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December 18, 2017

VIA ELECTRONIC FILING

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: *Application of 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*
Docket No. E-22, Sub 546

Dear Ms. Jarvis:

On behalf of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (the "Company"), enclosed for filing in the above-referenced proceeding please find the Proposed Order Approving Fuel Charge Adjustment ("Proposed Order"). In addition, a copy in Word format is being submitted via email to briefs@ncuc.net.

The Proposed Order contains information designated by the Company as confidential and qualifies as "trade secrets" under N.C.G.S. § 66-152(3). Pursuant to N.C.G.S. § 132-1.2, the Company has redacted this confidential information from the public version of this filing, and will contemporaneously file the confidential version of the above-referenced information under seal to be protected from public disclosure.

Please do not hesitate to contact me should you have any questions. Thank you for your assistance with this matter.

Very truly yours,

/s/Andrea R. Kells

ARK:kjg

Enclosure

**STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH**

DOCKET NO. E-22, SUB 546

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application by Virginia Electric and Power	)	PROPOSED
Company, d/b/a Dominion Energy North	)	ORDER APPROVING
Carolina For Authority to Adjust its Electric	)	FUEL CHARGE
Rates and Charges and Revise its Fuel Factor	)	ADJUSTMENT
Pursuant to N.C.G.S. § 62-133.2 and NCUC	)	
Rule R8-55	)	

HEARD: Monday, November 6, 2017, beginning at 1:30 p.m. in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Dominion Energy North Carolina

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 E. Six Forks Road, Suite 260, Raleigh, North Carolina 27069

Mary Lynne Grigg, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For the Carolina Industrial Group for Fair Utility Rates I (CIGFUR I)

Warren K. Hicks, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

For Nucor Steel-Hertford

Joseph W. Eason, Nelson Mullins Riley Scarborough, LLP, 4140 Park Lake Avenue, Suite 200, Raleigh, North Carolina 27622

For the Public Staff:

Lucy E. Edmondson, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On August 23, 2017, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (the Company), filed its application for a fuel charge adjustment, along with accompanying testimony and exhibits, pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities (Application).¹ The Application was accompanied by the testimony and exhibits of Bruce E. Petrie, James D. Merritt, Ronnie T. Campbell, Tom A. Brookmire, and Gregory A. Workman.

On August 30, 2017, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

Petitions to intervene were filed by the Carolina Industrial Group for Fair Utility Rates I (CIGFUR) on August 28, 2017 and Nucor Steel-Hertford (Nucor) on August 31, 2017. These petitions were granted by Orders dated September 12 and 13, 2017. The Public Staff's participation and intervention was recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On October 2, 2017, the Company filed a letter requesting that the Commission allow the Company to publish an Amended Public Notice correcting two errors in the original Public Notice. On October 3, 2017, the Commission issued an Order Requiring Publication of the Amended Public Notice.

¹ Pursuant to G.S. 62-133.2(a3), the Company is not eligible to recover non-fuel (but still fuel-related) costs through the annual rate adjustments authorized pursuant to G.S. 62-133.2, except for certain costs authorized by G.S. 62-133.2(a1)(6), which the Company did not incur during the test period and is not projected to incur during the rate period. Therefore, throughout this Order, the costs being considered for recovery shall be termed "fuel costs," and the proceeding shall be termed the "fuel charge proceeding."

On October 23, 2017, the Public Staff filed the testimony of Dustin R. Metz, and the affidavit of Sonja R. Johnson. The Public Staff filed the revised testimony of Dustin R. Metz on October 25, 2017.

On October 30, 2017, the Company filed the rebuttal testimony of Brandford L. Stanley, John Rosenberger, Julius A. Wright, and Bruce E. Petrie.

On November 2, 2017, the Company and the Public Staff filed a joint motion requesting that the Commission issue an order excusing the appearance of some witnesses at the hearing. The Commission granted the motion by Order dated November 3, 2017.

The matter came on for evidentiary hearing on November 6, 2017, as scheduled. No public witnesses appeared at the hearing. Witness Petrie testified on direct on behalf of the Company; witness Metz testified on behalf of Public Staff; and witnesses Stanley, Rosenberger, Petrie and Wright testified on behalf of the Company on rebuttal. All other testimony was received into evidence as if given orally from the stand.

Based upon the verified application, the evidence received at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. The Company is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. The Company is lawfully before this Commission based on its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2017.

3. The Company's fuel procurement practices during the test period were reasonable and prudent.

4. The per books test period system sales are 83,820,303,238 kilowatt-hours (kWh).

5. The per books test period system generation is 84,848,419 megawatt-hours (MWh), which includes various types of generation as follows:

<u>Generation Types</u>	<u>MWh</u>
Nuclear	27,998,627
Coal	18,885,985
Heavy Oil	186,787
Wood and Natural Gas Steam	1,530,691
Combined Cycle and Combustion Turbine	28,477,922
Solar and Hydro – Conventional and Pumped	3,155,211
Net Power Transactions	7,176,726
Less: Energy for Pumping	(2,563,530)

6. In both the 2015-2016 and 2016-2017 test periods, the Company exceeded the standard for reasonable and prudent nuclear capacity performance contained in Rule R8-55(k).

7. The nuclear capacity performance standard contained in Rule R8-55(k) is a system-wide performance metric.

8. A clear demonstration of a causal relationship between a utility's decisions or actions and resulting outages is required to support disallowances of fuel costs.

9. Imprudence must be demonstrated by evidence that the Company knew, or should have known, that its actions would lead to additional costs to ratepayers.

10. It is not necessary or appropriate to base determinations of prudence under Rule R8-55 on Root Cause Evaluations (RCEs).

11. Even if it were appropriate to consider RCEs for purposes of determining prudence, the evidence presented in this proceeding shows that the Company's management of and response to outages at the Surry and North Anna Stations during the prior test period (held for consideration from Docket No. E-22, Sub 534) and this test period was reasonable and prudent so as to minimize fuel costs.

12. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel costs, including management of and response to outages at its nuclear units.

13. It is reasonable for the Company to assume a 2% Equivalent Forced Outage rate (EFOR) when calculating replacement power costs.

14. The nuclear capacity factor appropriate for use in this proceeding is 93.6%, which is the estimated nuclear capacity factor for the 12 months beginning January 1, 2018.

15. The adjusted test period system sales for use in this proceeding are 84,774,563,328 kWh.

16. The adjusted test period system generation for use in this proceeding is 85,796,167 MWh, which is categorized as follows:

<u>Generation Types</u>	<u>MWh</u>
Nuclear	27,442,508
Coal (including wood and natural gas steam)	20,939,580
Heavy Oil	191,548
Combined Cycle and Combustion Turbine	29,207,250
Hydro	3,106,119
Solar	49,093
Net Power Transactions	7,472,692
Less: Energy for Pumping	(2,563,530)

17. A marketer percentage serves as a proxy for fuel costs when actual fuel costs associated with power purchases are not available. A marketer percentage of 78% should be applied in this proceeding to appropriately determine the fuel cost of such power purchases.

18. The adjusted test period system fuel expense for use in this proceeding is \$1,758,608,978.

19. The proper fuel factors for Rider A for this proceeding, including the regulatory fee, are as follows:

<u>Customer Class</u>	<u>Rider A</u>
Residential	0.006 ¢/kWh
SGS &PA	0.006 ¢/kWh
LGS	0.003 ¢/kWh
Schedule NS	0.006 ¢/kWh
6VP	0.006 ¢/kWh
Outdoor Lighting	0.006 ¢/kWh
Traffic	0.006 ¢/kWh

20. The appropriate North Carolina retail test period jurisdictional fuel expense over collection (including carrying costs) is \$5,450,950, including interest, and the adjusted North Carolina retail jurisdictional test period system sales are 4,299,466,351 kWh.

21. The appropriate Experience Modification Factors (EMF or Rider B) for this proceeding (including the regulatory fee) are as follows:

<u>Customer Class</u>	<u>EMF Billing Factor</u>
Residential	(0.128) ¢/kWh
SGS &PA	(0.128) ¢/kWh
LGS	(0.127) ¢/kWh
Schedule NS	(0.123) ¢/kWh
6VP	(0.125) ¢/kWh
Outdoor Lighting	(0.128) ¢/kWh
Traffic	(0.128) ¢/kWh

22. The total under-recovery balance for the 24 months ended December 31, 2016 is \$381,535, and the appropriate EMF Rider B2 Factors, including the regulatory fee, are therefore as follows:

<u>Customer Class</u>	<u>Rider B2 EMF Billing Factor</u>
Residential	0.009 ¢/kWh
SGS &PA	0.009 ¢/kWh
LGS	0.009 ¢/kWh
Schedule NS	0.009 ¢/kWh
6VP	0.009 ¢/kWh
Outdoor Lighting	0.009 ¢/kWh
Traffic	0.009 ¢/kWh

23. The total fuel factors to be billed to the Company's retail customers during the 2018 fuel charge billing period, including the regulatory fee, are as follows:

<u>Customer Class</u>	<u>Class-Specific Prospective Factor</u>
Residential	1.982 ¢/kWh
SGS &PA	1.980 ¢/kWh
LGS	1.964 ¢/kWh
Schedule NS	1.906 ¢/kWh
6VP	1.933 ¢/kWh
Outdoor Lighting	1.982 ¢/kWh
Traffic	1.982 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for the Company. The Company's filing was based on the 12 months ended June 30, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every ten years and each time the utility's fuel procurement practices change. The Company's current fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on December 20, 2013.

In his direct testimony, Company witness Workman explained that after descending to recent historic-low levels last year, commodity prices have begun to recover and stabilize. Natural gas prices have increased approximately 32%, coal prices have increased approximately 37%, and oil has increased by approximately 16% compared to prices in the prior test period.

Mr. Workman described the Company's fossil fuel procurement practices and explained that the Company continues to follow the same procurement practices it has in the past in accordance with its report filed in Docket No. E-100, Sub 47A.

In regard to natural gas procurement, Mr. Workman explained that the Company employs a disciplined natural gas procurement plan to ensure a reliable supply of natural gas at competitive prices. Through periodic solicitations and the open market, the Company serves its gas-fired fleet using a combination of day-ahead, monthly, seasonal, and multiyear physical gas supply purchases. Witness Workman also described how the Company evaluates its diverse portfolio of pipeline transportation and storage contracts to determine the most reliable and economical delivered fuel options for each power station, and how this portfolio of natural gas transportation contracts provides access to multiple natural gas supply points from the Gulf region to the Marcellus shale region. He also noted that the Company actively participates in the interstate pipeline capacity release and physical supply markets as well as long-term, pipeline expansion projects that will augment its transportation portfolio and enhance reliability at a reasonable cost. Witness Workman testified that, since the Company's 2016 fuel charge adjustment proceeding, the Company has continued to utilize more natural gas to serve its customers' electricity needs, noting that during the test period in this case, energy production at its gas-fired power stations accounted for about 33.6% of the electricity produced for customers, and during the 2013-2016 time period, the Company increased its gas consumption by an average of 23% per year, including with the most recent addition of the Brunswick County Power Station becoming operational in April 2016. (5)

In regard to coal procurement, Mr. Workman testified that the Company employs a multi-year physical procurement plan to ensure a reliable supply of coal, delivered to its generating stations by truck or rail, at competitive prices. The Company accomplishes this by procuring long-term coal requirements primarily through periodic solicitations

and secondarily on the open market for short-term or spot needs. He noted that this blend of contract terms creates a diverse coal fuel portfolio and allows the Company to proactively manage its fuel procurement strategy, contingency plans, and any risk of supplier non-performance.

