redacted]

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[57] *Id.*

[58] RCE 3002174, Section 2.10 Equipment Reliability/PM Adequacy, Work Practices, pages 19-20.

[redacted]

[redacted]

59 RCE 3002174, Section 2.2.2 Pressurizer Spray Valve Body to Bonnet Leakage Event July 2015, page 10.

60 https://www.garlock.com/en

61 RCE 3002174, Section 2.12, page 22 of 57.

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

Q. DO YOU HAVE ANY GENERAL CONCERNS BASED UPON YOUR FINDINGS?

Yes, I am concerned, however, that issues were **[BEGIN CONFIDENTIAL]** [redacted]

[62] RCE 3002174, Section 2.10, Work Practices, page 19 of 57.

[63] RCE 3002174, Section 1.3, Work Practices, page 4 of 57 & Attachment 10 (CC1), page 57 of 57.

[redacted]

[END CONFIDENTIAL]

Q. ARE THERE ANY OUTAGES YOU BELIEVE WERE WITHIN OR AT LEAST PARTIALLY WITHIN THE COMPANY'S CONTROL?

A. Yes. There were three outages that I believe were within the Company's control: (1) ~11 day outage at Surry Unit 1 in July, 2015, to replace a RCP seal damaged by foreign material; (2) ~ 36 day outage at Surry Unit 1 in October and November, 2015, due to a fault with the main generator; and (3) ~ 8 day refueling outage extension at Surry Unit 2 in December, 2015, related to the October/November Surry Unit 1 outage.

<u>**SUB 534 OUTAGE NO. 2**</u>

Q. PLEASE DESCRIBE THE JULY 2015 SURRY UNIT 1 FORCED OUTAGE.

A. Surry Unit 1 exited a scheduled refueling outage on May 28, 2015. **[BEGIN CONFIDENTIAL** [redacted]

[64]**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** RCE 3002046, Section 2.4, page 21.

[redacted]

[redacted]

[redacted]

[65] Foreign Material Exclusion

[66] Sub 534 Data Request No. 2-4(b).

[67] DENC RCE 3002046, Section 1.2 Root Cause (RC-1), page 3.

[redacted]

[68] This potential failure was the result of a design issue by Westinghouse Electric Company, LLC, and had impacted another nuclear plant in Salem, Massachusetts in 2014; Event Notification Report, for RCPs delivered to Salem Unit 2 and Surry Units 1 & 2, United States Nuclear Regulatory Commission, July 15, 2014.

[70] RCE 3002046, pg. 10 of 50.

[redacted]

[redacted]

[redacted]

[redacted]

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71 RCE 3002046 Attachment 2, Time Line, pages 36 and 37 of 50.

72 Scoring occurs due to removal of metal from an object due to high contact pressure/sliding velocity. Scoring resembles scratches or gouges in metal, as part of the metal has been either removed or displaced.

73 RCE 3002046, Attachment 2, Time Line, 7/14/2015, 0611, p. 36 of 50. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

[74] RCE 3002046, Attachment 2, Time Line, 7/14/2015, 0730, page 37 of 50. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[75] 3x refers to 3 samples.

[76] PG = Primary Grade

[77] RCE 3002046, Attachment 2, Time Line, 7/15/2015, 2341, page 37 of 50. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[redacted]

[redacted]

[78] RCE 3002046, Seal Disassembly, page 12.

[79] RCE 3002046, Attachment 5, Surry Unit 1 B RCP Seal Examination and Flush Debris Analysis CR 581101, pp. 13, 20.

[80] RCE 3002046 p. 16.

[redacted]

> [redacted]

[redacted]

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[81] RCE 3002046, Potential Sources of FM, page 15 of 50.

[redacted]

[82] The Public Staff's understanding is that the CRB is an internal tool used to determine risks for a project. The CRB would review the overall process of planned work and potentially the work package/design change (or equivalent) to ensure that the proper hazards are addressed. In other words, it is a peer check to ensure that the quality of the final product does not violate plant policies/procedures and meets safe operation standards.

[83] In reference to a piping system, once the last piece of pipe is connected/installed, it would not be possible to recover any foreign material (metal, tools, cleaning rags, etc.) from the system. A system flush would be required to purge any potential foreign material left in the system. Non-recoverable can also mean in this context that the piping system cannot be immediately inspected for the foreign material items previously mentioned. If inspection is not possible or foreign material is not reachable due to the nature of installation or length of pipe, it would be classified as non-recoverable.

[redacted] **[END CONFIDENTIAL]**

The Company indicated to the Public Staff that it had included extra time for pipe flushing in the master outage schedule for the May 2015 refueling outage. This inclusion of extra time suggests that the Company was aware of the risk of foreign material potentially being introduced into the system.

