STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 579

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	)	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, November 12, 2019, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioner ToNola D. Brown-Bland, Commissioner Lyons Gray and Commissioner Daniel G. Clodfelter

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

Andrea R. Kells, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For Carolina Industrial Group for Fair Utility Rates I:

Warren K. Hicks, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For the Using and Consuming Public:

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

BY THE COMMISSION: On August 13, 2019, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company), filed its Application for a fuel charge adjustment, along with accompanying testimony and exhibits, pursuant to N.C. Gen. Stat. § 62-133.2 and North Carolina Utilities Commission (Commission) Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities (Application). The application was accompanied by the testimony and exhibits of Katherine E. Farmer, Ronnie T. Campbell, Dale E. Hinson, Tom A. Brookmire, and George G. Beasley.

On September 4, 2019, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

On September 6, 2019, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a petition to intervene. The petition was granted on September 17, 2019.

On September 27, 2019, Nucor Steel-Hertford (Nucor) filed a petition to intervene. The petition was granted on October 2, 2019.

On October 4, 2019, the Company filed its affidavit of publication.

On October 22, 2019, the Public Staff filed the direct testimony of Dustin R. Metz and affidavit of Jenny X. Li.

On October 31, 2019, the Company filed a letter in lieu of rebuttal testimony indicating there were no issues in dispute between the Company and the Public Staff based upon the Public Staff's testimony and affidavit.

On November 5, 2019, the Public Staff and the Company filed a joint motion to excuse witnesses from appearing at the November 12, 2019 evidentiary hearing, stating that they had reached agreement on all issues in this docket and had agreed to waive cross-examination of each other's witnesses.

On November 6, 2019, the Commission granted the joint motion to excuse witnesses.

This matter came on for hearing as scheduled on November 12, 2019. No public witnesses appeared at the hearing. DENC presented the testimony and exhibits of witnesses Farmer, Campbell, Hinson, Brookmire, and Beasley, and the Public Staff presented the testimony of witness Metz and affidavit of witness Li. The testimony, exhibits, and affidavits were accepted into evidence.

On December 23, 2019, a joint proposed order was filed by DENC and the Public Staff.

Based upon the evidence presented and the entire record in this proceeding, 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 N.C. Gen. Stat. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended June 30, 2019.

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

4. The per books test period system sales are 87,363,222,000 kilowatt-hours (kWh).

5. The per books test period system generation is 90,757,143 megawatt-hours (MWh), which includes various types of generation as follows:

Generation Types	MWh
Nuclear	28,083,596
Coal	9,259,384
Heavy Oil	0
Wood and Natural Gas Steam	1,032,011
Combined Cycle and Combustion Turbine	35,509,724
Solar and Hydro – Conventional and Pumped	4,609,788
Net Power Transactions	15,301,134
Less: Energy for Pumping	(3,038,494)

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

7. The nuclear capacity factor appropriate for use in this proceeding is 95.7%, which is the estimated nuclear capacity factor for the 12 months beginning February 1, 2020.

8. The adjusted test period system sales for use in this proceeding are 85,389,162,794 kWh.

9. The adjusted test period system generation for use in this proceeding is 88,616,747 MWh, which is categorized as follows:

Generation Types	MWh
Nuclear	28,061,493
Coal (including wood and natural gas steam)	9,950,079
Heavy Oil	0
Combined Cycle and Combustion Turbine	34,331,961
Hydro	4,533,733
Solar	76,055
Net Power Transactions	14,777,975
Less: Energy for Pumping	(3,038,494)

10. 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 71% should be applied in this proceeding to approximate the fuel cost of such power purchases.

