NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

July 16, 2021

Ms. A. Shonta Dunston, Interim Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-7, Sub 1250 - Application Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities

Dear Ms. Dunston:

Attached for filing is the Public Staff's Proposed Order in the above-referenced docket. By copy of this letter, I am forwarding a copy to all parties of record by electronic delivery.

Sincerely,

Electronically submitted
s/ William E. H. Creech
Staff Attorney
zeke.creech@psncuc.nc.gov

WEHC/cla

Attachment

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1250

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	**PROPOSED ORDER OF THE PUBLIC STAFF**

HEARD: Tuesday, June 1, 2021 Evidentiary Hearing starting at 1:00 p.m. via WebEx

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

APPEARANCES:

For Duke Energy Carolinas, LLC:

Jack Jirak
Deputy General Counsel
Duke Energy Corporation
NCRH 20/P.O. Box 1551
Raleigh, North Carolina 27602-1551

Robert W. Kaylor
Law Office of Robert W. Kaylor, P.A.
353 Six Forks Road, Suite 260
Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc. (“CUCA”):

Marcus W. Trathen
Craig D. Schauer
Brooks, Pierce, McLendon,
Humphrey & Leonard, LLP
Suite 1700, Wells Fargo Capitol Center
150 Fayetteville Street
P.O. Box 1800 (zip 27602)
Raleigh, North Carolina 27601

For Carolinas Industrial Group for Fair Utility Rates III (“CIGFUR”):

Jeffrey P. Gray
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

For Sierra Club:

Gudrun Thompson
Tirrill Moore
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association (“NCSEA”):

Peter Ledford
Benjamin Smith
Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

For the Using and Consuming Public:

William E.H. Creech
John Little
Staff Attorneys
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On February 23, 2021, Duke Energy Carolinas, LLC (“Duke Energy Carolinas,” “DEC,” or the “Company”) filed an application pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Bryan L. Sykes, Kevin Y. Houston, John A. Verderame, Steve Immel, and Steven D. Capps.

Petitions to intervene were filed by CUCA on April 5, 2021; by NCSEA on April 8, 2021; by the Sierra Club on April 19, 2021; and CIGFUR III on April 22, 2021. The Commission granted CUCA's petition to intervene on April 8, 2021, NCSEA's petition to intervene on April 12, 2021, the Sierra Club's petition to intervene on April 20, 2021, and CIGFUR III's petition to intervene on April 23, 2021. The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On March 18, 2021, the Commission issued an *Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice* in which the Commission set this matter for hearing, established deadlines for the submission of intervention petitions, intervenor testimony, DEC rebuttal testimony, required the provision of appropriate public notice, and mandated compliance with certain discovery guidelines.

On May 25, 2021, and May 27, 2021, DEC filed affidavits of publication indicating that the initial public notice and second public notice had been provided in accordance with the Commission's procedural order.

On April 29, 2021, DEC filed the supplemental testimony and revised exhibits and work papers of Bryan L. Sykes. Witness Sykes presented revised rates reflecting the impacts related to updated numbers presented in his direct exhibits and workpapers regarding the inclusion of under-recovery amounts in the Experience Modification Factor ("EMF") period related to January – February 2021. These updated numbers resulted in an overall increase in the amount requested in the original application.

On May 10, 2021, the Public Staff filed the affidavit of June Chiu and the direct testimony of Dustin R. Metz. On May 17, 2021, the Sierra Club filed direct testimony and exhibits of Devi Glick. On June 1, 2021, the Sierra Club filed corrected direct testimony of witness Glick.

On May 27, 2021, DEC filed the rebuttal testimony of John A. Verderame. On May 24, 2021, DEC and the Public Staff filed a joint motion to excuse all Company and Public Staff witnesses. On May 28, 2021, the Commission issued an *Order Excusing Certain Witnesses and Accepting Testimony*. All parties filed notices consenting to remote hearings.

On May 27, 2021, DEC filed a motion to cancel public hearings. On May 28, 2021, the Commission issued an *Order Canceling Public Hearings*.