Mr. Workman also discussed the Company's biomass procurement practices. He testified that, effective January 1, 2017, the Company's biomass stations at Hopewell and Southampton are served by multiple suppliers under long-term agreements, which enables the Company to increase the reliability of its biomass supply by diversifying its supplier base. He also noted that the Company continues to purchase long-term fuel supply through one supplier for its Altavista and Pittsylvania Power Stations, and to procure biomass needs for the Virginia City Hybrid Energy Center via short-term contracts with various suppliers.

Finally, Mr. Workman described how, with respect to its oil procurement practices, the Company purchases No. 2 fuel oil and No. 6 fuel oil requirements on the spot market and optimizes its inventory, storage, and transportation to ensure reliable supply.

Company witness Brookmire testified that the nuclear fuel market has softened considerably in the past five years, largely due to the earthquake and tsunami in Japan in March 2011, but also due to reductions in demand. He noted that some reductions in supply may have in part offset some of the downward trend in demand. Witness Brookmire indicated that the spot market price for conversion services has dropped significantly due to reduced near-term demand, while long-term prices have remained high. He also noted that the cost for enrichment services appears to have stabilized, and

that domestic trends in fabrication prices continue to be difficult to measure, but that the general consensus is that costs will continue to increase. He pointed out that there may be some short-term price lift on front end components due to the potential restart of several more reactors in Japan and the growth of China's nuclear energy program.

Witness Brookmire stated that these changes in market costs have not impacted the Company's projected near-term costs significantly, as the Company's current mix of longer-term front-end component contracts has reduced its exposure to the market price escalation and volatility that has occurred over the past several years. Witness Brookmire also pointed out that the 18-month refueling schedule for the Company's nuclear plants delays the full effect of any significant changes in a component price. He also noted that the Company has been active in the market and has some market-based contracts that allow the Company to take advantage of current lower prices. Witness Brookmire testified that the Company continues to follow the same procurement practices as it has in the past in accordance with the procedures filed in Docket No. E-100, Sub 47A. (2, 3-4)

No party offered testimony contesting the Company's fuel procurement and power purchases practices. Based on the foregoing, the Commission concludes that the Company's fuel procurement and power purchasing practices during the test period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 4-5

The evidence for these findings of fact is contained in the direct testimony and exhibits of the Company witnesses Campbell and Petrie.

The Company witness Campbell testified that the Company's per books test period system sales were 83,820,303,238 kWh, and witness Petrie testified that the

Company's per books test period system generation was 84,848,419 MWh. Witness Petrie stated that the per books test period system generation is categorized as follows:

<u>Generation Types</u>	<u>MWh</u>
Nuclear	27,998,627
Coal	18,885,985
Heavy Oil	186,787
Wood and Natural Gas Steam	1,530,691
Combined Cycle and Combustion Turbine	28,477,922
Solar and Hydro – Conventional and Pumped	3,155,211
Net Power Transactions	7,176,726
Less: Energy for Pumping	(2,563,530)

No other party offered or elicited testimony on the level of per books test period system MWh sales or generation. The Commission thus concludes that the foregoing test period per books levels of sales and generation are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 6-12

The evidence for these findings of fact is contained in the direct testimony of Company witness Petrie, the testimony of Public Staff witness Metz, and the rebuttal testimonies of Company witnesses Stanley, Rosenberger, Wright, and Petrie, and the transcript of testimony provided at the hearing held in this proceeding.

For purposes of determining the EMF rider, Commission Rule R8-55(k) requires that a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent Generating Availability Report of the North American Electric Reliability Corporation (NERC), appropriately weighted for size and type of plant, or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the

system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant. Rule R8-55(k) also provides that, if a utility does not meet either standard, a rebuttable presumption is created that the increased cost of fuel was incurred imprudently and a disallowance may be appropriate. Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events.

In his direct testimony, Company witness Petrie testified that the Company's net capacity factors during the test period for its four nuclear units were:

North Anna Unit 1	91.6%
North Anna Unit 2	100.6%
Surry Unit 1	96.6%
Surry Unit 2	93.1%

Thus, the aggregate capacity factor for the Company's nuclear units during the test period was 95.5%, which exceeded the five-year industry weighted average capacity factor of 88.5% for the period 2011-2015 for 800-999 megawatt (MW) units, as reported by NERC in its latest Generating Availability Report. Mr. Petrie testified in addition that, for the same five-year period (i.e., 2011-2015), the Company's net nuclear capacity factor was 91.0% compared to the national average of 88.5%. Based on these figures, he stated that the Company's nuclear fleet performance during the test period was clearly better than the industry five-year average for comparable units.

Witness Petrie explained that the nuclear net capacity factor is the best measure for reliable baseload performance and related operating efficiency and is the predominant standard recognized in the energy arena when evaluating nuclear power plant performance. He stated that a high net capacity factor reflects an excellent level of reliable baseload operations, which translates into many customer benefits in terms of reduced system fuel cost and consistency in availability, and that maximizing generation from baseload resources such as nuclear units reflects good operating efficiency and results in overall lower energy costs to customers.

Witness Petrie recounted that, in the Company's 2016 fuel adjustment proceeding, the Public Staff investigated several outages at the Surry station during the summer and fall of 2015. Since the matter was still being discussed at the conclusion of that case, the Public Staff and the Company agreed that any resulting recommendations would be made in the 2017 fuel case. He stated that in its final order in the 2016 case, the Commission concluded, subject to further consideration of these outages, that the Company managed its baseload plants prudently and efficiently so as to minimize fuel costs. Witness Petrie testified that the Company has reasonably and prudently followed well-established procedures prior to and throughout these nuclear outages that, without exception, had been successful in prior years, and that it had no reason to expect that procedures it followed leading up to these outages would not be adequate. He also testified that the Company's management of and response to these outages were reasonable and prudent. He pointed out that the Company has continued the excellent overall nuclear unit performance that was shown in the 2016 case, and that those units had an aggregate capacity factor during the 2015-2016 test period of 92.2%, followed by the factor for this

test period of 95.5%. He specified that the 2011-2015 capacity factor (91.0%), July 2015-July 2017 capacity factor (93.8%) and July 2016-July 2017 factor (95.5%) all far exceed the industry average during 2011-2015 of 88.5%. Witness Petrie explained that the Company's excellent nuclear performance over the industry average has resulted in lower fuel costs for its customers, and noted that nuclear fuel expenses are much lower than other types of baseload fuel expenses.

Public Staff witness Metz acknowledged that the Company met the standards of Commission Rule R8-55(k) with both an actual system-wide capacity factor and a two year simple average of the system wide capacity factor that exceeded the NERC weighted average capacity factor. Witness Metz stated that throughout the year, he tracks the Company's monthly filed Baseload Power Plant Performance Reports, as well as United States Nuclear Regulatory Commission (NRC) Reactor Status Report, NRC Reactor Event Notifications, the Reserve Situation Report generated weekly by the Public Staff, and other sources of industry data such as SNL. He noted that the Public Staff contacts the Company regarding specific outages, as well as the overall operation of the generation fleet. Witness Metz discussed certain specific outages that took place during the test period reviewed in this proceeding as well as outages from the prior test period, which this Commission ruled, in Docket No. E-22, Sub 534, would be subject to further consideration in this proceeding. Mr. Metz testified that his analysis of these outages was based on Root Cause Evaluations (RCEs) provided by the Company. He stated that RCEs are documents prepared to investigate the causes of, and contributing factors to, a specific outage and determine corrective actions.

With regard to this 2017 fuel case, out of 78 non-nuclear and six nuclear outages reported during the 2016-2017 test year, Mr. Metz stated that he requested more information regarding seven of those outages, and further scrutinized two of those, both of which were nuclear. He contended that both of those nuclear outages were within the Company's control. First, North Anna Unit 2 experienced a forced outage from July 29, 2016 through August 3, 2016, to repair a Reactor Coolant Pump (RCP) Seal return line.

[BEGIN CONFIDENTIAL] [REDACTED]

[END

CONFIDENTIAL] Second, Surry Unit 2 experienced an outage from October 9, 2016, through October 13, 2016, due to a water intrusion event with the external station service transformers. [BEGIN CONFIDENTIAL] [REDACTED]

[END CONFIDENTIAL]

Mr. Metz recommended that the Commission find that, had North Anna Unit 2 and Surry Unit 2 been prudently managed in the test year, these outages could have been avoided, and that replacement power costs associated with these outages allocated to North Carolina of \$232,474 (excluding interest) be excluded from test year costs.

With regard to the 2016 fuel case, out of 79 non-nuclear and five nuclear outages reported during the 2015-2016 test year, Mr. Metz stated that he requested more information from the Company regarding 15 outages. He concluded that none of the ten outages at the Company's three Mt. Storm coal-fired units could have been prevented

under prudent management. Of the five nuclear outages, Mr. Metz recommended 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 December 4-11, 2015, could have been avoided. For the July 11-22, 2015 Surry Unit 1 outage, [BEGIN CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [END CONFIDENTIAL] For

the October/November 2015 outage at Surry Unit 1, Mr. Metz concluded that [BEGIN CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [END CONFIDENTIAL] For the December 2015 outage at Surry Unit 2, witness Metz concluded that, while it was prudent to restart Surry 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. With regard to all of these outages, Mr. Metz asserted that most of the maintenance or repair activities had occurred previously. While he recognized the Company's indication that it had no reason to expect the same procedures it followed in the past to be inadequate for utilization going forward until the forced outages occurred, he contended that the fact that a plant starts up without any issues related to the task in which an individual procedure is used does not mean that the

procedure can be expected to work in the future. Mr. Metz recommended that replacement power costs of \$1,575,422 (excluding interest) associated with the two Surry Unit 1 outages and the December 2015 outage at Surry Unit 2 be excluded from the EMF. For the July 13-22, 2015 outage at Surry Unit 2, Mr. Metz did not recommend a disallowance, though he expressed some general concerns about the Company's actions with regard to this outage.

In total, Mr. Metz recommended a total disallowance of \$1,807,896 for five outages across the 2015-2016 and 2016-2017 test years.

At the hearing, witness Metz answered in response to questions from the Chairman that the NRC's oversight of nuclear facility operations focuses on safety, and testified that he was not aware of any action taken by the NRC with respect to the issues that the Public Staff had identified as demonstrating imprudence in this case. He also agreed that in order to disallow purchased power costs, any mistakes made by the Company would have to have a causal relationship to the outage or prolonging of the outage. In response to questioning from the Chairman as to whether he could say that different action with regard to the dead legs or low flow areas in the piping system of would have flushed the foreign material and prevented the July 2015 outage at Surry Unit 1, witness Metz testified that there were a combination of things not properly done, that in his opinion caused the outage. He pointed to the RCE's identification of the piping system as the source of the issue, and stated that it would seem that [BEGIN

CONFIDENTIAL] [REDACTED]

[END

CONFIDENTIAL] Witness Metz stated in response to questioning from the Company's counsel that he has not been inside the North Anna or Surry containment vessels.

In rebuttal testimony, Company witness Stanley testified that the 5.5% difference between the Company's nuclear average capacity factor and the NERC average capacity factor reduced North Carolina customers' fuel expense by approximately \$2.0 million. He testified further that the result of the Company's efficient application of intellectual capital and engineering resources is the continued safe, reliable, near-zero emissions, stable fuel supply, and 24/7 baseload supply for customers, and that he does not agree with the Public Staff's proposed adjustments to the EMF based on the outages at North Anna 2 and Surry 2 during the 2016-2017 test period.

