PUBLIC VERSION

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 558

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities	)))))))	THE PUBLIC STAFF'S PROPOSED ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Monday, November 5, 2018, beginning at 1:30 p.m. and Thursday, November 8, 2018, beginning at 9:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

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

APPEARANCES:

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

Ralph McDonald, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

For Dominion Energy North Carolina:

Mary Lynne Grigg and Andrea R. Kells, McGuireWoods LLP, 2600 Two Hanover Square, Raleigh, North Carolina 27601

For Nucor Steel Hertford (Nucor):

Christopher J. Blake, Nelson Mullins Riley & Scarborough, LLP, 4140 Park Lake Avenue, Suite 200, Post Office Box 301519, 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 30, 2018, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or Company), filed its application for a fuel charge adjustment, along with accompanying testimony and exhibits, pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities. The application was accompanied by the direct testimony and exhibits of Bruce E. Petrie, Manager of Generation System Planning, Ronnie T. Campbell, Supervisor of Accounting for the Power Generation and Power Delivery Groups, Gregory A. Workman, Director-Fuels, Tom A. Brookmire, Manager of Nuclear Fuel Procurement, and George G. Beasley, Regulatory Specialist.

On September 7, 2018, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

On October 2, 2018, the Commission granted a motion to amend the procedural schedule filed by the Public Staff to have the hearing set for November 5, 2018 to be for the taking of testimony of public witnesses and to set a hearing on November 8, 2018, for the taking of the testimony of expert witnesses.

Petitions to Intervene were filed by CIGFUR on October 15, 2018, and Nucor on October 23, 2018. These petitions were granted by separate Orders dated October 25, 2018. The Public Staff's participation and intervention was recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On October 25, 2018, the Commission granted the joint motion of Nucor and CIGFUR to extend the date by which intervenor testimony must be filed to October 26, 2018.

On October 26, 2018, the Public Staff filed the testimony of Dustin R. Metz, Engineer, Public Staff Electric Division, Darlene P. Peedin, Accounting Manager, Electric Section, Public Staff Accounting Division, and Michelle M. Boswell, Staff Accountant, Public Staff Accounting Division; CIGFUR filed the testimony of Nicholas Phillips, Jr.; and Nucor filed the testimony of Paul J. Weilgus.

The Company filed its Affidavit of Publication on October 29, 2018.

On November 5, 2018, DENC filed the rebuttal testimony of witnesses Petrie and Beasley.

On November 6, 2018, the Public Staff filed a joint motion on behalf of all the parties requesting that the Commission issue an order excusing the appearance of all witnesses at the hearing and accepting their prefiled testimony and exhibits into evidence. The Commission granted the motion by Order dated November 7, 2018.

The matter came on for hearing for the taking of the testimony of public witnesses on November 5, 2018. No public witnesses appeared.

The matter came on for hearing for the taking of expert testimony on November 8, 2018, as scheduled. No public witnesses appeared at the hearing. The pre-filed testimony of all witnesses was stipulated into evidence as if given orally from the stand and the exhibits entered into the record.

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. DENC 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. DENC is lawfully before this Commission based on its application filed pursuant to N.C.G.S. § 62-133.2.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2018.

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

4. The per books test period system sales are 86,260,348,958 kilowatt-hours (kWh).

5. The per books test period system generation is 89,584,657 megawatt-hours (MWh), which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,650,942
Coal, including wood and natural gas steam	14,918,376
Heavy Oil	357,813
Combined Cycle and Combustion Turbine	29,436,131
Solar and Hydro - Conventional and Pumped Storage	3,437,770
Net Power Transactions	17,153,828
Less: Energy for Pumping	(3,370,203)

6. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel costs.

7. The nuclear capacity factor appropriate for use in this proceeding is 94.1%, which is the estimated nuclear capacity factor for the 12-month rate period ending January 31, 2020.