The case came on for hearing remotely by WebEx as scheduled on June 1, 2021. The prefiled direct and supplemental testimonies of DEC's witnesses, the prefiled affidavit and testimony of the Public Staff's witnesses, the prefiled testimony and exhibits of Sierra Club's witness, and the prefiled rebuttal testimony of DEC's witness were received into evidence. No other party presented witnesses or exhibits.

At the conclusion of all testimony, Chair Mitchell ruled that briefs and proposed orders should be filed 30 days after the mailing of the transcript. The transcript was posted on June 17, 2021. Since July 17, 2021 falls on a Saturday, the Public Staff filed its proposed order on July 15, 2021.

Based upon the Company's verified application, testimony, and exhibits received into evidence at the hearing, the testimony, affidavit, and exhibit of the Public Staff, and the testimony and exhibits of Sierra Club, the Commission makes the following findings:

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended December 31, 2020 ("test period").

3. In its supplemental testimony including exhibits in this proceeding, DEC requested a total decrease of $59 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEC include EMF riders and take into account fuel and fuel-related cost under-recoveries and over-

recoveries experienced during the test period, including the update period of January 2021 – February 2021. The overall under-recovery for the test period is $20.5 million. DEC also inadvertently overstated and adjusted the cost of power purchased from Duke Energy Progress, LLC's ("DEP") under the Joint Dispatch Agreement from September 2020 through December 2020, DEC agreed that the Public Staff should be permitted to review the results of its audit on this during in the Company's 2022 fuel adjustment proceeding.

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

5. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

6. The test period per book system sales are 82,983,046 megawatt-hours ("MWh"). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 88,446,852 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	14,738,937
Natural Gas, Oil and Biomass	16,291,653
Nuclear	44,314,601
Hydro – Conventional	3,016,593
Hydro Pumped Storage	(505,461)
Solar DG	148,719
Purchased Power – subject to economic dispatch or curtailment	7,311,075
Other Purchased Power	2,621,272
Interchange Power	509,463
Total Net Generation	**88,446,852**

7. The appropriate nuclear capacity factor for use in this proceeding is 93.21%.

8. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 58,002,609 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	23,329,575
General Service/Lighting	23,102,975
Industrial	11,570,060
Total	**58,002,609**

9. The projected billing period (September 2021-August 2022) sales for use in this proceeding are 87,689,996 MWh on a system basis and 57,967,737 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,803,077
General Service/Lighting	24,128,419
Industrial	12,036,241
Total	**57,967,737**

10. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 93,289,595 MWh and is categorized as follows:

Generation Type	MWh
Coal	18,691,906
Gas Combustion Turbine (CT) and Combined Cycle (CC)	21,189,718
Nuclear	43,773,885
Hydro	4,030,270
Net Pumped Storage Hydro	(2,872,983)
Solar Distributed Generation (DG)	367,302
Purchased Power	8,109,496
Total	**93,289,595**

11. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

a. The coal fuel price is $23.44/MWh.

b. The gas combustion turbine ("CT") and combined cycle ("CC") fuel price is $22.83/MWh.

c. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, "Reagents") is $25,707,869.

d. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.05/MWh.

e. The total system purchased power cost (including the impact of Joint Dispatch Agreement ("JDA") Savings Shared) is $256,651,255.

f. System fuel expense recovered through intersystem sales is $28,691,221.

12. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $951,489,668.

13. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $20.5 million, consisting of an over-recovery for the Residential class of $6.6 million and an under-recovery for the General Service/Lighting and Industrial classes of $11.0 million and $16.1 million, respectively.

14. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1228 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

15. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.5337 cents/kilowatt-hour ("kWh") for the Residential class; 1.6895 cents/kWh for the General Service/Lighting class; and 1.7243 cents/kWh for the Industrial class.