Mr. Stanley stated that Rule R8-55(k) does not require or even suggest, and the Public Staff does not contend, that the Company is required to operate its nuclear fleet flawlessly. He explained that the operation of nuclear power stations is a technical and highly regulated process under which forced or unplanned outages will and do occur, and that the Company anticipates having occurrences when safe operations dictate a reduction in output. Mr. Stanley noted that, by setting a benchmark based on industry averages, Rule R8-55 implicitly acknowledges that forced outages will occur and do not necessarily represent unreasonable or imprudent operations. He testified that the Company's high overall nuclear capacity factor for the test period, combined with the testimony of Company witness Rosenberger, shows that the Company clearly exceeded the benchmark and demonstrated reasonable and prudent operations of its nuclear units.

Witness Stanley testified that the Nuclear Regulatory Commission (NRC) mandates that each nuclear licensee establish measures to assure that conditions adverse

to quality are promptly identified and corrected, that in cases of significant conditions adverse to quality the measures assure that the cause of the condition is determined and corrective action taken to prevent repetition, and that the identification of the condition, the cause, and the corrective action be documented and reported. He discussed in detail the Company's Corrective Action Procedure to implement these requirements. Under this Procedure, when a condition adverse to quality is identified, a Condition Report is generated, the Condition Report Review Team reviews the report, and an RCE is performed to determine the cause or causes and identify corrective actions. He explained how the RCE team members are selected and how the Corrective Action Review Board (CARB) approves that team and the RCE problem statement, and provides management oversight of the Corrective Action Program. He noted that every other year, the NRC performs a Program Identification and Resolution (PI&R) inspection of the licensee's Corrective Action Program (CAP), which includes RCEs, and that the last inspection for North Anna and Surry Power Stations did not identify any findings or violations of more than minor significance and none as related to RCEs.

Witness Stanley explained that the RCE process is not designed to assess prudence, but rather to systematically evaluate conditions adverse to quality and ensure that appropriate corrective actions are taken to preclude repetition in compliance with NRC regulations. He testified that using portions of the RCE beyond the root cause, such as contributing causes identified in an RCE, exposes the Company to unwarranted risk of disallowance of costs due to other parties' unfamiliarity with the applicability and intent of the RCE process and from potential misinterpretation of the different elements that were evaluated in that process. Mr. Stanley noted that, until 2016, the Company did not

provide entire RCEs to the Public Staff, or any party other than the NRC, because by their nature RCEs use hindsight to analyze operations and are not based on what could have reasonably been known at the time, which Mr. Stanley stated is his understanding of the standard for evaluating prudence. He noted further that RCEs contain highly sensitive information regarding the inner workings of the Company's nuclear facilities, thereby presenting a safety and security risk to North Carolina and Virginia residents if they fall into the wrong hands, which risk is not fully satisfied by treating these documents as confidential in these regulatory proceedings.

At the hearing, witness Stanley agreed with counsel for the Public Staff that the NRC is not looking at prudence when it carries out periodic evaluations of RCEs, but rather is looking to see that the Company has found the root cause and the corrective actions are logically a result of that and are taken in a timely and effective manner. He also clarified that while the information contained in the RCEs related to the outages at issue can be relied upon for the purpose of evaluating the root cause and contribution causes and actions for the outages, they were not written or intended to be used to determine prudence.

On rebuttal, Company Witness Rosenberger noted that witness Metz focused on the category of forced outages identified by NERC guidance that results from the extreme unit trip, and that half of the disputed outages in this case fall within the other two outage categories. Witness Rosenberger also echoed witness Stanley's testimony that RCEs are not written with the intent to assess reasonable and prudent operations, but rather contain conclusions based on contributing causes or enhancements discovered during the evaluation process. He cautioned against selectively applying information from RCEs, or

from conversations that occurred outside of the formal discovery process. He noted that, of the 168 outages associated with the 2015-2016 and 2016-2017 test periods, only 11 occurred at nuclear units, meaning that only 7% of the outages to be assessed as reasonable and prudent would have an RCE available to review, since non-nuclear units are not required to perform these evaluations.

Witness Rosenberger also provided detailed and specific responses to each of the outages addressed by Public Staff witness Metz, as discussed below.

North Anna 2: July 30-August 3, 2016. Witness Rosenberger testified that Company personnel at Unit 2 of the Company's North Anna station observed unidentified leakage of the Reactor Coolant System (RCS), determined that there was an unisolable through-wall leak in the piping associated with the Reactor Coolant Pump seal, and as a result initiated a shutdown of Unit 2, which was required by the station's technical specifications. **[BEGIN CONFIDENTIAL]** [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] **[END CONFIDENTIAL]** He stated that the Company remedied the situation by placing the unit in a condition to perform needed repairs, collecting vibration data associated with the piping, replacing the piping, performing post-maintenance testing, and fully restoring the unit to service. He stated that the outage was performed in a thorough and efficient manner. Mr. Rosenberger disagreed with witness Metz's conclusions regarding this outage, stating that **[BEGIN**

CONFIDENTIAL]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

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[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[END CONFIDENTIAL] He

therefore concluded that the Company could not have anticipated the leak on the seal return line.

Surry Unit 2: October 9-13, 2016. Mr. Rosenberger testified that Unit 2 at the Company's Surry station automatically tripped due to a generator differential lockout, which occurred at a time when no activities were in progress, and grid conditions were stable. [BEGIN CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [END CONFIDENTIAL]

He stated that the Company remedied the situation by removing drain plugs and drying all components that experienced water intrusion, extensively inspecting and testing components exposed to water, replacing gaskets and applying silicon to flange surfaces and fully restoring the unit to service approximately four days later. He stated that the quick restoration of the unit to service included a thorough evaluation of the components while performing actions to prevent recurrence. Mr. Rosenberger disagreed with Mr. Metz's conclusion, explaining that reliance solely on the RCE conclusions omits a significant detail regarding the amount of rainfall experienced at this site. He explained that the root cause must be within the control of the licensee with actions to prevent repeat occurrences, and that, since weather is not a factor that can be controlled by the Company, it could not be found as either a root cause or contributing cause. He testified that this outage and the Company's management of it were reasonable and prudent, and stated that the collection of water within the enclosure could not have been anticipated.

He explained that even though extreme weather cannot factor into the RCE process due to regulatory constraints, the unprecedented amount of rainfall in the area is applicable to the analysis of whether the outage was reasonable and prudent. He noted that some areas surrounding Surry Power Station experienced back-to-back 100-year storms and a few experienced rainfall in amounts that reached 500-year storm levels. He noted that Surry experienced 11 inches of rain in an 18-day period with over 5 inches falling in the 2 days prior to the outage with wind gusts reaching 41 miles per hour. He stated that the Company had no reason to believe that the vendor product would not meet the station's needs, and that the vendor, which is experienced in providing water tight enclosures, was contracted to provide enclosures within certain specifications. He concluded that it was not possible for the Company to foresee the extreme weather the station experienced, or the fact that the enclosures would not perform their design function.

At the hearing in response to questions from Public Staff counsel, witness Rosenberger testified that operating experience is used as an input to designing and planning the installation of a modification, in an effort to not repeat mistakes others have made and to apply learnings others have acquired. He also stated his belief that the missed opportunity noted by the RCE with respect to operating experience in this instance was to further explore and consider the effect of the operating experience. He testified in addition that the Company would have come to the same conclusion even after further exploration and consideration of the operating experience, which was that if it carried out the normal vendor recommended maintenance activities, the Company would be able to detect any problem.

Surry Unit 2: July 13-22, 2015. Turning to the outages that were at issue in the Company's 2016 fuel adjustment proceeding, witness Rosenberger testified that on July 13, 2015, Unit 2 at the Company's Surry station was ramped offline due to increased external leakage from a Pressurizer Spray Valve. He stated that the Company remedied the situation by placing the unit in a condition to support leak seal of the valve, successfully leak sealing the body to bonnet area, and fully restoring the unit to service approximately 9 days later. He noted that Mr. Metz's investigation of this outage did not result in a recommendation of disallowance of any costs associated with the outage.

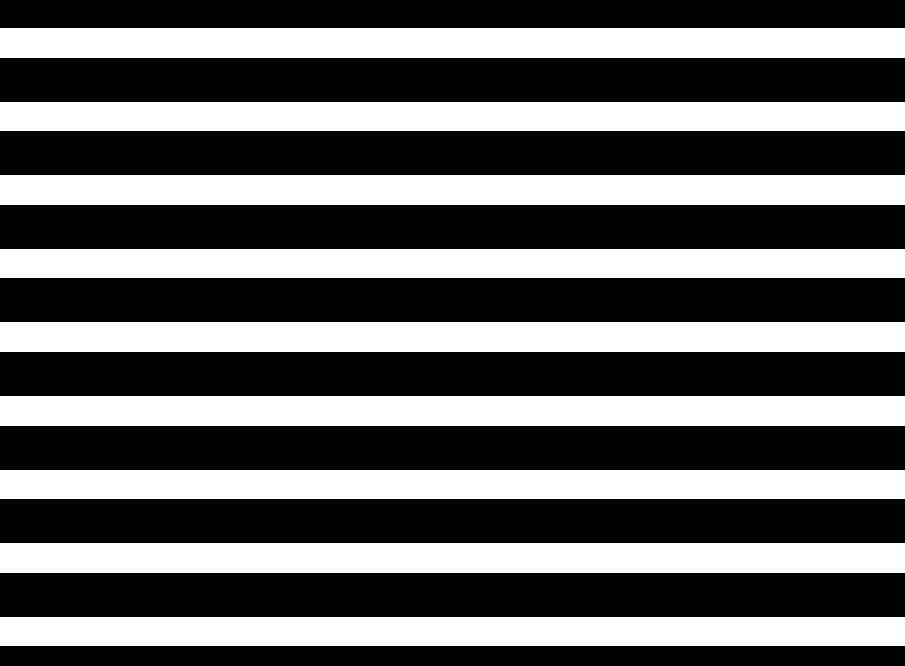
Surry Unit 1: July 11-22, 2015. Mr. Rosenberger testified that, on May 31, 2015, a newly installed seal at Unit 1 of the Company's Surry station showed evidence of degradation and declining differential pressure across the #1 seal and #3 seal, with the result that the Company shut down Unit 1 on July 11, 2015 to replace the seal. Upon investigation, the Company determined the direct cause of the issue to be [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] The Company remedied the situation by replacing the seal and fully restoring the unit to service on July 22, 2015.

In response to Mr. Metz's analysis of this outage, Mr. Rosenberger testified that, [BEGIN CONFIDENTIAL] [REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[illegible]

[REDACTED]

[REDACTED]



[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

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[REDACTED]

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[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [END CONFIDENTIAL]

Surry Unit 1: October 13 – November 18, 2015. Witness Rosenberger testified that the Unit 1 reactor at the Surry station tripped after receiving fault signals from the main generator protection system. [BEGIN CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED] [END CONFIDENTIAL] The unit was offline while the Company disassembled the failed components, procured and refurbished a new exciter, repaired the main generator shaft, replaced the exciter shaft coupling with a

newly manufactured coupling, and installed the Surry Unit 2 exciter onto the Unit 1 generator.

Mr. Rosenberger testified that, [BEGIN CONFIDENTIAL]

[REDACTED]

[REDACTED]

[illegible]

[REDACTED]
[REDACTED] [END CONFIDENTIAL]

Surry Unit 2: December 4-11, 2015. Witness Rosenberger testified that after Unit 2 at Surry Station entered a planned refueling, the planned outage was extended by approximately eight days because certain components from Surry Unit 2 had been used to expedite restart of Unit 1 from its October 2015 forced outage. Mr. Rosenberger stated that the decision to extend the Surry Unit 2 outage in order to expedite the return to service of Unit 1 should be viewed as a stand-alone case. He explained that in a situation where two nuclear units are in outage, the prudent response is to return each to service as safely and efficiently as possible. He stated that by returning Surry Unit 1 and extending the Surry Unit 2 outage, the Company reduced total outage time by approximately 17.5 days, saving approximately \$474,626 on a North Carolina jurisdictional basis.

