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July 25, 2022

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 1263

Dear Ms. Dunston:

Enclosed for filing with the Commission is the Joint Proposed Order of Duke Energy Carolinas, LLC, and the Public Staff in the referenced matter. An electronic copy 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 1263

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

HEARD: Tuesday, June 7, 2022, at 10:50 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

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 Carolina Utility Customers Association, Inc. (CUCA):

Craig D. Schauer, Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, 150 Fayetteville Street, 1700 Wells Fargo Capitol Center, Raleigh, North Carolina 27601

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

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

For Sierra Club:

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

For North Carolina Sustainable Energy Association (NCSEA):

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

Taylor Jones, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

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 March 1, 2022, 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 Bryan L. Sykes, Kevin Y. Houston, John A. Verderame, Bryan Walsh, and Steven D. Capps.

On March 14, 2022, 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, and DEC rebuttal testimony, required the provision of appropriate public notice, and mandated compliance with certain discovery guidelines.

Petitions to intervene were filed by CUCA on March 7, 2022, NCSEA on March 10, 2022, CIGFUR III on March 15, 2022, and the Sierra Club on April 20,

2022. The Commission granted CUCA's petition to intervene on March 8, 2022, NCSEA's petition to intervene on March 11, 2022, CIGFUR III's petition to intervene on March 16, 2022, and the Sierra Club's petition to intervene on April 22, 2022. 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 9, 2022, DEC filed the supplemental testimony and revised exhibits and work papers of Bryan L. Sykes, direct testimony of David B. Johnson, and proposed second public notice. Among other matters, 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 2022. This update resulted in an overall increase in the amount requested in the original application.

On May 17, 2022, the Public Staff filed the affidavit of June Chiu and the joint testimony and exhibits of Evan D. Lawrence and Dustin R. Metz. On May 17, 2022, the Sierra Club filed direct testimony and exhibits of Gregory M. Lander.

On June 3, 2022, June 6, 2022, and June 22, 2022, 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 May 26, 2022, DEC filed the rebuttal testimony of John A. Verderame. On June 3, 2022, DEC and the Public Staff filed a joint motion to excuse all Company and Public Staff witnesses. On June 6, 2022, the Commission issued an Order Granting in Part and Denying in Part Motion to Excuse Witnesses.

The case came before the Commission for hearing as scheduled on June 7, 2022. 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 testimony, Chair Mitchell ruled that briefs and proposed orders should be filed 30 days after notice of the mailing of the transcript.

On June 9, 2022, DEC submitted Late Filed Exhibits 1 and 2. A consumer statement of position was filed June 20, 2022.

On June 30, 2022, the Commission issued an Order Increasing Regulatory Fee, in NCUC Docket No. M-100, Sub 142, for noncompetitive jurisdictional revenues to be set at 0.14% effective July 1, 2022, for all utilities regulated by the Commission. This change in regulatory fee had no impact on the amounts presented in the Company's Application. The Company intends to reflect the updated regulatory fee in its compliance filing.

The transcript was posted on June 24, 2022. On July 25, 2022, DEC and the Public Staff filed a joint proposed order.

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

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, 2021 (test period).

3. In its supplemental testimony, including exhibits in this proceeding, DEC requested a total increase of $457 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 2022. The overall under-recovery for the test period is $327 million.

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 86,551,610 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 92,430,168 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	13,569,695
Natural Gas, Oil and Biomass	22,252,424
Nuclear	45,445,584
Hydro – Conventional	1,950,233
Hydro Pumped Storage	(610,077)
Solar DG	293,289
Purchased Power – subject to economic dispatch or curtailment	8,915,991
Other Purchased Power	722,775
Interchange Power	(109,745)
Total Net Generation	92,430,168

7. The appropriate nuclear capacity factor for use in this proceeding is 93.94%.

8. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 58,418,933 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	22,926,377
General Service/Lighting	23,198,571
Industrial	12,293,985
Total	58,418,933