16. The appropriate EMF riders established in this proceeding, excluding the regulatory fee, are as follows: a decrement of (0.0282) cents/kWh for the Residential class, an increment of 0.0476 cents/kWh for the General Service/Lighting class; and an increment of 0.1391 cents/kWh for the Industrial class.

17. The appropriate EMF interest decrement rider established in this proceeding, excluding the regulatory fee, are as follows: a decrement of (0.0041) cents/kWh for the Residential class; 0.0000 cents/kWh for the General Service/Lighting class; and 0.0000 cents/kWh for the Industrial class.

18. The total net fuel and fuel-related costs factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.5014 cents/kWh for the Residential class; 1.7371 cents/kWh for the General Service/Lighting class; and 1.8634 cents/kWh for the Industrial class.

19. The base fuel and fuel-related costs as approved in Docket No. E-7, Sub 1214 of 1.6027 cents/kWh, 1.7583 cents/kWh, and 1.6652 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively will be adjusted by amounts equal to (0.0690) cents/kWh, (0.0688) cents/kWh, and 0.0591 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively. The resulting approved fuel and fuel-related costs will be further adjusted by EMF increments (decrements) of (0.0282) cents/kWh, 0.0476 cents/kWh, and 0.1391 cents/kWh and EMF interest (decrements) of (0.0041) cents/kWh, 0.0000 cents/kWh, and 0.0000 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

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 to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(c) prescribes the 12 months ending December 31 as the test period for DEC. The Company's filing in this proceeding was based on the 12 months ended December 31, 2020.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the supplemental testimony of Company witness Sykes, the direct testimony of Public Staff witness Metz, and the entire record in this proceeding. This finding is not contested by any party. The Public Staff shall review the cost of power purchased from DEP under the Joint Dispatch Agreement that was inadvertently overstated from September 2020 through March 2021 in the Company's 2022 fuel adjustment proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the direct testimony of Company witnesses Capps and Immel.

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 North American Electric Reliability Corporation ("NERC") Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and unusual events.

Company witness Capps testified that the Company's seven nuclear units operated at a system average capacity factor of 95.05% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 96.07%, exceeded the five-year industry weighted average capacity factor of 91.95% for the period 2015 - 2019 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Capps testified that, for the twenty-first consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, which included five refueling outages. Further, witness Capps testified that on a larger industry basis using early release data for 2020 from the Electric Utility Cost Group, all three of DEC's nuclear plants rank in the top quartile in total operating cost among the 56 U.S. operating nuclear plants.

Company witness Immel testified concerning the performance of DEC's fossil, hydro, and solar assets. He stated that the primary objective of the Company's fossil, hydro, and solar generation department is to provide safe, reliable and cost-effective electricity to DEC's customers. Witness Immel further stated that DEC complies with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability.

Company witness Immel testified that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor ("EAF"), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (i.e., forced outage time); (2) net capacity factor ("NCF"), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF is affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate ("EFOR"), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outages and derated hours, which equates to a higher reliability measure; and (4) starting reliability ("SR"), which represents the percentage of successful starts.

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Immel testified that in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. During the test period, most of these units had at least one small planned outage to inspect and maintain plant equipment.

In the Spring 2020, Cliffside Unit 5 performed a boiler outage. The primary purpose of the outage was to perform Mercury and Air Toxics Standards ("MATS") boiler repairs, absorber recycle pump upgrade, turbine bearing inspection and repairs, motor transformer replacement, and safety relief valves inspection and repairs. Cliffside Unit 6 also performed a boiler outage. The primary purpose of the outage was to perform MATS boiler repairs, turbine valve inspections and repairs, and recirculating pump replacement. Marshall Unit 3 performed an outage to change out the burners for the Dual Fuel Optionality ("DFO") conversion project. The outage was stopped for the COVID-19 pandemic. The work re-commenced with updated health and safety measures in place. Belews Creek Unit 1 performed an outage to repair the High-Pressure and Low-Pressure hydrogen coolers. Rockingham CT Unit 3 and Unit 4 performed an outage to install new exhaust stack silencers. Lincoln CT Unit 1 through Unit 8 had an outage to perform switchyard work to tie in Unit 17. Lincoln CT Unit 13 and Unit 14 had an outage to upgrade generator breaker relay for NERC compliance.