Witness Rosenberger reiterated that the Company has exhibited exceptional nuclear performance over both the test period and the prior five-year period. He noted that forced outages on nuclear generating units will occasionally occur under even the best of scenarios, and that the Company's expertise and experience in operating its nuclear units allowed the Company to keep these outages to the minimum timeframe necessary, while also ensuring the safety and reliability of its system.

In his rebuttal, Company witness Wright testified that, while he respects the diligence and efforts of the Public Staff on this issue, he believes that the Public Staff's standard of review for nuclear capacity fuel cost recovery is far different from what is intended by Rule R8-55 and from what the Commission, the affected utilities, and the Public Staff have historically applied, based on his experience as a Commissioner at the

time when the fuel cost recovery and related nuclear capacity standards were adopted as well as on his review of relevant precedent.

Witness Wright provided the history of the current G.S. 62-133.2 and Rule R8-55(k). He explained that the 1987 legislation that resulted in the Rule R8-55 in use today instructed the Commission to establish a general mechanism and standard by which it could consistently, both over time and from utility to utility, measure a utility's prudence and efficiency in minimizing the cost of fuel borne by customers, including the cost of nuclear fuel. He testified that this was also clearly the Commission's intent in the rulemaking proceedings undertaken to implement that law. He emphasized that the resulting nuclear performance prudence standard, which was agreed to by the Public Staff, was a system wide performance metric, and reflects a consistent, impartial, and quantitative measure that defines a presumption of prudence of management efficiency in operating a nuclear system. He testified to the importance of the Commission maintaining a clear and consistent standard as it relates to reviewing a utility's operation of its nuclear system. He explained that, by adopting and maintaining a prudence standard that compares system-wide operations to a national standard, the Commission is notifying management, ratepayers, investors, and all utilities of a standard of review that is known in advance and fair to all parties. He testified that it would be a surprise to most such parties for the Commission to make a determination that results in a North Carolina regulated electric utility having higher fuel cost recovery risks when it operates its nuclear system above the defined prudence standards but is subjected to cost disallowances inconsistent with the existing rules.

Dr. Wright also testified to how the standard for nuclear performance in Rule R8-55 has generally been applied as a benchmark for determining the prudence of the Company's nuclear fuel costs in hearings before the Commission. He explained that, consistent with the intent of the 1987 legislation and resulting Commission Rules regarding nuclear system performance standards, the nuclear system capacity factor standard has historically been used as a quantitative benchmark or gauge upon which to measure consistently, across time and across companies, management efficiency in the operation of a North Carolina utility's nuclear system. He noted that, when this benchmark was met, nuclear system operations have historically been deemed prudent and, when not met, there is a rebuttable presumption that the nuclear system operations related to fuel costs are in some way imprudent and further investigation by the Public Staff is called for. He provided evidence of the use of the nuclear capacity performance standard as the benchmark for judging prudence of utility nuclear operations in previous Company fuel adjustment proceedings. He noted in addition that, in the Company's 2009 fuel adjustment proceeding, at least one of the nuclear facilities had a capacity factor less than the NERC five-year average. However, the Commission and the Public Staff used the system's fleet average for a comparative basis and to establish the representative capacity factor. He stated that this indicates that the Commission and the Public Staff (at the time) recognized that the performance of an individual plant should not be the determinative factor when assessing nuclear plant performance. He discussed how the Public Staff's position and the Commission orders in the Company's 2011 and 2012 fuel adjustment cases, in which the Company did not meet the Rule R8-55 standard, were also consistent with this approach, as they recognized that a system performance below the NERC

benchmark was reason to dispute the fuel costs related to nuclear performance. He stated that, from 2001-2012, the Public Staff used the system nuclear capacity factor average as a measure of whether the Company's nuclear operations were operated in a prudent manner as a means to judge whether a company's nuclear facilities were operated in a prudent manner.

Dr. Wright testified further that, while the nuclear capacity performance standard has not changed during the last four years, the Public Staff's application of that standard has changed during that time. Specifically, he noted that, beginning in 2013, the Public Staff began to add an additional level of prudence to its review of nuclear performance, in which it evaluates the performance of individual nuclear plants, even when the Company achieved the nuclear system performance benchmark in the Commission rules. He noted that the Public Staff applied this same new approach to Duke Energy Carolinas, LLC fuel adjustment proceedings starting in 2013. Dr. Wright stated that this is a new, additional, and inconsistent level of prudence review that goes beyond what the Commission's rule envisioned with respect to judging a utility's nuclear operations.

Specific to this case, Dr. Wright stated that the Public Staff's selection of specific outages at an individual unit, and deeming of some of the related fuel costs imprudent, even while the Company's nuclear system exceeded the prudency standard, conflicts with the entire purpose of adopting a nuclear system-wide capacity factor management prudency standard as required by the statute. He also noted that if investors perceive this type of disallowance as a new and greater risk related to fuel cost recovery, which he believes they would, the result will likely be higher costs for debt and equity, in turn resulting in higher long term electric rates for ratepayers. He testified that, according to

Rule R8-55, if the performance standard in that rule is not met, there is a rebuttable presumption that the utility was imprudent in its nuclear fleet operations. He explained that, to be equitable, the flip side of the rebuttal presumption of Rule R8-55 should also be true, such that when the standard is met, there is the presumption that the utility has operated its nuclear fleet prudently. He clarified that, while the Public Staff can question the prudence of costs related to an individual nuclear unit, the clear language of the statute and the resulting Commission rulemaking orders establish the standard that a utility's nuclear fuel costs are presumed prudent if the system-wide capacity factor is above the NERC average. He also noted that it would be illogical for Rule R8-55(k) to state that a utility "must achieve" a system-wide nuclear capacity factor that exceeds the NERC average only, when that benchmark is achieved, to ignore that standard.

Witness Wright also explained that the Public Staff's proposed prudence standard requires a standard of perfection as opposed to a standard of prudence, thereby overlooking the reality of nuclear generation performance, which is that at some point in time, a nuclear system will likely have some units operate below the NERC average capacity factor while other units operate above the average. He testified that use of the overall nuclear system's average capacity factor as a benchmark from which to judge whether the system is being operated efficiently reflects this reality. In contrast, undertaking an annual, burdensome review of every nuclear outage and innumerable debates over the prudence of every nuclear operation decision addition would conflict with this prescribed use of system-wide averages as a nuclear performance benchmark. While acknowledging that the Public Staff is entitled to investigate all fuel costs, he testified that it is inconsistent to applaud the Company's nuclear personnel for

management excellence as measured by exceeding the national nuclear capacity performance benchmark while at the same time accusing the same management team of imprudence during one or several specific events. Applied this way, Dr. Wright explained, the Public Staff's approach is a "heads I win, tails you lose" proposition.

Finally, Dr. Wright argued that the Public Staff's proposal presents the Company with an asymmetrical fuel cost recovery risk, because the Company receives no reward by operating above the NERC average, nor is it rewarded for the many decisions made every year that lead to efficient operations and that save customers millions of dollars. In the Public Staff's view, he explained, if perfect performance is not achieved during every nuclear refueling cycle, the Company and its customers should be penalized even though the Company met the overall system benchmark for performance. This presents an asymmetrical risk, because the Company can only lose money, and is never rewarded for exceptional performance. In addition, it presents the risk of a negative reaction from investors, leading to higher rates for all North Carolina regulated electric customers. Dr. Wright noted that such an increase in costs for debt and equity would continue for years, while the Public Staff's proposed fuel cost savings would only last one year.

Dr. Wright clarified that an exception to his position may be appropriate where a nuclear outage had particularly poor maintenance and management oversight, but that great care should be taken even in such a case, as prudence should not mean perfection, particularly with regard to such inherently complicated engineering systems as nuclear plants. Dr. Wright testified that adoption of the Public Staff's position would effectively render a comparison of the NERC averages to system-wide nuclear operations unnecessary and meaningless. He also stated that, if the Public Staff feels there is a

specific outage that should have been handled more efficiently, the best approach would be for the Commission to require the Company to file a report on the particular incident, in which the Company could discuss the circumstances surrounding the incident and if needed identify actions taken to ensure appropriate attention is given to the Public Staff's concerns. This approach would, he stated, maintain the Commission's historical NERC benchmark for nuclear fuel cost recovery.

At the hearing, Dr. Wright explained, in support of his opinion that investor perception of a new and greater risk of fuel cost disallowance could result in higher long-term electric rates for all ratepayers, that he had provided through discovery publications consistent with his position, as well as an order downgrading another utility due to a significant fuel cost disallowance. He also noted a 2009 Moody's Global Report that specified the ability to recover cost and earn returns, and "potentially greater tendency for regulatory intervention, or greater disallowances such as challenging efficiency assumptions or delaying of some cost, even where automatic fuel and purchased power recovery provisions are applicable," as factors Moody's considers when rating electric utilities. Dr. Wright explained that this means that, rather than helping customers in the short term by denying costs associated with individual outages based on an assertion of imprudence even when the Company exceeds the NERC average performance, in the long run ratepayers may actually be harmed, because they will end up paying for higher debt and equity costs. He also acknowledged that the Company can improve and learn from these events, but noted that none of these are repeat offenses, but rather first time happenings at these units.

DISCUSSION AND CONCLUSIONS

Commission Rule R8-55(k) provides as follows:

(k) The burden of proof as to the correctness and reasonableness of any charge and as to whether the test year cost of fuel and fuel-related costs were reasonable and prudently incurred shall be on the utility. For purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Corporation's Generating Availability Report, appropriately weighted for size and type of plant or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Corporation's Generating Availability Report, appropriately weighted for size and type of plant, or a presumption will be created that the utility incurred the increased cost of fuel and fuel-related costs resulting therefrom imprudently and that disallowance thereof is appropriate. The utility shall have the opportunity to rebut this presumption at the hearing and to prove that its test year cost of fuel and fuel-related costs were reasonable and prudently incurred. To the extent that the utility rebuts the presumption by the preponderance of the evidence, no disallowance will result.

It is undisputed that the Company met the standard of Rule R8-55(k). The Company's aggregate system-wide nuclear capacity factor during the test period of 95.5% clearly exceeded the five-year industry weighted average capacity factor of 88.5% for the period 2011-2015 for 800-999 megawatt (MW) units, as reported by NERC in its latest Generating Availability Report. This level of performance continues the Company's recent history of superior performance. As Witness Petrie noted, for the same five-year period (i.e., 2011-2015), the Company's net nuclear capacity factor was 91.0% compared to the national average of 88.5%. Therefore the rebuttable presumption that is created if a utility does not meet either of the performance standards in Rule R8-55(k) does not arise here.

Even though the Company has met both standards provided in Rule R8-55(k) during both the previous and most recent test periods, the Public Staff contends, largely based on its review of RCEs, that the Company's management of certain of its nuclear units during these test periods was not reasonable and prudent and therefore resulted in outages at those units that could have been prevented through efficient management and economic operations. Based on this contention, the Public Staff recommends disallowance of \$1,807,896 in replacement power costs associated with these outages. For the reasons discussed below, the Commission concludes that the Public Staff's position as to these outages is a departure from its previous approach to evaluating utility nuclear performance in the fuel factor and is inconsistent with the purpose of Rule R8-55(k). We also conclude that the Public Staff's position is not supported by the evidence presented in this case, even if we do consider the RCEs, which as we also discuss below should not be relied upon to make determinations of reasonable and prudent nuclear facility operations.

