Ladawn S. Toon
Associate General Counsel

NCRH 20 / P.O. Box 1551
Raleigh, NC 27602

o: 919.546.7971

Ladawn.Toon@duke-energy.com

July 24, 2023

VIA ELECTRONIC FILING

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

RE: Joint Proposed Order of Duke Energy Carolinas, LLC and the Public Staff
Docket No. E-7, Sub 1282

Dear Ms. Dunston:

Please find enclosed for filing in the above-referenced docket the Joint Proposed Order of Duke Energy Carolinas, LLC and the Public Staff of the North Carolina Utilities Commission. Of note, certain test period outages, which occurred at the Company's Belews Creek Steam Station Unit 2 and W.S. Lee Combined Cycle Plant ("Outages"), remain in dispute. As such, the Company and Public Staff will make separate filings as to those Outages. For avoidance of doubt, there is no disagreement between the Company and the Public Staff regarding the rates that should go into effect on September 1, 2023. The resolution of the Outages at issue would not impact the upcoming billing period (September 1, 2023 – August 31, 2024). The impact, if any, would appear in the next billing period (September 1, 2024 - August 31, 2025). An electronic copy of the Proposed Order is being emailed to briefs@ncuc.net.

Please contact me if you have any questions.

Sincerely,

Ladawn S. Toon

Enclosure
cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1282

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	))))	JOINT PARTIAL PROPOSED ORDER OF DUKE ENERGY CAROLINAS, LLC AND THE PUBLIC STAFF APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, May 30, 2023, at 4:40 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Karen M. Kemerait, Presiding; and Chair Charlotte A. Mitchell, and Commissioners ToNola D. Brown-Bland, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

APPEARANCES:

For Duke Energy Carolinas, LLC:

Ladawn Toon, Associate General Counsel, Duke Energy Corporation, NCRH 20 / Post Office 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 Carolinas Industrial Group for Fair Utility Rates III (CIGFUR):

Christina Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

Douglas Conant, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

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

Marcus W. Trathen, Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, 150 Fayetteville Street, 1700 Wells Fargo Capitol Center, Raleigh, North Carolina 27601

For Southern Alliance for Clean Energy (SACE):

Thomas Gooding, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

Munashe Magarira, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

William S. F. Freeman, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

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

BY THE COMMISSION: On February 28, 2023, Duke Energy Carolinas, LLC (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 Sigourney Clark, Jeffrey Flanagan, John Swez, David Johnson, Kevin Y. Houston, and Steven D. Capps.

On March 1, 2023, DEC filed a corrected Application to replace the previously filed version.

On March 16, 2023, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

Petitions to intervene were filed by Carolina Utility Customers Association, Inc. ("CUCA") on March 27, 2023, Carolina Industrial Group for Fair Utility Rates III ("CIGFUR III") on April 10, 2023, and the Southern Alliance for Clean Energy ("SACE") on April 20, 2023. The Commission granted CUCA's petition to intervene on March 28, 2023, CIGFUR III's petition to intervene on April 12, 2023, and SACE's petition to intervene on April 24, 2023. The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On May 4, 2023, DEC filed the supplemental testimony and revised exhibits of Sigourney Clark.

On May 5, 2023, DEC filed the supplemental testimony of John Swez.

On May 9, 2023, the Public Staff filed the joint testimony of Witnesses Darrell Brown, Public Utility Regulatory Analyst, Accounting Division, and Fenge Zhang, Public Utility Regulatory Manager, Accounting Division, and the confidential testimony and exhibits of Evan D. Lawrence, Engineer with the Energy Division.

Also, on May 9th, 2023, CIGFUR III filed the direct testimony and exhibits of Brian C. Collins.

On May 18,2023, DEC filed the rebuttal testimony of Jeffrey Flanagan, and the rebuttal testimony of John Swez as well as the joint rebuttal testimony of Witness Clark and Chris Bauer.

On May 19, 2023, DEC filed the corrected exhibits and work papers for the rebuttal testimony of Witness Clark.

On May 23, 2023, CIGFUR III filed a motion to excuse Witness Brian C. Collins from attending the expert witness hearing.