8. The adjusted test period system sales for use in this proceeding are 85,266,747,633 kWh.

9. The adjusted test period system generation for use in this proceeding is 88,445,965 MWh, which is categorized as follows:

Generation Types	MWh
Nuclear	27,578,419
Coal, including wood and natural gas steam	14,686,411
Heavy Oil	352,223
Combined Cycle and Combustion Turbine	28,978,466
Hydro	3,337,366
Solar	100,404
Net Power Transactions	16,883,282
Less: Energy for Pumping	(3,370,203)

10. Only actual fuel costs associated with power purchases may be recovered by DENC through its fuel charge proceeding and, therefore, a Marketer Percentage must be derived to serve as a proxy for fuel costs when actual fuel costs are not available. In this proceeding, a Marketer Percentage of 75% should be applied to rate period fuel costs when actual fuel costs are not available to determine purchase power expense.

11. A Marketer Percentage of 75% should be applied to the fuel savings projected to result from the Greensville Plant going on line. These reduced fuel savings resulting from application of the Marketer Percentage should be collected through the experience modification factor (EMF) set in the 2019 fuel adjustment proceeding.

12. The adjusted test period system fuel expense for use in this proceeding is $ 1,824,035,658.

13. It is appropriate to use a rate period of February 1, 2019, through January 31, 2020.

14. The proper fuel factors for both Riders A and B to be effective January 1, 2019, through January 31, 2019, including the regulatory fee, are $0.000 for all classes.

15. The proper fuel factors for Rider A to be effective as of February 1, 2019, for this proceeding, including the regulatory fee, are as follows:

Customer Class	Rider A
Residential	0.071¢/kWh
SGS & PA	0.071¢/kWh
LGS	0.068¢/kWh
NS	0.068¢/kWh
6VP	0.069¢/kWh
Outdoor Lighting	0.071¢/kWh
Traffic	0.071¢/kWh

16. The appropriate North Carolina retail test period jurisdictional fuel expense undercollection is $16,162,154, and the adjusted North Carolina retail jurisdictional test period sales are 4,175,472,287 kWh.

17. It is appropriate for the Company to recover the full under-collection of the test period fuel expenses in the rate period beginning February 1, 2019.

18. The appropriate Experience Modification Factors (EMF or Rider B) to be effective as of February 1, 2019, for this proceeding, including the regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	0.392¢/kWh
SGS & PA	0.392¢/kWh
LGS	0.389¢/kWh
NS	0.377¢/kWh
6VP	0.383¢/kWh
Outdoor Lighting	0.392¢/kWh
Traffic	0.392¢/kWh

19. The base fuel component approved in DENC's last general rate case, Docket No. E-22, Sub 532 (Sub 532), in the amount of 2.095 ¢/kWh for the Residential class, 2.093 ¢/kWh for the SGS & PA class, 2.079 ¢/kWh for the LGS class, 2.014 ¢/kWh for Schedule NS, 2.043 ¢/kWh for 6VP, 2.095 ¢/kWh for Outdoor Lighting, and 2.095 ¢/kWh for Traffic, should be adjusted by Rider A for each class as set forth in Finding of Fact No. 15, and further adjusted by EMF Rider B increments for each class as set forth in Finding of Fact No. 18. The final net fuel factors to be billed to DENC's retail customers during the 2019 fuel charge billing period effective February 1, 2019, including the regulatory fee, are as follows:

Customer Class	Total Net Fuel Factor
Residential	2.558¢/kWh
SGS & PA	2.556¢/kWh
LGS	2.536¢/kWh
NS	2.459¢/kWh
6VP	2.495¢/kWh
Outdoor Lighting	2.558¢/kWh
Traffic	2.558¢/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

N.C.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 DENC. The Company's filing was based on the 12 months ended June 30, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the direct testimony and exhibits of DENC witnesses Workman and Brookmire.

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 discussed the Company's fossil fuel procurement practices, including any recent changes to those practices. He explained that during the test period of July 2017 through June

2018, domestic natural gas production increased due to rising global oil prices, natural gas exports, and increased domestic natural gas demand. This increasing demand for natural gas, along with several periods of sustained, colder-than-normal winter weather in most parts of the eastern United States, led to short-term spikes in natural gas prices. Both coal and oil prices also rose.