In the Fall 2020, Rockingham CT Unit 5 performed an outage to conduct a hot gas path inspection. Buck CC had an outage to perform steam turbine inspections, valve upgrades, gas turbine generator inspections, and high energy piping inspections. Marshall Unit 3 had an outage to install the remaining gas piping for the DFO project, install flame monitoring equipment, and install gas igniters. Marshall Unit 4 had an outage to install gas burners for the DFO project, control upgrades, and inspection of high energy piping. Allen Unit 1 had an outage to inspect and repair turbine oil coolers.

Based on a preponderance of the evidence in the record, the Commission concludes that the Company managed its baseload plants during the test period prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in December 2014, and were in effect throughout the 12 months ending December 31, 2020. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses Sykes, Verderame, Immel, and Houston and the testimony of Public Staff witness Metz.

Company witness Sykes testified that key factors in DEC's ability to maintain lower fuel and fuel-related rates for the benefit of customers include its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of DEC's and DEP experience in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined companies; and the joint dispatch of DEC's and DEP's generation resources.

Company witness Verderame described DEC's fossil fuel procurement practices, set forth in Verderame Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts, monitoring delivered coal volume and quality against contract commitments, conducting short-term and spot purchases to supplement term natural gas supply, and obtaining natural gas transportation for the generation fleet through a mix of long term firm transportation agreements and shorter-term pipeline capacity purchases.

According to witness Verderame, the Company's average delivered cost of coal per ton for the test period was $90.53 per ton, compared to $82.11 per ton in the prior test period, representing an increase of approximately 10%. This includes an average transportation cost of $35.07 per ton in the test period, compared to $28.33 per ton in the prior test period, representing an increase of approximately 24%. Witness Verderame further testified that the Company's average price of gas purchased for the test period was $2.94 per Million British Thermal Units ("MMBtu"), compared to $3.40 per MMBtu in the prior test period, representing a decrease of approximately 14%. The cost of gas is inclusive of gas supply, transportation, storage, and financial hedging.

Witness Verderame stated that DEC's coal burn for the test period was 5.9 million tons, compared to a coal burn of 8.1 million tons in the prior test period, representing a decrease of approximately 28%. The Company's natural gas burn for the test period was 135.4 MMBtu, compared to a gas burn of 123.9 MMBtu in the prior test period, representing an increase of approximately 9%. As a result of load reduction from the COVID-19 pandemic, low natural gas prices, and mild winter weather, the Company experienced a significant shift in generation from coal to natural gas.

Witness Verderame stated that coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening access to investor financing coupled with deteriorating credit quality is increasing the overall costs of financing for coal producers; and, (7) corrections in production levels in an attempt to bring coal supply in balance with demand.

He also testified that with respect to natural gas, the nation's natural gas supply has grown significantly over the last several years, and producers continue to enhance production techniques, enhance efficiencies, and lower production costs.

Witness Verderame stated that DEC's current coal burn projection for the billing period is 6.9 million tons, compared to 5.9 million tons consumed during the test period. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $63.95 per ton for the billing period compared to $90.53 per ton in the test period. This includes an average projected total transportation cost of $26.67 per ton for the billing period, compared to $35.07 per ton in the test period.