On May 24, 2023, DEC filed a motion to excuse David Johnson, Kevin Houston, and Steven D. Capps from appearing at the expert witness hearing.

On May 25, 2023, DEC filed affidavits of publication indicating that the public notice had been provided in accordance with the Commission's procedural order.

On May 26, 2023, the Commission issued an Order excusing witnesses and accepting testimony. In that Order, the Commission excused CIGFUR III Witness Collins and DEC Witnesses Johnson, Houston, and Capps from attending the expert witness hearing, and also the testimony and exhibits of these witnesses into evidence, and to be made part of the record in this proceeding.

On May 26, 2023, DEC filed the revised rebuttal testimony of John Swez and the revised rebuttal testimony of Jeffrey Flanagan.

On May 26, 2023, DEC filed the joint revised rebuttal testimony and second revised exhibits of Witness Clark and Chris Bauer.

Also, on May 26, 2023, the Public Staff filed a motion to compel, which was subsequently addressed and withdrawn without action from the Commission.

On May 31, 2023, DEC and the Public Staff entered into and filed an Agreement and Stipulation of Partial Settlement (Stipulation) resolving all issues between DEC and the Public Staff, except for three outages at the Company's Belews Creek Plant and the W. S. Lee Steam Station (and the timing of filing of the results of the Public Staff's investigation into the outages).

The case came before the Commission for hearing as scheduled on May 30, 2023. The prefiled direct and supplemental testimonies and exhibits of DEC's witnesses, the prefiled testimony and exhibits of the Public Staff's witnesses, the prefiled testimony and exhibits of CIGFUR III's witness, and the prefiled rebuttal testimony and revised rebuttal testimony and exhibits of DEC's witnesses were received into evidence. No other party presented witnesses or exhibits.

At the conclusion of testimony, Presiding Commissioner Kemerait ruled that briefs and proposed orders should be filed 30 days after notice of the mailing of the transcript.

The transcript was posted on June 16, 2023, and June 20, 2023.

On June 20, 2023, the Commission issued a Notice of Due Date of Proposed Orders and/or Briefs, setting the deadline as July 21, 2023.

On June 30, 2023, the Public Staff filed proposed Supplemental Testimony and exhibits of Evan D. Lawrence.

On July 6, 2023, DEC filed its Motion to Strike the Public Staff's Filing of Supplemental Testimony and Request for Relief in the Alternative (Motion to Strike) in opposition to the Public Staff's filing of proposed Supplemental Testimony and exhibits of witness Lawrence.

On July 11, 2023, the Public Staff filed its response to DEC's Motion to Strike as well as the Public Staff's motion to reopen the record to accept witness Lawrence's Supplemental Testimony and exhibits.

On July 14, 2023, the Commission issued its Order Ruling on Supplemental Testimony Proffered Post-Hearing to deny the Public Staff's motion to enter the Lawrence Supplemental Testimony and exhibits into the record and to grant DEC's Motion to Strike; however, the Commission permitted the parties to brief whether the three outages could be considered in DEC's 2024 fuel filing.

On July 20, 2023, the Public Staff, without objection from the other parties to the proceeding, requested a one business day extension to Monday, July 24, for the parties to file proposed orders and/or briefs.

On July 21, 2023, the Commission issued its Order granting the one business day extension.

On July 24, 2023, DEC and the Public Staff filed a joint partial proposed order, and filed separate briefs regarding the Commission's future consideration of the three outages in the 2024 fuel adjustment proceeding.

Based upon the Company's verified application, testimony, and exhibits received into evidence at the hearing, the testimony and exhibits of the Public Staff, and the testimony and exhibits of CIGFUR III, the Commission makes the following:

FINDINGS OF FACT

1. The Company 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. DEC 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, 2022 (test period).

3. In the Stipulation, including exhibits in this proceeding, DEC requested a total increase of $692 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 Experience Modification Factor (EMF) riders and take into account fuel and fuel-related cost under-recoveries and over-recoveries experienced during the test period. The overall under-recovery for the test period was $998 million.

4. The Public Staff and the Company were unable to reach an agreement with respect to the management of the Company's fossil plants during the test period.

Nevertheless, the rates set forth herein are agreed upon since the outages dispute will be resolved by the Commission.