9. The projected billing period (September 2022-August 2023) sales for use in this proceeding are 87,956,972 MWh on a system basis and 58,234,434 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	22,809,193
General Service/Lighting	23,222,537
Industrial	12,202,704
Total	58,234,434

10. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 93,814,326 MWh and is categorized as follows:

Generation Type	MWh
Coal	9,117,091
Gas Combustion Turbine (CT) and Combined Cycle (CC)	29,086,094
Nuclear	44,237,320
Hydro	4,980,701
Net Pumped Storage Hydro	(3,411,289)
Solar Distributed Generation (DG)	364,048
Purchased Power	9,440,360
Total	93,814,326

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 $32.12/MWh.

b. The gas combustion turbine (CT) and combined cycle (CC) fuel price is $31.11/MWh.

c. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $9,519,806.

d. The total nuclear fuel price (including Catawba Joint Owners generation) is $5.77/MWh.

e. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $281,833,833.

f. System fuel expense recovered through intersystem sales is $66,325,343.

12. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,107,043,925.

13. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $327 million, consisting of an under-recovery for the Residential, General Service/Lighting, and Industrial classes of $111.5 million, $145.1 million, and $70.4 million, respectively.

14. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1250, 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: 2.0003 cents/kilowatt-hour (kWh) for the Residential class; 1.8217 cents/kWh for the General Service/Lighting class; and 1.8396 cents/kWh for the Industrial class.

16. The appropriate EMF increments established in this proceeding, excluding the regulatory fee, are as follows: 0.4863 cents/kWh for the Residential class; 0.6254 cents/kWh for the General Service/Lighting class; and 0.5726 cents/kWh for the Industrial class.

17. 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: 2.4866 cents/kWh for the Residential class; 2.4471 cents/kWh for the General Service/Lighting class; and 2.4122 cents/kWh for the Industrial class.

18. 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 0.3976 cents/kWh, 0.0634 cents/kWh, and 0.1744 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 0.4863 cents/kWh, 0.6254 cents/kWh, and 0.5726 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

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 is set out in N.C.G.S. § 62-133.2(c). 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, 2021.

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 witnesses

Lawrence and Metz, and the entire record in this proceeding. This finding is not contested by any party. Public Staff witnesses Lawrence and Metz testified that the Clemson CHP facility is currently not close to achieving the designed availability factors. In their testimony, witnesses Lawrence and Metz also discussed the contract between DEC and Clemson University whereby steam from the Clemson CHP is processed and sold by DEC to Clemson University. Witnesses Lawrence and Metz discussed a billing error where DEC had incorrectly billed Clemson University for the purchase of the steam from the Clemson CHP. As this billing error occurred for 6 months in this test period, and 6 months within the next test period, the Company and Public Staff have agreed to discuss the Clemson CHP and make any necessary adjustments, including an adjustment to the current test year steam sale revenue, in next year's (2023) annual fuel 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 Walsh.

> 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 96.12% during

the test period. This capacity factor, as well as the Company's two-year average capacity factor of 95.58%, exceeded the five-year industry weighted average capacity factor of 92.07% for the period 2016 - 2020 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 22nd consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, which included four refueling outages. Further, witness Capps testified that on a larger industry basis using early release data for 2021 from the Electric Utility Cost Group, all three of DEC's nuclear plants rank in the top quartile in total operating cost among the 55 U.S. operating nuclear plants.

Company witness Walsh 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 Walsh 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 Walsh 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; (4) starting reliability (SR), which represents the percentage of successful starts; and (5) equivalent forced outage factor (EFOF) which quantifies the number of period hours in a year during which the unit is unavailable because of forced deratings.

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Walsh 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 planned outage to inspect and maintain plant equipment.