The nuclear capacity performance standard contained in Rule R8-55(k)
is a system-wide performance metric

We agree with Company witness Wright that the history of Commission Rule R8-55(k) and the Commission's precedent implementing that rule show that the nuclear capacity performance standard contained therein is intended to be a system-wide performance metric. First, we are persuaded by witness Wright's testimony that the language of the 1987 statute clearly intended that the Commission establish a general mechanism and standard by which it could consistently, over time and from utility to utility, measure a utility's prudence and efficiency in minimizing the cost of fuel borne by customers, including the cost of nuclear fuel. In addition, the Commission's order

implementing that standard in Docket No. E-100, Sub 55 also recognizes that the rule “employs as a standard of prudence the national average capacity factor for nuclear production facilities based on the most recent five-year period.” December 11, 1990 Order at 1.

We also agree with the Company that, because Rule R8-55(k) provides a system-wide performance standard, if a utility meets that standard, it should be presumed to have acted reasonably and prudently in its nuclear facility management. This is how the rule has traditionally been applied in fuel adjustment proceedings before the Commission. We note the Company’s 2009 fuel adjustment case (Docket No. E-22, Sub 456), in which at least one of the Company’s nuclear units had a capacity factor that was less than the NERC five-year average. As testified by Dr. Wright, the Commission and the Public Staff nonetheless used the system fleet average for a comparative basis and to establish the representative capacity factor. We agree that this shows that the Commission and the Public Staff at the time recognized that the performance of an individual plant should not be the determinative factor when assessing nuclear plant performance.

In contrast, in the Company’s 2011 fuel adjustment proceeding (Docket No. E-22, Sub 474), the system average nuclear capacity factor did not meet the Rule R8-55(k) standard, and as indicated by witness Wright, the Public Staff disputed the related fuel costs based on this performance. As the Public Staff witness in that case stated, the NERC performance standard is the standard for determining whether an adjustment is appropriate based on the Company’s nuclear plants’ performance. We agree with Dr. Wright that this result is the one that the Rule is intended to achieve.

Rule R8-55(k) has not changed since these cases. It does seem to be the case, however, that the Public Staff's method of applying the rule has changed. This is shown by the Public Staff's position in the Company's 2013 fuel proceeding (Docket No. E-22, Sub 502), in which, similar to 2009, one unit's performance did not meet the NERC benchmark, while as a system the Company did exceed the standard. Unlike the 2009 case, however, the Public Staff recommended a disallowance associated with that outage. The Public Staff took a similar approach in Duke Energy Carolinas, LLC's fuel adjustment case the same year (Docket No. E-7, Sub 1033), in which it recommended disallowances based on asserted imprudent nuclear operations although the utility met the nuclear performance standard. Again in 2014 for Duke Energy Progress, LLC (Docket No. E-2, Sub 1045) and in 2016 for the Company (Docket No. E-22, Sub 534), the Public Staff recommended disallowances based on its reviews of individual unit outages even though the utilities met the standard prescribed in Rule R8-55(k). Since—with the exception of the Company's 2016 case, which punted these issues to this proceeding—all of these cases were settled, the Commission has not until the current proceeding had occasion to make a determination of prudence with regard to nuclear operations in a case where the utility's overall system performance meets the current standard of Rule R8-55(k).

Given the history of this rule and its implementation up until approximately 2013, the Commission concludes that the Public Staff's approach in this case, by which it deems fuel costs related to individual nuclear unit outages imprudent even while the Company's overall nuclear fleet exceeded the prudence standard, conflicts with the purpose of the fuel statute and Rule R8-55(k) of having a system-wide prudence factor.

While not specified in the rule, it is reasonable to conclude from the language and history of the Rule that the clear language of the statute and the resulting Commission rulemaking orders establish the standard that a utility's nuclear fuel costs are presumed prudent if the system-wide capacity factor is above the NERC average. This conclusion is consistent with N.C. Gen. Stat. 62-133.2(d), which places the burden of proof on the utility to show that its fuel and fuel-related charge adjustments are just and reasonable—by demonstrating that its overall nuclear system met or exceeded at least one of the NERC performance standards, the utility shows that its nuclear operations were reasonable and prudent and therefore that its costs associated with any nuclear outages are just and reasonable. This is even more the case today, when nuclear generating units regularly achieve capacity factors of 90% or more, than it was when the current Rule R8-55(k) was adopted, at which time utilities common experienced nuclear capacity factors in the 60% range.

Rule R8-55(k) states that a utility “must achieve” one or both NERC performance standards to avoid a finding that its fuel and fuel-related costs were incurred imprudently. We therefore also agree with witness Wright that applying the two-pronged standard used by the Public Staff in this case would nullify this bright line obligation, and simply open up all fuel adjustment proceedings to micro-managed evaluations of individual nuclear unit performance regardless of whether the utility met the NERC standards.

In addition to conflicting with the clear language of Rule R8-55(k), adopting the Public Staff's position would effectively amend the Rule without allowing for notice and comment. As indicated by witness Wright's testimony, the Commission established Rule R8-55(k) over several years and rulemaking proceedings. Adopting the two-step

prudence review advocated by the Public Staff in this case would essentially amend the nuclear capacity rule outside of a normal rulemaking procedure. This would deprive other North Carolina electric utilities of the opportunity to provide comments and would deny the Commission the opportunity to ascertain through such comments what impact such a change would have on the utilities, including the increased financial risk noted above. The proper venue for implementing such a change is through rulemaking rather than in an individual utility's fuel adjustment proceeding.

In making these conclusions, we recognize that the Public Staff is authorized under the Public Utilities Act to investigate the utilities subject to the Commission's jurisdiction, and that pursuant to this authority it may ask questions with respect to a utility's nuclear outages. We also acknowledge that, in a case where clear evidence is presented showing that an outage could have been prevented by prudent management, and that the utility knew or should have known information upon which it failed to act reasonably, some disallowance may be justified even where the utility met the standard. However, if a utility has met the Rule R8-55(k) standard, rather than seeking disallowances related to individual unit outages, it would be more appropriate that in response to such questions the Company file a report with the Public Staff and the Commission explaining the outage and any lessons learned. We agree with witness Wright that this approach would maintain the Commission's historical NERC benchmark for nuclear fuel cost recovery as well as provide an avenue to address the Public Staff's concerns and not result in additional fuel cost recovery risk.

A clear demonstration of a causal relationship between utility management and a nuclear unit outage is required to support disallowances of fuel costs

The standard for determining the prudence of a utility actions should be whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. Order Granting Partial Increase in Rates and Charges at 14, Docket No. E-2, Sub 537 (Aug. 5, 1988) (Harris Order). The Commission noted further in the Harris Order that this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question, that perfection is not required, and that hindsight analysis – the judging of events based on subsequent developments – is not permitted. Id. The Commission also concluded that the proper amount chargeable to the ratepayer is the amount the plant would have cost but for the imprudent acts or decisions. Id. at 15. The Commission also stated that if the prudence standard is to have any meaningful application, specific and discreet incidents of imprudence if they exist must be identified, the existence of available prudent alternatives that the utility should have followed to avoid the imprudence must also be identified, and the effects of the specific acts of imprudence must be quantified by calculating the cost of the prudent alternative and comparing it with the costs incurred by the imprudent act. Id. at 15.

As discussed in the Harris Order, in that proceeding the Commission was presented with extensive and conclusive evidence of imprudence with regard to two sets of issues found to justify disallowance. Id. at 55-107 (discussion of Findings of Fact Nos. 9 and 10). This evidence included testimony of Carolina Power and Light Company (CP&L), the utility in the case, as well as an exhaustive audit performed by an outside consultant for the Public Staff that contained definitive conclusions regarding the impact

of CP&L actions or decisions on resulting costs, and the testimony of other parties. Based on that volume of evidence, the Commission was able to conclude that CP&L imprudently caused five months of avoidable delay in the construction of its Shearon Harris Unit 1, id. at 78, and that while it was for the most part prudent in controlling the extent of design deficiencies, construction misfabrication, and other errors, the record was replete with evidence that to at least a small degree the Company's design and construction and management errors exceeded a reasonable level, id. at 106.

The Harris Order demonstrates that, where the Commission has concluded that costs were incurred imprudently and therefore should be disallowed from recovery, those conclusions were based on the presentation of clear evidence that, if the utility had made a different decision based on what it knew or reasonably should have known at the time, the costs at issue clearly would have been avoided or reduced. In contrast to the Harris case, this standard requiring a link between the utility's decisions and the costs to customers has not been met here. Throughout his prefiled testimony, Public Staff witness Metz identified certain management decisions or actions that could or may have resulted in an outage. These instances include but are not limited to the following: Metz Testimony at 21:17-19 ("could have alerted the Company to the potential"); 52:10-13 ("may have prevented the outage"); 54:5-8 ("While there is no definitive evidence" ... "it is impossible to know whether"); 54:12-14 ("may have prevented the outage"); 61:8-10 ("there is a possibility"); 70:10-13 ("appears to acknowledge ... may have been inadequate and likely a contributing cause"); 84:10-12 ("[i]t is possible that"); 84:13-16 ("may have [had a result that] could contribute"); 89:4-7 ("could have been the direct cause"); 92:1-5 ("may have contributed"); and 96:7-97:2 ("could have created"). While

witness Metz testified that in his opinion each of the outages for which he recommended a disallowance could have been avoided with prudent management, the evidence he offered does not support a conclusion that the Company reasonably should have made different decisions and that those specific decisions would have prevented the outages. At the hearing and in response to questions from the Chairman, witness Metz agreed that a causal relationship between utility decisions or actions and an outage is needed to support recommended disallowance, but he was not able to testify that certain management decisions definitively caused the conditions that led to an outage. (T210:4-20; 212:21-213:7)

Particularly in a case where, as here, the utility clearly exceeds the Rule R8-55(k) nuclear capacity performance standards, the Commission concludes that it would be inappropriate to rely on speculation with regard to the impact of Company actions or decisions on a particular outage as support for a finding of imprudence and disallowed fuel costs. Without clear evidence showing imprudence, particularly where multiple expert engineering witnesses have credibly testified that Company management acted reasonably and prudently, such speculative evidence is not substantial, material, and competent evidence that would support a finding of imprudence or justify disallowance of the Company's recovery of its fuel and purchased costs.

Imprudence must be demonstrated by evidence that the Company knew, or should have known, that its actions would lead to additional costs to ratepayers

As the Harris Order made clear, the standard for determining the prudence of a utility's actions should be whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. Witness Metz has proposed several cost

disallowances related to what he has called imprudent operations by the Company. The Commission disagrees with these recommendations. The record in this case clearly indicates that the Company met this standard of review for the various incidents that Mr. Metz has cited. This finding is based on the evidence discussed below.

1. North Anna 2: July 30-August 3, 2016

Based on Mr. Rosenberger's testimony, we conclude that this outage could not have reasonably been prevented by the Company given the information it knew at the time, and that it did not result from unreasonable or imprudent management. We are persuaded by Mr. Rosenberger that the Company acted reasonably and prudently not only upon discovery of the Reactor Coolant System (RCS) leak, and by its remediation of the situation, but also prior to the event. Given the circumstances surrounding this area of piping, the Company's application of routine, approved procedures and good practice with regard to the installation of this piping and monitoring of the space as discussed by Mr. Rosenberger, we are not persuaded by Mr. Metz's testimony that the Company should have foreseen this issue. We also agree with the Company that Mr. Metz inappropriately cites to contributing causes identified in the RCE that did not directly cause the outage and were presented as support for additional corrective actions that go beyond addressing the root cause. We agree that the Company's management adhered to the applicable procedures, and that the fact that all of the personnel involved in the installation did not identify the issue supports a conclusion that it would not be reasonable to expect the Company to have detected the condition, and that it was reasonable for the Company not to conclude that the modifications it made would have the consequences that they did. We also conclude that witness Rosenberger's testimony

presented at the hearing with respect to this outage is especially persuasive. We particularly note witness Rosenberger's testimony at the hearing that indicated that this was an area of the unit that is characterized by a high degree of noise, close confinement, and a high dose of radiation, and conclude that personnel would reasonably complete their required duties without lingering to examine other parts of that area of the plant. We therefore conclude that the replacement power costs associated with this outage were prudently incurred under efficient management and economic operations at North Anna Unit 2.