5. The test period per book system sales are 88,284,042 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 94,862,494 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	8,102,494
Natural Gas, Oil and Biomass	28,503,894
Nuclear	44,225,032
Hydro – Conventional	1,696,649
Hydro Pumped Storage	(697,976)
Solar DG	320,481
Purchased Power – subject to economic dispatch or curtailment	11,383,508
Other Purchased Power	1,247,654
Interchange Power	80,759
Total Net Generation	94,862,494

6. The appropriate nuclear capacity factor for use in this proceeding is 93.60%.

7. The North Carolina retail test period sales, adjusted for customer growth and weather, are 59,559,458 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	22,892,401
General Service/Lighting	24,448,017
Industrial	12,219,040
Total	59,559,458

Under the proposed Stipulation, the Company agreed to recover its test period under-recovered fuel and fuel-related costs of $998 million over a 16-month period. In order to derive the Experience Modification Factor (EMF) rates by customer class, the Company proposed to use its projected sales during the 16-month recovery period of September 1, 2023, through December 31, 2024. Therefore, adjusted test period sales are not being used to derive the EMF rates. The Company's projected sales for North Carolina retail customer classes over the 16-month recovery period are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	30,273,969
General Service/Lighting	32,956,985
Industrial	16,210,185
Total	79,441,138

8. The projected billing period (September 2023-August 2024) sales for use in this proceeding to derive the prospective fuel and fuel-related costs (i.e., non-EMF rates) are 89,870,966 MWh on a system basis and 60,333,264 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	23,311,388
General Service/Lighting	24,873,076
Industrial	12,148,800
Total	60,333,264

9. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 95,978,101 MWh and is categorized as follows:

Generation Type	MWh
Coal	10,197,068
Gas Combustion Turbine (CT) and Combined Cycle (CC)	28,995,128
Nuclear	43,983,040
Hydro	5,280,351
Net Pumped Storage Hydro	(3,799,951)
Solar Distributed Generation (DG)	359,301
Purchased Power	10,963,165
Total	95,978,101

10. 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 $39.79/MWh.

b. The gas combustion turbine (CT) and combined cycle (CC) fuel price is $34.98/MWh.

c. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $25,288,082.

d. The total nuclear fuel price (including Catawba Joint Owners generation) is $5.61/MWh.

e. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $448,387,237.

f. System fuel expense recovered through intersystem sales is $39,473,663.

11. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,412,831,331.

12. The Company and the Public Staff entered into a "Stipulation Regarding the Proper Methodology for Determining the Fuel Costs Associated with Power Purchases from Power Marketers and Others" on January 5, 2023 (Fuel Proxy Agreement), Fuel Cost Proxy Percentage Calculation was increased in order to reflect a reasonable approximation of the fuel cost portion of power purchases based on current fuel commodity prices and a changing resource mix. Per the Fuel Proxy Agreement between the Company and the Public Staff, the Company will propose a composite total fuel costs to total energy ratio based upon combined short-term off-system sales for the calendar year. Such composite shall be no greater than 85%, but no less than 75% and, that to the extent that the analysis of annual composite short-term off-system sales revenue falls

outside the range of 75% to 85%, the composite proxy percentage will be adjusted accordingly to reflect either the minimum or maximum of the range.

13. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF is $998.4 million, consisting of an under-recovery for the Residential, General Service/Lighting, and Industrial classes of $380.8 million, $406.8 million, and $210.8 million, respectively.

14. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1263, 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: 2.6287 cents/kilowatt-hour (kWh) for the Residential class; 2.2596 cents/kWh for the General Service/Lighting class; and 1.9328 cents/kWh for the Industrial class. The prospective fuel and fuel-related cost factors will be billed for the 12-month period beginning September 1, 2023, and ending August 31, 2024.

16. In accordance with the Stipulation, the appropriate EMF increments established in this proceeding, excluding the regulatory fee, are as follows: 1.2579 cents/kWh for the Residential class, 1.2342 cents/kWh for the General Service/Lighting class; and 1.3007 cents/kWh for the Industrial class. The EMF increments will be billed for the 16-month period beginning September 1, 2023, and ending December 31, 2024.