However, flushing a system after foreign material has been introduced is not equivalent and should not replace first ensuring that the system is free of foreign material. Another way to state this is that utilization of a post-engineering control does not replace first line foreign material prevention controls. As with any foreign material prevention controls, system latencies always exist. Multiple levels of foreign material prevention barriers provide a depth of defense to help counter latencies that may be present in

[84] RCE 3002046, Work Planning, pages 15-16 of 50.

[85] RCE 3002046, Work Planning, page 15 of 50.

any system. For example, system flushing that is not analyzed or configured correctly could allow pieces of foreign material to enter downstream sections of the piping system (e.g., the flow of the flushing fluid through the pipe could result in a piece of foreign metal located in a bend of the pipe being pushed in the same direction of the flow into a crevice of a valve, later being displaced during plant operation and causing damage). Therefore, the first line of defense should be preventing the foreign metal from entering the system in the first place.

[BEGIN CONFIDENTIAL] [redacted]

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[86] Response to conference call question 11 on "1-RC-P-1B Seal Degradation (CR 1002289).

[87] RCE 3002046, Work Planning, page 16.

[redacted]

[redacted] **[END CONFIDENTIAL]** Adherence to existing plant procedures/processes reduces the risk of damage and plant shutdown from foreign material, and may have prevented the outage.

[BEGIN CONFIDENTIAL] [redacted]

[88] *Id.*

[redacted]

[redacted]

89 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** RCE 3001046, External OE, page 24 of 50.

90 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** RCE 3002046 p. 24 and INPO TR9-66 p. 2.

91 A low flow area of piping is a specific section or area of pipe that limits or restricts the flow or movement of water during a flushing activity. For example, with a section of piping that has a valve in series (in-line), the inside shape of the valve may be configured to create turbulence or have crevices such that a flushing media would not be able to exert the full force necessary to flush all foreign material. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

92 A "dead leg" is a section of pipe that no longer maintains a flow and is isolated from the piping system. Another example of a dead leg would be a pipe in the shape of the letter "T." If water entered from the bottom of the "T" and collected in the left hand side of the "T", the right hand side of the "T" would be considered a dead leg because it is unknown what quantity, if any, of the water ever entered the right hand section.

[redacted] **[END CONFIDENTIAL]** In my professional experience with installation of piping and pipe-related activities, any time there is cutting or welding activity on a piping system, a high probability exists that remnants from, or metal shavings of, the pipe cutting activity will be introduced into the piping system. Evaluation of the dead legs or low flow areas in the piping system and appropriate action may have prevented the outage.

Q. [BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[93] Dominion Virginia Power Purchase Order 70288441, p. 57.

[redacted]

[redacted]

[redacted]

94 RCE 3002046, Potential Sources of FM, p. 15.

[redacted]

[redacted]

[redacted]

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[95] Dominion Virginia Power Purchase Order 70288441, and response to conference call question 3(b)(c) 1-RC-P-1B Seal Degradation.

[96] Dominion Virginia Power Purchase Order 70288441, and response to conference call question 3(d), 1-RC-P-1B Seal Degradation.

[redacted]

[redacted]

97 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** A typical pipe isometric drawing would have all parts specified to a set length. The specified length minimizes the cutting and fitting stage of a project; however, due to the necessity sometimes to shift a component to miss an obstacle in the field, the start and finish pieces of pipe will be left with additional length. Any "long" section of pipe would require cutting at the time of installation (e.g. post pre-fabrication

98 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[99] Response to conference call question 4 1-RC-P-1B Seal Degradation, and Work Order 38103577010 pg. 12.

[redacted]

[redacted]

[redacted]

[redacted]

[100] WO 38103577010, FMEE, Attachment 3, page 1 of 1 (or page 160 of 165 of the work order).

[101] WO 38103577010, FMEE, Attachment 4

[102] WO 38103577010, FMEE, Attachment 4, page 1 of 2.

[redacted]

[redacted]

[redacted]

[103] WO 38103577010, FMEE, Attachment 4, page 2 of 2.

[redacted]

[redacted]

[redacted]

[104] RCE 3002046, Work Planning, page 16 of 50. The term “OE” as listed in this citation means Operational Experience.

[redacted]

[redacted]

[redacted]

105 These terms are typically used in an attempt to describe what a "typical" worker with "X" amount of years' experience should be able to perform. Nuclear outage work often requires a very high level "skill of the trade" in order to ensure that standard work practices are followed.

106 **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]. **[END CONFIDENTIAL]**

[107] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (RCE 3002046, Work Planning, page 15 of 50).

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[108] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[109] NAPS RCE000219

[redacted]

[redacted]

[110] Sometime in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as identified on page 58 of RCE000219 as N-2006-2392 and N-2006-2441.