11. The adjusted test period system fuel expense for use in this proceeding is $1,783,381,223.

12. The reasonable and appropriate system base fuel factor, as approved in the Commission's Notice of Decision in Docket Nos. E-22, Subs 562 and 566 (Sub 562 Order), is 2.092¢/kWh (including the regulatory fee), and the reasonable and appropriate North Carolina retail class-specific base fuel factors, as also approved in the Sub 562 Order, including the regulatory fee, are as follows:

Customer Class	Class-Specific Base Fuel Factor
Residential	2.118 ¢/kWh
SGS & PA	2.115 ¢/kWh
LGS	2.098 ¢/kWh
Schedule NS	2.036 ¢/kWh
6VP	2.065 ¢/kWh
Outdoor Lighting	2.118 ¢/kWh
Traffic	2.118 ¢/kWh

13. DENC filed this fuel charge adjustment Application in conjunction with its general rate case filed on March 29, 2019, in Sub 562. All prospective components of fuel costs are included in the base fuel rates that take effect pursuant to the Sub 562 Order. Therefore, DENC will not have a Rider A in this proceeding.

14. The appropriate North Carolina retail test period jurisdictional fuel expense under-collection is ($550,353), and the adjusted North Carolina retail jurisdictional test period system sales are 4,308,591,154 kWh.

15. The appropriate experience modification factors (EMF or Rider B) for this proceeding (including the regulatory fee) are as follows:

Customer Class	EMF Billing Factor
Residential	0.014 ¢/kWh
SGS &PA	0.014 ¢/kWh
LGS	0.014 ¢/kWh
Schedule NS	0.013 ¢/kWh
6VP	0.013 ¢/kWh
Outdoor Lighting	0.014 ¢/kWh
Traffic	0.014 ¢/kWh

16. The class-specific base fuel components approved in the Sub 562 Order should be adjusted by EMF Rider B increments for each class as set forth in Finding of Fact No. 15. Therefore, the total fuel factors to be billed to the Company's retail customers during the February 1, 2020 through January 31, 2021 fuel charge billing period, including the regulatory fee, are as follows:

Customer Class	Class-Specific Total Factor
Residential	2.132 ¢/kWh
SGS &PA	2.129 ¢/kWh
LGS	2.112 ¢/kWh
Schedule NS	2.049 ¢/kWh
6VP	2.078 ¢/kWh
Outdoor Lighting	2.132 ¢/kWh
Traffic	2.132 ¢/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

North Carolina General Statute Section 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, 2019.

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 Company witnesses Hinson 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 Hinson stated that domestic natural gas production increased during the test period in conjunction with an increase in natural gas exports as well as an increase in domestic natural gas demand, particularly in the electric generation and industrial sectors. He stated that despite weather volatility in January and February 2019, natural gas prices averaged lower than the previous winter period. He went on to explain that for the first half of the test period, coal prices rose, but that there was a steady decline in coal prices for the second half of the test period. He stated that after a short period of decline, oil prices have had upward momentum for the test period.

Witness Hinson described the Company's 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. He also testified to the Company's price hedging program under which it price hedges commodities needed for power generation using a range of volume targets, gradually decreasing over a three-year period.

In regard to natural gas procurement, witness Hinson explained that the Company employs a disciplined natural gas procurement plan to ensure a reliable supply of natural gas at competitive prices. He stated that 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 Hinson 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 and trading points from the Marcellus shale region to the southeast region. He also noted that the Company actively participates in the interstate pipeline capacity release and physical supply markets as well as longer-term, pipeline expansion projects that will augment its transportation portfolio and enhance reliability at a reasonable cost. Witness Hinson testified that, since the Company's 2018 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 39.1% of the electricity produced for customers. Finally, he noted that in late 2018, the Company added the Greensville County Power Station (Greensville Station or Greensville) to its regulated fleet, in addition to retiring certain older, less efficient natural gas units in March 2019.

In regard to coal procurement, witness Hinson 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.

Witness Hinson also testified that the Company has a varied procurement strategy for its biomass stations depending on their geographical region. He stated that the Company's biomass stations at Hopewell and Southampton continue to be served by multiple suppliers under both short and 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 Power Station, and to procure biomass needs for the Virginia City Hybrid Energy Center via short and long-term contracts with various suppliers.