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, 2021. 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, Walsh, and Houston and the testimony of Public Staff witnesses Lawrence and 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; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors cited by witness Sykes 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 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 for the test period was $78.22 per ton, compared to $90.53 per ton in the prior test period, a decrease of approximately 14%. This includes an average transportation cost of $31.68 per ton in the test period, compared to $35.07 per ton in the prior test period, a decrease of approximately 10%. Witness Verderame further testified that the Company's average price of gas purchased for the test period was $4.22 per Million British Thermal Units (MMBtu), compared to $2.94 per MMBtu in the prior test period, an increase of approximately 44%. Witness Verderame indicated that 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 5.3 million tons, compared to a coal burn of 5.9 million tons in the prior test period, a decrease of approximately 9%. The Company's natural gas burn for the test period was 189.6 million MBtu, compared to a gas burn of 135.4 million MBtu in the prior test period, an increase of approximately 40%. Changes in coal and natural gas burns were impacted by increased demand from the economic rebound experienced following the COVID-19 shutdowns in 2020.

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 following the past several years of steep declines in coal generation demand, which has impacted the ability of producers to respond to changes in demand during 2021; (2) natural gas price volatility; (3) renewed uncertainty regarding regulations for power plants; (4) increased 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 that is increasing the overall costs of financing for coal producers; (7) 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, (8) increasing labor and resource constraints due to structural changes in the coal industry further limiting suppliers' operational flexibility. In addition, the coal supply chain experienced increasing challenges throughout 2021 as historically low utility stockpiles combined with rapidly increasing demand for coal, both domestically and internationally, made procuring additional coal supply increasingly challenging. Witness Verderame 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 2021 to record levels.

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 Verderame stated that DEC's current coal burn projection for the billing period is 3.3 million tons, compared to 5.3 million tons consumed during the test period. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $91.89 per ton for the billing period compared to $78.22 per ton in the test period. This includes an average projected total transportation cost of $29.63 per ton for the billing period, compared to $31.68 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 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 Verderame further testified that DEC's current natural gas burn projection for the billing period is approximately 242.0 MMBtu, which is an increase from the 189.6 MMBtu consumed during the test period. Witness Verderame indicated that 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 coal prices increasing more than gas as well as forecasts for less expensive gas supply to come into the portfolio early in the billing period. The Company now expects projected natural gas burn volumes to be reduced during the billing period based on delays in anticipated lower cost gas supply coming into the portfolio which became known after the billing period forecast was complete. 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.

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.

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 Walsh 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 dioxide (SO2) emissions.

Company witness Walsh 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.

Sierra Club witness Lander testified regarding the Company's reliance on fossil fuels exposing ratepayers to significant price volatility, especially for gas which is driven by domestic as well as international supply and demand considerations. He also discussed the factors that, in his view, are contributing to the significant, recent gas price increases and further testified that ratepayers can expect these price increases to persist for the foreseeable future.

Witness Lander then went on to discuss how utilities can mitigate their customers' exposure to fossil fuel price volatility. Witness Lander discussed various hedging strategies including financial instruments, collar strategies where a utility purchases the option to buy a quantity of fuel over a specific time period, and physical hedging. He testified that financial hedging strategies have limits but agreed that the volumes the Company chose to hedge appear to have delivered savings to the Company's customers. Witness Lander discussed physical hedging through the use of wind and solar resources to immunize the Company and its customers from gas price increases and recommended the Commission encourage the Company to obtain as much renewable hedging value as possible as part of a comprehensive hedging strategy.

Witness Lander testified that the Company's fuel cost planning and forecasting practices are missing an additional forecast that measures and projects the impact on consumer bills of future fuel price spikes if such spikes were to occur in the billing period. He testified that the purpose of this forecast would be to provide the Commission with a preview of the potential impact of such projected fuel price spikes and help inform the Company's strategy to reduce or mitigate its customers' exposures to future, projected price increases.

In rebuttal testimony, Company witness Verderame testified that the purpose of this fuel proceeding is to obtain Commission approval of the Company's proposed fuel rates and that the content and structure of the Company's application in this proceeding conforms with N.C.G.S. § 62-133.2(c) and (d) and Commission Rule R8-55, including the specific information required to be included in a fuel rider application. Witness Verderame testified regarding the Commission's conclusions in regard to previous additional reporting recommendations in the 2020 DEC and DEP fuel proceedings and stated that in those proceedings the Commission observed that the scope and level of detail contained in the Company's application, testimony, exhibits and workpapers conforms with applicable law. Witness Verderame recommended that the Commission reject the recommendation of the Sierra Club witness in this proceeding. Witness Verderame further testified that no party has recommended an adjustment to the fuel rates proposed by the Company.