17. In accordance with the Stipulation, the appropriate EMF interest increments established in this proceeding, excluding the regulatory fee, are as follows: 0.0084

cents/kWh for the Residential class, 0.0082 cents/kWh for the General Service/Lighting class; and 0.0087 cents/kWh for the Industrial class. The EMF interest increments will be billed for the 16-month period beginning September 1, 2023, and ending December 31, 2024.

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: 3.8950 cents/kWh for the Residential class; 3.5020 cents/kWh for the General Service/Lighting class; and 3.2422 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 1.0260 cents/kWh, 0.5013 cents/kWh, and 0.2676 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 of 1.2579 cents/kWh, 1.2342 cents/kWh, and 1.3007 cents/kWh, and EMF interest increments of 0.0084 cents/kWh, 0.0082 cents/kWh, and 0.0087 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. Gen. Stat. § 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, 2022.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Settlement Exhibits and Workpapers, which serves as the basis for the Stipulation and the entire record in this proceeding. This finding is not contested by any party. Public Staff witness Lawrence recommended the Company re-calculate projected fuel costs based on a more recent forecast and the Company has done so in the Stipulation between the Public Staff and the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The Company and the Public Staff were unable to reach agreement regarding this finding insofar as certain outages, which occurred at the Company's Belews Creek Steam Station Unit 2 and W.S. Lee Combined Cycle Plant. As such, the Company and the Public Staff will each address these outages under separate cover. The Public Staff maintains that such outages should be subject to further review in subsequent fuel clause proceedings (notwithstanding anything to the contrary) and the Company disagrees.

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, 2022. 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 Clark, Swez, Flanagan, and Houston and the testimony of Public Staff witness Lawrence.

Company witness Clark 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; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors cited by witness Clark include the combination of DEC's and DEP's 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 Swez described DEC's fossil fuel procurement practices, set forth in Swez 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 Swez, the Company's average delivered cost of coal for the test period was $99.86 per ton, compared to $78.22 per ton in the prior test period, an increase of approximately 28%. This includes an average transportation cost of $33.65 per ton in the test period, compared to $31.68 per ton in the prior test period, an increase of approximately 6%. Witness Swez further testified that the Company's average price of gas purchased for the test period was $6.94 per Million British Thermal Units (MMBtu), compared to $4.22 per MMBtu in the prior test period, an increase of approximately 65%. Witness Swez indicated that the cost of gas is inclusive of gas supply, transportation, storage, and financial hedging.

Witness Swez stated that DEC's coal burn for the test period was 3.2 million tons, compared to a coal burn of 5.3 million tons in the prior test period, a decrease of approximately 40%. The Company's natural gas burn for the test period was 253.5 million MBtu, compared to a gas burn of 189.6 million MBtu in the prior test period, an increase of approximately 34%. Company witness Swez stated that changes in coal and natural gas burns were primarily driven by the relationship of coal commodity prices during 2022 relative to natural gas prices in the same period, as record high coal commodity prices off-set higher natural gas costs, reducing gas to coal generation switching especially at the Company's dual fuel operating ("DFO") stations.

Witness Swez stated that coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) the inability of coal suppliers to respond to increasing demand over 2021 and 2022, following the prior years of steep declines in coal generation demand; (2) natural gas price volatility; (3) continued uncertainty regarding proposed and imposed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) increased demand in global markets for both steam and metallurgical coal; (5) tightened access to investor financing; (6)

continued shifts in production from thermal to metallurgical coal as producers move away from supplying declining electric generation to take advantage of increasing demand from industry; and, (7) continued labor and resource constraints further limiting suppliers' operational flexibility. In addition, Company witness Swez stated that the coal supply chain experienced significant challenges throughout 2021 and 2022 as historically low utility stockpiles combined with rapidly increasing demand for coal, both domestically and internationally, made procuring additional coal supply increasingly challenging. Witness Swez indicated that producers were unable to respond to this rapid rise in demand due to capacity constraints resulting from labor and resource shortages, factors that combined to drive both domestic and export coal prices in late 2021 to record levels. Witness Swez also indicated that continued labor and resource constraints, including the on-going threat of a rail strike in Q4 2022, caused prices to remain elevated over the course of 2022.