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 uses a disciplined natural gas procurement plan to ensure a reliable supply of natural gas at competitive prices. He stated that the Company procures natural gas through periodic solicitations and the open market, with day-ahead, monthly, seasonal, and multiyear physical gas supply purchases. Mr. Workman also described how the Company uses its portfolio of pipeline transportation and storage contracts, which provide access to multiple natural gas supply points. He also noted the Company's participation in the interstate pipeline capacity release and physical supply markets, as well as pipeline expansion. Mr. Workman testified that during the Test Period, energy production at the Company's gas-fired power stations accounted for about 33% of the electricity generated for the Company's customers. He noted that in late 2018, the Company will add the 1,588 MW Greensville gas-fired combined cycle power station (Greensville) to its regulated fleet. Mr. Workman also described how the Company price-hedges natural gas using a range of volume targets, which gradually decrease over a three-year period.

Mr. Workman also discussed the Company's coal procurement, which is accomplished primarily through periodic solicitations and secondarily on the open market for short-term or spot needs. This practice allows a layering-in of contracts with staggered terms and blended prices, to ensure a reliable supply of coal and to limit exposure to potential dramatic market price swings and supplier non-performance.

In regard to biomass, Mr. Workman explained that the Hopewell and Southampton Power Stations continue to be served by multiple suppliers under long-term agreements, the Altavista Power Station is served by one primary supplier, and the co-fired Virginia City Hybrid Energy Center facility continues to be served via short-term contracts with various suppliers. He noted that the Company purchases its 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 to its power generating facilities and to mitigate price volatility.

Company witness Brookmire testified that the nuclear fuel market has softened considerably in the past six to seven years, largely due to the earthquake and tsunami in Japan in March 2011. He also noted reductions in demand due to plant closures in Germany and the United States, as well as some reductions in supply, which may have offset some of the downward trend in demand. Mr.

Brookmire pointed out that secondary sources of production and high global inventory levels continue to mitigate some of these reductions. He also noted that the uranium market prices, while relatively stable, have continued to be stable.

Mr. Brookmire indicated that the spot market price for conversion services has dropped significantly, though long-term prices have remained high. He also noted that the cost for enrichment services has declined slightly. Mr. Brookmire explained that the general consensus is that fabrication costs will continue to increase. He also pointed out that there may be some short-term price lift on front-end components due to the restart of reactors in Japan and the growth of China's nuclear energy program.

Company witness Brookmire stated that while these changes in market costs have had some impact on the Company's projected near-term costs, the Company's mix of longer-term front-end component contracts has reduced its exposure to the market price escalation and volatility. Mr. 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. Further, he noted that the Company has some market-based contracts that allow it to take advantage of current lower prices. Mr. Brookmire also noted that the Company continues to follow the same nuclear fuel procurement practices as it has in the past, in accordance with its procedures filed in Docket No. E-100, Sub 47A.

No party offered testimony contesting the Company's fuel procurement and power purchasing 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 FINDINGS OF FACT NOS. 4 - 5

The evidence for these findings of fact is contained in the direct testimony and exhibits of DENC witnesses Beasley and Petrie and the testimony of Public Staff witnesses Boswell and Metz.

DENC witness Beasley testified that the Company's per books test period system sales were 86,260,340,958 kWh and witness Petrie's Exhibit BEP-1, Schedule 4 showed that the Company's per books test period system generation was 86,584,657 MWh. Exhibit BEP-1, Schedule 4 also showed that the per books test period system generation is categorized as follows:

Generation Types	MWh
Nuclear	27,650,942
Coal, including wood and natural gas steam	14,918,376
Heavy Oil	357,813
Combined Cycle and Combustion Turbine	29,436,131
Solar and Hydro - Conventional and Pumped	3,437,770
Net Power Transactions	17,153,828
Less: Energy for Pumping	(3,370,203)

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 FINDINGS OF FACT NO. 6

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

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 five-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. 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.

Company witness Petrie testified that the Company's four nuclear units operated at an aggregate capacity factor of 94.2% during the test period, which exceeded the five-year industry weighted average capacity factor of 89.8% for the period 2012-2016 for 800 to 999 megawatt (MW) units, as reported by NERC in its latest Generating Availability Report. He noted that the Company's nuclear units' net capacity factor of 93.5% was better than the national average for comparable units for the last five years of 89.8%.