[redacted]

[redacted]

[redacted]

[redacted]

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[111] RCE000219, p. 58.

[112] *Id*. at p. 69.

[113] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** RCE000219, p. 69.

[redacted]

[redacted]

[redacted]

[114] NAPS RCE000219, p. 71.

[redacted]

[redacted]

[redacted]

[redacted]

[115] NAPS RCE000219, p. 26.

[redacted]

[redacted] **[END CONFIDENTIAL]** As listed above, there are a number of causes that directly impacted or contributed to the outage. But for these causes, I do not believe the outage would have occurred. These various causes considered in the aggregate show a lack of efficient management of the plant in regard to this outage.

Q. WHAT IS THE NORTH CAROLINA RETAIL PORTION OF THE REPLACEMENT POWER COSTS FOR THE SURRY UNIT 1 JULY 2015 OUTAGE, EXCLUSIVE OF THE COMPANY'S 2% FORCED OUTAGE ALLOWANCE?

A. The North Carolina portion of replacement power costs for this outage is approximately $369,184.

SUB 534 OUTAGE NO. 3

Q. PLEASE DESCRIBE THE OCTOBER 2015 SURRY UNIT 1 FORCED OUTAGE.

A. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[116] Sub 534 Data Request 2-5.a.

[redacted]

[redacted]

[redacted]

[117] RCE-CA3015336, 2.2.2 Background and Design Discussion, p. 18.

[redacted]

[redacted]

[redacted]

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[118] The Surry Unit 2 generator replacement and corresponding uprate were completed in 2003; the replacement and uprate for Surry Unit 1 occurred in 2006.

[119] The exciter is a piece of equipment that attaches to the generator, providing generator field current in the rotor windings, which in turn creates the magnetic field used to produce AC current as the rotor turns.

[120] RCE-CA3015336, p. 20. Confidential Metz Exhibit 3: **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

[121] **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

[redacted]

[redacted]

[redacted]

[redacted]

122 Melting point of copper is 1984.32 °F, http://www.rsc.org/periodic-table/element/29/copper

[redacted]

[redacted]

[redacted]

> [redacted]

> [redacted]

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[123] RCE-CA3015336, Attachment 15, pages 7 and 8.

[124] RCE-CA3015336, 2.10 Equipment Reliability/PM Adequacy para. 10, p. 45.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[125] RCE-CA3015336, 1.2 Root Cause, p. 5.

[126] Design Change Package can also be referred to as EC's or Engineering Change

[127] RCE-CA3015336, 1.2 Root Cause, p. 4.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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128 Thread galling is a common, yet often misunderstood, problem with threaded fasteners. Galling, often referred to as a cold-welding process, occurs when the surfaces of male and female threads are placed under heavy pressure. During the tightening of the fastener, pressure builds between the contacting thread surfaces and breaks down the protective oxide coatings. With the absence of the oxide coating, the metal high points of the threads are exposed to one another, which increases friction. The combination of these two events can generate enough heat to fuse and seize the nut and bolt together. The frustrating aspect of fastener galling is that galled nuts and bolts may pass all required inspections (threads, material, mechanical, etc.), yet still fail to function together.
Minor galling may cause only slight damage to the thread surface and the installer may still be able to remove the fastener. However, in severe cases, galling can completely weld the nut and bolt together and prevent removal of the fastener. If the tightening process is continued once galling begins, the fastener may be twisted off or have its threads stripped. If the fastener is over tightened, the threads can begin to yield which will include friction between the mating services. In addition, galled threads result in premature achievement of a torque value due to the bolt becoming "seized" in the fastener prior to the bolted connection providing the necessary counter force against the applied torque.
https://www.fastenal.com/content/feds/pdf/Article%20-%20Galling.pdf,
http://www.fastenal.com/content/documents/FastenalTechnicalReferenceGuide.pdf

129 RCE-CA3015336, 2.2.8 Procedure/Process Review, p. 30.

[redacted]

[redacted]

130 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

131 RCE–CA3015336, Attachment 15, Figure 1 and Figure 2. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

132 RCE-CA3015336, Attachment 1, (OC2), p. 4.

[redacted]

[redacted]

[redacted]

[133] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (RCE-CA3015336, 2.2.7.2 Examination of Unit 2 components and assembly lessons learned, p. 27).

[redacted]

[redacted]

[redacted]

[redacted]

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134 RCE-CA3015336, 2.2.7.3 Ground Detection system, p. 28.

135 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

136 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[redacted]

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[137] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[141] RCE-CA3015336, 2.2.8 Procedure/Process Review, pp. 30-31.