Witness Verderame testified that this cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEC is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

Witness Verderame further testified that DEC's current natural gas burn projection for the billing period is approximately 169.6 MMBtu, which is an increase from the 135.4 MMBtu consumed during the test period. The net increase in DEC's overall natural gas burn projections for the billing period versus the test period is primarily driven by coal to gas switching as a result of the change in coal rail transportation rates that are forecasted to go into effect April 1, 2021. While coal burns are projected to increase, they remain well below historic coal burns. Increased gas burns are also impacted by the inclusion of natural gas generation at Belews Creek Unit 2, and Marshall Units 3 and 4 as a result of the dual fuel conversions being commercially available over the course of the billing period, combined with lower forecasted natural gas prices in the back half of the billing period. The current average forward Henry Hub price for the billing period is $2.86 per MMBtu, compared to $2.08 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

According to witness Verderame, DEC continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost effective manner. Witness Verderame also testified that the Company has implemented natural gas procurement practices that include periodic Requests for Proposal and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply that includes contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption. According to witness Verderame, DEC continues to maintain a short-term financial natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach. Finally, witness Verderame testified that the Company procures long-term firm interstate and intrastate transportation to provide natural gas to its generating facilities.

N.C.G.S. § 62-133.2(a1)(3) permits DEC to recover the cost of “ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions.” Company witness Immel testified that the Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for nitrogen oxide (“NO_x)” and sulfur oxide (“SO_X”) emissions.

Company witness Immel further testified that overall, the type and quantity of chemicals used to reduce emissions at the Company’s plants vary depending on the generation output of the unit, the chemical constituents in the fuel burned, and the level of emissions reduction required. He stated that the Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. He also stated that the goal is to effectively comply with emissions regulations and provide the optimal total-cost solution for operation of the unit.

Company witness Houston testified as to DEC's nuclear fuel procurement practices, which include computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Houston explained that for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. He further stated that diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply.

N.C.G.S. §§ 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Verderame testified that DEP and DEC consider the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

Based upon the fuel procurement practices report and the evidence in the record, the Commission concludes that the Company's fuel procurement and power purchasing practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the direct and supplemental testimony and exhibits of Company witness Sykes.

According to the exhibits sponsored by Company witness Sykes, the test period per book system sales were 82,983,046 MWh, and test period per book system generation and purchased power amounted to 88,446,852 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Sykes Exhibit 6):

Net Generation Type	MWh
Coal	14,738,937
Natural Gas, Oil and Biomass	16,291,653
Nuclear	44,314,601
Hydro – Conventional	3,016,593
Hydro Pumped Storage	(505,461)
Solar DG	148,719
Purchased Power – subject to economic dispatch or curtailment	7,311,075
Other Purchased Power	2,621,272
Interchange Power	509,463
Total Net Generation	**88,446,852**

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness Sykes' exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 82,983,046 MWh and system generation and purchased power of 88,446,852 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the direct testimony and exhibits of Company witness Capps.

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's facilities and unusual events. The Company proposed using a 93.21% capacity factor in this proceeding based on the operational history of the Company's nuclear units and the number of planned outage days scheduled during the billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 91.95% for the period 2015-2019 as reported in the NERC Brochure during the period of 2015 to 2019.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, and the fact that the Public Staff did not dispute the Company's proposed capacity factor, the Commission concludes that the 93.21% nuclear capacity factor, and its associated generation of 59,945,886 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 - 10

The evidence supporting these findings of fact is contained in the supplemental testimony and exhibits of Company witness Sykes.

On Sykes Revised Exhibit 4, Company witness Sykes set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 58,002,609 MWh, comprised of Residential class sales of 23,329,575 MWh, General Service/Lighting class sales of 23,102,975 MWh, and Industrial class sales of 11,570,060 MWh.

Witness Sykes used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Sykes Revised Exhibit 2, Schedule 1, is 87,689,996 MWh. The projected level of generation and purchased power used was 93,289,595 MWh (calculated using the 93.21% capacity factor found reasonable and appropriate above), as set forth on Sykes Revised Exhibit 2, Schedule 3, and was broken down by witness Sykes as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	18,691,906
Gas Combustion Turbine (CT) and Combined Cycle (CC)	21,189,718
Nuclear	43,773,885
Hydro	4,030,270
Net Pumped Storage Hydro	(2,872,983)
Solar Distributed Generation (DG)	367,302
Purchased Power	8,109,496
Total	**93,289,595**

As part of Sykes Workpaper 7, Company witness Sykes also presented an estimate of the projected billing period North Carolina retail Residential, General Service/Lighting, and Industrial MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,803,077
General Service/Lighting	24,128,419
Industrial	12,036,241
Total	**57,967,737**

These class totals were used in Revised Sykes Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits (normalized for customer growth and weather), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the direct and supplemental testimony and exhibits of Company witness Sykes, and the testimony of Public Staff witness Metz.