Public Staff witness Metz testified that the Company met both of the standards set out in Rule R8-55(k) with an actual system-wide nuclear capacity factor that exceeded the NERC weighted average nuclear capacity factor and a two-year simple average of its system-wide nuclear capacity factor that exceeded the NERC weighted average nuclear capacity factor.

Mr. Metz testified that the Public Staff investigated the greater than expected fuel costs in January 2018, which led to a significant underrecovery of fuel costs. He stated that after reviewing discovery responses and discussing the issue with the Company, the Public Staff was satisfied that these fuel costs were reasonably and prudently incurred.

Based upon the evidence in the record, the Commission concludes that DENC managed its baseload plants prudently and efficiently so as to minimize fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

Company witness Petrie testified in his direct testimony that for the 12 months ending January 31, 2020, North Anna Unit 1 is projected to operate at a net capacity factor of 93.9%, North Anna Unit 2 is projected to operate at a net capacity factor of 90.3%, Surry Unit 1 is projected to operate at a net capacity factor of 91.8%, and Surry Unit 2 is projected to operate a net capacity factor of 100.2%. 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. DENC's projected fuel costs are based on a 94.1% nuclear capacity factor, which is what DENC anticipates for the twelve months from February 1, 2019, through January 31, 2020, the period the new rates will be in effect.

No party contested DENC's use of a 94.1% 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 94.1% is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is contained in the direct testimony of DENC witness Beasley and the testimony of Public Staff witness Metz.

Witness Beasley testified that he was sponsoring the calculation of the adjustment to the Company's system sales for the twelve months ended June 30, 2018, due to changes in usage, weather normalization, and customer growth, in accordance with Commission Rule R8-55(d)(2). The Company's filing further states that the methodology used for the normalization is the same as used in Sub 532, and the last fuel charge adjustment case, Docket No. E-22, Sub 546. Witness Beasley adjusted total Company sales by (993,601,325) 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 these adjustments.

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, 2018, are 85,266,747,633 kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

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

DENC witness Petrie presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2018, 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 88,445,965 MWh. The Public Staff accepted this adjusted generation level, which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,578,419
Coal, including wood and natural gas steam	14,686,411
Heavy Oil	352,223
Combined Cycle and Combustion Turbine	28,978,466
Hydro	3,337,366
Solar	100,404
Net Power Transactions	16,883,282
Less: Energy for Pumping	(3,370,203)

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 88,445,965 MWh is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the direct testimony of DENC witnesses Petrie and Campbell and the testimony of Public Staff witness Peedin.

Company witness Campbell explained that for dispatchable non-utility generators (NUGs) that do not provide actual fuel costs, the Company included as fuel cost 78% of the reasonable and prudent energy costs in the EMF calculation (Birchwood and Spruance Genco, LLC). Additionally, to the extent a dispatchable NUG provides market-based energy rather than dispatching its facility, the Company included 78% of those reasonable and prudent energy costs in the EMF calculation. He noted that use of the 78% “marketer’s percentage” was agreed to between the Company and the Public Staff and approved by the Commission in the Company’s 2016 fuel factor proceeding, Docket No. E-22, Sub 534.

Company witness Petrie testified that the Company believed the Marketer Percentage of 78% applied to PJM and NUG purchases is reasonable and it did not propose a change.

Public Staff witness Peedin testified that costs recoverable by DENC in an annual fuel proceeding are set forth in N.C. Gen. Stat. § 62-133.2(a3), which provides that the utility may recover in annual fuel clause proceedings the costs identified in N.C. Gen. Stat. § 62- 3 133.2(a3)(1), (2), (6), and (7), and (10) and "the fuel cost component, as may be modified by the Commission, of electric power purchases identified in subdivision (4) of that subsection." She explained that because DENC buys substantial amounts of purchased power in transactions where the fuel cost component of the purchased power is not disclosed, a Marketer Percentage is used as a proxy to determine the cost to be recovered by the Company through the fuel factor. Ms. Peedin noted that the Commission approved a Stipulation between the Public Staff and DENC in Sub 532[1] that provided in Section IV.A.:

> The Stipulating Parties agree to adjust the Company's base fuel and non-fuel expenses to reflect 78% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage). This represents a reduction from the Company's current Marketer Percentage of 85%. The 78% Marketer Percentage shall remain in effect until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