2. Surry Unit 2: October 9-13, 2016

We agree with witness Rosenberger that the collection of water within the enclosure, which caused the Surry Unit 2 to trip and resulted in this outage, is applicable to the analysis of whether the outage was reasonable and prudent, and could not have been anticipated by the Company. Surry station experienced an unprecedented amount of rainfall in the area and, prior to this outage, the Company had no reason to believe that the product at issue from the vendor would not meet the needs of the station. The vendor is experienced in providing watertight enclosures, and was contracted by the Company to provide enclosures within certain specifications. It was not possible for the Company to foresee the extreme weather the station experienced, or the fact that the enclosures would not perform their design function. We also find persuasive witness Rosenberger's testimony at the hearing that, even after further exploration and consideration of the relevant operating experience, it would have come to the same conclusion, which was that if it carried out the normal vendor recommended maintenance activities, the Company would be able to detect any problem. This is an example of where the normal

course of the Public Staff's investigation – asking the Company about any outages regarding which more information is needed – would have produced the rainfall data and led to a more accurate picture of the cause of this outage, which was outside of the Company's control, than did the RCE, which as witness Rosenberger explained could not identify as a root cause, or even a contributing cause, a factor that was beyond the Company's control. This is why using RCEs for prudency determinations is not appropriate – it can lead to the wrong result. Based on the evidence presented we therefore conclude that the Company could not have anticipated this issue, that it managed Surry Unit 2 prudently and efficiently during the test period, and that the replacement power costs associated with this outage were prudently incurred under efficient management and economic operations.

3. Surry Unit 1: July 11-22, 2015

This outage was incurred to allow the Company to replace a seal at Unit 1 that had degraded after being modified. Based on witness Rosenberger's testimony, we conclude that the Company had established a program and process consistent with industry practices to address the issue that caused this outage, and that it followed that process and even performed additional preventative measures beyond that process. We are not persuaded by witness Metz's testimony that, if the Company had followed other specific procedures, or pursued the vendor for more information beyond what was provided, the outage could have been prevented. The Company reasonably relied upon the relevant operating experience at another utility to inform its process with respect to the seal modification. In addition, as Mr. Rosenberger explains, the Company would have had no reason to pursue the vendor for more information prior to this event, in part

because the vendor representatives would have worked closely with the Company to design the seal installation and would have been onsite with the Company for installation and for the subsequent modifications. We also do not agree with Mr. Metz that the Company's previous experience with this seal does not support a conclusion that it acted reasonably and prudently with respect to the seal at this Unit. We are convinced in this regard by Mr. Rosenberger's testimony that the Company had been maintaining its seals according to a procedure that had been in place since 2009 and had not presented any issues before. In particular we note his testimony that the Company had replaced a similar seal in May 2015 with no issues or degradation. We also note his testimony from the hearing that adequate procedures should have addressed the issue that gave rise to this outage, and conclude that it is clear from the evidence that the Company reasonably believed it had implemented adequate procedures in this case. We agree that based on this and other factors the Company's procedures as they relate to the issue giving rise to this outage were prudent and robust and sufficient to ensure quality work and reliable operation of the pumps. We also note Mr. Rosenberger's testimony that because the North Anna failure event cited by Mr. Metz as previous indication of this issue dealt with a distinct issue at that facility and that the Surry Unit 1 event resulting in the July 2015 outage did not have the same initiating cause or extended consequences as the North Anna event, it is not appropriate to compare the two events at these facilities or the Company's actions taken in response. Based on the evidence presented we therefore conclude that the Company could not have anticipated the issue underlying this outage, that it managed Surry Unit 1 prudently and efficiently during the test period, and that the

replacement power costs associated with this outage were prudently incurred under efficient management and economic operations.

4. Surry Unit 1: October 13 – November 18, 2015

This outage event involved Unit 1 tripping after receiving fault signals from the main generator protection system, and was determined to result from an issue with the design of a component of this Unit installed a decade earlier. We are persuaded by witness Rosenberger's testimony that based on representations of the vendor that supplied this component that had been used elsewhere, and on the Company's recent experience with a similar component at Surry Unit 2, it was reasonable for the Company to not expect that additional maintenance practices were required and to believe that this was a prudently designed component with effective maintenance instructions. We also find notable Mr. Rosenberger's testimony that Company personnel used the guidance regarding this component that was available, and could not have known that that guidance did not fully identify the latent issue with this component, and that even the original manufacturer did not fully understand this latent vulnerability with equipment that is disconnected only approximately every nine years, so it could not have relayed such information to the Company. Finally, his explanation that the Company had operating experience using the same procedures and process with regard to Surry Unit 2 in 2012, combined with the factors noted above, are convincing evidence that the Company had no reason to believe that the maintenance activities it had successfully performed previously would have led to this event. Based on all of these factors, we conclude that the Company could not have anticipated this issue, that it managed Surry Unit 1 prudently and efficiently during the test period, and that the replacement power

costs associated with this outage were prudently incurred under efficient management and economic operations.

5. Surry Unit 2 from December 4-11, 2015

This outage resulted from the extension of a planned outage at Surry Unit 2, which the Company undertook in order to use certain components from Unit 2 to expedite restart of Surry Unit 1 from the October-November, 2015 outage discussed above. We agree with witness Rosenberger that in a situation where two nuclear units are in outage, the prudent response is to return each to service as safely and efficiently as possible, and find persuasive his testimony that by returning Surry Unit 1 to service and extending the Surry Unit 2 outage, the Company reduced total outage time by approximately 17.5 days, saving approximately \$474,626 on a North Carolina jurisdictional basis. While we agree with Mr. Metz's testimony that, had Unit 1 not tripped in the first place, Unit 2 would not have incurred additional outage time, that does not mean that the Unit 2 outage resulted from inefficient or imprudent management. Viewed on a stand-alone basis, as advocated by witness Rosenberger, we agree that the Company reasonably and prudently managed Unit 2. Even viewed in combination with the Unit 1 outage, since we have concluded as discussed above that the Company reasonable and prudently managed Surry Unit 1 during the 2015-2016 test period, it follows that the Unit 2 outage extension, which was incurred to return Unit 1 to service more quickly, was also prudently managed. Therefore, based on the evidence presented we conclude that the Company managed Surry Unit 2 prudently and efficiently during the test period, and that the replacement power costs associated with this outage were prudently incurred under efficient management and economic operations.

It is not appropriate or necessary to rely on RCEs
to determine prudence and recommend disallowances

The evidence presented in this case clearly indicates that the NRC's primary concern is with safety, not with prudence and efficient management as it is conceived in Rule R8-55. Both Company witness Stanley and Public Staff witness Metz agreed on this point. It follows that RCEs, which are documents produced to comply with NRC regulations, are also driven by a concern for safety, rather than by any prudence determination. This is further evidenced by the testimony of witness Stanley, which discussed the NRC requirement that each nuclear licensee establish measures to assure that conditions adverse to quality are promptly identified and corrected, that in cases of significant conditions adverse to quality the measures assure that the cause of the condition is determined and corrective action taken to prevent repetition, and that the identification of the condition, the cause, and the corrective action be documented and reported. We find persuasive witness Stanley's testimony that by their nature RCEs use hindsight to analyze operations and are not based on what could have reasonably been known at the time, which we agree is the standard for evaluating prudence. We also note witness Stanley's exchange with counsel for the Public Staff, that the NRC is not looking at prudence when it carries out periodic evaluations of RCEs, but rather is looking to see that the Company has found the root cause and the corrective actions are logically a result of that and are taken in a timely and effective manner. In short, the purpose of an RCE is to identify a cause for the event, and to identify corrective actions to be taken to prevent the recurrence of the event. RCEs are not intended to evaluate whether management of nuclear facility operations was reasonable or prudent. Management could be 100%

reasonable and prudent, and still the RCE for a nuclear outage must identify a cause of that outage. That would not be a reasonable result.

The Commission is also persuaded by witness Stanley's testimony as to the security risk of providing RCEs, resulting from their inclusion of highly sensitive information regarding the inner workings of the Company's nuclear facilities, which presenting a safety and security risk to North Carolina and Virginia residents if they fall into the wrong hands. Normally and with respect to other utility materials that are treated confidentially, the usual protections afforded such material in Commission proceedings is sufficient to protect against dissemination and outweighs the risk of publication. However, in cases such as this one that involve highly sensitive nuclear facility operations information that could result in great harm if it were accessed by the wrong third party, we are not confident that that risk is fully satisfied by treating these documents as confidential in these regulatory proceedings. Particularly in a context where, as we have found herein, RCEs are not relevant to prudence and are not as discussed below necessary for determining prudence, incurring the risk associated with distribution of RCEs in fuel adjustment proceedings is inappropriate.

In addition to not being appropriate, it also does not appear to be necessary that the Public Staff review RCEs in order to determine prudence of particular nuclear outages that it determines warrant further investigation. We note Mr. Metz's testimony regarding the multiple sources of data that the Public Staff consults on a regular basis with regard to the Company's nuclear fleet performance. We also note as testified by Company witness Stanley that of the 84 outages during the 2016-2017 test year that Mr. Metz reviewed, he recommended disallowances only for two nuclear outages, for which

there are RCEs. We agree that the likelihood of a conclusion that an event could have been avoided may increase in the case of a nuclear outage, for which there is an RCE, than for other types of outages, and conclude that this supports our conclusion that RCEs should not be relied on for prudence determinations.

Based on the foregoing, we conclude that reliance on RCEs, either for those documents' analysis of root causes or contributing causes, for purposes of determining prudence is not appropriate.

Based on all of the evidence presented, even including the RCEs,
none of these outages resulted from unreasonable or imprudent management

Notwithstanding our conclusion that it is inappropriate to consider RCEs in making prudence determinations with respect to nuclear outages, even if the RCEs addressing these outages are considered, based upon the evidence in the record and as discussed above, the Commission is unable to conclude that the Company acted imprudently in its management of its nuclear fleet or that its imprudence resulted in the five outage events during this and the prior test period identified for disallowance by the Public Staff. Based on the evidence, we conclude that the Company's actions were consistent with its past practices, which had not resulted in any outage events, and were reasonable and prudent based on the information known to the Company at the time, such that the Company could not have anticipated the events that resulted in these outages. We agree with the Company's witnesses that while the Company can improve and learn from these events, none of these are repeat offenses, but rather first time happenings at these units.

Generally speaking, we find persuasive the testimony of Company witnesses Wright and Stanley that prudence does not require perfection. Specifically, we agree

with witness Stanley that Rule R8-55(k) does not require or even suggest, and the Public Staff does not contend, that the Company is required to operate its nuclear fleet flawlessly. We recognize that nuclear generating unit operations is highly complex and that forced or unplanned outages will and do occur even with efficient management and economic operations. We also agree with Mr. Stanley that, by setting a benchmark based on industry averages as discussed above, Rule R8-55 implicitly acknowledges that forced outages will occur and do not necessarily represent unreasonable or imprudent operations. We also agree with Company witness Rosenberger that forced outages will occasionally occur at nuclear generating units even under the best of scenarios. We also agree with witness Rosenberger, with regard to the incidents cited by Mr. Metz, that the Company operated in accordance with both its own and industry standards, and that the Company had no information available at the time to indicate that its maintenance procedures or that the equipment supplied by its vendors would not produce the desired results. Therefore, we conclude that the Company's high overall nuclear capacity factor for the current and previous test periods, combined with the testimony of Company witness Rosenberger, shows that the Company clearly exceeded the benchmark and demonstrated reasonable and prudent operations of its nuclear units. Notably and as testified by witness Stanley, the Company's exceedance of the standard saved customers \$2 million, an amount that no party to the proceeding disputed.