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

Witness Swez stated that DEC's current coal burn projection for the billing period is 3.7 million tons, compared to 3.2 million tons consumed during the test period. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $105.86 per ton for the billing period compared to $99.86 per ton in the test period. This includes an average projected total transportation cost of $30.48 per ton for the billing period, compared to $33.65 per ton in the test period.

Witness Swez 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 Central Appalachian coal DEC is able to purchase and deliver and the non-Central Appalachian coal DEC is able to consume; (3) changes in transportation rates; (4) performance of contract deliveries by suppliers and railroads which may not occur; 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 Swez further testified that DEC's current natural gas burn projection for the billing period is approximately 260.9 MMBtu, which is an increase from the 253.5 MMBtu consumed during the test period. Witness Swez stated that projected natural gas burn volumes will also vary on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

Witness Swez indicated that the net increase in DEC's overall burn projections for the billing period versus the test period is primarily driven by increases in projected load over the period.

According to witness Swez, 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 Swez 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 Swez, 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. Witness Swez stated that DEC monitors and makes adjustments as necessary to its natural gas hedging program to ensure it remains appropriate based on market conditions and the Company's fuel procurement strategy. Finally, witness Swez testified that the Company procures long-term firm interstate and intrastate transportation to provide natural gas to its generating facilities.

Pursuant to N.C.G.S. § 62-133.2(a1)(3), DEC may recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Flanagan testified that the Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for nitrogen oxide (NOx) and sulfur dioxide (SO2) emissions.

Company witness Flanagan further testified that overall, the type and quantity of chemicals used to reduce emissions at the Company's plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, or 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 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.

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 Settlement Exhibits and Workpapers filed in conjunction with the Company's proposed Order and the entire record in this proceeding.

According to the Settlement Exhibits and Workpapers sponsored by Company witness Clark, the test period per book system sales were 88,284,042 MWh, and test period per book system generation and purchased power amounted to 94,862,494 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Clark Exhibit 6):

Net Generation Type	MWh
Coal	8,102,494
Natural Gas, Oil and Biomass	28,503,894
Nuclear	44,225,032

Hydro – Conventional	1,696,649
Hydro Pumped Storage	(697,976)
Solar DG	320,481
Purchased Power – subject to economic dispatch or curtailment	11,383,508
Other Purchased Power	1,247,654
Interchange Power	80,759
Total Net Generation	94,862,494

No party took issue with the portions of witness Clark's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented, the Commission concludes that the per books levels of test period system sales of 88,284,042 MWh and system generation and purchased power of 94,862,494 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. In the partial settlement between the Company and Public Staff, the Company proposed nuclear capacity factor of 93.60%, 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 91.87% for the period 2017-2021 as reported in the NERC Brochure during the period of 2017 to 2021.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, the Commission concludes that the 93.60% nuclear capacity factor and its associated generation of 58,871,920 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 Settlement Exhibits and Workpapers of Company witness Clark.

On Clark Settlement Exhibit 4, Company witness Clark set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 59,559,458 MWh, comprised of Residential class sales of 22,892,401 MWh, General Service/Lighting class sales of 24,448,017 MWh, and Industrial class sales of 12,219,040 MWh.

Witness Clark 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 Clark Settlement Exhibit 2, Schedule 1, is 89,870,966 MWh. The projected level of generation and purchased power used is 95,978,101 MWh (calculated using the 93.60% capacity factor found reasonable and appropriate above), as set forth on Clark Settlement Exhibit 2, Schedule 1, and was broken down by witness Clark as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	10,197,068
Gas Combustion Turbine (CT) and Combined Cycle (CC)	28,995,128
Nuclear	43,983,040

Hydro	5,280,351
Net Pumped Storage Hydro	(3,799,951)
Solar Distributed Generation (DG)	359,301
Purchased Power	10,963,165
Total	95,978,101

As part of Clark Settlement Workpaper 7, Company witness Clark 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	23,311,388
General Service/Lighting	24,873,076
Industrial	12,148,800
Total	60,333,264

These class totals were used in Clark Supplemental 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 rebuttal testimony and exhibits of Company witness Clark, and the testimony of Public Staff witness Lawrence.