Company witness Sykes recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $23.44/MWh.

B. The gas CT and CC fuel price is $22.83/MWh.

C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, "Reagents") is $25,707,869.

D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.05/MWh.

E. The total system purchased power cost (including the impact of Joint Dispatch Agreement ("JDA") Savings Shared) is $256,651,255.

F. System fuel expense recovered through intersystem sales is $28,691,221.

These amounts are set forth on or derived from Sykes Exhibit 2, Schedule 1. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his testimony, Public Staff witness Metz stated that, based upon his review, it appears that the projected fuel and fuel-related costs set forth in DEC's testimony, and the prospective components of the total fuel factor, have been calculated appropriately.

No other party presented evidence on the level of DEC's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness Sykes and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding within the requirement of N.C.G.S. §62.133.2.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Sykes and the testimony of Public Staff witness Metz.

Consistent with N.C.G.S. § 62-133.2(a2), witness Sykes testified that the annual increase in the aggregate amount of purchased power costs under the relevant sections of N.C.G.S. §62-133.2(a1) does not exceed 2.5% of DEC's total North Carolina jurisdictional gross revenues for 2020.

According to Revised Sykes Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $951,489,668. Public Staff witness Metz did not take issue with his calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $951,489,668 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 13-18

The evidence supporting these findings of fact is contained in the direct and supplemental testimony and exhibits of Company witness Sykes, the affidavit of Public Staff witness Chiu, and the testimony of Public Staff witness Metz.

Company witness Sykes presented DEC's original fuel and fuel-related expense over-collection and prospective fuel and fuel-related cost factors. Company witness Sykes' supplemental testimony and revised exhibits set forth the projected fuel and fuel-related costs, the subsequent amount of under-collection for purposes of the EMF, the method for allocating the decrease in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with exhibits and workpapers reflecting the following adjustments: (1) inclusion of the under-collection balances for the update period January – February 2021, (2) corrected costs of purchased power from Duke Energy Progress, LLC, under the Joint Dispatch Agreement, and (3) a revision to the weather adjustment related to test period kWh sales for the wholesale jurisdiction.

Public Staff witness Chiu testified that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost over-recovery of $(6,587,808) for the Residential customer class and under-recoveries of $10,990,202 and $16,092,490 for the General Service/Lighting and Industrial classes, respectively. Witness Chiu recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost over- and under-recovery amounts and on the Company's proposed normalized North Carolina retail sales of 23,329,575 MWh for the Residential class, 23,102,975 MWh for the General Service/Lighting class, and 11,570,060 MWh for the Industrial class, as proposed by the Company. She stated that these amounts produce EMF increment/(decrement) riders for each North Carolina retail customer class as follows, including EMF interest but excluding the regulatory fee:

Residential	(0.0282) cents per kWh
General Service/Lighting	0.0476 cents per kWh
Industrial	0.1391 cents per kWh

Public Staff witness Chiu also recommended an EMF interest decrement rider for each North Carolina retail customer class as follows, excluding the regulatory fee, resulting from the over-recovered fuel amounts from each class:

Residential	(0.0041) cents per kWh
General Service/Lighting	0.0000 cents per kWh
Industrial	0.0000 cents per kWh

Company witness Sykes calculated the Company's proposed fuel and fuel-related cost factors for which there is no specific guidance in N.C.G.S. § 62-133.2(a2) using a uniform bill adjustment method. He stated that DEC proposes to use the same uniform percentage average bill adjustment methodology to adjust its fuel rates to reflect a proposed decrease in fuel and fuel-related costs as it did in its 2020 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1228. No party opposed the use of this allocation method. Public Staff witness Metz recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Company witness Sykes' supplemental testimony and revised exhibits.