She also pointed out that the Commission found in Sub 546 that the Marketer Percentage would be reviewed in the 2018 fuel proceeding or the next general rate case, whichever occurred first.[2]

Ms. Peedin stated that while the Public Staff agreed with the Company's application of the 78% Marketer Percentage for the test year EMF, it did not agree that it should remain at 78% for the rate period. Using a methodology proposed by DENC in its 2008 fuel proceeding, Docket No. E-22, Sub 451, Ms. Peedin took the fuel component of the cost of energy from the 2016 and 2017 State of the Market reports for PJM, 73.3% and 69.5%, along with data provided by the Company that blended DENC's internal data with PJM State of the Market report data for the Dominion Zone for calendar years 2016 and 2017 of [**BEGIN CONFIDENTIAL**] xxxxxxxxxxxxxxxxxxx [**END CONFIDENTIAL**] respectively. Ms. Peedin then calculated an [**BEGIN CONFIDENTIAL**] xxxxxxxxxxxxxxxx

[1] See p. 18, Finding of Fact No. 51, *Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions*, issued December 22, 2016, Docket No. E-22, Sub 532.

[2] *Order Deciding Contested Issues and Requiring Compliance Filing*, p. 23, issued January 25, 2018, Docket No. E-22, Sub 546.

xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx [**END CONFIDENTIAL**] that yielded a 75% Marketer Percentage as set forth in Confidential Peedin Exhibit 1. Ms. Peedin also recommended that the Company true-up PJM purchases, certain NUGs, and the effect of the fuel savings due to the addition of the Greensville Plant in next year's EMF (July 2018 – June 2019) to reflect the implementation of the 75% Marketer Percentage effective February 1, 2019.

In rebuttal, DENC Petrie testified that the Company disagreed with the Public Staff's proposed 75% Marketer Percentage because it would deny the Company an opportunity to recover all of its prudently incurred PJM costs. He contended that any changes in the percentage should be made in conjunction with the Company's next base rate case. Mr. Petrie further contended that the 78% is a better representation of fuel-related costs and is consistent with the Company's method used in Sub 532.

The Commission finds it appropriate to review the Marketer Percentage in this proceeding, as provided in the Stipulation agreed to by DENC and the Public Staff and approved by the Commission in Sub 532. There is no requirement that the Marketer Percentage change only in conjunction with a rate case, and the Sub 532 and Sub 546 Orders both contemplate that the Marketer Percentage will change outside of a rate case.[3] The Commission notes that the calculation performed by Ms. Peedin uses the same methodology utilized in Sub 532. Indeed,

[3] The Commission notes that the Marketer Percentage for DENC was changed in DENC's 1997, 2000, 2001, 2002, and 2006 fuel proceedings, and none of those changes in the Marketer Percentage was made in conjunction with a rate case.

DENC does not contest the calculations. Based upon the foregoing, the Commission concludes that it is reasonable to apply a 75% fuel-to-energy Marketer Percentage to DENC's purchases from suppliers that do not provide the Company with actual fuel costs as the proxy for actual fuel costs associated with such purchases during the rate period, effective February 1, 2019. Accordingly, in the true up of the July 2018 through June 2019 test year, a Marketer Percentage of 78% should be applied for the period of July 2018 through January 2019, and the 75% Marketer Percentage should be applied for the period February 2019 through June 2019. Further, the Commission finds that the Marketer Percentage should be reviewed in the context of DENC's next general rate case or its 2020 fuel charge adjustment proceeding, whichever occurs first.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for these findings of fact is contained in the direct testimony of Company witness Petrie and Public Staff witnesses Metz and Peedin.

DENC witness Petrie testified that system fuel expense was adjusted to reflect the addition of the Greensville County natural gas-fired combined cycle power station in December 2018. He indicated that the Company calculated the system fuel savings using the PROMOD production cost, resulting in a forecast of approximately $90.7 million of savings in 2019.