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

A. The coal fuel price is $39.79/MWh.

B. The gas CT and CC fuel price is $34.98/MWh.

C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $25,288,082.

D. The total nuclear fuel price (including Catawba Joint Owners generation) is $5.61/MWh.

E. The total system purchased power cost (including the impact of JDA Savings Shared) is $448,387,237.

F. System fuel expense recovered through intersystem sales is $39,473,663.

These amounts are set forth on or derived from Clark Settlement 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 direct testimony, Public Staff witness Lawrence recommended the Company re-calculate projected fuel costs due to fuel commodity cost changes since the Company filed its application, which the Company did and filed in its rebuttal testimony and exhibits. 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 Clark 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 settlement testimony and exhibits of Company witness Clark and the testimony of Public Staff witness Lawrence.

Consistent with N.C.G.S. § 62-133.2(a2), witness Clark 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 2022.

According to Clark Settlement Exhibit 2, Schedule 1, Page 3, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,412,831,331. Public Staff witness Lawrence did not take issue with this 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 testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related costs for the North Carolina retail jurisdiction of $1,412,831,331 are reasonable

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

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

Company Witness Swez stated that the most recent proxy percentage was established during the 2008 fuel proceeding and that since the 2008 proceeding, the proxy has not been updated. Witness Swez further testified that due to increasing fuel commodity prices and a changing resource mix, the Company and the Public Staff agreed that the fuel proxy established in the 2008 fuel proceeding no longer represents a reasonable approximation of the fuel cost portion of power purchases. Witness Swez testified that the Company and the Public Staff consider it reasonable to continue to use the accepted methodology of using the fuel component of the Companies' off-system sales as a reasonable basis for approximating fuel costs associated with power purchases when actual fuel costs are unavailable or unidentified as a component of the price paid for energy under a power purchase agreement.

Witness Swez testified that, per the Fuel Agreement between the Company and the Public Staff (a copy of said agreement is found as Exhibit 4 to witness Swez's testimony), starting with the Company's 2023 annual fuel rider proceeding, an annual compilation of actual total fuel and fuel-related costs as a component of total short-term off-system sales revenue is an appropriate basis for estimating fuel costs on power purchases when the actual fuel component is unavailable or unidentified as a component of the price paid for energy under a power purchase contract. Witness Swez states that for the Company's annual fuel rider proceedings filed during 2023-2027, the Company will propose a composite total fuel cost to total energy cost ratio, based on DEC's and Duke Energy Progress, LLC's ("DEP") combined short-term off-system sales for the calendar year. Witness Swez states that such composite shall be no greater than 85%, but no less than 75% and that to the extent that the analysis of annual composite short-term off-system sales revenue falls outside the range of 75% to 85%, the composite proxy percentage will be adjusted accordingly to reflect either the minimum or maximum of the range.

The executed Stipulation between the Company and the Public Staff is provided as Swez Exhibit 4.

No other party presented evidence regarding the methodology for determining fuel costs associated with power purchases from power marketers.

Based upon the evidence in the record as to the appropriate methodology, the Commission concludes that the methodology recommended by Company witness Swez and accepted by the Public Staff in the executed Stipulation for purposes of determining the fuel cost portion of power purchases is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-19

The evidence supporting these findings of fact is contained in the Stipulation and in the exhibits of Company witness Clark.

Company witness Clark presented DEC's original fuel and fuel-related expense under-collection and prospective fuel and fuel-related cost factors. The Stipulation between the Company and Public Staff 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 increase 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) Clemson CHP (Combined Heat & Power) billing update and (2) inclusion of the Spring 2023 forecast.