Summary of prudence related issues

The Commission declines to order any replacement cost disallowances as recommended by Public Staff. We agree with Company witness Rosenberger that forced outages will occasionally occur at nuclear generating units even under the best of

scenarios, and that the Company's expertise and experience in operating its nuclear units during these events allowed the Company to keep these outages to a minimum timeframe while ensuring system safety and reliability. Therefore, based on the credible evidence in the record presented by the Company's witnesses, the Commission concludes that the Company managed its baseload plants during the present and prior test periods, including its nuclear fleet, prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is contained in the direct and rebuttal testimony of Company witness Petrie, the testimony of Public Staff witness Metz and the affidavit of Public Staff witness Johnson, and the transcript of testimony provided at the hearing held in this proceeding.

Public Staff witness Metz discussed the Company's methodology for calculating 2% forced outage allowance for its nuclear generating units and for calculating replacement power costs. He stated that the Company does not allocate any allowance remaining for one unit to other units that exceeded their allowances. He also described the Company's position as being that if the total replacement power costs associated with a unit's outage or outages does not exceed the forced outage allowance, it did not have replacement power costs. Witness Metz testified that he did not agree with the Company's practice of deducting a 2% forced outage allowance from its total replacement power costs. He asserted that, while forecasting a 2% forced outage rate is reasonable for the planning purposes, it is not reasonable for use in calculating replacement power costs. He stated that the Company is responsible for operating its plants in a reasonable and prudent manner, and that if the Commission finds that an

outage resulted from unreasonable or imprudent actions, ratepayers should not bear the costs of the replacement power necessary to replace the power foregone due to that outage. He stated that 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.

In his rebuttal, Company witness Petrie testified that the Company's nuclear electric generation performance should be compared to its planned operations, not to perfect operations. He explained that the Company plans for a 2% forced outage rate, which is a very high standard of performance for nuclear operations. He stated that allowing a 2% equivalent forced outage rate (EFOR) is a reasonable practice when calculating replacement power costs from a customer point of view. He explained that when the Company determines its forecasted system fuel expenses, that is based on the actual incurred fuel expenses in the historic test year, adjusted for certain pro-forma items, one of which is the expected nuclear generation in the upcoming rate year. The expected nuclear generation includes a 2% unplanned unavailability allowance. Mr. Petrie testified that this 2% EFOR is included to reflect the reality that machines, people, and processes are not perfect. He explained that the objective of calculating replacement power costs is to determine the increase in the system fuel expenses caused by the additional unit outage. In other words, the objective is to determine the financial harm to customers relative to the plan, as opposed to perfect operations. He noted that not using the forced outage allowance would mean that the Company would be held to a standard of perfect performance and 100% unit availability, which is unreasonable and not consistent with the determination of the prospective fuel rate.

Mr. Petrie noted that the Company prepared replacement power cost calculations in its 2011 and 2013 fuel charge adjustment cases that included the 2% forced outage allowance, and that those calculations were not challenged by the Public Staff.

At the hearing, Mr. Petrie testified that in the Company's 2013 fuel case, Docket No. E-22, Sub 502, Public Staff witness Ellis testified that Public Staff had reviewed the 2% cap calculation pursuant to N.C. Gen. Stat. 62-133.2 and agreed with that calculation. During cross examination by counsel for the Public Staff, witness Petrie clarified that witness Ellis would have been speaking of the 2% forced outage allowance when he referenced a 2% cap calculation, given that his testimony on the 2% followed a statement presenting an adjustment to remove disallowed fuel cost relating to an outage in that case, and that that adjusted amount was contained in a Company response to an interrogatory where the Company presented the 2% forced outage allowance calculation. During further cross examination and on redirect, Witness Petrie testified that the fuel statute does not contain a 2% cap for the Company. He explained that during the 2016 fuel adjustment proceeding, the Company first provided a high level description of the calculation of replacement power costs to the Public Staff through discovery, and later clarified the application of the 2% forced outage allowance in a subsequent discovery response. Witness Petrie also clarified that, as reflected in the Company's description of the formula for calculating replacement power cost provided in a late-filed exhibit in the Company's 2011 fuel adjustment proceeding (Docket No. E-22, Sub 474), the 2% forced outage allowance was applied to the replacement cost that resulted from that formula, before deriving the North Carolina jurisdictional amount.

DISCUSSION AND CONCLUSIONS

The methodology for calculating replacement power cost becomes important in cases where it is determined that a utility's nuclear outage resulted from unreasonable and imprudent management and, as a result, some or all of the replacement power costs associated with that outage should be disallowed. Here, we have determined that the Company managed its nuclear fleet during the previous two test years in a reasonable and prudent manner, and have therefore rejected the Public Staff's proposed disallowances of the replacement power costs associated with those outages. However, we address this issue here in order to provide clarity should it arise in future fuel adjustment proceedings.

Witness Metz is correct that the Company has the obligation to operate its plants in a reasonable and prudent manner, and that if the Commission finds that an outage resulted from unreasonable or imprudent actions, ratepayers should not bear the costs of the replacement power necessary to replace the power foregone due to that outage. We are, however, persuaded by witness Petrie's testimony that in such cases the Company's nuclear electric generation performance should be compared to its planned operations, rather than to perfect operations, and agree that allowing a 2% EFOR is a reasonable practice when calculating replacement power costs.

First, we recognize that the Company's determination of its forecasted system fuel expenses is based on the actual incurred fuel expenses in the historic test year, adjusted for certain pro-forma items, one of which is the expected nuclear generation in the upcoming rate year, which in turn includes a 2% unplanned unavailability allowance. We agree with witness Petrie that such an allowance is reasonable in order to reflect the reality that machines, people, and processes are not perfect. As witness Petrie explains,

the purpose of the replacement power cost calculation is to determine the increase in the system fuel expenses—or financial harm to customers—caused by the additional unit outage, relative to the plan, not relative to perfect operations. The question is, what would fuel costs have been but for the outage. Even without the outage having occurred, the Company's fuel costs would include the forced outage allowance. Customers are not paying more than they would but for the outage, because the 2% was accounted for as part of the Company's reasonable planning assumptions for its fleet for the year. Therefore, the appropriate comparison for purposes of replacement power cost calculations is to the Company's planned operations, including the 2%. We agree that prohibiting the application of the 2% in the calculation of replacement power costs would unreasonably hold the Company to a standard of perfection rather than the standard of performing in accordance with its planned operations. We also conclude that, in the interest of accurately determining replacement power costs for a particular unit in the case of an outage, the Company reasonably does not apply the forced outage allowance for an individual unit that did not reach the cap with other units that did reach the cap.

The Commission also notes that the 2% forced outage rate that the Company assumes for its nuclear fleet is a very high standard of performance for nuclear operations. It assumes that the fleet will operate at 98% between refueling outages, which is clearly above the NERC average or even the Company's most recent performance. It also gives the Company much less room for outages than, for example, a forced outage allowance of 5% or 10% would.

The Commission also finds it persuasive that the Public Staff has in previous recent fuel adjustment proceedings not taken issue with the 2% forced outage allowance

that the Company applies to its replacement power costs. Not until this proceeding has the Commission seen testimony from the Public Staff contesting that approach. It is clear that the Public Staff was aware of the Company's approach to calculating replacement power costs as far back as 2011, as evidenced by the data the Company provided in its 2011 fuel factor proceeding, which was presented during cross examination of witness Petrie. With respect to the testimony offered by the Public Staff in the Company's 2013 fuel factor case, that testimony was simply stating that the Public Staff had reviewed the 2% "cap" (which is the term sometimes used by the Public Staff to refer to the forced outage allowance) to evaluate whether it was consistent with N.C. Gen. Stat. 62-133.2 and had found that it was, and was not suggesting, nor is the Company in this case suggesting, that that statute provides for a 2% forced outage allowance. Further, the fact that the statute does not provide for the forced outage allowance does not prohibit the Company from applying such an allowance if doing so is reasonable, as we determine here that it is.

Based on the evidence presented, the Commission concludes that the Company's inclusion of a 2% unplanned availability allowance for its nuclear units when calculating power replacement costs for purposes of these fuel adjustment proceedings is reasonable and appropriate. We also conclude that, in the event that a future outage is found to have resulted from imprudent management, any disallowed costs should be limited to costs that exceed the 2% allowance.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding of fact is contained in the direct testimony of Company witness Petrie.

Company witness Petrie testified in his direct testimony that for the 12 months ending December 31, 2018, North Anna Unit 1 is projected to operate at a net capacity factor of 90.4%, North Anna Unit 2 is projected to operate at a net capacity factor of 99.6%, Surry Unit 1 is projected to operate at a net capacity factor of 93.1%, and Surry Unit 2 is projected to operate at a net capacity factor of 91.0%. For the nuclear fleet, the projected nuclear generation during the upcoming rate year is expected to be slightly lower than the actual generation during the test period. Based on this projection, the Company has normalized expected nuclear generation and fuel expenses in developing the proposed fuel cost rider. The Company's projected fuel costs are based on a 93.6% nuclear capacity factor, which is what the Company anticipates for the twelve months from January 1, 2018, through December 31, 2018, the period the new rates will be in effect.

No party presented any testimony contesting the Company's use of a 93.6% nuclear capacity factor to normalize estimated rate year fuel expenses. Based on the foregoing evidence, the Commission concludes that a projected normalized system nuclear capacity factor of 93.6% is reasonable and appropriate in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is contained in the direct testimony of the Company witness Merritt and the affidavit of Public Staff witness Johnson.

Witness Merritt testified that he was sponsoring the calculation of the adjustment to the Company's system sales for the twelve months ended June 30, 2017, due to changes in usage, weather normalization, and customer growth, in accordance with Commission Rule R8-55(d)(2). Mr. Merritt stated the adjustment is consistent with the methodology used in the Company's last general rate case (Docket No. E-22, Sub 532) and the last fuel charge adjustment case (Docket No. E-22, Sub 534). Witness Merritt adjusted total system Company sales by 996,840,129 kWh. This adjustment is the sum of adjustments for changes in usage, weather normalization, and customer growth. The Public Staff reviewed and accepted these adjustments. No other party offered or elicited testimony on the adjustment.

Based on the foregoing, the Commission concludes that the adjustments for changes in usage, weather normalization, and customer growth are reasonable and appropriate adjustments for use in this proceeding. The adjusted system sales for the twelve months ended June 30, 2017, are 84,774,563,328 kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is contained in the direct testimony of Company witness Petrie.

Company witness Petrie presented an adjustment to per books MWh generation for the 12-month period ended June 30, 2017, to incorporate nuclear generation based upon the expected future operating parameters for each unit. Other sources of generation

were then normalized, including an adjustment for weather, customer growth, and increased usage. This methodology for normalizing test period generation resulted in an adjusted generation level of 85,796,167 MWh. The Public Staff accepted this adjusted generation level, which includes various types of generation as follows:

<u>Generation Types</u>	<u>MWh</u>
Nuclear	27,442,508
Coal (including wood and natural gas steam)	20,939,580
Heavy Oil	191,548
Combined Cycle and Combustion Turbine	29,207,250
Hydro	3,106,119
Solar	49,093
Net Power Transactions	7,472,692
Less: Energy for Pumping	(2,563,530)

No other party offered or elicited testimony on the adjusted test period system generation for use in this proceeding. Thus, based on the foregoing, the Commission concludes that the adjusted test period system generation level of 85,796,167 MWh is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

This finding of fact is based on the Commission's Order Approving Rate Increase issued December 22, 2016 in Docket No. E-22, Sub 532 (Sub 532 Order), as reflected in the direct testimony of Company witness Petrie, and in the affidavit of Public Staff witness Johnson. It is not controverted.