Based upon the testimony and exhibits in the record, the Commission concludes that DEC's projected fuel and fuel-related cost of $951,489,668 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The

Commission also concludes that (1) DEC's EMFs proposed in this proceeding, excluding the regulatory fee and (2) DEC's prospective fuel and fuel-related cost factors proposed in this proceeding for each of DEC's rate classes are appropriate. Additionally, the Commission concludes that DEC's decrease in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1228, other than those costs allocated pursuant to N.C.G.S. § 62-133.2(a2), should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEC's past fuel cases.

The following tables summarize the impact of the rates approved in this case and the rates approved in Docket No. E-7, Sub 1228 (excluding regulatory fee).

E-7 Sub 1250			
	Residential	General Service Lighting	Industrial
Description	**cents/kWh**	**cents/kWh**	**cents/kWh**
Base Fuel	1.6027	1.7583	1.6652
Prospective Component	(0.0690)	(0.0688)	0.0591
EMF Component	(0.0282)	0.0476	0.1391
EMF Interest Component	(0.0041)	-	-
Total Fuel Factor	1.5014	1.7371	1.8634

E-7 Sub 1228			
	Residential	General Service Lighting	Industrial
Description	**cents/kWh**	**cents/kWh**	**cents/kWh**
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	(0.1801)	(0.1580)	(0.3555)
EMF Component	0.0364	0.0666	0.2658
EMF Interest Component	-	-	-
Total Fuel Factor	1.6391	1.8249	1.9310

Summary of Differences Sub 1250 — 1228 (excluding regulatory fee):

Change in Fuel Rates			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	(0.1801)	(0.1580)	(0.3555)
Prospective Component	0.1111	0.0892	0.4146
EMF Component	(0.0646)	(0.0190)	(0.1267)
EMF Interest Component	(0.0041)	-	-
Total Fuel Factor	(0.1377)	(0.0878)	(0.0676)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding of fact is contained in the direct and supplemental testimony of Company witness Sykes, the affidavit of Public Staff witness Chiu and testimony of Public Staff witness Metz and is discussed in more detail in Evidence and Conclusions for Finding of Fact Nos. 5 and 13 through 18.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculations, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 1.5014 cents/kWh for the Residential class, 1.7371 cents/ kWh for the General Service/Lighting class, and 1.8634 cents/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.5337 cents/kWh, 1.6895 cents/kWh, and 1.7243 cents/kWh, EMF increments/(decrements), including interest, of (0.0323) cents/kWh, 0.0476 cents/kWh, and 0.1391 cents/kWh, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after September 1, 2021, DEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 1.6027 cents/kWh, 1.7583 cents/kWh, and 1.6652 cents/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively as approved in Docket No. E-7, Sub 1214, by amounts equal to (0.0690) cents/kWh, (0.0688) cents/kWh, and 0.0591 cents/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively; that DEC shall adjust the resulting approved fuel and fuel-related costs by EMF increments (decrements) of (0.0282) cents/kWh for the Residential class, 0.0476 cents/kWh for the General Service/Lighting class, and 0.1391 cents/kWh for the Industrial class (excluding the regulatory fee); and that DEC shall adjust the resulting approved fuel and fuel-related costs by EMF interest increments (decrements) of (0.0041) cents/kWh for the Residential class, 0.0000 cents/kWh for the General Service/Lighting class, and 0.0000 cents/kWh for the Industrial class (excluding the regulatory fee). The EMF and EMF interest increments (decrements) are to remain in effect for service rendered through August 31, 2022.

2. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments as soon as practicable.

3. That DEC shall work with the Public Staff to prepare a notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket Nos. E-7, Sub 1246, and E-7, Sub 1247, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in all three dockets.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of _______, 2021.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston, Interim Chief Clerk