Public Staff and the Company agree in the Stipulation that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost under-recoveries of $380,810,058 for the Residential customer class, $406,768,116 for the General Service/Lighting customer class, and $210,851,011 for the Industrial customer class. The partial settlement proposed that DEC's EMF rider for each customer class be based on these net fuel and fuel-related cost under-recovery amounts and on the Company's proposed projected North Carolina retail sales (over the 16-month recover period) of 30,273,969 MWh for the Residential class, 32,956,985 MWh for the General Service/Lighting class, and 16,210,185 MWh for the Industrial class. The partial settlement also stated that these amounts produce an EMF increment rider for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	1.2579 cents per kWh
General Service/Lighting	1.2342 cents per kWh
Industrial	1.3007 cents per kWh

The partial settlement also proposed an EMF interest increment rider for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	0.0084 cents per kWh
General Service/Lighting	0.0082 cents per kWh
Industrial	0.0087 cents per kWh

Company witness Clark 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. She stated that DEC proposes to use the same uniform percentage average bill adjustment methodology to adjust its fuel rates to reflect a proposed increase in fuel and fuel-related costs as it did in its 2022 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1263. No party opposed the use of this allocation method. In the partial settlement agreement, the Company and Public Staff agree that the billing to all customer classes will utilize the uniform percentage average bill adjustment methodology.

Based upon the testimony and exhibits in the record, the Commission 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; provided, however, that disagreement exists as to the three outages. Additionally, the Commission concludes that DEC's increase in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1263, 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 1263 (excluding regulatory fee).

E-7 Sub 1282

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	1.6027	1.7583	1.6652
Prospective Component	1.0260	0.5013	0.2676
EMF Component	1.2579	1.2342	1.3007
EMF Interest Component	0.0084	0.0082	0.0087
Total Fuel Factor	3.8950	3.5020	3.2422

E-7 Sub 1263			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	1.6027	1.7583	1.6652
Prospective Component	0.3976	0.0634	0.1744
EMF Component	0.4863	0.6254	0.5726
EMF Interest Component	-	-	-
Total Fuel Factor	2.4866	2.4471	2.4122

Summary of Differences Sub 1282 — 1263(excluding regulatory fee):

Change in Fuel Rates			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	-	-	-
Prospective Component	0.6284	0.4379	0.0932
EMF Component	0.7716	0.6088	0.7281
EMF Interest Component	0.0084	0.0082	0.0087
Total Fuel Factor	1.4084	1.0549	0.8300

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding of fact is contained in the partial settlement agreement between Public Staff and the Company is discussed in more detail in Evidence and Conclusions for Findings of Fact Nos. 7 and 15-20.

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 and EMF interest increments, 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 3.8950 cents/kWh for the Residential class, 3.5020 cents/ kWh for the General Service/Lighting class, and 3.2422 cents/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel- related cost factors of 2.6287 cents/kWh, 2.2596 cents/kWh, and 1.9328 cents/kWh, EMF increments of 1.2579 cents/kWh, 1.2342 cents/kWh, and 1.3007 cents/kWh, and EMF interest increments of 0.0084 cents/kWh, 0.0082 cents/kWh, and 0.0087 cents/kWh, respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered during the 12-month period September 1, 2023 to August 31, 2024, 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 to1.0260 cents/kWh, 0.5013 cents/kWh, and 0.2676 cents/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively;

2. That, effective for service rendered during the 16-month period September 1, 2023 to December 31, 2024, DEC shall adjust the resulting approved fuel and fuel-related costs by EMF increments of 1.2579 cents/kWh for the Residential class, 1.2342 cents/kWh for the General Service/Lighting class, and 1.3007 cents/kWh for the Industrial class, and EMF interest increments of 0.0084 cents/kWh for the Residential class, 0.0082 cents/kWh for the General Service/Lighting class, and 0.0087 cents/kWh for the Industrial class (excluding the regulatory fee);

3. That the Fuel Proxy Agreement between the Company and the Public Staff be accepted and that the change in the fuel cost proxy percentage calculation be applied starting with the 2023 fuel proceeding;

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

5. 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 1281, and E-7, Sub 1283, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten days after the Commission issues orders in all three dockets.

ISSUED BY ORDER OF THE COMMISSION.

This the _____ day of August, 2023.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston, Chief Clerk

CERTIFICATE OF SERVICE

I certify that a copy of the Joint Proposed Order of Duke Energy Carolinas, LLC and the Public Staff, in Docket No. E-7, Sub 1282, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 24th day of July, 2023.

Ladawn S. Toon

Ladawn S. Toon
Associate General Counsel
Duke Energy Corporation
P.O. Box 1551/NCRH 20
Raleigh, North Carolina 27602
Tel: 919.546.7971
ladawn.toon@duke-energy.com