Finally, witness Hinson 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 seven to eight 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 have in part offset some of the downward trend in demand. Witness Brookmire indicated that the price for conversion services has experienced some upward price life due to production cuts in the U.S. He also noted that the cost for enrichment services has stabilized somewhat during the test period, and that despite prices in this market still being depressed, there appears to be more balance in the supply and demand of enrichment services. He explained that while the price trend in the U.S. domestic nuclear fuel fabrication industry continues to be difficult to measure due to the lack of a spot market, the general consensus is that costs will continue to increase due to regulatory requirements, reduced competition, and underserved demand in the U.S. and abroad, and financial distress recently experienced by parent companies for U.S. nuclear fuel fabricators. He also 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 significantly impacted the Company's projected near-term costs, as the Company's current mix of longer-term front-end component contracts has reduced its exposure to the market price 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 and fixed price 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.

Witness Brookmire also testified that the President announced he will take no action with regard to the Department of Commerce's recommendation on the Section 232 petition filed by two U.S. miners in January 2018, and that no quotas or tariffs will be imposed on foreign-supplied uranium as a result. However, he stated that the President, in his decision on the uranium Section 232 case, requested that a high level interagency Working Group be formed to investigate means to improve the commercial viability of the domestic nuclear fuel supply chain, and that the Working Group's final report is expected in October 2019. He testified that any action stemming from the Working Group's recommendations could have an impact on nuclear fuel prices, but that any such impact would be far less significant than those resulting from either tariffs or quotas.

No party offered testimony contesting the Company's fuel procurement practices. Based on the foregoing, the Commission concludes that the Company's fuel procurement 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 Company witnesses Campbell and Farmer.

Company witness Campbell's Schedule 3 shows that the Company's per books test period system sales were 87,363,222,000 kWh, and witness Farmer's Schedule 3 shows that the Company's per books test period system generation was 90,757,143 MWh. Witness Farmer's Schedule 3 showed that the per books test period system generation is categorized as follows:

Generation Types	MWh
Nuclear	28,083,596
Coal	9,259,384
Heavy Oil	0
Wood and Natural Gas Steam	1,032,011
Combined Cycle and Combustion Turbine	35,509,724
Solar and Hydro – Conventional and Pumped	4,609,788
Net Power Transactions	15,301,134
Less: Energy for Pumping	(3,038,494)

No other party offered 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 NO. 6

The evidence for this finding of fact is contained in the direct testimony of Company witness Farmer and the testimony of 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. 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 her direct testimony, Company witness Farmer testified to the performance of the Company's major generating units during the test period. Witness Farmer also testified that the Company's net capacity factors during the test period for its four nuclear units were:

North Anna Unit 1	101.1%
North Anna Unit 2	89.9%
Surry Unit 1	101.3%
Surry Unit 2	90.6%

Thus, the aggregate capacity factor for the Company's nuclear units during the test period was 95.7%, which exceeded the five-year industry weighted average capacity factor of 91.4% for the period 2013-2017 for 800-999 megawatt (MW) units, as reported by NERC in its latest Generating Availability Report. Witness Farmer testified in addition that, for the same five-year period (i.e., 2013-2017), the Company's net nuclear capacity factor was 94.7%, compared to the national average of 91.4%. Based on these figures, she stated that the Company's nuclear fleet performance during the test period was clearly better than the industry five-year average for comparable units.

Public Staff witness Metz testified 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 also discussed three outages occurring during the test year that the Public Staff investigated. These outages included an approximate 200-day outage at Scott Solar I, a Company-owned 17 MWAC photovoltaic solar facility, from a lightning

strike on September 2, 2018, and two separate approximately one-day outages at the North Anna Power Station. Witness Metz, however, testified that the Public Staff did not recommend a disallowance of replacement power costs due to these outages, as the Public Staff, based on its investigation of the outages, did not conclude that there had been imprudence or mismanagement on the Company's part. He went on to explain that although the Public Staff was not recommending any disallowances, there were three important reasons to bring these outages to the Commission's attention.

First, he testified that it is important to report to the Commission any concerns related to the operations or status of the Company's generation fleets, as well as any trends that merit attention. He stated that there is value in bringing these issues to the Company's attention to indicate areas of plant operation that are of interest to the Public Staff or the Commission, or would be of interest in future proceedings should these issues continue or recur. Second, he explained that the events that contributed to these outages were of particular concern to the Public Staff, but, again, that the Public Staff did not find that there was imprudence or mismanagement on the Company's part. He testified that to the extent the Company has not already done so, the Public Staff believes that the Company should implement and continue mitigation actions to prevent future occurrences of the nature identified in the Public Staff's investigations of these outages. Finally, witness Metz testified that, to the extent these issues continue or recur, in future fuel factor proceedings the Public Staff could conclude that there had been imprudence or mismanagement on the Company's part, which may justify the Public Staff recommending a disallowance of future power replacement costs.