[redacted]

[redacted]

[redacted]

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[142] A traceability number for calibrated equipment: (1) allows the tool to be traced through its use with multiple projects; (2) provides a means to test the tool on a periodic cycle to ensure that the value displayed on the tool indicator is calibrated to the tool performance value; and (3) provides trending data for analysis that will indicate whether or not the tool is suspect, or trending towards failure.

[143] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[144] Per Company administrative procedure PI-AA-500 Verification Practices; **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[145] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (RCE–CA 3015336, Section 2.2.8, Procedure/Process Review, p. 31).

[redacted]

[redacted]

[redacted]

[146] **[BEGIN CONFIDENTIAL]** [redacted] **[ENDCONFIDENTIAL]**.

[147] RCE-CA3015336 pg. 27.

[redacted]

[redacted]

[redacted]

[148] RCE-CA3015336, 2.2.8 Procedure/Process Review, Field Observations, p. 33.

[149] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[150] RCE-CA3015336, 2.2.8 Procedure/Process Review, Field Observations, p. 33.

[151] *Id.*

[redacted]

[redacted]

[redacted]

[152] AD-AA-100, Revision 5, page 89 of 11, Attachment 5, "Technical Procedure Traveler."

[redacted]

[redacted]

[redacted]

[redacted]

[153] RCE-CA3015336, 2.2.8 Procedure/Process Review, Procedure Development Rigor, p. 34.

[redacted]

[redacted]

[redacted]

[154] RCE-CA3015336, 2.2.8 Procedure/Process Review, pp. 30-31.

[redacted]

[redacted]

[redacted]

[155] A feeler gauge is a tool with multiple pieces of thin metal (or equivalent) that you can slide between to objects. The goal is to start small with the thinnest piece of metal and see if it can pass freely between the two objects and then work your way upward. The intent is to (1) determine if there is space between two objects, and then (2) measure the distance between two objects. Feeler gauges may vary; however, they can be used on spaces measuring 0.003” (as thin as a piece of standard paper). The air gaps in question are illustrated in Figure 1 below.

[redacted]

[redacted]

[redacted]

[156] Such bending may not be visible to the naked eye.

[redacted]

[redacted]

[redacted]

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[157] Earlier in my testimony, I discussed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[158] Asperity from a material science perspective is the unevenness of a surface or roughness.

[159] "[The] flow of the current between surfaces is affected by the true area of contact for each load level. Since only a few, scattered asperities are actually in contact for any given load level, the current is restricted to very small contact patches when compared to the area of the entire surface. As the current flows through these asperity peaks, it will be effectively "bottlenecked" resulting in some resistance to the conduction." http://www.eng.auburn.edu/~jacksr7/Wilson-ECRsurfaceseperation-2010c.pdf

[160] A method to overcome asperity, which is a naturally occurring phenomenon, would be to compress the mating surfaces together via a force (torque). This compression would ultimately "smooth" out the peaks and the valleys and thus eliminate the "very small contact patches."

[redacted]

[redacted]

[161] **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]** All of the causes identified were within the control of Dominion and could have been avoided. Further, for the reasons discussed above, I believe that

[redacted] **[END CONFIDENTIAL]**.

[165] RCE-CA3015336 Procedure/Process Review, p. 31.

this outage could have been avoided through more prudent management.

Q. WHAT IS THE NORTH CAROLINA RETAIL PORTION OF THE REPLACEMENT POWER COSTS FOR THE SURRY UNIT 1 FALL 2015 FORCED OUTAGE?

A. The North Carolina retail portion of the replacement power costs for this outage is approximately $1,003,635.

<u>SUB 534 OUTAGE NO. 4</u>

Q. PLEASE DESCRIBE THE REFUELING OUTAGE EXTENSION FOR SURRY UNIT 2 IN DECEMBER 2015 FOR WHICH THE PUBLIC STAFF RECOMMENDS DISALLOWANCE OF REPLACEMENT POWER COSTS.

A. Surry Unit 2 entered a planned refueling outage in November 2015. The refueling outage was extended by approximately 8 days (December 4, 2015, to December 11, 2015) due to the use of Unit 2 components to expedite the restart of Surry Unit 1 from its October 2015 forced outage discussed previously in my testimony. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** While it was prudent to restart Unit 1 as soon as possible, had it not tripped in the first place, Unit 2 would not have incurred the additional approximate 8 days of outage. As a result, it is not reasonable for North Carolina retail ratepayers to incur the replacement power costs for the additional outage time.

Q. WHAT IS THE NORTH CAROLINA RETAIL PORTION OF THE REPLACEMENT POWER COSTS FOR SURRY UNIT 2'S FALL 2015 REFUELING OUTAGE EXTENSION?