Public Staff witness Metz testified that in its investigation of the Greensville fuel savings, it had determined that the Company had not applied the Marketer

Percentage and it had used a projected capacity factor that is likely higher than what should be reasonably expected for the February – June 2019 portion of the rate period. Mr. Metz noted that the Company had requested full recovery of its proposed rates, which is supported by the Public Staff. If the Commission approves full recovery of the Company's requested fuel adjustment, then adjustment to the savings attributable to the addition of Greensville would be made in the next fuel proceeding. However, he noted that the Company had also put forth a mitigation alternative that would allow the EMF underrecovery to be collected over two years. Should the mitigation alternative be approved, Mr. Metz proposed that the Company adjust the EMF by recalculating the savings attributable to the addition of Greensville by applying the appropriate Marketer Percentage and adjusting the capacity factor. Public staff witness Peedin testified that the appropriate Marketer Percentage to be applied to the Greensville fuel savings was 75%.

In rebuttal, DENC witness Petrie contended that the Company reasonably estimated the expected fuel and purchased energy savings from the addition of Greensville. He noted that if the Commission determines that it is appropriate to implement the rate mitigation alternative, the Company will work with the Public Staff to revise the Greensville adjustment to account for a lower capacity factor and apply the Marketer Percentage.

The Commission finds that the Marketer Percentage and a more appropriate capacity factor should have been used to calculate the savings attributable to the addition of the Greensville plant. As a result, the savings included in the calculation of Rider A are likely overstated, making the rider lower than it should have been. As discussed *supra*, the Commission finds that it is appropriate to approve recovery of the full EMF underrecovery as filed by DENC, rather than the mitigation alternative, and thus, adjustment of the fuel savings will not occur until the next proceeding. The Commission notes that if it had approved the mitigation alternative, it would have ordered that a Marketer Percentage of 75% be applied to the fuel savings and that a revised capacity factor be used to recalculate the EMF.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 - 15

The evidence for these findings of fact is contained in the direct testimony of Company witnesses Petrie and Beasley, and the testimony of Public Staff witness Metz.

Company witness Petrie presented the Company's system fuel expense for the test period and the normalized system fuel expense projected for the 12-month period ending January 31, 2020 of $1,824,035,658. He testified that he normalized fuel expenses using a methodology approved in previous North Carolina fuel rate cases. More specifically, the expense rates for nuclear, coal, oil, and NUGs were based on the actual 12-month average expense rates incurred during the test period. As discussed previously, Mr. Petrie noted that the system fuel expense was adjusted to reflect the expected fuel benefits related to the addition of the Greensville plant. He also pointed out that due to the enactment of North Carolina

House Bill 589 on July 27, 22 2017, and House Bill 374 on June 27, 2018, the Company has included in system fuel expenses the total delivered costs associated with certain purchases of power from qualifying facilities under PURPA that are not subject to economic dispatch or curtailment. Further, the NUG expense was adjusted higher to account for this legislation and the expense rate for natural gas was adjusted downward to account for a return to normal weather during the rate period.

Company witness Beasley testified that the Company proposes to change the effective date of the proposed Fuel Charge Rider A and EMF Rider B by one month, to a 12-month rate period beginning February 1, 2019. He noted that since the existing tariffs approved in Docket No. E-22, Sub 546 will expire on December 31, 2018, the Company is proposing interim tariffs for January 2019 showing Riders A and B both set to zero, and Rate Period tariffs for February 2019 through January 2020 with updated rates.

Company witness Beasley 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 2.142 ¢/kWh, based on system fuel expenses of $1,824,035,658, and system sales of 85,266,747,633, that reflected adjustments for changes in usage, weather normalization, and customer growth. Witness Beasley 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, based upon its investigation, the Public Staff determined that the projected fuel costs and the prospective components of the total fuel factor (Rider A), as set forth in the application, were calculated appropriately for this proceeding.

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 $1,824,035,658. The Commission further concludes that it is appropriate to use a rate period of February 1, 2019, through January 31, 2020 in this proceeding, and that the proper fuel factors for both Riders A and B to be effective January 1, 2019, through January 31, 2019, including the regulatory fee, are $0.000 for all classes. Finally, the Commission concludes that the proper fuel factors (Rider A) for use for the 12-month rate period effective February 1, 2019, including the regulatory fee, are as follows:

Customer Class	Rider A
Residential	0.071¢/kWh
SGS & PA	0.071¢/kWh
LGS	0.068¢/kWh
NS	0.068¢/kWh
6VP	0.069¢/kWh
Outdoor Lighting	0.071¢/kWh
Traffic	0.071¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 16 -18

The evidence supporting these findings of fact is contained in the direct testimony and exhibits of DENC witnesses Beasley, Campbell, and Petrie, and the testimony of CIGFUR witness Phillips, Nucor witness Weilgus, and Public Staff witness Boswell.