Witness Metz next detailed the three outages, the first of which occurred at Scott Sola I, a Company-owned 17 MWAC photovoltaic facility, from a lightning strike on September 2, 2018. The facility was repaired, but during plant startup, a transformer fire occurred. Witness Metz explained that the transformer fire was caused by faulty electrical connections that had been repaired following the lightning event. The Company's evaluation revealed that the electrical assemblies were performed incorrectly or exhibited poor workmanship. Witness Metz testified, however, that the Company performed tests on the electrical connections after the initial repairs, but that the test did not reveal the embedded failure risks of the incorrectly installed electrical connections, and that post-installation visual inspections would not have been able to identify the issues listed in the report. Therefore, although the Public Staff did not conclude that there had been imprudence or mismanagement by the Company, witness Metz testified that it is crucial for DENC to ensure that quality workmanship is used on all generation assets, and that part of DENC's supervision and control should include having policies and procedures in place to provide direction, documentation, and oversight of contractual agents' work.

Regarding the nuclear-related outages at North Anna Power Station, witness Metz testified that although the outages occurred at different physical locations, they had some issues in common. However, witness Metz testified that in reviewing the Company's responses to Public Staff discovery, as well as the Company self-initiated action items well underway by the time of the Company's filing in this docket, the Company had

implemented a corrective action program to help mitigate and prevent future occurrences of this type.

The Commission appreciates the Public Staff's investigation of DENC's outages occurring during the test period. Based on the Public Staff's investigation of these outages as testified to by witness Metz, the Commission accepts the Public Staff's recommendation in regard to these outages that there be no finding of Company imprudence or mismanagement, and thus there be no disallowance of replacement power costs. To the extent the Company experiences outages of a similar nature in the future, the Commission will consider evidence pertaining to any such outages, as it would for any outage, in future proceedings to determine whether the Company has managed its baseload plants prudently and efficiently.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

Witness Farmer testified that for the 12-month rate period ending January 31, 2021, North Anna Unit 1 is projected to operate at a net capacity factor of 100.4%, North Anna Unit 2 is projected to operate at a net capacity factor of 92.4%, Surry Unit 1 is projected to operate at a net capacity factor of 100.2%, and Surry Unit 2 is projected to operate at a net capacity factor of 89.6%. Based on this projection, the Company normalized expected nuclear generation and fuel expenses in developing the proposed fuel cost rider. DENC's projected fuel costs are based on a 95.7% nuclear capacity factor, which is what DENC anticipates for the 12 months from February 1, 2020 through January 31, 2021, the period the new rates will be in effect. No party offered testimony contesting the projected normalized system nuclear capacity factor.

Based on the foregoing evidence, the Commission concludes that a projected normalized system nuclear capacity factor of 95.7% 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 the Company witness Beasley and the testimony of the Public Staff.

Witness Beasley testified that he was sponsoring the calculation of the adjustment to the Company's system sales for the 12 months ended June 30, 2019, due to changes in usage, weather normalization, and customer growth. Witness Beasley 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 558). Witness Beasley adjusted total system Company sales by 1,974,059,206 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 12 months ended June 30, 2019, are 85,389,162,794 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 Farmer.

Company witness Farmer presented an adjustment to per books MWh generation for the 12-month period ended June 30, 2019, 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 88,616,747 MWh, which includes various types of generation as follows:

Generation Types	MWh
Nuclear	28,061,493
Coal (including wood and natural gas steam)	9,950,079
Heavy Oil	0
Combined Cycle and Combustion Turbine	34,331,961
Hydro	4,533,733
Solar	76,055
Net Power Transactions	14,777,975
Less: Energy for Pumping	(3,038,494)

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 88,616,747 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 Sub 562 Order, the direct testimony of Company witness Farmer, and the affidavit of Public Staff witness Li.