A. The North Carolina retail portion of the replacement power costs for this outage is approximately $202,603.

GENERAL CONCLUSIONS REGARDING OUTAGES 1 THROUGH 4

Q. [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

Q. DO YOU AGREE THAT BECAUSE A PROCEDURE IS SUCCESSFUL ONCE, IT WILL BE SUCCESSFUL IN THE FUTURE?

A. No, I do not. Just because the plant started up and operated without any issues related to the task in which an individual procedure was used does not mean that the procedure can be expected to work in the future.

Q. SIMILARLY, DO YOU BELIEVE THAT THERE IS LESS CAUSE FOR CONCERN IF A PROCEDURE IS NOT FOLLOWED DURING A REPAIR OR MAINTENANCE, BUT NO OUTAGE OCCURS?

A. No. The procedures developed by the Company are designed to reduce the risk of damage to personnel and the plant. They are also designed to reduce the risk of an outage or outage extension. Regardless of whether an outage or damage occurs, the risk remains. These procedures are also in place to protect ratepayers from risks associated with outages and increased costs.

SECTION 4: PROPOSED FUEL AND FUEL RELATED COST FACTORS

Q. IN TOTAL, WHAT IS THE APPROPRIATE AMOUNT OF COSTS THAT SHOULD BE EXCLUDED FROM THE EMF ON A NORTH CAROLINA RETAIL BASIS FOR THE FIVE OUTAGES IDENTIFIED?

A. Based on my analysis, the total replacement power costs associated with the three outages that should be excluded from cost recovery is $1,807,896 on a North Carolina retail basis.

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. PLEASE PROVIDE THE ADJUSTED PROPOSED FUEL AND FUEL-RELATED COST FACTORS WITH YOUR PROPOSED ADJUSTMENTS.

A. Exhibit No. 4 shows the Proposed Fuel and Fuel-Related Cost Factors with my proposed adjustments,

SECTION 5 FORCED OUTAGE ALLOWANCE

Q. PLEASE EXPLAIN WHAT REPLACEMENT POWER COSTS ARE.

A. In general, replacement power costs are the costs associated with a forced generator outage where the costs of replacement generation (or purchase) of power are greater than costs of generation by the unit that experienced the forced outage. The Company defines replacement power costs as the variable costs for the unit that is in an outage and the actual market price for power (the Day-Ahead (DA) Dom Zone LMP). The difference between the two is deemed to be the "replacement cost" of that unit. According to a Company data response, this difference is then multiplied by the missing generation capacity (appropriate to the month involved) to generate the hourly replacement power cost.

Based upon my understanding, as a member of the PJM Regional Transmission Organization, the Company is required to bid into the day-ahead market. Once PJM completes the auction process for the day-ahead market, the Company must purchase its power requirements to serve the load it bid as day ahead load at the resulting market clearing price (locational marginal price, or LMP).

Because the Company purchases its entire power requirements from the PJM market, its replacement power costs are a fairly straightforward determination. A loss of generation that was bid into the market and then repurchased to serve load would be replaced from the next available resource in the PJM market.

In the Company's case, after it determines the base replacement power costs, it deducts a 2% forced outage allowance (FOA) from the total replacement power costs. Once the 2% FOA is deducted from the total system replacement power costs, the North Carolina retail allocable share of ~5% is applied to arrive at the North Carolina replacement power costs.

Q. DO YOU AGREE WITH THE METHODOLOGY EMPLOYED BY THE COMPANY FOR CALCULATING THE REPLACEMENT POWER COSTS?

A. No. I do not agree with the Company including a 2% FOA in its calculation of replacement power costs.

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATES THE 2% FORCED OUTAGE ALLOWANCE FOR ITS REPLACEMENT POWER COSTS.

A. In response to a data request from the Public Staff, the Company defined its FOA equation as follows:

$$FOA = Average\ MDC\ x\ annual\ available\ hours\ x\ annual\ LMP\ x\ 2\%$$

Where:

- <u>Average MDC</u> represents the average unit maximum dependable capacity over a period of 12 months. Because most generating facilities have both a summer and winter rating, an annual average MDC is used (six winter months and six summer months) to determine this value. Each individual generating unit has its own unique MDC. The MDC is equivalent to the unit's MW output rating.

- <u>Annual available hours</u> represents the total hours in a year (8,760 hours in non-leap years, or 8,784 hours in a leap year) <u>reduced by the planned outage</u> hours (such as refueling outages and scheduled maintenance outages). The Company's nuclear fleet operates in 18-month refueling cycles, thus the annual available hours will vary from year to year. In addition, not all refueling outages are of the same duration, so the annual available hours would also vary based upon the type of work that is being scheduled for the outage.

- Annual LMP represents the annual average Dominion Zone DA LMP. In a data response, the Company indicated that it takes an annual average of the applicable LMPs for the entire year.