Company witness Petrie testified that cold winter weather and higher commodity prices during the test year resulted in an underrecovery of fuel costs. He noted that energy use in January 2018 reached a peak near DENC's all-time peak experienced in the winter of 2015. Company witness Campbell testified that the fuel costs allocated to North Carolina jurisdictional customers totaled $104,925,682, while the Company received fuel revenues totaling $88,763,528 during the test year. The difference between the fuel costs and the fuel revenues resulted in an underrecovery of $16,162,154 for the test period. To determine the EMF (Rider B), Company witness Beasley divided this net balance by the adjusted jurisdictional test period sales of 4,175,472,287 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 Boswell testified that the Public Staff had reviewed the calculations of the EMF provided by the Company and set forth in the direct testimony and exhibits of Company witnesses Beasley and Campbell. Ms. Boswell did not recommend any adjustments to the EMF calculated by the Company.

Based upon the findings and conclusion herein, the Commission concludes that the appropriate North Carolina retail test period jurisdictional fuel expense undercollection is $16,162,154 and that the adjusted North Carolina jurisdictional test period sales appropriate for computing the EMF (Rider B) are 4,175,472,287 kWh.

DENC witness Beasley testified that the Company was requesting approval of all of the June 30, 2018, fuel deferral account balance of $16,162,154 over the February 1, 2019 – January 31, 2020, rate period. To mitigate the impact of the increase necessary to recover this underrecovery, Mr. Beasley explained that the Company had voluntarily proposed a mitigation alternative, should the Commission find it to be in the public interest. The Company proposed that under the mitigation alternative, the Company would recover half of this deferral balance in the rate period beginning February 1, 2019, and the other half during the rate period beginning February 1, 2020. Thereafter, there would be a final true up to be collected during the rate period beginning February 1, 2022. Finally, the Company would agree not to seek interest on the deferral balance during this period.

CIGFUR witness Phillips testified that the increase in the fuel rate amounts to a 29.9% increase over the current fuel rate, which he characterized as significant, and which, if approved for full recovery, would have a detrimental effect on customers. He noted that in Docket No. E-22, Sub 515, the Commission approved a similar mitigation plan when otherwise residential rates would have increased by 5.3% and Rate VP by 8.5%. In this proceeding, the full increase would result in a residential increase of 5.4% and a Rate 6VP increase of 9.7%. Mr. Phillips pointed out that the proposed fuel increase would significantly increase the cost of energy for DENC's industrial base, could lead to the loss of industrial customers, and negatively impact the economy of the DENC region. He argued that the mitigation alternative offered by the Company would levelize the increase and lessen rate shock on customers.

Nucor witness Weilgus testified that the full deferral amount is materially significant and that full recovery would cost Nucor approximately an additional $300,000 per month. He stated that full recovery of the underrecovery would negatively affect the Company's competiveness and lead to rate shock.

Public Staff witness Boswell testified that it was the Public Staff's recommendation that the Commission approve and implement full recovery rates as opposed to the mitigation alternative. She noted that the impact of the EMF under full recovery is $3.88 on a 1,000 kWh bill, in effect for a one-year period, while the mitigation alternative would defer recovery of half of that amount ($1.94 per each 1,000 kWh bill) until the annual billing period beginning February 1, 2020, with the underrecovery recovered over a two-year period. Ms. Boswell pointed out that the underrecovery was primarily driven by cold weather and higher commodity prices, and that increased fuel expenses due to periods of cold weather were not new to the region and are likely to occur again. She noted that if similar weather occurs again and causes another underrecovery, that underrecovery would presumably be recovered along with the underrecovery related to the mitigation alternative, compounding any underrecovery in future fuel cases and further increasing the rates to be collected in those future years. She also noted that as detailed by Public Staff witness Metz, the Company overstated its fuel credit related to the Greensville plant, leading to a known underrecovery for the item in the 2019 EMF period. Moreover, Ms. Boswell explained that if there were a base rate increase next year DENC, ratepayers would likely be paying base rates and fuel costs higher than they would be without the mitigation alternative. She concluded that in the long-term, the Public Staff believes that it is in ratepayers' interest for the Company to recover the underrecovery in full over the upcoming rate period.