In her direct testimony, Company witness Farmer testified that as filed in the 2019 base rate case in Docket No. E-22, Sub 562, the Company is using an updated marketer percentage of 71% to approximate the percentage of unreported power purchase costs related to fuel. Therefore, witness Farmer utilized the updated 71% marker percentage to calculate the Company's costs associated with purchases of power from the PJM Interconnection, L.L.C. market and dispatchable non-utility generators. Public Staff witness Li stated that the Public Staff does not object to the use of a marketer percentage of 71%, subject to the Commission's final order in the Company's 2019 rate case.

Consistent with the Sub 562 Order and based on the evidence in this proceeding, the Commission concludes that it is reasonable for the Company to apply a 71% marketer percentage to purchases from suppliers that do not provide DENC with actual fuel costs as a proxy for actual fuel costs associated with such purchases in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-13

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

Company witness Farmer presented the Company's system fuel expense for the test period and the normalized system fuel expenses for the upcoming rate period of $1,783,381,223. She testified that the fuel under-recovery experienced by the Company during the test year was primarily driven by moderate winter weather and the absence of major spikes or movements in commodity prices. She further testified that she used the expense normalization methodology that has been used by the Company and approved in previous North Carolina annual 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 January 2021. 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. She stated that this methodology for normalizing the test period generation resulted in adjusted annual system energy requirements of 88,616,747 MWh.

Witness Farmer also testified that the addition of DENC's 1,588 MW Greensville Station in December 2018, as well as the Colonial Trail West Solar Facility expected to be in service by December 2019, will benefit system fuel expense. She stated that the

system fuel expense in this case is adjusted to reflect the expected full-year fuel benefits related to the Greensville Station. She also stated that the Company placed 10 generating units into "cold reserve," and that these units were retired in March 2019 and are no longer in operation. In addition, she stated that the power purchase contracts for the 200 MW associated with the Roanoke Valley NUG expired in March 2019 and the 218 MW associated with another NUG contract was terminated in April 2019. She testified that the Company does not anticipate a significant impact to system fuel expense from these changes. Finally, she noted that due to the enactment of House Bill 589 and House Bill 374, the Company can now recover the total delivered costs, including capacity and non-capacity costs, associated with certain purchases of power from qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 that are not subject to economic dispatch or curtailment. She stated that reflecting those costs increases system fuel expense allocated to the North Carolina jurisdiction by approximately $44.7 million.

Company witness Beasley presented the Company's calculation of the base fuel component for the North Carolina jurisdiction and each customer class. He first determined the average system base fuel factor of 2.092 ¢/kWh, based on system fuel expenses of $1,783,381,223, and system sales of 85,389,162,794 kWh, that reflected adjustments for changes in usage, weather normalization, and customer growth. Witness Beasley also presented the calculations used to differentiate the jurisdictional base fuel component by voltage to determine the class fuel factors, and testified that these are consistent with the methodology used in the Company's previous fuel proceeding, Docket No. E-22, Sub 558. Witness Beasley also testified that in Sub 562, the Company would update the base fuel component for each class to be equal to the system fuel expense rate, adjusted for respective losses calculated in this case. He stated that therefore the fuel cost Rider A in this case would be set to $0.00000/kWh for all classes.

Public Staff witness Metz testified that the Public Staff recommended approval of the base fuel factors as shown in his Table 2. These factors are the same as those contained at Company Additional Supplemental Exhibit PBH-1, Schedule 3, which accompanied the additional supplemental testimony of Paul B. Haynes filed in Sub 562, and are as follows for each of the Company's North Carolina retail customer classes:

Customer Class	Class-specific Base Fuel Factor
Residential	2.118 ¢/kWh
SGS &PA	2.115 ¢/kWh
LGS	2.098 ¢/kWh
Schedule NS	2.036 ¢/kWh
6VP	2.065 ¢/kWh
Outdoor Lighting	2.118 ¢/kWh
Traffic	2.118 ¢/kWh

No other party offered or elicited testimony on the adjusted test period system fuel expense for use in this proceeding. In the Sub 562 Order, the Commission approved the

marketer percentage, the system base fuel factor, and the North Carolina retail class-specific base fuel factors. Based upon that approval and the evidence presented in this proceeding, 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 $1,783,381,223, the appropriate system average base fuel factor (including regulatory fee) is $ 0.02092 per kWh, and the appropriate class-specific base fuel factors (including regulatory fee) are as set forth in Table 2 of Public Staff witness Metz's testimony in this case.