- 2% represents the Company's estimate of expected forced outages for its nuclear fleet of units outside of the ~18 month "planned" refueling outage.[166]

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATES ITS NORTH CAROLINA REPLACEMENT POWER COSTS.

A. The Company defines the replacement power costs (RPC) equation as follows:

$$RPC = (\sum((LMP - Unit\ Cost) * MDC) - FOA) * NC\ Allotment$$

Where:

[166] 18-month refueling cycle pertains to the Company's nuclear fleet. Any type of generating unit could have a FOA; it does not solely pertain to a nuclear unit.

- $\sum$ = the summation of each result identified in ( ) for each hour of the event
- LMP represents the Dominion Zone DA LMP price during each hour of the outage in question.
- Unit Cost represents the variable costs for the unit in question including fuel, transportation of the fuel, reagents, emissions allowances, etc.
- Duration represents the time span of the forced outage in question, expressed in hours.
- MDC represents the average maximum dependable capacity as previously defined.
- FOA represents the 2% forced outage allowance previously defined.
- NC allotment represents the North Carolina retail energy factor, approximately 5%.

Q. HOW IS THE 2% FOA ALLOCATED BY OPERATING UNIT DURING THE YEAR?

A. An FOA is calculated for each operating unit for each year. For each unit, the replacement power costs for each outage would count toward the allowance until the actual unit replacement energy costs exceed the dollar value of the forced outage allowance on an annualized basis. In other words, there is an annual cap on the forced outage allowance. Thus, in a year, a unit could experience multiple outages before exceeding its allowance, never exceed its allowance, or exceed its allowance in only one outage. The Company does not allocate any remaining allowance for an operating unit to other operating units that have exceeded their allowances.

For example, let us take four units each with the same nameplate rating (MDC) and a 2% FOA of $250k for each unit (Unit A thru D).

Scenario 1: Unit A has a single forced outage and incurs replacement power costs of $1M. The FOA of $250k would be deducted from the $1M and DENC would contend it incurred $750k of replacement power costs.

Scenario 2: Unit A has three forced outages and incurs replacement power costs of $50k each. Under this example, the total for the three outages ($150k) does not exceed the FOA allowance of $250k. Therefore, DENC would contend that it had no replacement power costs because it did not use all of its FOA, which can be thought of a bucket or pool of money that may be used for a particular unit throughout the entire year.

Scenario 3: Unit B and Unit D have forced outages and incurs $375k and $100k, respectively, in replacement power costs. Any unused FOA for one unit does not carry over to another unit that had exhausted its FOA. Therefore, Unit B would have exceeded its FOA by $125k, but Unit D did not exceed its FOA. DENC would contend that it incurred $125k of replacement power costs.

Q. WHAT IS THE 2% FOA FOR SURRY POWER STATION IN SUB 534?

A. In Sub 534, each unit at Surry had a FOA with a dollar value assigned based on its operation during the applicable test year.

- Surry Unit 1 had an allowance of $5,103,261 with a North Carolina retail allocable share of $255,163.
- Surry Unit 2 had an allowance of $5,039,669 with a North Carolina retail allocable share of $251,983.

Q. WHAT IS THE 2% FOA FOR NORTH ANNA POWER STATION UNIT 2 AND SURRY POWER STATION UNIT 2 IN SUB 546?

A. In Sub 546, North Anna Unit 2 and Surry Unit 2 each had a FOA with a dollar value assigned based on its operation, available hours, during the applicable test year.[167]

- Surry Unit 2 had an allowance of $3,290,710 with a North Carolina retail allocable share of ~$164,535.
- Surry Unit 2 had an allowance of $3,376,582 with a North Carolina retail allocable share of ~$181,808.

[167] Company response to Public Staff Data Request 8.2.b.

Q. HOW WOULD THE APPLICATION OF A 2% FOA AFFECT YOUR PROPOSED ADJUSTMENTS FOR TO REPLACEMENT POWER COSTS IN SUB 546?

A. Because my proposed adjustment to replacement power costs for North Anna Unit 2 and Surry Unit 2 fall below the 2% FOA, the Company has indicated to the Public Staff that it does not have any replacement power costs for the two Sub 546 outages discussed previously.

Q. WHY DO YOU DISAGREE WITH THE COMPANY'S USE OF THE 2% FOA IN THE REPLACEMENT POWER COST CALCULATION?

A. While forecasting a 2% forced outage rate is reasonable for the Company's planning, it is not reasonable for the Company to grant itself a 2% FOA. The Company is responsible for operating its plants in a reasonable and prudent manner. If the cause of an outage is found by the Commission to result from unreasonable and or imprudent actions, ratepayers should not bear the costs of the replacement power necessary to replace the power foregone due to that outage. Regardless of whether an outage falls within the 2% forced outage rate used for planning purposes, ratepayers should not be forced to pay for replacement power if the outage could or should have been avoided through efficient management or it was not otherwise reasonably and prudently incurred.