In his rebuttal testimony, DENC witness Beasley explained that the Company's proposed reduction in rates due to the impact of the Tax Act would offset in part the bill impacts of the increases in fuel expense under either full recovery or the mitigation alternative. However, he noted that large high load factor customers would face substantial increases if full recovery of fuel expenses were approved.

In regard to the issue of whether to approve full recovery of the underrecovery as requested by DENC and recommended by the Public Staff, as opposed to approving the mitigation alternative offered by DENC and supported by CIGFUR and Nucor, the Commission must determine whether it is in the public interest to approve a substantial, but known amount of increase for one year, or put off recovery of a portion of the increase until next year, to be combined with an unknown amount of either increase or decrease determined in the next fuel proceeding. Mr. Metz is correct to note that the overstatement of the fuel savings attributable to the addition of the Greensville plant will increase fuel expense next year. Further, as DENC witness Beasley points out, reductions in rates as a result of the Tax Act will serve to mitigate the impact of the increase in the fuel rates.

As pointed out by CIGFUR witness Phillips, the Commission approved a similar mitigation plan in Docket No. E-22, Sub 515. But while the mitigation alternative may mitigate rates in the first year, it may exacerbate rates in the next year. Such a situation recently occurred in Duke Energy Progress, LLC's (DEP's) 2018 fuel adjustment proceeding, Docket No. E-2, Sub 1173, where an underrecovery of approximately $42 million from the 2017 proceeding was deferred to 2018, when it was approved for recovery along with an underrecovery of approximately $182 million from the 2018 proceeding. Additionally, in Docket No. E-2, Subs 765, 784, 806, 833, 851, 868, 889, 903, 929, 949, and 976, portions of underrecoveries and interest were deferred from one fuel proceeding for DEP to the next over the 2000-2010 time period. Thus, while full recovery of an underrecovery may cause rate shock, deferral of a portion of the underrecovery may cause even greater rate shock. The Commission concludes that as the Tax Act will mitigate the increase in fuel rates to some extent, the fuel expense will be higher next year when the Marketer Percentage and a revised capacity factor are applied to the Greensville fuel savings, and there is a significant risk of even higher rates should there be another underrecovery next year, the Company should recover the full undercollection of the test period fuel expenses in the rate period beginning February 1, 2019.

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

Customer Class	EMF Billing Factor
Residential	0.392¢/kWh
SGS & PA	0.392¢/kWh
LGS	0.389¢/kWh
NS	0.377¢/kWh
6VP	0.383¢/kWh
Outdoor Lighting	0.392¢/kWh
Traffic	0.392¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is cumulative and is contained in the direct testimony and exhibits of DENC witnesses Beasley, Petrie, Campbell, Brookmire, and Workman, and the testimony of Public Staff witnesses Metz, Boswell, and Peedin.

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

Customer Class	Total Net Fuel Factor
Residential	2.558¢/kWh
SGS & PA	2.556¢/kWh
LGS	2.536¢/kWh
NS	2.459¢/kWh
6VP	2.495¢/kWh
Outdoor Lighting	2.558¢/kWh
Traffic	2.558¢/kWh

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on or after January 1, 2019 through January 31, 2019, that DENC shall implement a Fuel Cost Rider A and Rider B of $0.000 for all classes, including regulatory fee.

2. That effective beginning with usage on and after February 1, 2019, DENC shall implement a Fuel Cost Rider A increment as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 12 - 15 above.

2. That an EMF Rider increment (Rider B) as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 16 -18 above, shall be instituted and remain in effect for usage from February 1, 2019, through January 31, 2020.

3. That DENC 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 DENC shall work with the Public Staff to prepare a joint proposed Notice to Customers of the rate adjustments ordered by the Commission in Docket Nos. E-22, Subs 556, 557, and 558, 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, 2018.

NORTH CAROLINA UTILITIES COMMISSION

Chief Clerk