Public Staff witness Johnson stated that, during the test year for this proceeding, the Company purchased power through markets administered by the PJM Interconnection, L.L.C. and from a dispatchable non-utility generator (NUG) that did not provide actual fuel costs associated with the purchases. Because the Company does not have actual fuel costs for these purchases, a proxy Marketer Percentage was applied to

the total energy costs of these purchases to arrive at a fuel cost component. The use of a “proxy” for this purpose has been accepted by this Commission as reasonable in every fuel proceeding for which a proxy was necessary since 1997, when the Public Staff, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc. (DEP), and the Company agreed on a methodology to determine an appropriate Marketer Percentage to be used to apply to the total energy costs for suppliers that would not provide actual fuel costs.

Witness Johnson stated further that, up through and including December 31, 2016, the Company included 85% of the reasonable and prudent energy costs in the EMF calculation. Additionally, to the extent a dispatchable NUG provides market-based energy rather than dispatching its facility, the Company included 85% of the reasonable and prudent energy costs for such market based energy in the EMF calculation up through December 31, 2016. Continued use of the 85% “marketer’s percentage” was agreed to between the Company and the Public Staff and approved by the Commission in the Company’s 2012 fuel factor proceeding, Docket No. E-22, Sub 485, and was maintained up through the 2015 fuel factor proceeding, Docket No. E-22, Sub 526. Beginning in 2017, the Company used the 78% marketer's percentage as approved by the Commission in the Company’s 2016 general rate case in the Sub 532 Order. This change was implemented January 1, 2017. The 78% Marketer Percentage is to remain in effect until the sooner of the Company’s next general rate case or the 2018 fuel charge adjustment proceeding (with rates effective January 1, 2019).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 18-19

The evidence for this finding of fact is contained in the direct testimony of Company witnesses Petrie and Merritt, and the affidavit of Public Staff witness Metz.

Company witness Petrie presented the Company's system fuel expense for the test period and the normalized system fuel expenses for the calendar year 2018 rate period of \$1,758,608,978. He testified that the fuel over-recovery experienced by the Company was driven primarily by mild weather, moderate commodity prices, and the additional of new and efficient natural gas generation, in addition to the Company's optimization of its diverse fleet of generating assets to reduce system fuel expense. He further testified that he used the expense normalization methodology that the Company has used and the Commission has approved in previous North Carolina fuel factor proceedings. Specifically, the first step in computing normalized system fuel expense is to calculate nuclear generation based on the expected future operating parameters for each unit. The expected generation from the nuclear units was calculated for the 12-month period ending December 2018. Other sources of generation were then normalized for the test period. The total of coal, heavy oil, combustion turbine and combined cycles, non-utility generation (NUG), and purchased energy during the test period was then calculated. A percentage of this total was then calculated for each of these resources. Normalized generation was computed by applying these percentages to a new total, including an adjustment for weather, customer growth, increased usage, and the net change in nuclear generation. Witness Petrie also noted that the NUG expense was adjusted higher to account for retirements of certain contracts.

Company witness Merritt presented the Company's calculation of the Fuel Cost Rider A applicable for each North Carolina retail jurisdiction customer class. He first determined the average system fuel factor of 2.077 ¢/kWh, based on system fuel expenses of \$1,758,608,978, and system sales of 84,774,563,328 kWh, that reflected adjustments for changes in usage, weather normalization, and customer growth. Witness Merritt then used customer class expansion factors to determine the North Carolina retail jurisdictional voltage differentiated prospective fuel factors at the sales level applicable to each customer class. For each customer class, the appropriate factor was then compared to its corresponding base fuel factor to determine the appropriate Fuel Cost Rider A rate. In his testimony, Public Staff witness Metz stated that he agreed with the Company's determination and calculation of its proposed Rider A.

No other party offered or elicited testimony on the adjusted test period system fuel expense for use in this proceeding. Based upon the foregoing, the Commission concludes that the appropriate level of fuel expenses to be used to set the prospective, or forward-looking, fuel factor in this proceeding is \$1,758,608,978.

The Commission further concludes that the proper fuel factors (Rider A) for use in this proceeding, including the regulatory fee, are as follows:

<u>Customer Class</u>	<u>Rider A</u>
Residential	0.006 ¢/kWh
SGS &PA	0.006 ¢/kWh
LGS	0.003 ¢/kWh
Schedule NS	0.006 ¢/kWh
6VP	0.006 ¢/kWh
Outdoor Lighting	0.006 ¢/kWh
Traffic	0.006 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 20-22

The evidence supporting this finding of fact is contained in the direct testimony and exhibits of Company witness Merritt, Petrie, and Campbell, the testimony of Public Staff witness Metz, and the affidavit of Public Staff witness Johnson.

Company witness Petrie testified that mild weather, moderate commodity prices, and the addition of new and efficient natural gas generation, as well as the Company's optimization of its diverse fleet of generating assets to reduce system fuel expense, resulted in an over-recovery of fuel costs. Company witness Campbell testified that the fuel costs allocated to North Carolina jurisdictional customers totaled \$87,012,025, while the Company received fuel revenues totaling \$91,751,981 during the test year. The difference between the fuel costs and the fuel revenues resulted in an over-recovery of \$4,739,956 for the test period. Company witness Merritt testified that this total over recovered fuel expense was adjusted by \$710,993 to account for interest, for a total net balance of \$5,450,950. To determine the EMF (Rider B), witness Merritt divided this net balance by the adjusted jurisdictional test period sales of 4,299,466,351 kWh. He then used customer class expansion factors to differentiate the uniform factor by voltage to determine the North Carolina retail jurisdictional voltage differentiated EMF fuel factors at the sales level applicable to each customer class.

Public Staff witness Metz testified that he agreed with the Company's proposed Rider A, the base proposed system average fuel factor for the billing period. He also stated that he agreed with the Company's methodology and supporting calculation of Rider B, the EMF, and agreed with the Company's calculation of its over-recovery of \$5,450,950. He also recommended as discussed above that Rider B be adjusted with

regard to the Company's replacement power costs associated with certain outages. Specifically, he recommended that \$1,807,896 in replacement power costs be excluded from the EMF – \$232,473.83 for outages during the 2015-2016 test period and \$1,575,422.45 for outages during the 2016-2017 test period. (101)

Public Staff witness Johnson stated that based on the recommendation of Public Staff witness Metz, she included adjustments to disallow \$1,807,896 in replacement power costs associated with outages during the prior and current test periods. As a result of these adjustments, she recommended that the Company's EMF decrement rider (Rider B) for each customer class be based on net over-recovery of fuel and fuel-related costs of \$6,547,853 and interest of \$982,178, for a total over-recovery of \$7,530,031. Her revised over-recovery produced an EMF decrement rider (Rider B) of 0.00175 c/kWh.

Based upon the evidence, the Commission concludes that the appropriate North Carolina retail test period jurisdictional fuel expense over collection is \$5,450,950 (including interest) and that the adjusted North Carolina jurisdictional test period sales appropriate for computing the EMF (Rider B) are 4,299,466,351 kWh. Consistent with the Commission's rejection of the Public Staff's proposed disallowance of replacement power costs discussed herein, the Commission also concludes that these amounts should not be adjusted as recommended by the Public Staff.

Company witness Merritt testified regarding Rider B2 approved in Docket No. E-22, Sub 515, to mitigate the rate impact of the high fuel costs that occurred during extremely cold weather in January through March 2014 by allowing the costs to be collected in the EMF for the 2015 and 2016 fuel years, without interest, subject to a final true-up to be determined in the 2017 fuel case and recovered over the 2018 fuel year.

Mr. Merritt set forth the total under-recovery balance for the 24 months ended December 31, 2016, of \$381,535 as presented in Company witness Campbell's exhibits. Mr. Merritt calculated the proposed uniform Rider B2 EMF applicable to the North Carolina jurisdiction and the resulting factor for each customer class of \$0.00009/kWh. Public Staff witness Metz agreed that the final true-up of the EMF Rider B2 should be set to \$0.00009/kWh for the 2018 fuel year. Public Staff witness Johnson recommended approval of the Company's proposed Rider B2 EMF in the amount of \$0.00009/kWh. (5) The Commission includes that it is appropriate to implement this final phase of the mitigation proposal EMF Rider B2 in this docket consistent with the Company's proposal.

The appropriate Experience Modification Factors (EMF) (Rider B) for this proceeding, including interest and the regulatory fee, are as follows:

<u>Customer Class</u>	<u>EMF Billing Factor</u>
Residential	(0.128) ¢/kWh
SGS &PA	(0.128) ¢/kWh
LGS	(0.127) ¢/kWh
Schedule NS	(0.123) ¢/kWh
6VP	(0.125) ¢/kWh
Outdoor Lighting	(0.128) ¢/kWh
Traffic	(0.128) ¢/kWh

The appropriate EMF Rider B2 EMF Factors for this proceeding including the current regulatory fee are as follows:

<u>Customer Class</u>	<u>EMF Billing Factor</u>
Residential	0.009 ¢/kWh
SGS &PA	0.009 ¢/kWh
LGS	0.009 ¢/kWh
Schedule NS	0.009 ¢/kWh
6VP	0.009 ¢/kWh
Outdoor Lighting	0.009 ¢/kWh
Traffic	0.009 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting this finding of fact is cumulative and is contained in the direct testimony and exhibits of the Company witnesses Petrie, Merritt, Campbell, Brookmire, and Workman, the testimony of Public Staff witness Metz, the affidavit of Public Staff witness Johnson, and the rebuttal testimony and exhibits of the Company witnesses Stanley, Rosenberger, Wright, and Petrie.

Based upon the above findings and conclusions, the Commission finds and concludes that the total net fuel factors (¢/kWh) are determined as follows (with Regulatory Fee):

<u>Customer Class</u>	<u>Total Net Fuel Factor</u>
Residential	1.982 ¢/kWh
SGS &PA	1.980 ¢/kWh
LGS	1.964 ¢/kWh
Schedule NS	1.906 ¢/kWh
6VP	1.933 ¢/kWh
Outdoor Lighting	1.982 ¢/kWh
Traffic	1.982 ¢/kWh

IT IS THEREFORE ORDERED as follows:

1. That effective beginning with usage on and after January 1, 2018, the Company shall implement a Fuel Cost Rider A, EMF Rider increment (Rider B), and Rider B2 for all classes as approved and set forth in the Evidence and Conclusions for findings of Fact Nos. 12-23 above.

2. That a total fuel factor as approved and set forth in the Evidence and Conclusion for Finding of Fact No. 23 above, shall be instituted and remain in effect for usage from January 1, 2018, through December 31, 2018.

3. That the Company shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein no later than five working days from the date of receipt of this Order.

4. That the Company shall work with the Public Staff to prepare a joint proposed Notice to Customers of the rate adjustments ordered by the Commission herein, and the Company shall file such proposed notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION

This, the ____ day of December, 2017.

NORTH CAROLINA UTILITIES COMMISSION

Chief Clerk

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Proposed Order Approving Fuel Charge Adjustment, as filed in Docket No. E-22, Sub 546, was served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 18th day of December, 2017.

/s/Andrea R. Kells

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