Witness Verderame agreed with witness Lander that natural gas prices are volatile and subject to domestic and international supply and demand factors, putting upward pressure on gas prices in the near term. He further agreed that hedging does help reduce volatility and that hedging benefited customer during the test period and the billing period. Witness Verderame testified the Company hedged nearly 50% of its actual natural gas volumes resulting in total savings of approximately $114 million.

Witness Verderame then addressed witness Lander's recommendation that the Company use wind and solar energy to the fullest extent possible to hedge against fossil fuel price volatility. Witness Verderame testified that there is no basis under applicable law to suggest that the Company's fuel proceeding is the appropriate forum to evaluate inclusion of utility scale wind and solar generation in the Company generating mix and therefore suggested this recommendation be disregarded.

Witness Verderame testified to the Company's phased hedging approach where financial hedges are executed over time for a percentage of the Company's forecasted natural gas burns. He testified that this strategy includes utilizing fixed price financial instruments including fixed price swaps and cost-less collar options to hedge price exposure on a rolling 60-month period. Witness Verderame testified that the Company's multi-year approach to executing fixed price transactions for a portion of projected natural gas burns provides a reasonable and prudent approach to mitigate price volatility in uncertain fuel markets. Witness Verderame also testified that the Company continuously evaluates its hedging program to ensure it remains appropriate based on market conditions. The most recent changes extended the hedging program from 36 months to 60 months in late 2020 and in 2021 to further increase the hedging target ranges by an additional five percent for the periods of 25 to 60 months in order to decrease gas price exposure and smooth the transition from one hedging period to another. Witness Verderame then testified to the use of optional physical natural gas supply and daily optimization of its physical gas supply as examples of the Company's physical hedging of natural gas supply.

Witness Verderame discussed the Company's review of its forecasting process to evaluate the risk of significant under-recovery of fuel costs from changing natural gas prices. He testified that the Company's results were laid out in the Commission's Order in Docket No. E-7, Sub 1228, where the Commission deemed the Company's fuel and reagent procurement and power purchasing practices during the test period to be reasonable and prudent. Finally, witness Verderame testified that incorporating historical high market price events or other speculative forecasting assumptions into the Company's current forecasting processes to potentially mitigate large under-recoveries is speculative and could arbitrarily increase forecasted costs billed to customers with the unwanted consequence of more consistent over-recoveries in the long-term.

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 revised exhibits sponsored by Company witness Sykes, the test period per book system sales were 86,551,610 MWh, and test period per book system generation and purchased power amounted to 92,430,168 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Sykes Revised Exhibit 6):

Net Generation Type	MWh
Coal	13,569,695
Natural Gas, Oil and Biomass	22,252,424
Nuclear	45,445,584
Hydro – Conventional	1,950,233
Hydro Pumped Storage	(610,077)
Solar DG	293,289
Purchased Power – subject to economic dispatch or curtailment	8,915,991
Other Purchased Power	722,775
Interchange Power	(109,745)
Total Net Generation	92,430,168

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' revised 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 86,551,610 MWh and system generation and purchased power of 92,430,168 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 93.94% 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 92.07% for the period 2016-2020 as reported in the NERC Brochure during the period of 2016 to 2020.

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 93.94% nuclear capacity factor and its associated generation of 60,454,296 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 58,418,933 MWh, comprised of Residential class sales of 22,926,377 MWh, General Service/Lighting class sales of 23,198,571 MWh, and Industrial class sales of 12,293,985 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 87,956,972 MWh. The projected level of generation and purchased power used is 93,814,326 MWh (calculated using the 93.94% capacity factor found reasonable and appropriate above), as set forth on Sykes Revised Exhibit 2, Schedule 1, and was broken down by witness Sykes as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	9,117,091
Gas Combustion Turbine (CT) and Combined Cycle (CC)	29,086,094
Nuclear	44,237,320
Hydro	4,980,701
Net Pumped Storage Hydro	(3,411,289)
Solar Distributed Generation (DG)	364,048
Purchased Power	9,440,360
Total	93,814,326

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	22,809,193
General Service/Lighting	23,222,537
Industrial	12,202,704
Total	58,234,434

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 witnesses Lawrence and 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 \$32.12/MWh.