The Commission further concludes that because the class-specific factors have been incorporated in the base rates approved in Sub 562, fuel cost Rider A should be set to $0.00000/kWh for all classes.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-15

The evidence for these findings of fact is contained in the Company's Application, the direct testimony of Company witnesses Campbell, Farmer, and Beasley, as well as the direct testimony of Public Staff witness Metz and the affidavit of Public Staff witness Li.

Company witness Farmer's direct testimony explained moderate winter weather and the absence of major spikes or movements in commodity prices during the test year resulted in a minor under-recovery of fuel costs. Company witness Campbell testified that the fuel costs allocated to North Carolina jurisdictional customers totaled $92,397,802, while the Company received fuel revenues total $91,847,449. The difference between the fuel costs and the fuel revenues resulted in an under-recovery of $550,353 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 4,308,591,154 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 class.

Public Staff witness Li's affidavit stated that the Public Staff had reviewed the calculations of the EMF provided by DENC, and based on that review recommended that DENC's EMF increment rider (Rider B) for each customer class be based on a net under-recovery of fuel and fuel-related costs of $550,353 and the Company's pro forma North Carolina retail sales of 4,308,591,154 kWh. This conclusion is consistent with the Company's Application. She stated that this produces an EMF increment rider (Rider B), of $0.00013 per kWh, including the regulatory fee, for all North Carolina retail customer classes.

Based on the evidence in this proceeding, the Commission concludes that the appropriate North Carolina retail test period jurisdictional fuel expense under-collection is $550,353 and that the adjusted North Carolina jurisdictional test period sales appropriate for computing the EMF (Rider B) are 4,308,591,154 kWh.

Company witnesses Farmer and Beasley, as well as Public Staff witnesses Metz and Li, testified regarding Rider A1 approved in the Sub 562 Order. Company witnesses

Farmer and Beasley explained that to reduce DENC's anticipated over-recovery for the second half of 2019, and to further mitigate the effect of the November 1, 2019 non-fuel base rate increase, the Company proposed to implement Rider A1, a three-month decrement rider, for each class to be effective November 1, 2019 through and including January 31, 2019. Company witness Beasley indicated that the Company was requesting that the Rider A1 rates be set to ($0.00375)/kWh for all classes be approved to allow for a seamless, no impact, transition of total fuel rates ($/kWh) between November 1, 2019, and February 1, 2020, based on the Company's proposed rates in this proceeding. The Commission approved Rider A1 in the Sub 562 Order.

The Commission concludes that the appropriate EMF Rider B increments for this proceeding, including interest and the regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	0.014 ¢/kWh
SGS &PA	0.014 ¢/kWh
LGS	0.014 ¢/kWh
Schedule NS	0.013 ¢/kWh
6VP	0.013 ¢/kWh
Outdoor Lighting	0.014 ¢/kWh
Traffic	0.014 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is cumulative and is contained in the direct testimony and exhibits of Company witnesses Farmer, Campbell, Brookmire, and Beasley, the testimony of Public Staff witness Metz and affidavit of Public Staff affiant Li.

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

Customer Class	Total Net Fuel Factor
Residential	2.132 ¢/kWh
SGS &PA	2.129 ¢/kWh
LGS	2.112 ¢/kWh
Schedule NS	2.049 ¢/kWh
6VP	2.078 ¢/kWh
Outdoor Lighting	2.132 ¢/kWh
Traffic	2.132 ¢/kWh

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after February 1, 2020, the Company shall implement a Fuel Cost Rider A of $0.00000/kWh for all classes as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 11 and 12 above;

2. That EMF Rider B increments as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 14-15 above, shall be instituted and remain in effect for usage from February 1, 2020, through January 31, 2021;

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 this Order; and

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 in Docket Nos. E-22, Subs 562, 577, and 578, and the Company shall file such proposed notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION

This the 23rd day of January, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell, Chief Clerk