SECTION 6: RECOMMENDATIONS OF THE PUBLIC STAFF

Q. WHAT OTHER RECOMMENDATIONS DOES THE PUBLIC STAFF HAVE?

A. Due to shortened time for review of DENC's fuel rider as opposed to those of Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP), (75 days vs. 90 days between filing and the hearing per Commission Rule R8-55(f)) the Public Staff has a narrow window to review plant performance. To the extent there are delays in receiving documentation related to outages, especially RCEs, the investigation time is shortened. Having access to completed and readily available RCEs as a starting point of the investigation allows the Public Staff to more quickly review the events that took place and focus the investigation.

The Public Staff and the Company experienced a discovery dispute that was eventually resolved. However, due to this delay, the Public Staff did not have an opportunity to begin its review of the two Sub 546 RCEs until the end of September. The Public Staff sent detailed data requests on each of the RCEs to the Company, and the

Company responded in a timely manner. However, because the North Anna plant was in a refueling outage and the volume of the information requested by the Public Staff, the Company was unable to respond to a number of questions within the time allowed.[168]

In an effort to avoid delays, which have happened in both Sub 534 and Sub 546, due to these types of issues, the Public Staff recommends that the Commission require DENC to provide completed RCEs on a semi-annual basis. DEC and DEP already have an agreement in place with the Public Staff to provide all available RCEs to the Public Staff twice a year.

This will allow the Public Staff to review outage information throughout the year, thus allowing a more complete review of information and easing the limitations imposed by the narrow timeline. It will also reduce the strain on the Company, which has its own time limitations during a fuel proceeding, such as this year when it was constrained in responding to some data requests regarding the RCEs due to a refueling outage.

The Company should be applauded on the amount of hard work, effort, and thoroughness it put into each of its RCEs. Continual

[168] Responses to Public Staff Sub 546 Data Request Nos. 14-2d, 14-35b, 14-35b.i., 14-36e.iii.2, and 14-51a-j.

reviewing of lessons learned and striving to improve the work product is a vital part of the culture of nuclear work.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, this concludes my testimony.

<u>Dustin R. Metz</u>

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, 2008 and 2009 respectively. I graduated from Central Virginia Community College with Associates of Applied Science degrees in Electronics & Electrical Technology (Magna Cum Laude), 2011 and 2012 respectively, and an Associates of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management.

I have over 12 years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control system in industrial and commercial nuclear facilities, project planning and management, and general construction experience.

I joined the Public Staff in the fall of 2015 and have worked on utility rate case, fuel cases, applications for certificates of public convenience and necessity, customer complaints, nuclear decommissioning, power plant performance, and other aspects of utility regulation.

Confidential Exhibit 1:

Confidential Exhibit 2: Detailed View

Confidential Exhibit 3:

Exhibit 4: Proposed Fuel and Fuel-Related Cost Factors in cents per kWh effective January 1, 2018 (includes regulatory fee, which currently has a multiplier of 1.0014)

Rate Class	Base	Rider A	Rider B[169]	Rider B2	Total
Residential	$0.02095	$0.00006	($0.00177)	$0.00009	$0.01933
Small General Service & Public Authority	$0.02093	$0.00006	($0.00177)	$0.00009	$0.01931
LGS (Large General Service)	$0.02079	$0.00003	($0.00175)	$0.00009	$0.01916
Schedule NS (Nucor Steel)	$0.02014	$0.00006	($0.00170)	$0.00009	$0.01859
6VP (LGS – Variable Pricing)	$0.02043	$0.00006	($0.00172)	$0.00009	$0.01886
Outdoor Lighting	$0.02095	$0.00006	($0.00177)	$0.00009	$0.01933
Traffic Control	$0.02095	$0.00006	($0.00177)	$0.00009	$0.01933

[169] My Rider B calculations reflect the application of the voltage differentiation factors used by the Company in its Application, which the Public Staff accepts.