B. The gas CT and CC fuel price is \$31.11/MWh.

C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is \$9,519,806.

D. The total nuclear fuel price (including Catawba Joint Owners generation) is \$5.77/MWh.

E. The total system purchased power cost (including the impact of JDA Savings Shared) is \$281,833,833.

F. System fuel expense recovered through intersystem sales is \$66,325,343.

These amounts are set forth on or derived from Sykes Revised 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 their joint testimony, Public Staff witnesses Lawrence and Metz stated that, based upon their 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, are reasonable and 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 direct and supplemental testimony and exhibits of Company witness Sykes and the joint testimony of Public Staff witnesses Lawrence and 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 2021.

According to Sykes Revised 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 $1,107,043,925. Public Staff witnesses Lawrence and 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 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 $1,107,043,925 are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-17

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 joint testimony of Public Staff witnesses Lawrence and Metz.

Company witness Sykes presented DEC's original fuel and fuel-related expense under-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 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) inclusion of the under-collection balance for the update period January 2022, (2) inclusion of the final 2021 cost of service study's production plant allocation factors, (3) inclusion of the final 2021 coincidental peak data and (4) a revision to the retail customer growth adjustment and wholesale weather adjustment related to test period kWh sales.

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 under-recoveries of $111,487,845 for the Residential customer class, $145,085,337 for the General Service/Lighting customer class, and $70,401,036 for the Industrial customer class. Witness Chiu recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost under-recovery amounts and on the Company's proposed normalized North Carolina retail sales of 22,926,377 MWh for the Residential class, 23,198,571 MWh for the General Service/Lighting class, and 12,293,985 MWh for the Industrial class, as proposed by the Company. She stated that these amounts produce EMF increment riders for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	0.4863 cents per kWh
General Service/Lighting	0.6254 cents per kWh
Industrial	0.5726 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 increase in fuel and fuel-related costs as it did in its 2021 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1250. No party opposed the use of this allocation method. Public Staff witnesses Lawrence and 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 (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 increase in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1250, 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 1250 (excluding regulatory fee).

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

E-7 Sub 1250			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial 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

Summary of Differences Sub 1263 — 1250 (excluding regulatory fee):

Change in Fuel Rates			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	-	-	-
Prospective Component	0.4666	0.1322	0.1153
EMF Component	0.5145	0.5778	0.4335
EMF Interest Component	0.0041	-	-
Total Fuel Factor	0.9852	0.7100	0.5488

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

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 the joint testimony of Public Staff witnesses Lawrence and Metz and is discussed in more detail in Evidence and Conclusions for Finding of Fact Nos. 6 and 13 - 17.

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 2.4866 cents/kWh for the Residential class, 2.4471 cents/ kWh for the General Service/Lighting class, and 2.4122 cents/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel- related cost factors of 2.0003 cents/kWh, 1.8217 cents/kWh, and 1.8396 cents/kWh, EMF increments of 0.4863 cents/kWh, 0.6254 cents/kWh, and 0.5726 cents/kWh, respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after September 1, 2022, 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 0.3976 cents/kWh, 0.0634 cents/kWh, and 0.1744 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 of 0.4863 cents/kWh for the Residential class, 0.6254 cents/kWh for the General Service/Lighting class, and 0.5726 cents/kWh for the Industrial class (excluding the

regulatory fee). The EMF increments are to remain in effect for service rendered through August 31, 2023;

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; and

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 1262, and E-7, Sub 1264, 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, 2022.

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 1263, 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 25th day of July, 2022.

Ladawn S. Toon
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