Metz Exhibit No. 4a
Schedule 1

DOMINON NORTH CAROLINA POWER
Docket No. E-22 Sub 546
North Carolina Annual Fuel Expenses
Proposed Nuclear Capacity Factor of 93.54%
CALCULATION OF FUEL COST RIDER B BY CUSTOMER CLASS
Test Period Ended June 30, 2017
Billing Period January 1, 2018 - December 31, 2018

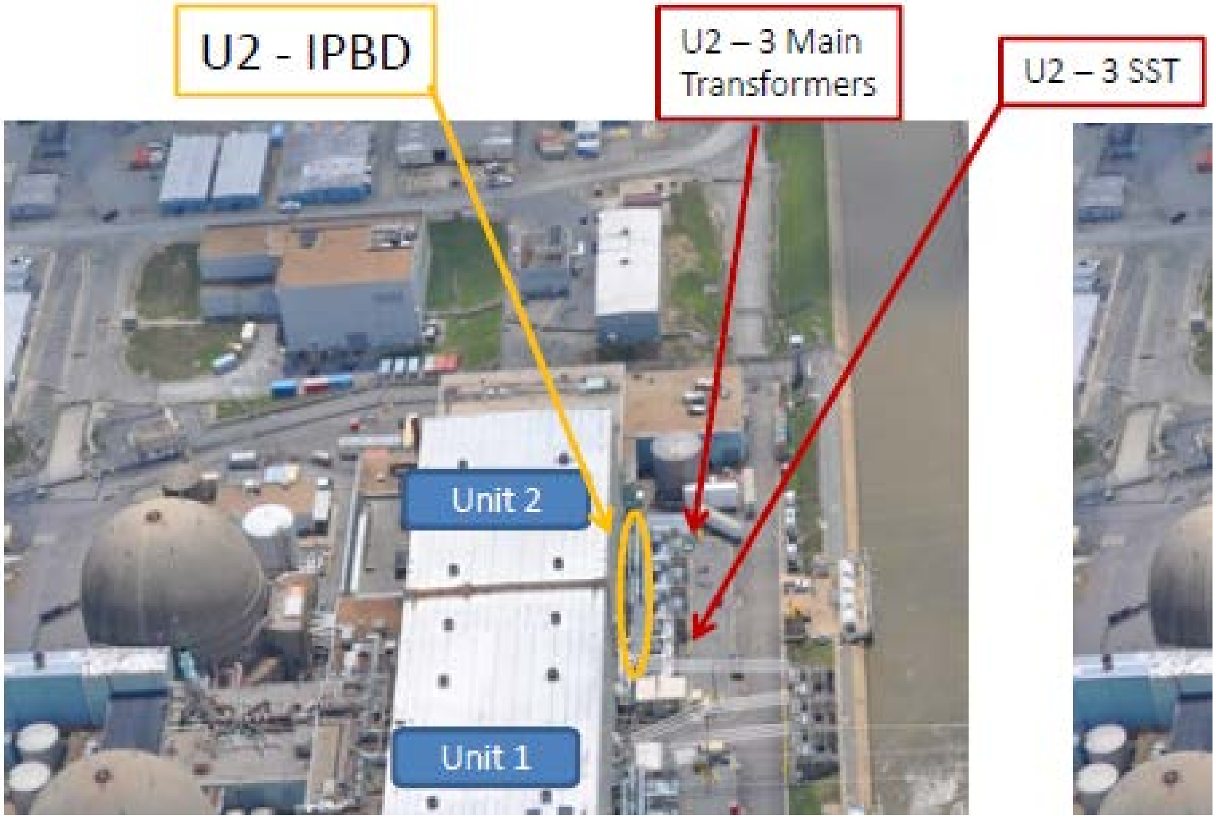
EMF RATES INCLUDE NCUC REGULATORY FEE

Line No.	Customer Class	Adjusted NC Retail kwh Sales	Total EMF Rate Including System Fuel Factor	Fuel Revenue Uniform Rate	Class Expansion Factor	Class kwh @ Generation Level	Jurisdictional Voltage Differentiated EMF Rate @ Sales Level (Rider B)
		A	B	C	D	E	E
			Johnson Ex 1, Sch 1	C= A x B	Ex JDM-1, Sch 4, p 2	C= A x D	Uniform rate X D
1	Residential	1,601,013,554	(0.00175)	(28,057)	1.05204180	1,684,333,181	(0.00177)
2	SGS & PA	817,305,119	(0.00175)	(14,323)	1.05087924	858,888,982	(0.00177)
3	LGS	710,913,646	(0.00175)	(12,458)	1.04236129	741,028,865	(0.00175)
4	Schedule NS	880,048,860	(0.00175)	(15,422)	1.01138685	890,069,844	(0.00170)
5	6VP	264,735,757	(0.00175)	(4,639)	1.02593554	271,601,822	(0.00172)
6	Outdoor Lighting	17,207,930	(0.00175)	(302)	1.05204180	18,103,462	(0.00177)
7	Traffic	8,241,485	(0.00175)	(144)	1.05204180	8,670,387	(0.00177)
8	NC Retail	4,299,466,351		(75,346)		4,472,696,545	
				Jurisdictional Uniform Rate @ Generation Level		(0.00168)	

Confidential Exhibit 5:

Confidential Exhibit 6

Exhibit 7: IPDB and SST Location



Confidential Exhibit 8: