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March 1, 2022

VIA ELECTRONIC FILING

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

**RE: Duke Energy Carolinas, LLC's Fuel Charge Adjustment Proceeding
Docket No. E-7, Sub 1263**

Dear Ms. Dunston:

Enclosed for filing with the North Carolina Utilities Commission ("NCUC" or the "Commission") is the Application of Duke Energy Carolinas, LLC ("DEC") pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 relating to the fuel charge adjustments for electric utilities, together with the testimony and exhibits of Bryan L. Sykes, Kevin Y. Houston, John A. Verderame, Bryan Walsh and Steven D. Capps containing the information required in NCUC Rule R8-55.

Certain information contained in the exhibits of Mr. Capps and Mr. Verderame is a trade secret, and confidential, proprietary, and commercially sensitive information. For this reason, it is being filed under seal pursuant to N.C. Gen. Stat. § 132-1.2. Parties to the docket may contact the Company regarding obtaining copies pursuant to an appropriate confidentiality agreement.

Please contact me if you have any questions.

Sincerely,

Ladawn S. Toon

Enclosure
cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's Fuel Charge Adjustment Proceeding, 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 1st day of March, 2022.

Ladawn S. Toon
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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	)))))	**DUKE ENERGY CAROLINAS, LLC'S APPLICATION**

Duke Energy Carolinas, LLC ("DEC," "Company," or "Applicant"), pursuant to North Carolina General Statutes ("N.C. Gen. Stat.") § 62-133.2 and North Carolina Utilities Commission ("NCUC" or the "Commission") Rule R8-55, hereby makes this Application to adjust the fuel and fuel-related cost component of its electric rates. In support thereof, the Applicant respectfully shows the Commission the following:

1. The Applicant's general offices are located at 526 South Church Street, Charlotte, North Carolina, and its mailing address is:

Duke Energy Carolinas, LLC
P. O. Box 1321
Charlotte, North Carolina 28201

2. The names and addresses of Applicant's attorneys are:

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Copies of all pleadings, testimony, orders and correspondence in this proceeding should be served upon the attorneys listed above.

3. NCUC Rule R8-55 provides that the Commission shall schedule annual hearings pursuant to N.C. Gen. Stat. § 62-133.2 in order to review changes in the cost of fuel and fuel-related costs since the last general rate case for each utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service. Rule R8-55 schedules an annual cost of fuel and fuel-related costs adjustment hearing for DEC and requires that DEC use a calendar year test period (12 months ended December 31). Therefore, the test period used in this Application for these proceedings is the calendar year 2021.

4. In Docket No. E-7, Sub 1250, DEC's last fuel case, the Commission approved the following base fuel and fuel-related costs factors (excluding gross receipts tax and regulatory fee):

Residential - 1.5014 ¢ per kWh
Commercial - 1.7371 ¢ per kWh
Industrial - 1.8634 ¢ per kWh

5. In this Application, DEC proposes base fuel and fuel-related costs factors (excluding gross receipts tax and regulatory fee) of:

Residential - 1.9315¢ per kWh
Commercial - 1.8573¢ per kWh

Industrial - 1.9011¢ per kWh

The base fuel and fuel-related cost factors should be adjusted for the Experience Modification Factor ("EMF") by an increment/(decrement) (excluding gross receipts tax and regulatory fee) of:

Residential - 0.3785¢ per kWh
Commercial - 0.4625¢ per kWh
Industrial - 0.4128¢ per kWh

The base fuel and fuel-related costs factors should also be adjusted for the EMF interest (decrement) (excluding gross receipts tax and regulatory fee) of:

Residential - 0¢ per kWh
Commercial - 0¢ per kWh
Industrial - 0¢ per kWh

This results in composite fuel and fuel-related costs factors (excluding gross receipts tax and regulatory fee) of:

Residential - 2.3100¢ per kWh
Commercial - 2.3198¢ per kWh
Industrial - 2.3139¢ per kWh

The new fuel factors would have an effective date of September 1, 2022.

6. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Bryan L. Sykes, Kevin Y. Houston, John A. Verderame, Bryan Walsh and Steven D. Capps which are being filed simultaneously with this Application and incorporated herein by reference.

7. For comparison, in accordance with Rule R8-55(d)(1) and R8-55(e)(3), base fuel and fuel-related costs factors were also calculated based on the most recent North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor (92.07%) and projected period sales and the methodology used for

fuel costs in DEC's last general rate case. These base fuel and fuel-related costs factors are:

	NERC Average	Last General Rate Case
Residential -	2.3433¢ per kWh	2.2947¢ per kWh
Commercial -	2.3438¢ per kWh	2.3131¢ per kWh
Industrial -	2.3324¢ per kWh	2.3050¢ per kWh

WHEREFORE, Duke Energy Carolinas requests that the Commission issue an order approving composite fuel and fuel-related costs factors (excluding gross receipts tax and regulatory fee) of:

Residential -	2.3100¢ per kWh
Commercial -	2.3198¢ per kWh
Industrial -	2.3139¢ per kWh

Respectfully submitted this 1st day of March, 2022.

By: ______________________

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ATTORNEYS FOR DUKE ENERGY CAROLINAS, LLC

VERIFICATION

STATE OF NORTH CAROLINA)
) DOCKET NO. E-7, SUB 1263
COUNTY OF MECKLENBURG)

Bryan L. Sykes, being first duly sworn, deposes and says:

That he is Director - Rates and Regulatory Planning for Duke Energy Carolinas, LLC; that he has read the foregoing Application and knows the contents thereof; that the same is true except as to the matters stated therein on information and belief; and as to those matters, he believes it to be true.

Bryan L. Sykes

Signed and sworn to before me this day by Bryan L. Sykes
Name of principal

Date: February 16, 2022

Official Signature of Notary (Official Seal)

Aloma M. Felder, Notary Public
Notary's printed or typed name

My commission expires: August 9, 2025

ALOMA M. FELDER
NOTARY PUBLIC
CABARRUS COUNTY, N. C.

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	)	**DIRECT TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF BRYAN L. SYKES FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY CAROLINAS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bryan L. Sykes. My business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Rates Director for Duke Energy Carolinas, LLC ("DEC" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received my Bachelor of Science and Master of Science Degrees in Accounting from East Carolina University. I am a certified public accountant licensed in the State of North Carolina. I began my career in 2001 with Arthur Andersen, LLP as a staff auditor. From 2001 until 2006 I held various roles in public accounting firms, including Grant Thornton, LLP (successor to Arthur Andersen, LLP) and subsequently PricewaterhouseCoopers, LLP. In 2006, I began working at Progress Energy, Inc. as a financial auditor and subsequently held a variety of positions in the accounting organization before and after the merger with Duke Energy Corporation in 2012. I joined the Rates Department in 2019 as Manager, Rates and Regulatory Filings and recently became Director, Rates and Regulatory Planning.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES DIRECTOR FOR DEC.

A. I am responsible for providing regulatory support for retail rates, providing guidance on DEC's fuel and fuel-related cost recovery application in North

Carolina, and its fuel cost recovery application in South Carolina.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I most recently provided testimony in last year's annual fuel proceeding for DEC in Docket No E-7, Sub 1250.

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DEC?

A. Yes. DEC's books of account follow the uniform classification of accounts prescribed by the Federal Energy Regulatory Commission ("FERC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the information and data required by North Carolina General Statutes ("N.C. Gen. Stat.") § 62-133.2(c) and (d) and Commission Rule R8-55, as set forth in Sykes Exhibits 1 through 6, along with supporting work papers. The test period used in supplying this information and data is the twelve months ended December 31, 2021 ("test period"), and the billing period is September 1, 2022 through August 31, 2023 ("billing period").

Q. WHAT IS THE SOURCE OF THE ACTUAL INFORMATION AND DATA FOR THE TEST PERIOD?

A. Actual test period kilowatt hour ("kWh") generation, kWh sales, fuel-related revenues, and fuel-related expenses were taken from DEC's books and records. These books, records, and reports of DEC are subject to review by the appropriate regulatory agencies in the three jurisdictions that regulate DEC's electric rates. In addition, independent auditors perform an annual audit to provide assurance that, in all material respects, internal accounting controls are operating effectively and DEC's financial statements are accurate.

Q. WERE SYKES EXHIBITS 1 THROUGH 6 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes, these exhibits were either prepared by me or at my direction and under my supervision, and consist of the following:

Exhibit 1: Summary Comparison of Fuel and Fuel-Related Costs Factors.

Exhibit 2:

Schedule 1: Fuel and Fuel-Related Costs Factors - reflecting a 93.94% proposed nuclear capacity factor and projected megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 93.94% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 92.07% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for pressurized water reactors and projected billing period MWh sales.

Exhibit 3:

Page 1: Calculation of the Proposed Composite Experience Modification Factor ("EMF") rate.

Page 2: Calculation of the EMF for residential customers.

Page 3: Calculation of the EMF for general service/lighting customers.

Page 4: Calculation of the EMF for industrial customers.

Exhibit 4: MWh Sales, Fuel Revenue, and Fuel and Fuel-Related Expense, as well as System Peak for the test period.

Exhibit 5: Nuclear Capacity Ratings.

Exhibit 6: December 2021 Monthly Fuel Reports.

1) December 2021 Monthly Fuel Report required by NCUC Rule R8-52.

2) December 2021 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

Q. PLEASE EXPLAIN SYKES EXHIBIT 1.

A. Sykes Exhibit 1 presents a summary of fuel and fuel-related cost factors, including the current fuel and fuel-related cost factors, the fuel and fuel-related cost factor calculations as required under Rule R8-55, and the proposed fuel and fuel-related cost factors.

Q. WHAT FUEL AND FUEL-RELATED COSTS FACTORS DOES DEC PROPOSE FOR INCLUSION IN RATES FOR THE BILLING PERIOD?

A. DEC proposes fuel and fuel-related costs factors for residential, general service/lighting, and industrial customers of 2.3100¢, 2.3198¢, and 2.3139¢ per kWh, respectively, to be reflected in rates during the billing period. The factors DEC proposes in this proceeding incorporate a 93.94% nuclear capacity factor as testified to by Company witness Capps, projected fossil fuel costs as testified to by Company witness Verderame, projected nuclear fuel costs as testified to by Company witness Houston, and projected reagents costs as testified to by Company witness Walsh. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Sykes Exhibit 1, are as follows:

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Total adjusted Fuel and Fuel Related Costs	1.9315	1.8573	1.9011	1.9011
EMF Increment (Decrement)	0.3785	0.4625	0.4128	0.4191
EMF Interest (Decrement)	-	-	-	-
Net Fuel and Fuel Related Costs Factors	2.3100	2.3198	2.3139	2.3202

Q WHAT IS THE IMPACT TO CUSTOMERS' BILLS IF THE PROPOSED FUEL AND FUEL-RELATED COSTS FACTORS ARE APPROVED BY THE COMMISSION?

A. The proposed fuel and fuel-related costs factors will result in an 8.16% increase on customers' bills. The table below shows both the proposed and existing fuel and fuel-related costs factors.

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Proposed Total Fuel Factor	2.3100	2.3198	2.3139	2.3202
Existing Total Fuel Factor	1.5014	1.7371	1.8634	1.6767
Increase in Fuel Factor	0.8086	0.5827	0.4505	0.6435

Q. WHAT ARE THE KEY DRIVERS IMPACTING THE PROPOSED FUEL

AND FUEL-RELATED COSTS FACTORS?

A. The increase in the proposed net fuel and fuel-related costs factors is primarily driven by a $245 million under-recovery in the current test period compared to a $20 million under-recovery included in current rates. The Company typically experiences some amount of over or under recovered fuel costs during the test period. The EMF provision of fuel rates was established to address the differences between fuel revenues realized and fuel costs incurred during a test period. Beginning around June 2021, a few months after the Company filed its proposed fuel rates on February 23, 2021, the Company experienced an unexpected increase in fuel commodity costs, as described in the direct testimony of Witness Verderame. For the test period months of June through December, the fuel revenues collected by DEC were materially less than the fuel costs incurred, resulting in a large under collection of costs, which is reflected in DEC's proposed EMF rates. In addition, estimated system fuel costs in the billing period are higher due to expected higher commodity prices.

Q. HOW DOES DEC DEVELOP THE FUEL FORECASTS FOR ITS GENERATING UNITS?

A. For this filing, DEC used an hourly dispatch model in order to generate its fuel forecasts. This hourly dispatch model considers the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities. In addition, the model dispatches DEC's and DEP's generation resources via joint dispatch, which optimizes the generation fleets of DEC and DEP for the benefit of customers.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON SYKES EXHIBIT 2, SCHEDULES 1, 2, AND 3, INCLUDING THE NUCLEAR CAPACITY FACTORS.

A. Exhibit 2 is divided into three schedules. Schedule 1 sets forth system fuel costs used in the determination of the prospective fuel and fuel-related costs. The calculation uses the nuclear capacity factor of 93.94% and provides the forecasted MWh sales for the billing period on which system generation and costs are based. Forecasted generation and purchased power associated with the Company's CPRE Program, established by N.C. Gen. Stat § 62-110.8 and approved by this Commission in Docket No. E-7, Sub 1156, used to supply the Company's native load has been included in Exhibit 2, as part of total system costs to supply native load sales. Recovery of the purchased and generated power costs associated with CPRE generation and purchased power are included in the Company's Rider CPRE filing in Docket No. E-7, Sub 1262.

Schedule 2 also uses the proposed capacity factor of 93.94% along with normalized test period kWh generation, as prescribed by NCUC Rule R8-55 (e)(3), which requires the use of the methodology adopted by the Commission in DEC's last general rate case.

The capacity factor shown on Schedule 3 is prescribed in NCUC Rule R8-55(d)(1). The normalized five-year national weighted average NERC nuclear capacity factor is 92.07%. This capacity factor is based on the 2016 through 2020 data reported in the NERC Generating Unit Statistical Brochure for pressurized water reactors rated at and above 800 MWs. Projected billing period kWh generation was also used for Schedule 3 per NCUC Rule R8-55 (d)(1).

Page 2 of Exhibit 2, Schedules 1, 2, and 3 presents the calculation of the proposed fuel and fuel-related costs factors by customer class resulting from the allocation of renewable and cogeneration power capacity costs by customer class on the basis of the final 2020 cost of service production plant allocators since the 2021 cost of service study is not available at the time of filing. When this allocator becomes known, DEC may elect to make a supplemental filing to adjust its proposed billing period rates, if the estimated rates are materially impacted.

Page 3 of Exhibit 2, Schedules 1, 2, and 3 shows the allocation of system fuel costs to the North Carolina retail jurisdiction, and the calculation of DEC's proposed fuel and fuel-related costs factors for the residential, general service/lighting and industrial classes, exclusive of regulatory fee, using the uniform percentage average bill adjustment method.

Q. PLEASE SUMMARIZE THE METHOD USED TO ADJUST TEST PERIOD KWH GENERATION IN SYKES EXHIBIT 2, SCHEDULES 2 AND 3.

A. The methodology used by DEC in its most recent general rate case for determining generation mix is based upon generation dispatch modeling as used on Sykes Exhibit 2, Schedule 1. For purposes of this filing, as a proxy for generation dispatch modeling, Sykes Exhibit 2, Schedules 2 and 3 adjust the coal generation produced by the dispatch model. For example, on Exhibit 2, Schedule 2, which is based on the proposed capacity factor and normalized test period sales, DEC decreased the level of coal generation to account for the difference between forecasted generation and normalized test period generation. On Exhibit 2, Schedule 3, which is based on the NERC capacity factor, DEC increased the level of coal generation to account for the decrease in nuclear generation. The decrease in nuclear generation results from assuming a 92.07% NERC nuclear capacity factor compared to the proposed 93.94% nuclear capacity factor.

Q. SYKES EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD (OVER)/UNDER RECOVERY BALANCE AND THE EMF RATE. HOW DID FUEL EXPENSES COMPARE WITH FUEL REVENUE DURING THE TEST PERIOD?

A. Sykes Exhibit 3, Pages 1 through 4, demonstrates that for the test period, DEC experienced an under-recovery for the residential, general service/lighting and industrial customer classes of $86.9 million, $107.3 million and $50.7 million respectively. There is one adjustment included in the calculation of the under-recovery balance at December 31, 2021. This adjustment relates to the months of January and February 2021, which were included in the fuel rate approved in the last fuel and fuel-related cost recovery proceeding and is included for Commission review in the current proceeding. The Company has excluded the amount of under-recovery for the months of January and February 2021 that was included in the EMF approved in Docket E-7, Sub 1250 when computing the proposed EMF factors.

The (over)/under recovery amount was determined each month by comparing the amount of fuel revenue collected for each class to actual fuel and fuel-related costs incurred by class. The revenue collected is based on actual monthly sales for each class. Actual fuel and fuel-related costs incurred were first allocated to the NC retail jurisdiction based on jurisdictional sales, with consideration given to any fuel and fuel-related costs or benefits that should be directly assigned. The North Carolina retail amount is further allocated among customer classes as follows: (1) capacity-related purchased power costs were allocated among customer classes based on production plant allocators from DEC's cost of service study and (2) all other fuel and fuel-related costs were allocated among customer classes based on fixed allocation percentages established in DEC's previous fuel and fuel-related cost recovery proceeding based on the uniform percentage average bill adjustment method.

The Company typically experiences some amount of (over)/under recovery of fuel costs during the test period. The EMF provision of fuel rates was established to address the differences between fuel revenues realized and fuel costs incurred during a test period. Beginning around June 2021, a few months after the Company filed its proposed fuel rates on February 23, 2021, the Company experienced an unexpected increase in fuel commodity costs, as described in the direct testimony of Witness Verderame. For the test period months of June through December, the fuel revenues collected by DEC were materially less than the fuel costs incurred, resulting in a large under collection of costs, which is reflected in DEC's proposed EMF rates.

Q. PLEASE EXPLAIN SYKES EXHIBIT 4.

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Sykes Exhibit 4 sets forth test period actual MWh sales, the customer growth MWh adjustment, and the weather MWh adjustment. Test period MWh sales were normalized for weather using a 30-year period and adjusted for projected customer growth. Both of these adjustments were determined using the methods approved for use in DEC's last general rate case (Docket No. E-7, Sub 1214) and used in its last fuel proceeding. Sykes Exhibit 4 also sets forth actual test period fuel-related revenue and fuel expense on a total DEC basis and for North Carolina retail. The test period peak demand data for the system and for NC retail customer classes, typically included on Exhibit 4, is not available at the time of this filing. The Company will make a supplemental filing to update Exhibit 4 to include this data when it becomes available.

Q. PLEASE EXPLAIN SYKES EXHIBIT 5.

A. Sykes Exhibit 5 sets forth the capacity ratings for each of DEC's nuclear units, in compliance with Rule R8-55(e)(12).

Q. DO YOU BELIEVE DEC'S FUEL AND FUEL-RELATED COSTS INCURRED IN THE TEST YEAR ARE REASONABLE?

A. Yes. As shown on Sykes Exhibit 6, DEC's test year actual fuel and fuel-related costs were 2.1273¢ per kWh. Key factors in DEC's ability to maintain lower fuel and fuel-related rates for the benefit of customers include (1) its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; (2) the high capacity factors of its nuclear fleet; and (3) fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of DEC's and DEP's respective skills in procuring, transporting, managing, and blending fuels, procuring reagents and the increased and broader purchasing ability of Duke Energy Corporation after its merger with Progress Energy, Inc., as well as the joint dispatch of DEC's and DEP's generation resources. Company witness Capps discusses the performance of DEC's nuclear generation fleet, and Company witness Walsh discusses the performance of the fossil and hydro fleet, as well as the use of chemicals for reducing emissions. Company witness Verderame discusses fossil fuel procurement strategies, and Company witness Houston discusses DEC's nuclear fuel costs and procurement strategies.

Q. IN DEVELOPING THE PROPOSED FUEL AND FUEL-RELATED COSTS FACTORS, WERE THE FUEL COSTS ALLOCATED IN ACCORDANCE WITH N.C. GEN. STAT. § 62-133.2(A2)?

A. Yes, the costs for which statutory guidance is provided are allocated in compliance with N.C. Gen. Stat. § 62-133.2(a2). These costs are described in subdivisions (4), (5), (6), (10) and (11) of N.C. Gen. Stat. § 62-133.2(a1). Subdivisions (4), (6), (10) and (11) address purchased power non-capacity costs. Subdivisions (5), (6), (10) and (11) address purchased power capacity costs. The allocation methods for these costs are as follows:

(a) Capacity-related purchased power costs in Subdivisions (5), (6), (10) and (11) are allocated based upon the final 2020 cost of service production plant allocators since the 2021 cost of service study is not available at the time of filing. During the billing period, when DEC computes its actual fuel costs for comparison to fuel revenues realized, DEC will use the appropriate production plant allocator from the 2021 cost of service study in determining North Carolina retail's share of actual costs by customer class. In addition, when this allocator becomes known, DEC may elect to make a supplemental filing to adjust its proposed billing period rates, if the estimated rates are materially impacted.

(b) Non-capacity related purchased power costs in Subdivisions (4), (6), (10) and (11) are allocated in the same manner as all other fuel and fuel-related costs, using a uniform percentage average bill adjustment method.

Q. HOW ARE THE OTHER FUEL AND FUEL-RELATED COSTS ALLOCATED FOR WHICH THERE IS NO SPECIFIC GUIDANCE IN N.C. GEN. STAT. § 62-133.2(A2)?

A. System costs are allocated to the NC retail jurisdiction based on jurisdictional sales, with consideration given to any fuel and fuel-related costs or benefits that should be directly assigned. Costs are further allocated among customer classes using the uniform percentage average bill adjustment methodology in setting fuel rates in this fuel proceeding. 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.

Q. PLEASE EXPLAIN THE CALCULATION OF THE UNIFORM PERCENTAGE AVERAGE BILL ADJUSTMENT METHOD SHOWN ON SYKES EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3.

A. Sykes Exhibit 2, Page 3 of Schedule 1, shows DEC's proposed fuel and fuel-related cost factors for the residential, general service/lighting and industrial classes, exclusive of regulatory fee. The uniform bill percentage change of 8.16% was calculated by dividing the fuel and fuel-related cost increase of $374,738,584 for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $4,591,210,481. The cost increase of $374,738,584 was determined by comparing the total proposed fuel rate per kWh to the total fuel rate per kWh currently being collected from customers and multiplying the resulting decrease in fuel rate per kWh by projected North Carolina retail kWh sales for the billing period. The proposed fuel rate per kWh represents the rate necessary to recover projected period fuel costs for the billing period (as computed on Sykes Exhibit 2, Schedule 1) and the proposed composite EMF decrement rate (as computed on Sykes Exhibit 3, page 1). This results in a uniform bill percentage change of 8.16% Sykes Exhibit 2, Page 3 of Schedules 2 and 3 uses the same calculation, but with the methodology as prescribed by NCUC Rule R8-55(e)(3) and NCUC Rule R8-55(d)(1), respectively.

Q. HOW ARE SPECIFIC FUEL AND FUEL-RELATED COSTS FACTORS FOR EACH CUSTOMER CLASS DERIVED FROM THE UNIFORM PERCENT ADJUSTMENT COMPUTED ON SYKES EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. Sykes Exhibit 2, Page 3 of Schedules 1, 2, and 3 uses the same calculation, but with the methodology as prescribed by NCUC Rule R8-55(e)(3) and NCUC Rule R8-55 (d)(1), respectively, with the breakdown shown on Sykes Exhibit 2, Page 2 of Schedules 2 and 3. The equal percent increase or decrease for each customer class is applied to current annual revenues by customer class to determine a dollar amount of increase or decrease for each customer class. The dollar increase or decrease is divided by the period sales for each class (either projected billing period or adjusted test period) to derive a cents per kWh increase or decrease. The current total fuel and fuel-related cost factors for each class are increased or decreased by the proposed cents per kWh increases or decreases to get the proposed total fuel and fuel-related cost factors. The proposed total factors are then separated into the prospective and EMF components by subtracting the EMF components for each customer class (as computed on Sykes Exhibit 3, Page 2, 3, and 4) to derive the prospective component for each customer class. This breakdown is shown on Sykes Exhibit 2, Page 2 of Schedules 1, 2, and 3.

Q. HAS DEC'S ANNUAL INCREASE IN THE AGGREGATE AMOUNT OF THE COSTS IDENTIFIED IN SUBDIVISIONS (4), (5), (6), (10) AND (11) OF N.C. GEN. STAT. § 62-133.2(a1) EXCEEDED 2.5% OF ITS NORTH CAROLINA RETAIL GROSS REVENUES FOR THE TEST PERIOD?

A. No. N.C. Gen. Stat. § 62-133.2(a2) limits the amount of annual increase in certain purchased power costs identified in § 62-133.2(a1) that DEC can recover to 2.5% of its North Carolina retail gross revenues for the preceding calendar year. The amount recoverable in DEC's proposed rates for purchased power under the relevant sections of N.C. Gen. Stat. § 62-133.2(a1) does not increase by more than 2.5% of DEC's gross revenues for its North Carolina retail jurisdiction for the test period.

Q. HAS DEC FILED WORK PAPERS SUPPORTING THE CALCULATIONS, ADJUSTMENTS, AND NORMALIZATIONS AS

REQUIRED BY NCUC RULE R8-55(E)(11)?

A. Yes. The work papers supporting the calculations, adjustments and normalizations are included with the filing in this proceeding**.**

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Summary Comparison of Fuel and Fuel Related Cost Factors
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Sykes Exhibit 1

Line #	Description	Reference	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
	Current Fuel and Fuel Related Cost Factors (Approved Fuel Rider Docket No. E-7, Sub 1250)					
1	Approved Fuel and Fuel Related Costs Factors	Input	1.5337	1.6895	1.7243	1.6414
2	EMF Increment (Decrement) cents/kWh	Input	(0.0282)	0.0476	0.1391	0.0353
3	EMF Interest Increment (Decrement) cents/kWh	Input	(0.0041)	0.0000	0.0000	0.0000
4	Approved Net Fuel and Fuel Related Costs Factors	Sum	**1.5014**	**1.7371**	**1.8634**	**1.6767**
	Fuel and Fuel Related Cost Factors Required by Rule R8-55					
5	Proposed Nuclear Capacity Factor of 93.94% and Normalized Test Period Sales	Exh 2 Sch 2 pg 2	**2.2947**	**2.3131**	**2.3050**	**2.3098**
6	NERC 5 Year Average Nuclear Capacity Factor of 92.07% and Projected Period Sales	Exh 2 Sch 3 pg 2	**2.3433**	**2.3438**	**2.3324**	**2.3467**
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 93.94%					
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	1.8997	1.8326	1.8810	1.8746
8	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.0318	0.0247	0.0201	0.0265
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	1.9315	1.8573	1.9011	1.9011
10	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.3785	0.4625	0.4128	0.4191
11	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
12	Net Fuel and Fuel Related Costs Factors cents/kWh	Sum	**2.3100**	**2.3198**	**2.3139**	**2.3202**

Note: Fuel factors exclude regulatory fee

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 93.94%
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	59,085,520	0.5773	341,071,825
2	Coal	Workpaper 3 & 4	9,117,091	3.2121	292,853,648
3	Gas CT and CC	Workpaper 3 & 4	29,962,094	3.1108	932,067,312
4	Reagents and Byproducts	Workpaper 9			9,519,806
5	Total Fossil	Sum	39,079,185		1,234,440,766
6	Hydro	Workpaper 3	4,980,701		
7	Net Pumped Storage	Workpaper 3	(3,411,289)		
8	Total Hydro	Sum	1,569,412		-
9	Solar Distributed Generation	Workpaper 3	364,048		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	100,098,166		1,575,512,591
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(20,639,342)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,848,200)		(85,734,604)
13	Fuel expense recovered through reimbursement	Workpaper 4			(14,027,557)
14	Net Generation	Sum Lines 10-13	84,373,966		1,455,111,088
15	Purchased Power	Workpaper 3 & 4	9,440,360	2.7656	261,085,798
16	JDA Savings Shared	Workpaper 5			20,748,035
17	Total Purchased Power		9,440,360		281,833,833
18	Total Generation and Purchased Power	Line 14 + Line 17	93,814,326	1.8515	1,736,944,921
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,964,801)	3.3757	(66,325,343)
20	Line losses and Company use	Line 22-Line 18-Line 19	(3,892,553)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,670,619,578
22	Projected System MWh Sales for Fuel Factor	Workpaper 7	87,956,972		87,956,972
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.8994

Note: Rounding differences may occur

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7	22,809,193	23,222,537	12,202,704	58,234,434
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 14,610,064
3	QF Purchased Power - Capacity	Workpaper 4				8,445,498
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 23,055,563
5	NC Portion - Jursidicational % based on 2020 Production Plant Allocator	Input				66.98%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 15,441,918
7	2020 Production Plant Allocation Factors	Input	47.00%	37.09%	15.90%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on 2020 Production Plant Allocator	Line 6 * Line 7	$ 7,258,416	$ 5,727,933	$ 2,455,569	$ 15,441,918
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0318	0.0247	0.0201	0.0265
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	1.8997	1.8326	1.8810	1.8746
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0318	0.0247	0.0201	0.0265
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.9315	1.8573	1.9011	1.9011
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.3785	0.4625	0.4128	0.4191
14	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	2.3100	2.3198	2.3139	2.3202

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 93.94%
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Rate Class	Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/(Decrease) as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1250	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	D	E	F	G
		Workpaper 7	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Sykes Exhibit 1	E + F = G
1	Residential	22,809,193	$ 2,259,696,240	$ 184,438,368	8.16%	0.8086	1.5014	2.3100
2	General Service/Lighting	23,222,537	1,658,017,092	135,328,794	8.16%	0.5827	1.7371	2.3198
3	Industrial	12,202,704	673,497,148	54,971,422	8.16%	0.4505	1.8634	2.3139
4	NC Retail	58,234,434	$ 4,591,210,481	$ 374,738,584	8.16%			

Line #	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
5	Total Fuel Costs for Allocation	Workpaper 7	$ 1,675,206,096
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	23,055,563
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,652,150,533
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7	88,132,893
9	NC Retail Projected Billing Period MWh Sales	Line 4	58,234,434
10	Allocation %	Line 9 / Line 8	66.08%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,091,670,180
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 1, Page 2	15,441,918
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,107,112,098
14	NC Retail Projected Billing Period MWh Sales	Line 4	58,234,434
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.9011
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.4191
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	2.3202
	Total Current Composite Fuel Rate - Docket E-7 Sub 1250:		
19	Current composite Fuel Rate cents/kWh	Sykes Exhibit 1	1.6414
20	Current composite EMF Rate cents/kWh	Sykes Exhibit 1	0.0353
21	Current composite EMF Interest Rate cents/kWh	Sykes Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.6767
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.6435
24	NC Retail Projected Billing Period MWh Sales	Line 4	58,234,434
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 374,738,583

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 93.94% and Normalized Test Period Sales
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	59,085,520	0.5773	341,071,825
2	Coal	Calculated	8,436,719	3.2121	270,999,143
3	Gas CT and CC	Workpaper 3 & 4	29,962,094	3.1108	932,067,312
4	Reagents and Byproducts	Workpaper 9	-		9,519,806
5	Total Fossil	Sum	38,398,813		1,212,586,260
6	Hydro	Workpaper 3	4,980,701		
7	Net Pumped Storage	Workpaper 3	(3,411,289)		
8	Total Hydro	Sum	1,569,412		
9	Solar Distributed Generation	Workpaper 3	364,048		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	99,417,794		1,553,658,085
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(20,639,342)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,848,200)		(85,734,604)
13	Fuel expense recovered through reimbursement	Workpaper 4			(14,027,557)
14	Net Generation	Sum	83,693,594		1,433,256,582
15	Purchased Power	Workpaper 3 & 4	9,440,360		261,085,798
16	JDA Savings Shared	Workpaper 5	-		20,748,035
17	Total Purchased Power	Sum	9,440,360		281,833,833
18	Total Generation and Purchased Power	Line 14 + Line 17	93,133,953		1,715,090,416
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,964,801)		(66,325,343)
20	Line losses and Company use	Line 22 - Line 19 - Line 18	(3,892,553)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,648,765,072
22	Normalized Test Period MWh Sales	Exhibit 4	87,276,600		87,276,600
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.8891

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 93.94% and Normalized Test Period Sales
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Normalized Test Period MWh Sales	Exhibit 4	22,961,890	23,202,419	12,293,985	58,458,294
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 14,610,064
3	QF Purchased Power - Capacity	Workpaper 4				8,445,498
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 23,055,563
5	NC Portion - Jursidicational % based on 2020 Production Plant Allocator	Input				66.98%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 15,441,918
7	2020 Production Plant Allocation Factors	Input	47.00%	37.09%	15.90%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on 2020 Production Plant Allocator	Line 6 * Line 7	$ 7,258,416	$ 5,727,933	$ 2,455,569	$ 15,441,918
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Normalized Test Period Sales	Line 8 / Line 1 / 10	0.0316	0.0247	0.0200	0.0264
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	1.8846	1.8259	1.8722	1.8643
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0316	0.0247	0.0200	0.0264
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.9162	1.8506	1.8922	1.8907
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.3785	0.4625	0.4128	0.4191
14	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	2.2947	2.3131	2.3050	2.3098

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 93.94% and Normalized Test Period Sales
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Rate Class	Normalized Test Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/(Decrease) as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1250	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	D	E	F	G
		Exhibit 4	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Sykes Exhibit 1	E + F = G
1	Residential	22,961,890	$ 2,259,696,240	$ 182,155,088	8.06%	0.7933	1.5014	2.2947
2	General Service/Lighting	23,202,419	$ 1,658,017,092	133,653,473	8.06%	0.5760	1.7371	2.3131
3	Industrial	12,293,985	$ 673,497,148	54,290,896	8.06%	0.4416	1.8634	2.3050
4	NC Retail	58,458,294	$ 4,591,210,481	$ 370,099,457				

Total Proposed Composite Fuel Rate:

Line #	Description	Source	Amount
5	Total Fuel Costs for Allocation	Workpaper 7a	$ 1,653,351,591
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	23,055,563
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,630,296,028
8	Normalized Test Period System MWh Sales for Fuel Factor	Workpaper 7a	87,452,521
9	NC Retail Normalized Test Period MWh Sales	Exhibit 4	58,458,294
10	Allocation %	Line 9 / Line 8	66.85%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,089,852,895
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 2, Page 2	15,441,918
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,105,294,813
14	NC Retail Normalized Test Period MWh Sales	Line 9	58,458,294
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.8907
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.4191
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	2.3098

Total Current Composite Fuel Rate - Docket E-7 Sub 1250:

Line #	Description	Source	Amount
19	Current composite Fuel Rate cents/kWh	Sykes Exhibit 1	1.6414
20	Current composite EMF Rate cents/kWh	Sykes Exhibit 1	0.0353
21	Current composite EMF Interest Rate cents/kWh	Sykes Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.6767
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.6331
24	NC Retail Normalized Test Period MWh Sales	Exhibit 4	58,458,294
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 370,099,457

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor of 92.07% and Projected Period Sales
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 2	57,909,218	0.5773	334,281,608
2	Coal	Calculated	9,997,788	3.2121	321,142,864
3	Gas CT and CC	Workpaper 3 & 4	29,962,094	3.1108	932,067,312
4	Reagents and Byproducts	Workpaper 9	-		9,519,806
5	Total Fossil	Sum	39,959,882		1,262,729,982
6	Hydro	Workpaper 3	4,980,701		
7	Net Pumped Storage	Workpaper 3	(3,411,289)		
8	Total Hydro	Sum	1,569,412		
9	Solar Distributed Generation	Workpaper 3	364,048		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	99,802,561		1,597,011,590
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(20,639,342)
12	Less Catawba Joint Owners	Calculated	(14,552,595)		(84,027,759)
13	Fuel expense recovered through reimbursement	Workpaper 4			(14,027,557)
14	Net Generation	Sum	84,373,966		1,478,316,932
15	Purchased Power	Workpaper 3 & 4	9,440,360		261,085,798
16	JDA Savings Shared	Workpaper 5	-		20,748,035
17	Total Purchased Power	Sum	9,440,360		281,833,833
18	Total Generation and Purchased Power	Line 14 + Line 17	93,814,326		1,760,150,766
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,964,801)		(66,325,343)
20	Line losses and Company use	Line 22 - Line 19 - Line 18	(3,892,553)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,693,825,422
22	Projected System MWh Sales for Fuel Factor	Workpaper 7b	87,956,972		87,956,972
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.9257

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
NERC 5 Year Average Nuclear Capacity Factor of 92.07% and Projected Period Sales
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7b	22,809,193	23,222,537	12,202,704	58,234,434
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 14,610,064
3	QF Purchased Power - Capacity	Workpaper 4				8,445,498
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 23,055,563
5	NC Portion - Jursidicational % based on 2020 Production Plant Allocator	Input				66.98%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 15,441,918
7	2020 Production Plant Allocation Factors	Input	47.00%	37.09%	15.90%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on 2020 Production Plant Allocator	Line 6 * Line 7	$ 7,258,416	$ 5,727,933	$ 2,455,569	$ 15,441,918
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0318	0.0247	0.0201	0.0265
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	1.9330	1.8566	1.8995	1.9011
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0318	0.0247	0.0201	0.0265
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.9648	1.8813	1.9196	1.9276
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.3785	0.4625	0.4128	0.4191
14	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	2.3433	2.3438	2.3324	2.3467

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
NERC 5 Year Average Nuclear Capacity Factor of 92.07% and Projected Period Sales
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Rate Class	Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1250	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	C / B = D	E	F	G
		Workpaper 7b	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Sykes Exhibit 1	E + F = G
1	Residential	22,809,193	$ 2,259,696,240	$ 192,033,732	8.50%	0.8419	1.5014	2.3433
2	General Service/Lighting	23,222,537	$ 1,658,017,092	$ 140,901,774	8.50%	0.6067	1.7371	2.3438
3	Industrial	12,202,704	$ 673,497,148	$ 57,235,202	8.50%	0.4690	1.8634	2.3324
4	NC Retail	58,234,434	$ 4,591,210,481	$ 390,170,708				

<u>Total Proposed Composite Fuel Rate:</u>

5	Total Fuel Costs for Allocation	Workpaper 7b	$ 1,698,411,934
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	23,055,563
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,675,356,371
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7b	88,132,893
9	NC Retail Projected Billing Period MWh Sales	Line 4	58,234,434
10	Allocation %	Line 9 / Line 8	66.08%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,107,075,490
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 3, Page 2	15,441,918
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,122,517,408
14	NC Retail Projected Billing Period MWh Sales	Line 4	58,234,434
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.9276
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.4191
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	2.3467

<u>Total Current Composite Fuel Rate - Docket E-7 Sub 1250:</u>

19	Current composite Fuel Rate cents/kWh	Sykes Exhibit 1	1.6414
20	Current composite EMF Rate cents/kWh	Sykes Exhibit 1	0.0353
21	Current composite EMF Interest Rate cents/kWh	Sykes Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.6767
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.6700
24	NC Retail Projected Billing Period MWh Sales	Line 4	58,234,434
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 390,170,708

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line No.	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/ Under Recovery (d)	Correction JDA Purchased Power (e)	Revised (Over)/Under Recovery (f)
1	January 2021			5,785,767	$ 1,309,433	$ -	$ 1,309,433
2	February			4,705,197	$ 24,172,571	$ (1,105,173)	$ 23,067,398
3	March [1]			4,216,102	$ (1,280,088)	$ -	$ (1,280,088)
4	April			4,231,666	$ (3,675,665)	$ -	$ (3,675,665)
5	May [1]			3,784,760	$ 9,106,398	$ -	$ 9,106,398
6	June			4,813,118	$ 15,273,578	$ -	$ 15,273,578
7	July			5,540,576	$ 32,252,591	$ -	$ 32,252,591
8	August			5,890,179	$ 37,907,835	$ -	$ 37,907,835
9	September			5,517,651	$ 13,769,502	$ -	$ 13,769,502
10	October [1]			4,297,619	$ 27,401,885	$ -	$ 27,401,885
11	November			4,396,624	$ 64,806,647	$ -	$ 64,806,647
12	December			4,888,703	$ 49,423,931	$ -	$ 49,423,931
13	**Total Test Period**			**58,067,962**	**$ 270,468,622**	**$ (1,105,173)**	**$ 269,363,445**
14	**Adjustment to remove (Over)/Under Recovery - January-February 2021[2]**				$ 25,482,004	$ (1,105,173)	$ 24,376,831
15	**Adjusted (Over)/Under Recovery**						**$ 244,986,614**
16	NC Retail Normalized Test Period MWh Sales					Exhibit 4	58,458,294
17	**Experience Modification Increment (Decrement) cents/kWh**						**0.4191**

[1] Prior period corrections not included in rate incurred but are included in over/(under) recovery total

[2] January and February 2021 filed in Docket E-7, Sub 1250 to update the EMF and included in the current EMF rate. Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 15.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/ Under Recovery (d)	Correction JDA Purchased Power (e)	Revised (Over)/Under Recovery (f)
1	January 2021	1.4543	1.6027	2,427,681	$ (3,602,217)	$ -	$ (3,602,217)
2	February	1.8056	1.6027	2,047,050	$ 4,154,380	$ (396,210)	$ 3,758,170
3	March [1]	1.2642	1.6027	1,996,845	$ (7,158,737)	$ -	$ (7,158,737)
4	April	1.5283	1.6027	1,585,020	$ (1,178,659)	$ -	$ (1,178,659)
5	May [1]	2.0368	1.6027	1,288,098	$ 5,643,932	$ -	$ 5,643,932
6	June	1.9547	1.6027	1,774,699	$ 6,246,872	$ -	$ 6,246,872
7	July	2.1114	1.6027	2,146,583	$ 10,918,699	$ -	$ 10,918,699
8	August	2.2422	1.6027	2,212,544	$ 14,149,173	$ -	$ 14,149,173
9	September	1.7462	1.5655	2,129,356	$ 3,848,250	$ -	$ 3,848,250
10	October [1]	2.3928	1.5337	1,481,929	$ 11,889,253	$ -	$ 11,889,253
11	November	3.5580	1.5337	1,359,179	$ 27,513,197	$ -	$ 27,513,197
12	December	2.2952	1.5337	1,975,540	$ 15,044,028	$ -	$ 15,044,028
13	**Total Test Period**			**22,424,524**	**$ 87,468,172**	**$ (396,210)**	**$ 87,071,961**
14	Test Period Wtd Avg. ¢/kWh	1.9797	1.5843				
15	Adjustment to remove (Over)/Under Recovery - January-February 2021 [2]				$ 552,163	$ (396,210)	$ 155,953
16	**Adjusted (Over)/Under Recovery**						**$ 86,916,008**
17	NC Retail Normalized Test Period MWh Sales					Exhibit 4	22,961,890
18	**Experience Modification Increment (Decrement) cents/kWh**						**0.3785**

Notes:

[1] Prior period corrections not included in rate incurred but are included in over/(under) recovery total

[2] January and February 2021 filed in Docket E-7, Sub 1250 to update the EMF and included in the current EMF rate. Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 16.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - GS/Lighting
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/ Under Recovery (d)	Correction JDA Purchased Power (e)	Revised (Over)/Under Recovery (f)
1	January 2021	1.8948	1.7583	2,224,452	$ 3,036,294	$ -	$ 3,036,294
2	February	2.5796	1.7583	1,711,092	$ 14,053,467	$ (474,850)	$ 13,578,617
3	March (1)	2.0380	1.7583	1,477,172	$ 3,654,007	$ -	$ 3,654,007
4	April	1.6824	1.7583	1,719,557	$ (1,305,025)	$ -	$ (1,305,025)
5	May (1)	1.8862	1.7583	1,656,907	$ 2,072,505	$ -	$ 2,072,505
6	June	2.0391	1.7583	2,021,651	$ 5,677,153	$ -	$ 5,677,153
7	July	2.3469	1.7583	2,284,951	$ 13,448,970	$ -	$ 13,448,970
8	August	2.5564	1.7583	2,286,069	$ 18,244,441	$ -	$ 18,244,441
9	September	1.9616	1.7212	2,297,610	$ 5,524,126	$ -	$ 5,524,126
10	October (1)	2.1455	1.6895	2,004,794	$ 8,129,521	$ -	$ 8,129,521
11	November	3.3527	1.6895	1,759,969	$ 29,272,230	$ -	$ 29,272,230
12	December	2.8474	1.6895	1,952,172	$ 22,604,847	$ -	$ 22,604,847
13	**Total Test Period**			**23,396,396**	**$ 124,412,536**	**$ (474,850)**	**$ 123,937,686**
14	Test Period Wtd Avg. ¢/kWh	2.2762	1.7378				
15	Adjustment to remove (Over)/Under Recovery - January-February 2021 (2)				$ 17,089,761	$ (474,850)	$ 16,614,911
16	**Adjusted (Over)/Under Recovery**						**$ 107,322,775**
17	NC Retail Normalized Test Period MWh Sales					Exhibit 4	23,202,419
18	**Experience Modification Increment (Decrement) cents/kWh**						**0.4625**

Notes:
(1) Prior period corrections not included in rate incurred but are included in over/(under) recovery total

(2) January and February 2021 filed in Docket E-7, Sub 1250 to update the EMF and included in the current EMF rate. Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 16.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Industrial
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/ Under Recovery (d)	Correction JDA Purchased Power (e)	Revised (Over)/Under Recovery (f)
1	January 2021	1.8306	1.6652	1,133,633	$ 1,875,356	$ -	$ 1,875,356
2	February	2.2950	1.6652	947,056	$ 5,964,724	$ (234,113)	$ 5,730,612
3	March [(1)]	1.9967	1.6652	742,085	$ 2,224,644	$ -	$ 2,224,644
4	April	1.5366	1.6652	927,089	$ (1,191,979)	$ -	$ (1,191,979)
5	May [(1)]	1.8321	1.6652	839,755	$ 1,389,961	$ -	$ 1,389,961
6	June	1.9946	1.6652	1,016,768	$ 3,349,552	$ -	$ 3,349,552
7	July	2.3762	1.6652	1,109,043	$ 7,884,922	$ -	$ 7,884,922
8	August	2.0615	1.6652	1,391,565	$ 5,514,222	$ -	$ 5,514,222
9	September	2.1003	1.6971	1,090,684	$ 4,397,125	$ -	$ 4,397,125
10	October [(1)]	2.6966	1.7243	810,897	$ 7,383,110	$ -	$ 7,383,110
11	November	2.3522	1.7243	1,277,476	$ 8,021,220	$ -	$ 8,021,220
12	December	2.9496	1.7243	960,991	$ 11,775,057	$ -	$ 11,775,057
13	**Total Test Period**			**12,247,042**	**$ 58,587,915**	**$ (234,113)**	**$ 58,353,802**
14	Test Period Wtd Avg. ¢/kWh	2.1672	1.6828				
15	Adjustment to remove (Over)/Under Recovery - January-March 2020[(2)]				$ 7,840,080	$ (234,113)	$ 7,605,968
16	**Adjusted (Over)/Under Recovery**						**$ 50,747,835**
17	NC Retail Normalized Test Period MWh Sales					Exhibit 4	12,293,985
18	**Experience Modification Increment (Decrement) cents/KWh**						**0.4128**

Notes:

[(1)] Prior period corrections not included in rate incurred but are included in over/(under) recovery total

[(2)] January and February 2021 filed in Docket E-7, Sub 1250 to update the EMF and included in the current EMF rate. Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 16.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Sales, Fuel Revenue, Fuel Expense and System Peak
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Sykes Exhibit 4

Line #	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina General Service/Lighting	North Carolina Industrial
1	Test Period MWh Sales (excluding inter system sales)	Exhibit 6 Schedule 1 (Line 4) and Workpaper 11 (NC Retail)	86,551,610	58,067,962	22,424,524	23,396,396	12,247,042
2	Customer Growth MWh Adjustment	Workpaper 13 Pg 1	128,987	(23,093)	198,268	(239,223)	17,862
3	Weather MWh Adjustment	Workpaper 12 Pg 1	596,003	413,425	339,099	45,245	29,081
4	Total Normalized MWh Sales	Sum	87,276,600	58,458,294	22,961,890	23,202,419	12,293,985
5	Test Period Fuel and Fuel Related Revenue *		$ 1,449,831,492	$ 967,961,388			
6	Test Period Fuel and Fuel Related Expense *		$ 1,845,020,858	$ 1,238,430,010			
7	Test Period Unadjusted (Over)/Under Recovery		$ 395,189,366	$ 270,468,622			

Line #	Description	2020 Summer Coincidental Peak (CP) kW
8	Total System Peak	17,438,327
9	NC Retail Peak	11,665,772
10	NC Residential Peak	5,482,921
11	NC General Service/Lighting Peak	4,326,963
12	NC Industrial Peak	1,855,888

* Total Company Fuel and Fuel-Related Revenue and Fuel and Fuel-Related Expense are determined based upon the fuel and fuel-related cost recovery mechanism in each of the company's jurisdictions.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Nuclear Capacity Ratings
Test Period Ended December 31, 2021
Billing Period September 2022 - August 2023
Docket E-7, Sub 1263

Sykes Exhibit 5

Unit	Rate Case Docket E-7, Sub 1214	Fuel Docket E-7, Sub 1250	Proposed Capacity Rating MW
Oconee Unit 1	847.0	847.0	847.0
Oconee Unit 2	848.0	848.0	848.0
Oconee Unit 3	859.0	859.0	859.0
McGuire Unit 1	1,158.0	1,158.0	1,158.0
McGuire Unit 2	1,157.6	1,157.6	1,157.6
Catawba Unit 1	1,160.1	1,160.1	1,160.0
Catawba Unit 2	1,150.1	1,150.1	1,150.1
Total Company	7,179.8	7,179.8	7,179.7

DECEMBER 2021 MONTHLY FUEL FILING

Sykes Exhibit 6
Schedule 1

DUKE ENERGY CAROLINAS
SUMMARY OF MONTHLY FUEL REPORT

Docket No. E-7, Sub 1248

Line No.		December 2021	12 Months Ended December 2021
1	Fuel and fuel-related costs	$ 189,923,750	$ 1,841,186,117
	MWH sales:		
2	Total system sales	7,230,301	87,792,832
3	Less intersystem sales	48,877	1,241,222
4	Total sales less intersystem sales	7,181,424	86,551,610
5	Total fuel and fuel-related costs (¢/KWH) (line 1/line 4)	2.6447	2.1273
6	Current fuel and fuel-related cost component (¢/KWH) (per Schedule 4, Line 7a Total)	1.6334	
	Generation Mix (MWH):		
	Fossil (by primary fuel type):		
7	Coal	285,789	13,569,695
8	Fuel Oil	2,720	53,988
9	Natural Gas - Combined Cycle	1,298,695	14,542,974
10	Natural Gas - Combined Heat and Power	9,589	15,739
11	Natural Gas - Combustion Turbine	61,155	1,131,529
12	Natural Gas - Steam	973,777	7,231,653
13	Biogas	1,215	21,502
14	Total fossil	2,632,940	36,567,080
15	Nuclear 100%	5,245,391	60,454,296
16	Hydro - Conventional	65,561	1,950,233
17	Hydro - Pumped storage	(77,236)	(610,077)
18	Total hydro	(11,675)	1,340,156
19	Solar Distributed Generation	15,972	293,289
20	Total MWH generation	7,882,628	98,654,821
21	Less joint owners' portion - Nuclear	1,413,367	15,008,712
22	Less joint owners' portion - Combined Cycle	70,455	744,961
23	Adjusted total MWH generation	6,398,806	82,901,148

Note: Detail amounts may not add to totals shown due to rounding.

Sykes Exhibit 6
Schedule 2

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS

Docket No. E-7, Sub 1248

Fuel and fuel-related costs:	December 2021	12 Months Ended December 2021
0501110 coal consumed - steam	$ 9,829,322	$ 428,535,150
0501310 fuel oil consumed - steam	86,054	1,264,107
0501330 fuel oil light-off - steam	10,457	1,119,252
Total Steam Generation - Account 501	9,925,833	430,918,509
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	21,591,353	259,578,561
Other Generation - Account 547		
0547100, 0547124 - natural gas consumed - Combustion Turbine	4,412,048	49,551,008
0547100 - Combustion Turbine - credit for inefficient fuel cost	(126,494)	(1,524,868)
0547100 natural gas consumed - Steam	61,810,549	331,328,622
0547101 natural gas consumed - Combined Cycle	54,245,577	392,828,920
0547101 natural gas consumed - Combined Heat and Power	817,949	1,710,128
0547106 biogas consumed - Combined Cycle	65,711	1,161,456
0547200 fuel oil consumed - Combustion Turbine	225,631	6,445,339
Total Other Generation - Account 547	121,450,971	781,500,605
Reagents		
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	851,596	18,393,982
Total Reagents	851,596	18,393,982
By-products		
Net proceeds from sale of by-products	905,813	6,884,190
Total By-products	905,813	6,884,190
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	154,725,566	1,497,275,847
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (economic)	215,310	10,765,481
Capacity component of purchased power (renewables)	662,095	16,335,530
Capacity component of purchased power (PURPA)	281,956	8,934,137
Fuel and fuel-related component of purchased power	36,195,486	353,899,479
Total Purchased Power and Net Interchange - Account 555	37,354,847	389,934,627
Less:		
Fuel and fuel-related costs recovered through intersystem sales	2,010,944	44,191,701
Fuel in loss compensation	138,819	1,368,818
Solar Integration Charge	(2,826)	(2,826)
Lincoln CT marginal fuel revenue	39,124	246,896
Miscellaneous Fees Collected	(29,400)	219,768
Total Fuel Credits - Accounts 447 /456	2,156,661	46,024,357
Total Fuel and Fuel-related Costs	$ 189,923,750	$ 1,841,186,117

Notes: Detail amounts may not add to totals shown due to rounding.
Report reflects net ownership costs of jointly owned facilities.

Sykes Exhibit 6
Schedule 3 - Purchases

DUKE ENERGY CAROLINAS
PURCHASED POWER AND INTERCHANGE
SYSTEM REPORT - NORTH CAROLINA VIEW

DEC 2021

Purchased Power	**Total**	**Capacity**	**Non-capacity**			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Carolina Power Partners, LLC	$ 573,300	-	11,400	$ 349,713	$ 223,587	
Cherokee County Cogeneration Partners	1,980,350	$ 215,310	32,635	1,605,083	159,957	
DE Progress - Native Load Transfer	20,239,048	-	573,789	19,367,526	861,570	$ 9,952
DE Progress - Native Load Transfer Benefit	3,261,712	-	-	3,261,712	-	
Haywood Electric - Economic	38,342	19,790	332	11,317	7,235	
Macquarie Energy, LLC	357,584	-	7,413	218,126	139,458	
NCMPA - Economic	335,160	-	9,120	204,448	130,712	
Piedmont Municipal Power Agency	710,145	-	21,612	417,565	292,580	
PJM Interconnection, LLC.	12,874	-	300	7,853	5,021	
Town of Dallas	584	584	-	-	-	
Town of Forest City	19,856	19,856	-	-	-	
	$ 28,978,259	**$ 255,540**	**698,740**	**$ 26,295,173**	**$ 2,417,594**	**$ 9,952**
Renewable Energy						
REPS	$ 5,049,069	$ 642,188	91,397	$ -	$ 4,406,882	
DERP - Purchased Power	304,103	19,907	5,264	-	205,494	78,703
DERP - Net Metered Generation	553	-	20			553
	$ 5,353,725	**$ 662,095**	**96,682**	**$ -**	**$ 4,612,376**	**$ 79,256**
HB589 PURPA Purchases						
CPRE - Purchased Power	(20,000)	-	-			(20,000)
Qualifying Facilities	2,710,938	281,956	49,804		2,343,504	85,478
	$ 2,690,938	**$ 281,956**	**49,804**	**$ -**	**$ 2,343,504**	**$ 65,478**
Non-dispatchable / Other						
Blue Ridge Electric Membership Corp.	1,100,555	$ 617,591	25,631	294,608		188,356
Haywood Electric	202,825	104,398	4,343	60,040		38,386
Macquarie Energy, LLC	60,500	-	1,100	36,905		23,595
NCEMC - Other	3,133	3,133	-	-		-
Piedmont Electric Membership Corp.	523,997	293,984	11,904	140,308		89,705
Generation Imbalance	683,926	-	20,622	412,075		271,851
Energy Imbalance - Purchases	63,494	-	6,933	32,476		31,018
Energy Imbalance - Sales	306,460	-	-	(49,070)		355,530
Other Purchases	717	-	28	-		717
	$ 2,945,607	**$ 1,019,107**	**70,561**	**$ 927,342**	**$ -**	**$ 999,158**
	-					
Total Purchased Power	**$ 39,968,528**	**$ 2,218,697**	**915,787**	**$ 27,222,515**	**$ 9,373,473**	**$ 1,153,843**
Interchanges In						
Other Catawba Joint Owners	7,311,950	-	710,249	4,176,265		3,135,685
WS Lee Joint Owner	1,557,572		29,613	1,437,844		119,728
Total Interchanges In	8,869,522	-	739,862	5,614,110	-	3,255,412
Interchanges Out						
Other Catawba Joint Owners	(7,168,642)	(134,209)	(693,456)	(4,077,519)		(2,956,913)
Catawba- Net Negative Generation	-	-	-	-		-
WS Lee Joint Owner	(2,094,784)		(40,405)	(1,937,093)		(157,691)
Total Interchanges Out	(9,263,426)	(134,209)	(733,861)	(6,014,612)	-	(3,114,604)
Net Purchases and Interchange Power	**$ 39,574,624**	**$ 2,084,488**	**921,788**	**$ 26,822,013**	**$ 9,373,473**	**$ 1,294,651**

NOTE: Detail amounts may not add to totals shown due to rounding.
CPRE purchased power amounts are recovered through the CPRE Rider.

DUKE ENERGY CAROLINAS
INTERSYSTEM SALES*
SYSTEM REPORT - NORTH CAROLINA VIEW

DEC 2021

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
SC Public Service Authority - Emergency	-	-	-	-	-
Market Based:					
Central Electric Power Cooperative, Inc.	-	$ -	-	-	-
Macquarie Energy, LLC	46,500	-	1,400	36,695	9,805
NCMPA	91,919	87,500	81	5,027	(608)
PJM Interconnection, LLC.	-	-	-	-	-
Other:					
DE Progress - Native Load Transfer Benefit	274,561	-	-	274,561	-
DE Progress - Native Load Transfer	1,685,438	-	45,652	1,658,000	27,439
Generation Imbalance	42,056	-	1,744	36,660	5,396
Total Intersystem Sales	**$ 2,139,006**	**$ 87,500**	**48,877**	**$ 2,010,944**	**$ 40,562**

* Sales for resale other than native load priority.

NOTE: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY CAROLINAS
PURCHASED POWER AND INTERCHANGE
SYSTEM REPORT - NORTH CAROLINA VIEW

Twelve Months Ended
DEC 2021

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Carolina Power Partners, LLC	$ 1,787,160	-	42,160	$ 1,090,168	$ 696,992	
Cherokee County Cogeneration Partners	25,303,689	$ 10,765,481	370,824	12,687,649	1,850,559	
Cube Yadkin Generation LLC	606,505	-	37,958	369,968	236,537	
DE Progress - Native Load Transfer	185,028,516	-	5,779,506	174,196,837	10,756,889	$ 74,790
DE Progress - Native Load Transfer (Prior Period Adjust)	-	-	-	-	-	
DE Progress - Native Load Transfer Benefit	21,186,870	-	-	21,186,870	-	
DE Progress - Fees	3,126	-	-	-	3,126	
EDF Trading North America, LLC.	-	-	-	-	-	
Exelon Generation Company, LLC.	311,275	-	4,945	189,878	121,397	
Florida Power & Light Company	-	-	-	-	-	
Haywood Electric - Economic	337,984	235,484	1,819	62,525	39,975	
Macquarie Energy, LLC	4,176,326	-	90,110	2,547,559	1,628,767	
NCEMC	-	-	-	-	-	
NCMPA	1,794,926	-	48,595	1,050,744	744,183	
NCMPA Load Following Economic	12,832,732	-	405,883	7,389,860	5,442,872	
Piedmont Municipal Power Agency	3,474,337	-	120,036	2,007,947	1,466,390	
PJM Interconnection, LLC.	189,850	-	5,700	115,809	74,042	
South Carolina Electric & Gas Company / Dominion Energy	152,750	-	3,550	92,690	60,061	
Southern Company Services, Inc.	706,464	-	20,793	430,943	275,521	
Tennessee Valley Authority	280,504	-	7,231	171,107	109,397	
The Energy Authority	69,600	-	2,400	42,456	27,144	
Town of Dallas	7,008	7,008	-	-	-	
Town of Forest City	238,272	238,272	-	-	-	
	$ 258,487,895	**$ 11,246,246**	**6,941,510**	**$ 223,633,007**	**$ 23,533,853**	**$ 74,790**
Renewable Energy						
REPS	$ 73,398,098	$ 16,092,597	1,192,575	$ -	$ 57,305,502	$ -
DERP - Purchased Power	3,789,475	242,933	65,917	-	2,583,689	962,853
DERP - Net Metered Generation	52,349	(56)	1,943	-		52,406
	$ 77,239,922	**$ 16,335,474**	**1,260,435**	**$ -**	**$ 59,889,191**	**$ 1,015,259**
HB589 PURPA Purchases						
CPRE - Purchased Power	$ (70,000)	$ -	-			$ (70,000)
Qualifying Facilities	43,116,103	8,934,138	714,046		$ 33,167,413	1,014,555
	$ 43,046,103	**$ 8,934,138**	**714,046**	**$ -**	**$ 33,167,413**	**$ 944,555**

Non-dispatchable / Other						
Blue Ridge Electric Membership Corp.	13,391,449	7,266,227	299,086	3,736,386		2,388,837
Carolina Power Partners, LLC	1,101,300	-	26,310	671,793		429,507
DE Progress - As Available Capacity	302,530	302,530	-	-		-
Exelon Generation Company, LLC.	131,200	-	1,600	80,032		51,168
Haywood Electric	2,619,594	1,317,250	55,640	794,430		507,914
Macquarie Energy, LLC	10,866,055	-	182,317	6,628,294		4,237,761
NCEMC - Other	724,944	30,315	8,941	423,724		270,905
NCMPA - Reliability	316,144	-	3,496	192,848		123,296
Piedmont Electric Membership Corp.	6,410,149	3,460,962	140,160	1,799,004		1,150,182
Southern Company Services, Inc.	541,806	-	6,886	330,502		211,304
Generation Imbalance	2,987,298		75,257	1,636,681		1,350,617
Energy Imbalance - Purchases	1,644,938		(77,146)	1,358,681		286,257
Energy Imbalance - Sales	(4,528,599)		-	(4,307,002)		(221,597)
Other Purchases	6,183	-	228	-		6,183
	$ 36,514,991	$ 12,377,283	722,775	$ 13,345,372	$ -	$ 10,792,336
Total Purchased Power	**$ 415,288,911**	**$ 48,893,141**	**9,638,766**	**$ 236,978,379**	**$ 116,590,457**	**$ 12,826,940**
						(6)
Interchanges In						
Other Catawba Joint Owners	71,832,695	-	7,544,326	42,400,464		29,432,231
WS Lee Joint Owner	15,839,014	-	462,339	13,941,298		1,897,716
Total Interchanges In	87,671,709	-	8,006,664	56,341,761	-	31,329,947
Interchanges Out						
Other Catawba Joint Owners	(74,348,518)	(1,580,207)	(7,701,093)	(43,504,130)		(29,264,180)
Catawba- Net Negative Generation	(258,387)	-	(13,290)	(214,466)		(43,921)
WS Lee Joint Owner	(14,126,778)	-	(402,026)	(12,292,521)		(1,834,257)
Total Interchanges Out	(88,733,683)	(1,580,207)	(8,116,409)	(56,011,117)	-	(31,142,358)
Net Purchases and Interchange Power	**$ 414,226,937**	**$ 47,312,934**	**9,529,021**	**$ 237,309,023**	**$ 116,590,457**	**$ 13,014,529**

NOTES: Detail amounts may not add to totals shown due to rounding.
CPRE purchased power amounts are recovered through the CPRE Rider.

DUKE ENERGY CAROLINAS
INTERSYSTEM SALES*
SYSTEM REPORT - NORTH CAROLINA VIEW

Twelve Months Ended DEC 2021

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
SC Public Service Authority - Emergency	506,304	-	5,909	429,565	76,740
SC Electric & Gas / Dominion Energy - Emergency	49,990	-	1,091	52,118	(2,128)
Market Based:					
Carolina Power Partners, LLC	134,880	-	2,780	109,765	25,115
Central Electric Power Cooperative, Inc.	4,590,375	$ 4,809,001	(5,516)	(209,410)	(9,216)
Macquarie Energy, LLC	3,477,999	-	97,200	3,350,868	127,130
NCMPA	1,376,522	1,050,000	6,271	337,204	(10,682)
PJM Interconnection, LLC.	219,886	-	8,198	207,112	12,773
SC Electric & Gas / Dominion Energy	191,976	-	3,925	151,852	40,123
Southern Company	18,750	-	1,250	22,085	(3,335)
Tennesse Valley Authority	1,800	-	50	1,674	126
The Energy Authority	246,025	-	3,875	211,674	34,351
Other:					
DE Progress - Native Load Transfer Benefit	5,711,116	-	-	5,711,116	-
DE Progress - Native Load Transfer	35,200,938	-	1,094,952	33,084,586	2,116,352
Generation Imbalance	740,062	-	21,237	731,493	8,569
BPM Transmission	(635,177)	-	-	-	(635,177)
Total Intersystem Sales	**$ 51,831,446**	**$ 5,859,001**	**1,241,222**	**$ 44,191,701**	**$ 1,780,742**

* Sales for resale other than native load priority.

NOTES: Detail amounts may not add to totals shown due to rounding.

Duke Energy Carolinas
(Over) / Under Recovery of Fuel Costs
Dec 2021

Line No.			Residential	Commercial	Industrial	Total
1	Actual System kWh sales	Input				7,181,424,304
2	DERP Net Metered kWh generation	Input				10,166,360
3	Adjusted System kWh sales	L1 + L2				7,191,590,664
4	N.C. Retail kWh sales	Input	1,975,539,867	1,952,172,317	960,990,889	4,888,703,073
5	NC kWh sales % of actual system kWh sales	L4 T / L1				68.07%
6	NC kWh sales % of adjusted system kWh sales	L4 T / L3				67.98%
7	Approved fuel and fuel-related rates (¢/kWh)					
	7a Billed rates by class (¢/kWh)	Input Annually	1.5337	1.6895	1.7243	1.6334
	7b Billed fuel expense	L7b * L4 / 100	$30,298,855	$32,981,951	$16,570,366	$79,851,172
8	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)					
	8a Docket E-7, Sub 1228 allocation factor	Input	35.00%	43.03%	21.96%	
	8b System incurred expense	Input				$189,029,546
	8c Incurred base fuel and fuel-related expense	L8b * L6 * 8a	$44,977,890	$55,298,766	$28,221,943	$128,498,599
	8d Incurred base fuel rates by class (¢/kWh)	L8c / L4 * 100	2.2767	2.8327	2.9368	2.6285
9	Incurred renewable purchased power capacity rates by class (¢/kWh)					
	9a NC retail production plant %	Input				66.98%
	9b Production plant allocation factors	Input	47.00%	37.09%	15.90%	100.00%
	9c System incurred expense	Input				$1,159,361
	9d Incurred renewable capacity expense	L9a * L9b * 9c	$364,993	$288,032	$123,480	$776,505
	9e Incurred renewable capacity rates by class (¢/kWh)	(L9a * L9c) * L9b / L4 * 100	0.0185	0.0148	0.0128	0.0159
10	Total incurred rates by class (¢/kWh)	L8d + L9e	2.2952	2.8474	2.9496	2.6444
11	Difference in ¢/kWh (incurred - billed)	L7a - L10	0.7615	1.1579	1.2253	1.0110
12	(Over) / under recovery [See footnote]	(L4 * L11) / 100	$15,044,028	$22,604,847	$11,775,057	$49,423,931
13	Adjustments	Input				
14	Total (over) / under recovery [See footnote]	L12+ L13	$15,044,028	$22,604,847	$11,775,057	$49,423,931
15	Total system incurred expense	L8b + L9c				$190,188,907
16	Less: Jurisdictional allocation adjustment(s)	Input				265,155
17	Total Fuel and Fuel-related Costs per Schedule 2	L15 + L16 + L17				$189,923,752
18	(Over) / under recovery for each month of the current calendar year [See footnote]					

	Year 2021	Total To Date	(Over) / Under Recovery Residential	Commercial	Industrial	Total Company
	January	$1,309,433	($3,602,217)	$3,036,294	$1,875,356	$1,309,433
	February	25,482,004	$4,154,380	$14,053,467	$5,964,724	$24,172,571
_/1	March	24,201,918	($7,158,737)	$3,654,007	$2,224,644	($1,280,086)
	April	20,526,255	($1,178,659)	($1,305,025)	($1,191,979)	($3,675,663)
_/1	May	29,632,653	$5,643,932	$2,072,505	$1,389,961	$9,106,398
	June	44,906,231	$6,246,872	$5,677,153	$3,349,552	$15,273,578
	July	77,158,822	$10,918,699	$13,448,970	$7,884,922	$32,252,591
	August	115,066,658	$14,149,173	$18,244,441	$5,514,222	$37,907,836
	September	128,836,159	$3,848,250	$5,524,126	$4,397,125	$13,769,501
	October	156,238,043	$11,889,253	$8,129,521	$7,383,110	$27,401,884
	November	$221,044,690	$27,513,197	$29,272,230	$8,021,220	$64,806,647
	December	$270,468,622	$15,044,028	$22,604,847	$11,775,057	$49,423,932
			$87,468,172	$124,412,536	$58,587,915	$270,468,622

Notes:

Detail amounts may not recalculate due to percentages presented as rounded.

Presentation of over or under collected amounts reflects a regulatory asset or liability. Over collections, or regulatory liabilities, are shown as negative amounts.
Under collections, or regulatory assets, are shown as positive amounts.

_/1 Includes adjustments.

_/2 Reflects a prorated rate and prorated allocation factor for periods in which the approved rates changed.

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
DECEMBER 2021

Description	Buck	Dan River	Lee	Clemson	Lee	Lincoln	(A) Lincoln (Unit17)	Mill Creek	Rockingham
	CC	CC	CC	CHP	Steam/CT	CT	CT	CT	CT
Cost of Fuel Purchased ($)									
Coal									
Oil	-	-	-		-	-	-	682,026	342,571
Gas - CC	$18,337,524	$14,701,746	$24,724,237						
Gas - CHP				$817,949					
Gas - CT					$14,021	$6,134	($127,461)	$293,036	$4,099,824
Gas - Steam					3				
Biogas	-	221,776	-						
Total	$18,337,524	$14,923,522	$24,724,237	$817,949	$14,024	$6,134	($127,461)	$975,062	$4,442,395
Average Cost of Fuel Purchased (¢/MBTU)									
Coal		-							
Oil					-	-	-	1,672.86	1,655.96
Gas - CC	632.40	632.14	634.66						
Gas - CHP				715.93					
Gas - CT					-	1,792.50	(1,005.99)	653.43	636.17
Gas - Steam					-				
Biogas	-	2,601.47	-						
Weighted Average	632.40	639.34	634.66	715.93	-	1,792.50	(1,005.99)	1,138.88	667.89
Cost of Fuel Burned ($)									
Coal		-	-		-				
Oil - CC	-	-	-						
Oil - Steam/CT					$49,924	-	154,413	21,294	-
Gas - CC	$18,337,524	$14,701,746	$24,724,237						
Gas - CHP				$817,949					
Gas - CT					14,021	$6,134	($127,461)	$293,036	$4,099,824
Gas - Steam					3				
Biogas	-	221,776	-						
Nuclear									
Total	$18,337,524	$14,923,522	$24,724,237	$817,949	$63,949	$6,134	$26,952	$314,330	$4,099,824
Average Cost of Fuel Burned (¢/MBTU)									
Coal					-				
Oil - CC									
Oil - Steam/CT					1,400.40	-	1,105.56	1,784.91	-
Gas - CC	632.40	632.14	634.66						
Gas - CHP				715.93					
Gas - CT					-	1,792.50	(1,005.99)	653.43	636.17
Gas - Steam					-				
Biogas	-	2,601.47	-						
Nuclear									
Weighted Average	632.40	639.34	634.66	715.93	1,793.79	1,792.50	101.18	682.75	636.17
Average Cost of Generation (¢/kWh)									
Coal		-	-		-	-	-		
Oil - CC	-	-	-						
Oil - Steam/CT		-	-		-	-	15.06	1.68	-
Gas - CC	4.44	4.43	4.47						
Gas - CHP				8.53					
Gas - CT					-	-	-	15.22	6.76
Gas - Steam					-	-	-	-	-
Biogas	-	18.25	-						
Nuclear									
Weighted Average	4.44	4.48	4.47	8.53	-	-	5.90	9.84	6.76
Burned MBTU's									
Coal					-				
Oil - CC									
Oil - Steam/CT					3,565	-	13,967	1,193	-
Gas - CC	2,899,674	2,325,698	3,895,675						
Gas - CHP				114,250					
Gas - CT					-	342	12,670	44,846	644,452
Gas - Steam					-				
Biogas	-	8,525	-						
Nuclear									
Total	2,899,674	2,334,223	3,895,675	114,250	3,565	342	26,637	46,039	644,452
Net Generation (mWh)									
Coal									
Oil - CC									
Oil - Steam/CT		-	-		(34)	-	1,025	1,269	-
Gas - CC	413,337	332,121	553,237		-				
Gas - CHP				9,589					
Gas - CT					(0)	(855)	(568)	1,925	60,653
Gas - Steam					(388)				
Biogas	-	1,215	-						
Nuclear 100%									
Hydro (Total System)									
Solar (Total System)									
Total	413,337	333,336	553,237	9,589	(422)	(855)	457	3,194	60,653
Cost of Reagents Consumed ($)									
Ammonia	$45,251	$0	$27,467						
Limestone									
Sorbents									
Urea									
Re-emission Chemical									
Dibasic Acid									
Activated Carbon									
Lime (water emissions)									
Total	$45,251	$0	$27,467						

Notes:
(A) Lincoln (Unit 17) fuel and fuel related costs represents pre-commercial generation during an extended testing and validation period.
Detail amounts may not add to totals shown due to rounding.
Data is reflected at 100% ownership.
Schedule excludes in-transit and terminal activity.
Cents/MBTU and cents/kWh are not computed when costs and/or net generation is negative.
Re-emission chemical reagent expense is not recoverable in NC.
Lime (water emissions) expense is not recoverable in SC fuel clause.

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
DECEMBER 2021

Description	Allen Steam	Marshall Steam - Dual Fuel	Belews Creek Steam - Dual Fuel	Cliffside Steam - Dual Fuel	Catawba Nuclear	McGuire Nuclear	Oconee Nuclear	Current Month	Total 12 ME December 2021
Cost of Fuel Purchased ($)									
Coal	$9,147	$13,307,577	$3,448,822	$4,617,247				21,382,792	$427,384,699
Oil	17,051	-	-	104,088				1,145,737	8,620,241
Gas - CC								57,763,507	416,957,828
Gas - CHP								817,949	1,710,128
Gas - CT								4,285,554	48,026,140
Gas - Steam		19,910,055	20,938,211	20,962,280				61,810,549	331,328,622
Biogas								221,776	3,513,761
Total	$26,198	$33,217,632	$24,387,033	$25,683,615				$147,427,864	$1,237,541,419
Average Cost of Fuel Purchased (¢/MBTU)									
Coal	-	341.95	388.15	353.46				351.32	311.27
Oil	1,657.42	-	-	1,659.76				1,666.35	1,557.24
Gas - CC								633.30	406.84
Gas - CHP								715.93	718.56
Gas - CT								639.90	378.17
Gas - Steam		632.16	632.96	644.19				636.47	447.74
Biogas				.				2,601.47	2,304.35
Weighted Average	2,546.48	471.76	581.13	562.42				571.14	377.95
Cost of Fuel Burned ($)									
Coal	$65,756	$5,862,319	$2,100,615	$1,800,631				$9,829,322	$428,535,150
Oil - CC								-	-
Oil - Steam/CT	29,766	10,457	-	56,288				322,142	8,828,699
Gas - CC								57,763,507	416,957,828
Gas - CHP								817,949	1,710,128
Gas - CT								4,285,554	48,026,140
Gas - Steam		19,910,055	20,938,211	20,962,280				61,810,549	331,328,622
Biogas								221,776	3,513,761
Nuclear					$10,271,789	$9,549,235	$10,065,209	29,886,234	346,155,577
Total	$95,522	$25,782,831	$23,038,826	$22,819,199	$10,271,789	$9,549,235	$10,065,209	$164,937,032	$1,585,055,905
Average Cost of Fuel Burned (¢/MBTU)									
Coal	308.89	306.80	326.30	296.55				308.80	323.27
Oil - CC								-	-
Oil - Steam/CT	1,714.61	1,448.33	-	1,600.91				1,304.27	1,513.70
Gas - CC								633.30	406.84
Gas - CHP								715.93	718.56
Gas - CT								639.90	378.17
Gas - Steam		632.16	632.96	644.19				636.47	447.74
Biogas								2,601.47	2,304.35
Nuclear					58.89	54.27	58.00	57.04	56.91
Weighted Average	414.88	509.44	583.01	590.45	58.89	54.27	58.00	219.17	170.26
Average Cost of Generation (¢/kWh)									
Coal	-	3.39	3.67	3.13				3.44	3.16
Oil - CC								-	-
Oil - Steam/CT	47.38	22.07	-	16.10				11.84	16.35
Gas - CC								4.45	2.87
Gas - CHP								8.53	10.87
Gas - CT								7.01	4.24
Gas - Steam		5.99	6.50	6.56				6.35	4.58
Biogas								18.25	16.34
Nuclear					0.59	0.54	0.59	0.57	0.57
Weighted Average	-	5.10	6.07	6.04	0.59	0.54	0.59	2.09	1.61
Burned MBTU's									
Coal	21,288	1,910,774	643,767	607,196				3,183,025	132,563,622
Oil - CC								-	-
Oil - Steam/CT	1,736	722	-	3,516				24,699	583,254
Gas - CC								9,121,047	102,486,732
Gas - CHP								114,250	237,993
Gas - CT								702,310	12,699,459
Gas - Steam		3,149,517	3,307,964	3,254,033				9,711,513	74,000,255
Biogas								8,525	152,484
Nuclear					17,441,318	17,596,089	17,353,876	52,391,283	608,224,167
Total	23,024	5,061,013	3,951,731	3,864,745	17,441,318	17,596,089	17,353,876	75,256,653	930,947,966
Net Generation (mWh)									
Coal	(1,949)	172,888	57,288	57,562				285,789	13,569,695
Oil - CC								-	-
Oil - Steam/CT	63	47	-	350				2,720	53,988
Gas - CC								1,298,695	14,542,974
Gas - CHP								9,589	15,739
Gas - CT								61,155	1,131,529
Gas - Steam		332,208	322,315	319,641				973,777	7,231,653
Biogas								1,215	21,502
Nuclear 100%					1,750,213	1,777,245	1,717,933	5,245,391	60,454,296
Hydro (Total System)								(11,675)	1,340,157
Solar (Total System)								15,972	293,289
Total	(1,886)	505,143	379,603	377,553	1,750,213	1,777,245	1,717,933	7,882,628	98,654,822
Cost of Reagents Consumed ($)									
Ammonia			$201,650	$36,996				$311,364	$3,138,382
Limestone	$0	$247,876	50,319	154,001				$452,195	12,981,466
Sorbents	-	31,875	-					$31,875	1,514,963
Urea	-	51,650						$51,650	389,401
Re-emission Chemical	-	-	-	-				$0	316,690
Dibasic Acid	-							$0	-
Activated Carbon	-	-						$0	358,930
Lime (water emissions)	-	-	8,010					$8,010	39,411
Total	-	331,401	$259,978	$190,997				$855,094	$18,739,243

Notes:
(A) Lincoln (Unit 17) fuel and fuel related costs represents pre-commercial generation during an extended testing and validation period.
Detail amounts may not add to totals shown due to rounding.
Data is reflected at 100% ownership.
Schedule excludes in-transit and terminal activity.
Cents/MBTU and cents/kWh are not computed when costs and/or net generation is negative.
Re-emission chemical reagent expense is not recoverable in NC.
Lime (water emissions) expense is not recoverable in SC fuel clause.

Sykes Exhibit 6
Schedule 6

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED CONSUMPTION AND INVENTORY REPORT
DECEMBER 2021

Description	Buck	Dan River	Lee	Clemson	Lee	Lincoln	(A) Lincoln (Unit17)	Mill Creek	Rockingham	Allen	Marshall	Belews Creek	Cliffside	Current Month	Total 12 ME December 2021
	CC	CC	CC	CHP	Steam/CT	CT	CT	CT	CT	Steam	Steam - Dual Fuel	Steam - Dual Fuel	Steam - Dual Fuel		
Coal Data:															
Beginning balance					-					110,834	714,068	709,231	600,419	2,134,553	2,088,546.52
Tons received during period										-	154,113	36,234	50,335	240,682	5,535,629.00
Inventory adjustments					-					-	0	(0)	0	0	(59,105.14)
Tons burned during period					-					885	74,950	25,810	23,739	125,384	5,315,219.09
Ending balance					-					109,949	793,231	719,654	627,016	2,249,850	2,249,850.29
MBTUs per ton burned					-					144.00	25.49	24.94	25.58	26.23	24.94
Cost of ending inventory ($/ton)					-					74.30	78.22	81.39	75.85	78.38	78.38
Oil Data:															
Beginning balance	-	-	-		644,737	8,458,109	1,345,366	3,435,783	2,760,864	74,474	297,507	95,645	190,014	17,302,499	18,142,757
Gallons received during period	-	-	-		-	-	-	295,436	149,907	7,455	-	-	45,444	498,242	4,011,299
Miscellaneous adjustments	-	-	-		-	-	(24,834)	-	-	-	-	(5,273)	(4,237)	(34,099)	(274,028)
Gallons burned during period		-	-		25,990	-	77,576	8,668	-	12,671	5,273	-	25,712	156,135	4,269,522
Ending balance	-	-	-		618,747	8,458,109	1,242,955	3,722,551	2,910,771	69,258	292,234	90,372	205,509	17,610,506	17,610,506
Cost of ending inventory ($/gal)	-	-	-		1.92	2.10	1.99	2.46	2.12	2.35	1.98	2.25	2.19	2.16	2.16
Natural Gas Data:															
Beginning balance															
MCF received during period	2,807,749	2,247,267	3,791,315	111,221	-	332	(158)	43,738	622,006		3,060,068	3,194,905	3,155,140	19,033,584	183,335,760
MCF burned during period	2,807,749	2,247,267	3,791,315	111,221	-	332	(158)	43,738	622,006		3,060,068	3,194,905	3,155,140	19,033,584	183,335,760
Ending balance															
Biogas Data:															
Beginning balance															
MCF received during period	-	8,237	-											8,237	147,532
MCF burned during period	-	8,237	-											8,237	147,532
Ending balance															
Limestone Data:															
Beginning balance										24,210	45,035	45,723	29,962	144,930	154,428
Tons received during period										-	12,544	1,676	8,277	22,498	281,447
Inventory adjustments										-	-	-	-	-	(1,837)
Tons consumed during period										-	5,699	1,074	1,915	8,688	275,299
Ending balance										24,210	51,880	46,325	36,324	158,739	158,739
Cost of ending inventory ($/ton)										49.08	43.49	46.83	42.16	45.02	45.02
														Qtr Ending December 2021	Total 12 ME December 2021
Ammonia Data: (B)															
Beginning balance	2,650													2,650	1,822
Tons received during period	996													996	5,129
Tons consumed during period	885													885	4,190
Ending balance	2,761													2,761	2,761
Cost of ending inventory ($/ton)	843.38													843.38	843.38

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit and terminal activity.
Gas is burned as received; therefore, inventory balances are not maintained.
(A) Lincoln (Unit 17) fuel and fuel related costs represents pre-commercial generation during an extended testing and validation period.
(B) Quarterly ammonia inventory amounts are revised to reflect a correction to June quantities, affecting the quarter ending September 2021 beginning balance. Revised amounts for quarter ending June 2021 are revised above.

Sykes Exhibit 6
Schedule 7

DUKE ENERGY CAROLINAS
ANALYSIS OF COAL PURCHASED
DECEMBER 2021

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ALLEN	SPOT	-	$ -	$ -
	CONTRACT	-	-	-
	FIXED TRANSPORTATION / ADJUSTMENTS	-	9,147	-
	TOTAL	-	9,147	-
BELEWS CREEK	SPOT	-	111,089	-
	CONTRACT	36,234	2,920,743	80.61
	FIXED TRANSPORTATION / ADJUSTMENTS	-	416,990	-
	TOTAL	36,234	3,448,822	95.18
CLIFFSIDE	SPOT	13,034	1,151,180	88.32
	CONTRACT	37,301	3,111,563	83.42
	FIXED TRANSPORTATION / ADJUSTMENTS	-	354,504	-
	TOTAL	50,335	4,617,247	91.73
MARSHALL	SPOT	76,949	6,966,864	90.54
	CONTRACT	77,165	5,901,064	76.47
	FIXED TRANSPORTATION / ADJUSTMENTS	-	439,649	-
	TOTAL	154,114	13,307,577	86.35
ALL PLANTS	SPOT	89,983	8,229,133	91.45
	CONTRACT	150,700	11,933,370	79.19
	FIXED TRANSPORTATION / ADJUSTMENTS	-	1,220,290	-
	TOTAL	240,683	21,382,793	$ 88.84

Sykes Exhibit 6
Schedule 8

DUKE ENERGY CAROLINAS
ANALYSIS OF COAL QUALITY RECEIVED
DECEMBER 2021

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
ALLEN	-	-	-	-
BELEWS CREEK	7.48	10.95	12,261	1.47
CLIFFSIDE	6.18	8.77	12,976	2.99
LEE	-	-	-	-
MARSHALL	6.73	9.31	12,626	1.95

Sykes Exhibit 6
Schedule 9

DUKE ENERGY CAROLINAS
ANALYSIS OF OIL PURCHASED
DECEMBER 2021

	ALLEN	BELEWS CREEK
VENDOR	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract
SULFUR CONTENT %	-	-
GALLONS RECEIVED	7,455	-
TOTAL DELIVERED COST	$ 17,051	$ -
DELIVERED COST/GALLON	$ 2.29	$ -
BTU/GALLON	138,000	138,000

	CLIFFSIDE	MARSHALL
VENDOR	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract
SULFUR CONTENT %	-	-
GALLONS RECEIVED	45,444	-
TOTAL DELIVERED COST	$ 104,088	$ -
DELIVERED COST/GALLON	$ 2.29	$ -
BTU/GALLON	138,000	138,000

	LEE	MILL CREEK	ROCKINGHAM
VENDOR	HighTowers	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract	Contract
SULFUR CONTENT %	-	-	-
GALLONS RECEIVED	-	295,436	149,907
TOTAL DELIVERED COST	$ -	$ 682,026	$ 342,571
DELIVERED COST/GALLON	$ -	$ 2.31	$ 2.29
BTU/GALLON	138,000	138,000	138,000

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: December 2021 - December 2021

Station	Unit	Date of Outage	Duration of Outage (Hours)	Scheduled / Unscheduled	Cause of Outage	Reason Outage Occurred	Remedial Actions Taken
Oconee	1						
	2	11/12/2021 - 12/07/2021	160.10	Scheduled	Refueling outage O2R30	Normal refueling outage	N/A - Normal refueling outage
	2	12/10/2021 - 12/12/2021	60.35	Unscheduled	Forced outage O2F30A due to spurious reactor protection system (RPS) relay actuation	Spurious reactor protection system (RPS) relay actuation	A failure investigation was started and the 2NI-5 linear amplifier was repaired
	3						
McGuire	1						
	2						
Catawba	1						
	2						

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2021

Belews Creek Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
1	12/1/2021 11:30:00 AM To 12/3/2021 5:00:00 PM	Sch	4899	Other miscellaneous generator problems	Generator PT appears to have a loose connection causing issues with closing	

Buck Combined Cycle Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
11	12/19/2021 10:42:00 AM To 12/19/2021 10:46:00 AM	Unsch	6171	IP Startup bypass system valves	12 HRH BYPASS STICKING. WOULD NOT OPERATE BEYOND 35%. CAUSING UPSETS TO OPPOSING UNIT.	
12	12/18/2021 2:00:00 PM To 12/18/2021 8:06:00 PM	Sch	0680	Feedwater valves (not feedwater regulating valve)	12 ECONOMIZER VENT VALVE REPLACEMENT. VALVE PACKING BLOWN OUT AND VALVE WAS STUCK AND WOULD NOT OPERATE.	
ST10	12/19/2021 9:04:00 AM To 12/19/2021 9:47:00 AM	Unsch	6171	IP Startup bypass system valves	12 HRH BYPASS STICKING. WOULD NOT OPERATE BEYOND 35%. CAUSING UPSET TO UNIT.	
ST10	12/19/2021 10:22:00 AM To 12/19/2021 11:04:00 AM	Unsch	6171	IP Startup bypass system valves	12 HRH BYPASS STICKING. WOULD NOT OPERATE BEYOND 35%. CAUSING UPSET TO UNIT	

Clemson CHP

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
1	11/24/2021 9:30:00 AM To 12/1/2021 9:00:00 AM	Sch	4551	Generator bearings	Planned outage to address generator bearing leaks. New seals installed.	
1	12/8/2021 10:13:00 AM To 12/8/2021 5:28:00 PM	Sch	4552	Generator lube oil system	Short outage for generator oil leakage inspection.	

Dan River Combined Cycle Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
8	12/8/2021 9:59:00 PM To 12/12/2021 1:27:00 PM	Sch	5261	Gas turbine/compressor washing	1x1 Planned Outage for Water Wash of GT8 and minor maintenance	

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% owne

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2021

9	12/4/2021 12:56:00 AM To 12/8/2021 6:52:00 PM	Sch	5261	Gas turbine/compressor washing	GT9 is in Planned Outage for 1X1 outage for Water Wash and Minor Maintenance	

Marshall Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
3	12/10/2021 2:29:00 AM To 12/16/2021 2:30:00 PM	Sch	0541	Cold reheat steam piping up to boiler	Reheat Piping Leak Repairs	
3	12/19/2021 12:44:00 PM To 12/19/2021 2:51:00 PM	Unsch	0530	Other main steam system problems	Superheat steam temp issues	
3	12/19/2021 2:51:00 PM To 12/20/2021 3:00:00 PM	Unsch	4240	Bearings	Unit 3 bearing vibration on attempted start.	
3	12/20/2021 3:00:00 PM To 12/30/2021 7:00:00 PM	Unsch	4240	Bearings	Unit 3 bearing vibration on attempted start. Unit will go into outage to repair the issue.	

WS Lee Combined Cycle

No Outages at Baseload Units During the Month.

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership.

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: December 2021 - December 2021

	Oconee 1	Oconee 2	Oconee 3	McGuire 1	McGuire 2	Catawba 1	Catawba 2
(A) MDC (MW)	847	848	859	1158	1158	1160	1150
(B) Period Hours	744	744	744	744	744	744	744
(C1) Net Gen (MWH)	643,930	419,589	654,414	888,551	888,694	880,196	870,017
(C2) Capacity Factor (%)	102.18	66.51	102.40	103.13	103.15	101.99	101.69
(D1) Net MWH Not Gen. Due to Full Schedule Outages	0	135,765	0	0	0	0	0
(D2) % Net MWH Not Gen. Due to Full Schedule Outages	0.00	21.52	0.00	0.00	0.00	0.00	0.00
(E1) Net MWH Not Gen. Due to Partial Scheduled Outages	0	18,509	0	0	0	0	0
(E2) % Net MWH Not Gen. Due to Partial Scheduled Outages	0.00	2.93	0.00	0.00	0.00	0.00	0.00
(F1) Net MWH Not Gen Due to Full Forced Outages	0	51,177	0	0	0	0	0
(F2) % Net MWH Not Gen Due to Full Forced Outages	0.00	8.11	0.00	0.00	0.00	0.00	0.00
(G1) Net MWH Not Gen due to Partial Forced Outages	-13,762	5,872	-15,318	-26,999	-27,142	-17,156	-14,417
(G2) % Net MWH Not Gen Due to Partial Forced Outages	-2.18	0.93	-2.40	-3.13	-3.15	-1.99	-1.69
(H1) Net MWH Not Gen Due to Economic Dispatch	0	0	0	0	0	0	0
(H2) %Net MWH Not Gen Due to Economic Dispatch	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(I1) Core Conservation	0	0	0	0	0	0	0
(I2) % Core Conservation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(J1) Net MWH Possible in Period	630,168	630,912	639,096	861,552	861,552	863,040	855,600
(J2) % Net mwh Possible in Period	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
(K) Equivalent Availability (%)	100.00	65.78	100.00	100.00	100.00	100.00	100.00
(L) Output Factor (%)	102.18	94.51	102.40	103.13	103.15	101.99	101.69
(M) Heat Rate (BTU/Net KWH)	10,130	10,277	9,961	9,901	9,901	9,991	9,939

Notes:
1) Fields (E1), (E2), (G1), (G2), (H1), (H2), (I1) and (I2) are estimates
2) Fields (D1), (D2), (F1) and (F2) include ramping losses
EAF is calculated using Standard NERC calculation and excludes OMC events

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2021

Belews Creek Station

	Unit 1	Unit 2
(A) MDC (mW)	1,110	1,110
(B) Period Hrs	744	744
(C) Net Generation (mWh)	-1,362	380,965
(D) Capacity Factor (%)	0.00	46.13
(E) Net mWh Not Generated due to Full Scheduled Outages	59,385	0
(F) Scheduled Outages: percent of Period Hrs	7.19	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	33,600
(H) Scheduled Derates: percent of Period Hrs	0.00	4.07
(I) Net mWh Not Generated due to Full Forced Outages	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	770
(L) Forced Derates: percent of Period Hrs	0.00	0.09
(M) Net mWh Not Generated due to Economic Dispatch	766,455	410,505
(N) Economic Dispatch: percent of Period Hrs	92.81	49.71
(O) Net mWh Possible in Period	825,840	825,840
(P) Equivalent Availability (%)	92.81	95.84
(Q) Output Factor (%)	0.00	46.13
(R) Heat Rate (BTU/NkWh)	0	10,986

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2021

Buck Combined Cycle Station

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	206	206	306	718
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	127,292	114,031	172,014	413,337
(D) Capacity Factor (%)	83.05	74.40	75.56	77.38
(E) Net mWh Not Generated due to Full Scheduled Outages	0	1,257	0	1,257
(F) Scheduled Outages: percent of Period Hrs	0.00	0.82	0.00	0.24
(G) Net mWh Not Generated due to Partial Scheduled Outages	231	231	525	987
(H) Scheduled Derates: percent of Period Hrs	0.15	0.15	0.23	0.18
(I) Net mWh Not Generated due to Full Forced Outages	14	0	434	447
(J) Forced Outages: percent of Period Hrs	0.01	0.00	0.19	0.08
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	383	383
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.17	0.07
(M) Net mWh Not Generated due to Economic Dispatch	25,727	37,745	54,308	117,781
(N) Economic Dispatch: percent of Period Hrs	16.79	24.63	23.85	22.05
(O) Net mWh Possible in Period	153,264	153,264	227,664	534,192
(P) Equivalent Availability (%)	99.84	99.03	99.41	99.42
(Q) Output Factor (%)	83.06	83.25	75.70	79.88
(R) Heat Rate (BTU/NkWh)	10,525	10,190	2,366	7,037

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2021

Clemson CHP

	Clemson CHP1
(A) MDC (mW)	16
(B) Period Hrs	744
(C) Net Generation (mWh)	9,589
(D) Capacity Factor (%)	83.15
(E) Net mWh Not Generated due to Full Scheduled Outages	252
(F) Scheduled Outages: percent of Period Hrs	2.18
(G) Net mWh Not Generated due to Partial Scheduled Outages	0
(H) Scheduled Derates: percent of Period Hrs	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0
(J) Forced Outages: percent of Period Hrs	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0
(L) Forced Derates: percent of Period Hrs	0.00
(M) Net mWh Not Generated due to Economic Dispatch	1,691
(N) Economic Dispatch: percent of Period Hrs	14.66
(O) Net mWh Possible in Period	11,532
(P) Equivalent Availability (%)	97.82
(Q) Output Factor (%)	86.79
(R) Heat Rate (BTU/NkWh)	11,176

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2021

Dan River Combined Cycle Station

	Unit 8	Unit 9	Unit ST07	Block Total
(A) MDC (mW)	206	206	308	720
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	84,374	107,001	141,961	333,336
(D) Capacity Factor (%)	55.05	69.81	61.95	62.23
(E) Net mWh Not Generated due to Full Scheduled Outages	18,018	23,470	0	41,488
(F) Scheduled Outages: percent of Period Hrs	11.76	15.31	0.00	7.74
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	127	127
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.06	0.02
(M) Net mWh Not Generated due to Economic Dispatch	50,872	22,793	87,064	160,729
(N) Economic Dispatch: percent of Period Hrs	33.19	14.87	37.99	30.00
(O) Net mWh Possible in Period	153,264	153,264	229,152	535,680
(P) Equivalent Availability (%)	88.24	84.69	99.94	92.23
(Q) Output Factor (%)	82.25	82.44	61.95	72.22
(R) Heat Rate (BTU/NkWh)	11,217	10,612	2,470	7,297

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2021

Marshall Station

	Unit 3	Unit 4
(A) MDC (mW)	658	660
(B) Period Hrs	744	744
(C) Net Generation (mWh)	77,447	297,472
(D) Capacity Factor (%)	15.82	60.58
(E) Net mWh Not Generated due to Full Scheduled Outages	102,659	0
(F) Scheduled Outages: percent of Period Hrs	20.97	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	177,836	0
(J) Forced Outages: percent of Period Hrs	36.33	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	131,610	193,568
(N) Economic Dispatch: percent of Period Hrs	26.88	39.42
(O) Net mWh Possible in Period	489,552	491,040
(P) Equivalent Availability (%)	42.70	100.00
(Q) Output Factor (%)	53.10	60.58
(R) Heat Rate (BTU/NkWh)	10,746	9,696

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2021

Sykes Exhibit 6
Schedule 10

WS Lee Combined Cycle

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	248	248	313	809
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	158,470	164,031	230,736	553,237
(D) Capacity Factor (%)	85.89	88.90	99.08	91.92
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	26,042	20,481	2,136	48,659
(N) Economic Dispatch: percent of Period Hrs	14.11	11.10	0.92	8.08
(O) Net mWh Possible in Period	184,512	184,512	232,872	601,896
(P) Equivalent Availability (%)	100.00	100.00	100.00	100.00
(Q) Output Factor (%)	85.89	91.67	99.08	92.78
(R) Heat Rate (BTU/NkWh)	10,989	10,610	2,508	7,340

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's
- Data is reflected at 100% ownership.

Duke Energy Carolinas
Intermediate Power Plant Performance Review Plan
December 2021

Sykes Exhibit 6
Schedule 10

		Cliffside Station
		Cliffside 6
(A)	**MDC (mW)**	849
(B)	**Period Hrs**	744
(C)	**Net Generation (mWh)**	380,358
(D)	**Net mWh Possible in Period**	631,656
(E)	**Equivalent Availability (%)**	96.32
(F)	**Output Factor (%)**	60.22
(G)	**Capacity Factor (%)**	60.22

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Carolinas
Peaking Power Plant Performance Review Plan
December 2021

Sykes Exhibit 6
Schedule 10

		Cliffside Station
		Unit 5
(A)	**MDC (mW)**	546
(B)	**Period Hrs**	744
(C)	**Net Generation (mWh)**	-2,805
(D)	**Net mWh Possible in Period**	406,224
(E)	**Equivalent Availability (%)**	0.00
(F)	**Output Factor (%)**	0.00
(G)	**Capacity Factor (%)**	0.00

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: January 2021 - December 2021

	Oconee 1	Oconee 2	Oconee 3	McGuire 1	McGuire 2	Catawba 1	Catawba 2
(A) MDC (MW)	847	848	859	1158	1158	1160	1150
(B) Period Hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760
(C1) Net Gen (MWH)	7,579,868	6,981,796	7,644,799	10,361,236	9,300,878	9,571,297	9,014,422
(C2) Capacity Factor (%)	102.16	93.99	101.59	102.14	91.69	94.19	89.48
(D1) Net MWH Not Gen. Due to Full Schedule Outages	0	503,797	0	0	840,901	523,488	883,200
(D2) % Net MWH Not Gen. Due to Full Schedule Outages	0.00	6.78	0.00	0.00	8.29	5.15	8.77
(E1) Net MWH Not Gen. Due to Partial Scheduled Outages	141	39,112	252	403	26,161	47,272	90,598
(E2) % Net MWH Not Gen. Due to Partial Scheduled Outages	0.00	0.53	0.00	0.00	0.26	0.47	0.90
(F1) Net MWH Not Gen Due to Full Forced Outages	0	51,177	0	0	81,871	78,396	147,045
(F2) % Net MWH Not Gen Due to Full Forced Outages	0.00	0.69	0.00	0.00	0.81	0.77	1.46
(G1) Net MWH Not Gen due to Partial Forced Outages	-160,289	-147,402	-120,211	-217,559	-105,731	-58,853	-61,265
(G2) % Net MWH Not Gen Due to Partial Forced Outages	-2.16	-1.99	-1.59	-2.14	-1.05	-0.58	-0.61
(H1) Net MWH Not Gen Due to Economic Dispatch	0	0	0	0	0	0	0
(H2) %Net MWH Not Gen Due to Economic Dispatch	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(I1) Core Conservation	0	0	0	0	0	0	0
(I2) % Core Conservation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(J1) Net MWH Possible in Period	7,419,720	7,428,480	7,524,840	10,144,080	10,144,080	10,161,600	10,074,000
(J2) % Net mwh Possible in Period	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
(K) Equivalent Availability (%)	100.00	90.67	100.00	100.00	90.25	93.06	88.87
(L) Output Factor (%)	102.16	101.58	101.59	102.14	100.86	100.12	99.68
(M) Heat Rate (BTU/Net KWH)	10,129	10,085	10,042	9,996	10,073	10,090	10,026

Notes:
1) Fields (E1), (E2), (G1), (G2), (H1), (H2), (I1) and (I2) are estimates
2) Fields (D1), (D2), (F1) and (F2) include ramping losses
EAF is calculated using Standard NERC calculation and excludes OMC events

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2021 through December, 2021

Belews Creek Station

	Unit 1	Unit 2
(A) MDC (mW)	1,110	1,110
(B) Period Hrs	8,760	8,760
(C) Net Generation (mWh)	4,275,170	4,734,846
(D) Capacity Factor (%)	43.97	48.69
(E) Net mWh Not Generated due to Full Scheduled Outages	1,696,635	1,108,465
(F) Scheduled Outages: percent of Period Hrs	17.45	11.40
(G) Net mWh Not Generated due to Partial Scheduled Outages	13,357	54,149
(H) Scheduled Derates: percent of Period Hrs	0.14	0.56
(I) Net mWh Not Generated due to Full Forced Outages	157,731	277,075
(J) Forced Outages: percent of Period Hrs	1.62	2.85
(K) Net mWh Not Generated due to Partial Forced Outages	188,070	72,653
(L) Forced Derates: percent of Period Hrs	1.93	0.75
(M) Net mWh Not Generated due to Economic Dispatch	3,392,638	3,476,412
(N) Economic Dispatch: percent of Period Hrs	34.81	35.75
(O) Net mWh Possible in Period	9,723,600	9,723,600
(P) Equivalent Availability (%)	78.86	84.45
(Q) Output Factor (%)	66.62	59.52
(R) Heat Rate (BTU/NkWh)	9,382	9,959

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership.
- Footnote: (R) Includes Light Off BTU's

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2021 through December, 2021

Sykes Exhibit 6
Schedule 10

Buck Combined Cycle Station

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	206	206	306	718
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,350,380	1,370,919	1,814,076	4,535,375
(D) Capacity Factor (%)	74.83	75.97	67.68	72.11
(E) Net mWh Not Generated due to Full Scheduled Outages	106,389	81,507	123,379	311,276
(F) Scheduled Outages: percent of Period Hrs	5.90	4.52	4.60	4.95
(G) Net mWh Not Generated due to Partial Scheduled Outages	114,711	117,301	11,070	243,082
(H) Scheduled Derates: percent of Period Hrs	6.36	6.50	0.41	3.86
(I) Net mWh Not Generated due to Full Forced Outages	14	1,507	434	1,955
(J) Forced Outages: percent of Period Hrs	0.00	0.08	0.02	0.03
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	3,024	3,024
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.11	0.05
(M) Net mWh Not Generated due to Economic Dispatch	233,066	233,325	728,577	1,194,969
(N) Economic Dispatch: percent of Period Hrs	12.92	12.93	27.18	19.00
(O) Net mWh Possible in Period	1,804,560	1,804,560	2,680,560	6,289,680
(P) Equivalent Availability (%)	87.75	88.90	94.86	91.11
(Q) Output Factor (%)	82.76	82.91	72.45	78.35
(R) Heat Rate (BTU/NkWh)	9,691	10,236	1,616	6,626

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership.
- Footnote: (R) Includes Light Off BTU's

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2021 through December, 2021

Clemson CHP

	Clemson CHP1
(A) MDC (mW)	16
(B) Period Hrs	8,760
(C) Net Generation (mWh)	15,739
(D) Capacity Factor (%)	11.59
(E) Net mWh Not Generated due to Full Scheduled Outages	24,977
(F) Scheduled Outages: percent of Period Hrs	18.40
(G) Net mWh Not Generated due to Partial Scheduled Outages	11,069
(H) Scheduled Derates: percent of Period Hrs	8.15
(I) Net mWh Not Generated due to Full Forced Outages	10,258
(J) Forced Outages: percent of Period Hrs	7.55
(K) Net mWh Not Generated due to Partial Forced Outages	0
(L) Forced Derates: percent of Period Hrs	0.00
(M) Net mWh Not Generated due to Economic Dispatch	73,736
(N) Economic Dispatch: percent of Period Hrs	54.13
(O) Net mWh Possible in Period	135,780
(P) Equivalent Availability (%)	65.90
(Q) Output Factor (%)	80.91
(R) Heat Rate (BTU/NkWh)	11,851

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership.
- Footnote: (R) Includes Light Off BTU's

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2021 through December, 2021

Dan River Combined Cycle Station

	Unit 8	Unit 9	Unit ST07	Block Total
(A) MDC (mW)	206	206	308	720
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,228,210	1,262,306	1,682,928	4,173,444
(D) Capacity Factor (%)	68.06	69.95	62.38	66.17
(E) Net mWh Not Generated due to Full Scheduled Outages	157,624	164,209	208,321	530,155
(F) Scheduled Outages: percent of Period Hrs	8.73	9.10	7.72	8.41
(G) Net mWh Not Generated due to Partial Scheduled Outages	138,404	138,401	283,369	560,174
(H) Scheduled Derates: percent of Period Hrs	7.67	7.67	10.50	8.88
(I) Net mWh Not Generated due to Full Forced Outages	11,268	8,992	13,003	33,263
(J) Forced Outages: percent of Period Hrs	0.62	0.50	0.48	0.53
(K) Net mWh Not Generated due to Partial Forced Outages	524	524	1,751	2,799
(L) Forced Derates: percent of Period Hrs	0.03	0.03	0.06	0.04
(M) Net mWh Not Generated due to Economic Dispatch	268,530	230,128	508,708	1,007,366
(N) Economic Dispatch: percent of Period Hrs	14.88	12.75	18.85	15.97
(O) Net mWh Possible in Period	1,804,560	1,804,560	2,698,080	6,307,200
(P) Equivalent Availability (%)	82.94	82.70	81.23	82.14
(Q) Output Factor (%)	80.86	81.25	70.26	76.33
(R) Heat Rate (BTU/NkWh)	10,791	10,678	1,695	7,089

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership.
- Footnote: (R) Includes Light Off BTU's

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2021 through December, 2021

Sykes Exhibit 6
Schedule 10

Marshall Station

	Unit 3	Unit 4
(A) MDC (mW)	658	660
(B) Period Hrs	8,760	8,760
(C) Net Generation (mWh)	1,592,995	3,404,773
(D) Capacity Factor (%)	27.64	58.89
(E) Net mWh Not Generated due to Full Scheduled Outages	2,776,058	686,268
(F) Scheduled Outages: percent of Period Hrs	48.16	11.87
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	309,786	223,256
(J) Forced Outages: percent of Period Hrs	5.37	3.86
(K) Net mWh Not Generated due to Partial Forced Outages	240,971	118,342
(L) Forced Derates: percent of Period Hrs	4.18	2.05
(M) Net mWh Not Generated due to Economic Dispatch	844,270	1,348,961
(N) Economic Dispatch: percent of Period Hrs	14.56	23.33
(O) Net mWh Possible in Period	5,764,080	5,781,600
(P) Equivalent Availability (%)	42.28	82.22
(Q) Output Factor (%)	64.91	71.49
(R) Heat Rate (BTU/NkWh)	10,324	9,746

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership.
- Footnote: (R) Includes Light Off BTU's

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2021 through December, 2021

WS Lee Combined Cycle

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	248	248	313	809
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,739,729	1,714,227	2,401,701	5,855,657
(D) Capacity Factor (%)	80.08	78.91	87.59	82.63
(E) Net mWh Not Generated due to Full Scheduled Outages	188,306	237,257	244,781	670,345
(F) Scheduled Outages: percent of Period Hrs	8.67	10.92	8.93	9.46
(G) Net mWh Not Generated due to Partial Scheduled Outages	51,608	54,497	0	106,105
(H) Scheduled Derates: percent of Period Hrs	2.38	2.51	0.00	1.50
(I) Net mWh Not Generated due to Full Forced Outages	9,507	0	1,951	11,458
(J) Forced Outages: percent of Period Hrs	0.44	0.00	0.07	0.16
(K) Net mWh Not Generated due to Partial Forced Outages	139	0	0	139
(L) Forced Derates: percent of Period Hrs	0.01	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	183,191	166,498	93,446	443,136
(N) Economic Dispatch: percent of Period Hrs	8.43	7.66	3.41	6.25
(O) Net mWh Possible in Period	2,172,480	2,172,480	2,741,880	7,086,840
(P) Equivalent Availability (%)	88.51	86.57	91.00	88.88
(Q) Output Factor (%)	88.72	89.14	96.57	91.91
(R) Heat Rate (BTU/NkWh)	10,545	10,515	2,312	7,160

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- Data is reflected at 100% ownership.
- Footnote: (R) Includes Light Off BTU's

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Intermediate Power Plant
Performance Review Plan
January, 2021 through December, 2021

Cliffside Station

Units	Unit 6
(A) MDC (mW)	849
(B) Period Hrs	8,760
(C) Net Generation (mWh)	4,021,882
(D) Net mWh Possible in Period	7,437,240
(E) Equivalent Availability (%)	74.43
(F) Output Factor (%)	72.44
(G) Capacity Factor (%)	54.08

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Sykes Exhibit 6
Schedule 10

Duke Energy Carolinas
Peaking Power Plant
Performance Review Plan
January, 2021 through December, 2021

Cliffside Station

Units	**Unit 5**
(A) MDC (mW)	546
(B) Period Hrs	8,760
(C) Net Generation (mWh)	729,303
(D) Net mWh Possible in Period	4,782,960
(E) Equivalent Availability (%)	42.38
(F) Output Factor (%)	37.28
(G) Capacity Factor (%)	15.25

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Sykes Workpaper 1

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs	9,185,657	9,129,849	9,990,936	9,257,839	6,686,733	7,360,722	7,473,786	59,085,520
Cost (Gross of Joint Owners)	$ 56,075,776	$ 52,811,775	$ 55,286,006	$ 50,528,496	$ 38,964,977	$ 42,478,337	$ 44,926,459	$ 341,071,825
$/MWh	6.1047	5.7845	5.5336	5.4579	5.8272	5.7709	6.0112	
Avg $/MWh		**5.7725**						
Cents per kWh		**0.5773**						

			Sept 2022 - August 2023
MDC			
CATA_UN01	Catawba	MW	1,160.0
CATA_UN02	Catawba	MW	1,150.1
MCGU_UN01	McGuire	MW	1,158.0
MCGU_UN02	McGuire	MW	1,157.6
OCON_UN01	Oconee	MW	847.0
OCON_UN02	Oconee	MW	848.0
OCON_UN03	Oconee	MW	859.0
			7,179.7
Hours In Year			8,760
Generation GWhs			
CATA_UN01	Catawba	GWh	9,186
CATA_UN02	Catawba	GWh	9,130
MCGU_UN01	McGuire	GWh	9,991
MCGU_UN02	McGuire	GWh	9,258
OCON_UN01	Oconee	GWh	6,687
OCON_UN02	Oconee	GWh	7,361
OCON_UN03	Oconee	GWh	7,474
			59,086
	Proposed Nuclear Capacity Factor		93.94%

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Sykes Workpaper 2

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs with NERC applied	9,295,832	9,216,497	9,279,804	9,276,599	6,911,469	6,919,629	7,009,388	57,909,218
Hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
MDC	1,160.0	1,150.1	1,158.0	1,157.6	847.0	848.0	859.0	7,179.7
Capacity factor	91.48%	91.48%	91.48%	91.48%	93.15%	93.15%	93.15%	92.07%
Cost	$ 53,660,292	$ 53,202,329	$ 53,567,774	$ 53,549,271	$ 39,896,533	$ 39,943,636	$ 40,461,773	$ 334,281,608

Avg $/MWh	**5.7725**
Cents per kWh	**0.5773**

2016-2020	Capacity Rating	NCF Rating	Weighted Average	
Oconee 1	847.0	93.15	10.99%	
Oconee 2	848.0	93.15	11.00%	
Oconee 3	859.0	93.15	11.14%	
McGuire 1	1,158.0	91.48	14.75%	
McGuire 2	1,157.6	91.48	14.75%	
Catawba 1	1,160.0	91.48	14.78%	
Catawba 2	1,150.1	91.48	14.65%	
	7,179.7		**92.07%**	Wtd Avg on Capacity Rating

rounding differences may occur

Duke Energy Carolinas, LLC **Sykes Workpaper 3**
North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation and Purchased Power in MWhs
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Resource Type	**Sept 2022 - August 2023**	
NUC Total (Gross)	59,085,520	
COAL Total	9,117,091	
Gas CT and CC total (Gross)	29,962,094	
Run of River	4,980,701	
Net pumped Storage	(3,411,289)	
Total Hydro	1,569,412	
Catawba Joint Owners	(14,848,200)	
Lee CC Joint Owners	(876,000)	
DEC owned solar	364,048	
Total Generation		84,373,966
Purchases for REPS Compliance	1,376,121	
Qualifying Facility Purchases - Non-REPS compliance	2,705,790	
Other Purchases	11,994	
Allocated Economic Purchases	610,715	
Joint Dispatch Purchases	4,735,740	
	9,440,360	
Total Generation and Purchased Power		93,814,326
Fuel Recovered Through Intersystem Sales	(1,964,801)	

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Fuel and Fuel Related Costs
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Sykes Workpaper 4

Resource Type	Sept 2022 - August 2023	
Nuclear Total (Gross)	$ 341,071,825	
COAL Total	292,853,648	
Gas CT and CC total (Gross)	932,067,312	
Catawba Joint Owner costs	(85,734,604)	
CC Joint Owner costs	(20,639,342)	
Non-Economic Fuel Expense Recovered through Reimbursement	(14,027,557)	
Reagents and gain/loss on sale of By-Products	9,519,806	Workpaper 9
Purchases for REPS Compliance - Energy	66,782,210	
Purchases for REPS Compliance - Capacity	14,610,064	
Purchases of Qualifying Facilities - Energy	40,652,503	
Purchases of Qualifying Facilities - Capacity	8,445,498	
Other Purchases	7,489,994	
JDA Savings Shared	20,748,035	Workpaper 5
Allocated Economic Purchase cost	14,263,480	Workpaper 5
Joint Dispatch purchases	108,842,049	Workpaper 6
Total Purchases	281,833,833	
Fuel Expense recovered through intersystem sales	(66,325,343)	Workpaper 5
Total System Fuel and Fuel Related Costs	**$ 1,670,619,578**	

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Joint Dispatch Fuel Impacts
Billing Period September 2022 through August 2023
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Positive numbers represent costs to ratepayers, Negative numbers represent removal of costs to ratepayers

	Allocated Economic Purchase Cost		Economic Sales Cost		Fuel Transfer Payment		JDA Savings Payment	
	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC
9/1/2022	$ 2,677,577	$ 3,781,762	$ (395,675)	$ (452,046)	$ (1,193,008)	$ 1,193,008	$ 136,476	$ (136,476)
10/1/2022	$ 542,827	$ 803,362	$ (661,032)	$ (762,575)	$ 3,557,663	$ (3,557,663)	$ 1,505,004	$ (1,505,004)
11/1/2022	$ 695,591	$ 1,037,984	$ (1,296,867)	$ (557,594)	$ (13,651,324)	$ 13,651,324	$ (2,905,662)	$ 2,905,662
12/1/2022	$ 569,647	$ 813,687	$ (4,426,520)	$ (2,671,233)	$ (8,969,486)	$ 8,969,486	$ (1,818,339)	$ 1,818,339
1/1/2023	$ 717,874	$ 1,045,814	$ (9,234,760)	$ (8,881,053)	$ (10,170,634)	$ 10,170,634	$ (3,592,449)	$ 3,592,449
2/1/2023	$ 158,723	$ 222,173	$ (7,642,791)	$ (9,248,399)	$ (5,978,839)	$ 5,978,839	$ (1,638,766)	$ 1,638,766
3/1/2023	$ 159,011	$ 226,144	$ (2,542,480)	$ (1,638,517)	$ (11,192,203)	$ 11,192,203	$ (2,501,768)	$ 2,501,768
4/1/2023	$ 956,508	$ 1,344,592	$ (1,195,044)	$ (315,259)	$ (3,210,699)	$ 3,210,699	$ (1,096,821)	$ 1,096,821
5/1/2023	$ 270,733	$ 388,566	$ (1,797,811)	$ (767,211)	$ (5,555,240)	$ 5,555,240	$ (2,753,841)	$ 2,753,841
6/1/2023	$ 1,051,586	$ 1,467,004	$ (701,390)	$ (742,280)	$ (2,897,748)	$ 2,897,748	$ (1,195,439)	$ 1,195,439
7/1/2023	$ 867,969	$ 1,183,718	$ (953,263)	$ (1,239,118)	$ (5,539,686)	$ 5,539,686	$ (3,293,157)	$ 3,293,157
8/1/2023	$ 1,368,896	$ 1,948,674	$ (968,553)	$ (940,559)	$ (5,931,346)	$ 5,931,346	$ (1,593,273)	$ 1,593,273
Sept 22 - Aug 23		$ 14,263,480		$ (28,215,845)		$ 70,732,550		$ 20,748,035

$ 108,842,049	Workpaper 6 - Transfer - Purchases
$ (38,109,498)	Workpaper 6 - Transfer - Sales
$ 70,732,550	Sept 22-Aug 23 Net Fuel Transfer Payment
$ (38,109,498)	Workpaper 6 - Transfer - Sales
$ (28,215,845)	Sept 22-Aug 23 Economic Sales Cost
$ (66,325,343)	**Total Fuel expense recovered through intersystem sales**

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Merger Payments
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Sykes Workpaper 6

	Transfer Projection		Purchase Allocation Delta		Purchase Adjusted Transfer	Sale	Fossil Gen Cost		Sale Pre-Net Payments	Purchase
	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC
9/1/2022	253,674	164,537	(35,758)	35,758	253,674	200,295	$ 29.07	$ 30.86	$ 6,180,396	$ 7,373,404
10/1/2022	212,025	305,749	(12,976)	12,976	212,025	318,726	$ 27.42	$ 29.40	$ 9,371,770	$ 5,814,107
11/1/2022	637,224	24,450	(141)	141	637,224	24,591	$ 22.69	$ 32.95	$ 810,289	$ 14,461,612
12/1/2022	387,962	37,723	(4,500)	4,500	387,962	42,223	$ 26.82	$ 34.00	$ 1,435,605	$ 10,405,091
1/1/2023	392,052	31,019	(2,330)	2,330	392,052	33,350	$ 28.90	$ 34.73	$ 1,158,324	$ 11,328,958
2/1/2023	268,628	41,858	(177)	177	268,628	42,035	$ 27.60	$ 34.15	$ 1,435,273	$ 7,414,112
3/1/2023	574,004	66,898	(447)	447	574,004	67,344	$ 23.22	$ 31.75	$ 2,137,998	$ 13,330,201
4/1/2023	385,453	158,440	(17,432)	17,432	385,453	175,872	$ 19.76	$ 25.05	$ 4,405,256	$ 7,615,955
5/1/2023	492,081	72,823	(5,284)	5,284	492,081	78,107	$ 15.12	$ 24.14	$ 1,885,732	$ 7,440,972
6/1/2023	343,644	136,582	3,192	(3,192)	346,836	136,582	$ 18.88	$ 26.73	$ 3,650,423	$ 6,548,171
7/1/2023	369,531	98,967	7,217	(7,217)	376,748	98,967	$ 22.05	$ 27.97	$ 2,768,573	$ 8,308,259
8/1/2023	393,768	106,684	15,285	(15,285)	409,053	106,684	$ 21.52	$ 26.90	$ 2,869,860	$ 8,801,206
Sept 22 - Aug 23	4,710,046	1,245,731	(53,351)	53,351	4,735,740	1,324,776			$ 38,109,498	$ 108,842,049
									Net Pre-Net Payments	$ 70,732,550

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 93.94%
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Fall 2021 Forecast
Billed Sales Forecast
Sales Forecast - MWhs (000)

		Projected sales for the Billing Period	Remove impact of SC DERP Net Metered Generation	Adjusted Sales
North Carolina:				
	Residential	22,809,193		22,809,193
	General	22,983,240		22,983,240
	Industrial	12,202,704		12,202,704
	Lighting	239,297		239,297
	NC RETAIL	58,234,434	-	58,234,434
South Carolina:				
	Residential	6,851,656	133,318	6,984,975
	General	5,765,026	42,173	5,807,199
	Industrial	8,959,835	429	8,960,264
	Lighting	39,929	-	39,929
	SC RETAIL	21,616,446	175,921	21,792,367
Total Retail Sales				
	Residential	29,660,849	133,318	29,794,168
	General	28,748,266	42,173	28,790,439
	Industrial	21,162,539	429	21,162,968
	Lighting	279,226	-	279,226
	Retail Sales	79,850,880	175,921	80,026,801
	Wholesale	8,106,092	-	8,106,092
	Projected System MWH Sales for Fuel Factor	87,956,972	175,921	88,132,893
	NC as a percentage of total	**66.21%**		**66.08%**
	SC as a percentage of total	24.58%		24.73%
	Wholesale as a percentage of total	9.22%		9.20%
		100.00%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	175,921
Marginal fuel rate per MWh for SC NEM	$ 26.07
Fuel benefit to be directly assigned to SC Retail	$ 4,586,518

System Fuel Expense	$ 1,670,619,578	Sykes Exhibit 2 Schedule 1 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,586,518	
Total Fuel Costs for Allocation	$ 1,675,206,096	Sykes Exhibit 2 Schedule 1 Page 3 of 3, L5

Reconciliation	**System**	**NC Retail Customers**	**Wholesale**	**South Carolina Retail**	
Total system fuel expense from Sykes Exhibit 2 Schedule 1 Page 1	$ 1,670,619,578				
QF and REPS Compliance Purchased Power - Capacity	$ 23,055,563				
Other fuel costs	$ 1,647,564,015				
SC Net Metering Fuel Allocation adjustment	$ 4,586,518				
Jurisdictional fuel costs after adj.	$ 1,652,150,533				
Allocation to states/classes		66.08%	9.20%	24.73%	
Jurisdictional fuel costs	$ 1,652,150,533	$ 1,091,670,180	$ 151,957,842	$ 408,522,511	66.98%
Direct Assignment of Fuel benefit to SC Retail	$ (4,586,518)		$ -	$ (4,586,518)	
Total system actual fuel costs	$ 1,647,564,015	$ 1,091,670,180	$ 151,957,842	$ 403,935,993	
QF and REPS Compliance Purchased Power - Capacity	23,055,563	15,441,918			
Total system fuel expense from Sykes Exhibit 2 Schedule 1 Page 1	$ 1,670,619,578	**$ 1,107,112,098**			
		Exh.2, Sch. 1 page 3, Line 13			

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 93.94% and Normalized Test Period Sales
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Sykes Revised Workpaper 7a

Fall 2021 Forecast
Billed Sales Forecast - Normalized Test Period Sales
Sales Forecast - MWhs (000)

	Test Period Sales	Customer Growth Adjustment	Weather Adjustment	Remove impact of SC DERP Net Metered generation	Normalized Test Period Sales
NC RETAIL	58,067,962	(23,093)	413,425	-	58,458,294
SC RETAIL	20,481,464	78,665	133,245	175,921	20,869,295
Wholesale	8,002,184	73,415	49,334	-	8,124,933
Normalized System MWH Sales for Fuel Factor	86,551,610	128,987	596,003	175,921	87,452,521
NC as a percentage of total	**67.09%**				**66.85%**
SC as a percentage of total	23.66%				23.86%
Wholesale as a percentage of total	9.25%				9.29%
	100.00%				100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	175,921
Marginal fuel rate per MWh for SC NEM	$ 26.07
Fuel benefit to be directly assigned to SC Retail	$ 4,586,518

System Fuel Expense	$ 1,648,765,072	Sykes Exhibit 2 Schedule 2 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,586,518	
Total Fuel Costs for Allocation	$ 1,653,351,591	Sykes Exhibit 2 Schedule 2 Page 3 of 3, L5

Reconciliation	**System**	**NC Retail Customers**	**Wholesale**	**South Carolina Retail**
Total system fuel expense from Sykes Exhibit 2 Schedule 2 Page 1	$ 1,648,765,072			
QF and REPS Compliance Purchased Power - Capacity	$ 23,055,563			
Other fuel costs	$ 1,625,709,510			
SC Net Metering Fuel Allocation adjustment	$ 4,586,518			
Jurisdictional fuel costs after adj.	$ 1,630,296,028			
Allocation to states/classes		66.85%	9.29%	23.86%
Jurisdictional fuel costs	$ 1,630,296,028	$ 1,089,852,895	$ 151,454,501	$ 388,988,632
Direct Assignment of Fuel benefit to SC Retail	$ (4,586,518)		$ -	$ (4,586,518)
Total system actual fuel costs	$ 1,625,709,510	$ 1,089,852,895	$ 151,454,501	$ 384,402,114
QF and REPS Compliance Purchased Power - Capacity	23,055,563	15,441,918		
Total system fuel expense from Sykes Exhibit 2 Schedule 2 Page 1	$ 1,648,765,072	**$ 1,105,294,813**		
		Exh. 2, Sch 2 page 3, Line 13		

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
NERC 5 Year Average Nuclear Capacity Factor of 92.07%
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Sykes Workpaper 7b

Fall 2021 Forecast
Billed Sales Forecast
Sales Forecast - MWhs (000)

		Projected sales for the Billing Period	Remove impact of SC DERP Net Metered generation	Adjusted Sales
North Carolina:				
	Residential	22,809,193		22,809,193
	General	22,983,240		22,983,240
	Industrial	12,202,704		12,202,704
	Lighting	239,297		239,297
	NC RETAIL	58,234,434	-	58,234,434
South Carolina:				
	Residential	6,851,656	133,318	6,984,975
	General	5,765,026	42,173	5,807,199
	Industrial	8,959,835	429	8,960,264
	Lighting	39,929	0	39,929
	SC RETAIL	21,616,446	175,921	21,792,367
Total Retail Sales				
	Residential	29,660,849	133,318	29,794,167
	General	28,748,266	42,173	28,790,440
	Industrial	21,162,539	429	21,162,968
	Lighting	279,226	-	279,226
	Retail Sales	79,850,880	175,921	80,026,801
	Wholesale	8,106,092	-	8,106,092
	Projected System MWh Sales for Fuel Factor	87,956,972	175,921	88,132,893
	NC as a percentage of total	**66.21%**		**66.08%**
	SC as a percentage of total	24.58%		24.73%
	Wholesale as a percentage of total	9.22%		9.20%
		100.01%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	175,921	
Marginal fuel rate per MWh for SC NEM	$ 26.07	
Fuel benefit to be directly assigned to SC Retail	$ 4,586,511	
System Fuel Expense	$ 1,693,825,422	Sykes Exhibit 2 Schedule 3 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,586,511	
Total Fuel Costs for Allocation	$ 1,698,411,934	Sykes Exhibit 2 Schedule 3 Page 3 of 3, Line 5

Reconciliation	**System**	**NC Retail Customers**	**Wholesale**	**South Carolina Retail**
Total system fuel expense from Sykes Exhibit 2 Schedule 3 Page 1	$ 1,693,825,422			
QF and REPS Compliance Purchased Power - Capacity	$ 23,055,563			
Other fuel costs	$ 1,670,769,860			
SC Net Metering Fuel Allocation adjustment	$ 4,586,511			
Jurisdictional fuel costs after adj.	$ 1,675,356,371			
Allocation to states/classes		66.08%	9.20%	24.73%
Jurisdictional fuel costs	$ 1,675,523,907	$ 1,107,075,490	$ 154,132,786	$ 414,315,631
Direct Assignment of Fuel benefit to SC Retail	$ (4,586,511)		$ -	$ (4,586,511)
Total system actual fuel costs	$ 1,670,937,395	$ 1,107,075,490	$ 154,132,786	$ 409,729,119
QF and REPS Compliance Purchased Power - Capacity	23,055,563	15,441,918		
Total system fuel expense from Sykes Exhibit 2 Schedule 3 Page 1	$ 1,693,992,958	**$ 1,122,517,408**		
		Exh. 2, Sch.3 page 3, Line 13		

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Annualized Revenue
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

	January 2022 Actuals			Normalized Sales	
	Revenue	**kWh Sales**	**Cents/ kWh**	**Sykes Exhibit 4**	**Total Annualized Revenues**
	(a)	(b)	(a)/(b) *100 = (c)	(d)	(c) * (d) * 10
Residential	$ 209,556,609	2,129,408,268	9.8411	22,961,890	$ 2,259,696,240
General	$ 137,324,675	1,921,732,056	7.1459	23,202,419	$ 1,658,017,092
Industrial	$ 51,372,485	937,750,891	5.4783	12,293,985	$ 673,497,148
Total	$ 398,253,769	4,988,891,215		58,458,294	$ 4,591,210,481

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Reagents and ByProducts
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Sykes Workpaper 9

Reagent and ByProduct projections

Date	Ammonia	Urea	Limestone	Magnesium Hydroxide	Calcium Carbonate	Lime	**Reagent Cost**	**Gypsum (Gain)/ Loss**	**Ash (Gain)/Loss**	**Steam (Gain)/Loss**	**Sale of By-Products (Gain)/Loss**
9/1/2022	$ 108,717	$ 13,489	$ 449,691	$ 48,393	$ 29,036	$ 34,615	**$ 683,941**	$ 128,362	$ (74,398)	$ (226,533)	**$ (172,570)**
10/1/2022	$ 51,960	$ 6,447	$ 214,926	$ 26,942	$ 16,165	$ 34,615	**$ 351,056**	$ 61,400	$ (31,726)	$ (223,486)	**$ (193,812)**
11/1/2022	$ 79,604	$ 9,877	$ 329,272	$ 36,588	$ 21,953	$ 34,615	**$ 511,909**	$ 84,600	$ (43,313)	$ (220,444)	**$ (179,157)**
12/1/2022	$ 314,933	$ 39,076	$ 1,302,676	$ 112,128	$ 67,277	$ 34,615	**$ 1,870,705**	$ 386,006	$ (232,116)	$ (217,449)	**$ (63,559)**
1/1/2023	$ 413,327	$ 51,284	$ 1,709,669	$ 144,939	$ 86,964	$ 34,615	**$ 2,440,799**	$ 512,709	$ (261,016)	$ (214,680)	**$ 37,013**
2/1/2023	$ 337,638	$ 41,893	$ 1,396,591	$ 110,882	$ 66,529	$ 34,615	**$ 1,988,148**	$ 415,640	$ (237,071)	$ (211,979)	**$ (33,410)**
3/1/2023	$ 106,399	$ 13,202	$ 440,102	$ 49,926	$ 29,955	$ 34,615	**$ 674,199**	$ 115,952	$ (59,337)	$ (209,446)	**$ (152,831)**
4/1/2023	$ 55,930	$ 6,940	$ 231,348	$ 31,061	$ 18,637	$ 34,615	**$ 378,532**	$ 53,252	$ (22,526)	$ (207,253)	**$ (176,528)**
5/1/2023	$ 33,535	$ 4,161	$ 138,712	$ 24,580	$ 14,748	$ 34,615	**$ 250,351**	$ 32,046	$ (8,814)	$ (206,220)	**$ (182,988)**
6/1/2023	$ 81,768	$ 10,146	$ 338,222	$ 42,487	$ 25,492	$ 34,615	**$ 532,731**	$ 91,664	$ (49,255)	$ (205,355)	**$ (162,945)**
7/1/2023	$ 115,903	$ 14,381	$ 479,414	$ 54,842	$ 32,905	$ 34,615	**$ 732,059**	$ 132,485	$ (71,586)	$ (204,536)	**$ (143,637)**
8/1/2023	$ 108,411	$ 13,451	$ 448,427	$ 49,538	$ 29,723	$ 34,615	**$ 684,165**	$ 112,582	$ (63,166)	$ (203,781)	**$ (154,364)**
	$ 1,808,126	$ 224,347	$ 7,479,051	$ 732,305	$ 439,383	$ 415,382	**$ 11,098,593**	$ 2,126,699	$ (1,154,325)	$ (2,551,161)	**$ (1,578,787)**

Total Reagent cost and Sale of By-products **$ 9,519,806**

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Twelve Months Ended December 31, 2021
Billing Period September 2022 through August 2023
Docket E-7, Sub 1263

Sykes Workpaper 10

Line No.	Description	Forecast $	(Over)/Under Collection $	Total $
1	Amount in current docket	100,803,928	13,526,437	114,330,365
2	Amount in Sub 1250, prior year docket	102,740,263	(4,999,624)	97,740,638
3	Increase/(Decrease)	(1,936,334)	18,526,061	16,589,727
4	2.5% of 2021 NC retail revenue of $4,720,136,851			118,003,421
	Excess of purchased power growth over 2.5% of revenue			0
	E-7, Sub 1263			
WP 4	Purchases for REPS Compliance - Energy	66,782,210	66.08%	44,126,819
WP 4	Purchases for REPS Compliance - Capacity	14,610,064	66.98%	9,785,379
WP 4	Purchases	7,489,994	66.08%	4,949,066
WP 4	QF Energy	40,652,503	66.08%	26,861,429
WP 4	QF Capacity	8,445,498	66.98%	5,656,539
WP 4	Allocated Economic Purchase cost	14,263,480	66.08%	9,424,695
		152,243,749		100,803,928
	E-7, Sub 1250			
	Purchases for REPS Compliance	62,808,851	65.99%	41,447,561
	Purchases for REPS Compliance Capacity	13,866,978	66.90%	9,276,635
	Purchases	2,586,674	65.99%	1,706,946
	QF Energy	53,822,291	65.99%	35,517,330
	QF Capacity	11,169,971	66.90%	7,472,410
	Allocated Economic Purchase cost	11,091,651	65.99%	7,319,380
		155,346,415		102,740,263

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1263

Sykes Workpaper 10a

2021	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**12 ME**
System KWH Sales - Sch 4, Adjusted	8,623,321,816	7,033,781,083	6,170,273,584	6,357,924,869	5,750,592,351	7,218,972,840	8,473,666,049	8,688,276,000	8,107,525,420	6,609,883,548	6,537,708,709	7,191,590,664	86,763,516,933
NC Retail KWH Sales - Sch 4	5,785,766,552	4,705,197,397	4,216,101,608	4,307,482,408	3,784,759,966	4,813,117,777	5,540,576,171	5,890,178,638	5,517,650,819	4,297,619,492	4,396,624,370	4,888,703,073	58,143,778,271
NC Retail % of Sales, Adjusted (Calc)	67.09%	66.89%	68.33%	67.75%	65.82%	66.67%	65.39%	67.79%	68.06%	65.02%	67.25%	67.98%	67.01%
NC retail production plant %	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 14,110,987	$ 21,997,962	$ 7,288,155	$ 1,159,999	$ 6,909,766	$ 19,650,947	$ 27,256,372	$ 22,941,922	$ 20,301,410	$ 27,877,777	$ 27,842,536	$ 26,295,173	$ 223,633,006
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	1,908,455	2,653,190	897,843	1,159,946	1,043,015	1,716,177	3,233,998	2,658,287	1,580,193	2,101,644	2,163,509	2,417,594	$ 23,533,851
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	3,836,471	3,851,010	3,578,469	1,634,328	5,557,142	6,244,501	5,777,306	6,144,771	5,617,037	5,684,750	4,972,836	4,406,882	$ 57,305,503
System Actual$ - Sch 3 Fuel-related$; SC DERP	148,221	63,773	117,353	217,851	155,453	263,492	427,484	260,031	242,117	236,248	246,176	205,494	$ 2,583,692
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	2,756,782	2,455,383	2,198,548	2,656,105	2,051,181	3,609,263	3,393,224	3,761,968	2,668,737	2,679,082	2,593,637	2,343,504	$ 33,167,413
Total System Economic & QF$	22,760,916	31,021,318	14,080,368	6,828,229	15,716,557	31,484,380	40,088,384	35,766,979	30,409,494	38,579,500	37,818,693	35,668,647	340,223,465
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 13,085,320	$ 20,311,355	$ 6,186,575	$ 12,225	$ 6,203,819	$ 19,379,239	$ 26,072,774	$ 21,770,863	$ 19,434,801	$ 26,816,502	$ 23,378,784	$ 23,491,467	$ 206,143,723
Total System Economic $ without Native Load Transfers	$ 9,675,596	$ 10,709,964	$ 7,893,793	$ 6,816,004	$ 7,306,104	$ 8,232,386	$ 14,015,610	$ 13,996,116	$ 10,974,693	$ 11,762,998	$ 14,439,909	$ 12,177,179	$ 128,000,354
NC Actual $ (Calc)	$ 6,491,783	$ 7,164,353	$ 5,393,769	$ 4,617,830	$ 4,808,522	$ 5,488,793	$ 9,164,222	$ 9,488,606	$ 7,468,928	$ 7,648,076	$ 9,710,873	$ 8,277,809	$ 85,723,565
Billed rate (¢/kWh):	0.1367	0.1367	0.1367	0.1367	0.1367	0.1367	0.1367	0.1367	0.1363	0.1357	0.1357	0.1357	
Billed $:	$ 7,911,008	$ 6,433,522	$ 5,764,770	$ 5,889,717	$ 5,174,987	$ 6,581,084	$ 7,575,754	$ 8,053,773	$ 7,518,618	$ 5,832,583	$ 5,966,949	$ 6,634,781	$ 79,337,545
(Over)/ Under $:	$ (1,419,225)	$ 730,832	$ (371,001)	$ (1,271,887)	$ (366,465)	$ (1,092,291)	$ 1,588,468	$ 1,434,833	$ (49,690)	$ 1,815,493	$ 3,743,924	$ 1,643,028	$ 6,386,020
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ 430,619	$ 430,619	$ 215,311	$ 215,310	$ 322,964	$ 1,399,512	$ 3,229,644	$ 3,229,644	$ 645,929	$ 215,310	$ 215,310	$ 215,310	$ 10,765,481
System Actual $ - Capacity component of Purchased Power for REPS Compliance	679,198	657,904	611,495	370,864	1,021,112	874,770	880,403	2,930,150	2,610,093	2,651,828	2,162,592	642,188	$ 16,092,597
System Actual $ - Capacity component of HB589 Purpa QF purchases	401,588	376,607	536,828	347,396	110,548	427,589	1,222,705	1,697,840	1,371,802	1,324,805	834,474	281,956	$ 8,934,138
System Actual $ - Capacity component of SC DERP	14,999	7,491	12,697	15,442	14,837	24,880	38,885	24,278	22,766	22,049	24,646	19,907	$ 242,878
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 1,526,405	$ 1,472,621	$ 1,376,331	$ 949,012	$ 1,469,461	$ 2,726,751	$ 5,371,637	$ 7,881,912	$ 4,650,590	$ 4,213,992	$ 3,237,022	$ 1,159,361	$ 36,035,094
NC Actual $ (Calc) (1)	$ 1,022,340	$ 986,317	$ 921,825	$ 635,619	$ 984,201	$ 1,826,295	$ 3,597,760	$ 5,279,066	$ 3,114,825	$ 2,822,404	$ 2,168,059	$ 776,505	$ 24,135,215
Billed rate (¢/kWh):	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0291	0.0289	0.0289	0.0289	
Billed $:	$ 1,698,557	$ 1,381,329	$ 1,237,743	$ 1,264,570	$ 1,111,112	$ 1,413,012	$ 1,626,576	$ 1,729,210	$ 1,608,069	$ 1,241,743	$ 1,270,349	$ 1,412,529	$ 16,994,798
(Over)/Under $:	$ (676,218)	$ (395,012)	$ (315,918)	$ (628,950)	$ (126,911)	$ 413,283	$ 1,971,184	$ 3,549,856	$ 1,506,756	$ 1,580,661	$ 897,710	$ (636,024)	$ 7,140,417
TOTAL (Over)/ Under $:	**$ (2,095,442)**	**$ 335,820**	**$ (686,918)**	**$ (1,900,837)**	**$ (493,375)**	**$ (679,008)**	**$ 3,559,653**	**$ 4,984,689**	**$ 1,457,065**	**$ 3,396,154**	**$ 4,641,634**	**$ 1,007,004**	**$ 13,526,437**

Note: The billed rate for September and October are pro-rated based on number of billing days in cycle on new rate schedules.
(1) January - May NC actual capacity shown herein is adjusted to reflect use of 2020 production plant allocation factor. Actual true-up related to allocator was made as prior period adjustment in May 2021 of Schedule 4.

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Twelve Months Ended December 31, 2020
Docket E-7, Sub 1263

Sykes Workpaper 10b

2020	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**12 ME**
System KWH Sales - Sch 4, Adjusted	7,193,812,943	7,229,160,762	6,557,632,220	5,948,571,625	5,649,816,171	6,745,745,153	8,113,658,335	8,454,195,025	7,632,668,505	6,227,418,819	7,077,137,814	6,283,453,698	83,113,271,070
NC Retail KWH Sales - Sch 4	4,799,050,153	4,852,514,770	4,419,004,658	4,009,530,882	3,737,497,506	4,445,349,080	5,381,133,760	5,679,285,065	5,143,265,080	4,161,108,724	4,768,316,561	4,115,807,397	55,511,863,636
NC Retail % of Sales, Adjusted (Calc)	66.71%	67.12%	67.39%	67.40%	66.15%	65.90%	66.32%	67.18%	67.38%	66.82%	67.38%	65.50%	66.79%
NC retail production plant %	67.55%	67.55%	67.55%	67.55%	67.55%	67.75%	67.75%	67.75%	67.75%	67.75%	67.75%	67.75%	67.71%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 11,218,315	$ 12,607,762	$ 5,300,111	$ 6,352,200	$ 8,395,303	$ 6,771,661	$ 12,440,459	$ 7,247,711	$ 9,073,495	$ 15,331,837	$ 6,958,738	$ 24,648,415	$ 126,346,007
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	1,491,771	1,826,422	990,649	729,743	909,315	1,057,292	2,012,867	1,346,379	1,036,893	1,743,448	1,074,835	4,774,389	$ 18,994,003
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	3,745,116	4,068,302	3,681,838	4,276,231	5,491,472	4,795,757	5,305,337	6,084,262	5,064,982	4,676,649	4,553,039	4,091,116	$ 55,834,101
System Actual$ - Sch 3 Fuel-related$; SC DERP	13,291	13,282	28,563	39,932	44,069	110,923	38,018	129,601	69,181	87,074	68,782	37,283	$ 679,999
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	2,051,485	2,097,916	2,123,359	2,681,961	3,213,134	2,547,168	2,552,543	2,889,199	2,519,264	2,799,837	2,863,763	2,568,618	$ 30,908,248
Total System Economic & QF$	18,519,978	20,613,684	12,124,520	14,080,067	18,053,293	15,282,801	22,349,224	17,697,152	17,763,815	24,638,845	15,519,157	36,119,821	232,762,358
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 9,403,952	$ 10,746,417	$ 3,681,146	$ 5,959,074	$ 8,211,008	$ 5,694,556	$ 12,728,156	$ 6,086,984	$ 8,789,272	$ 15,071,913	$ 5,685,045	$ 21,638,297	$ 113,695,820
Total System Economic $ without Native Load Transfers	$ 9,116,026	$ 9,867,267	$ 8,443,374	$ 8,120,993	$ 9,842,285	$ 9,588,245	$ 9,621,068	$ 11,610,168	$ 8,974,543	$ 9,566,932	$ 9,834,112	$ 14,481,524	$ 119,066,539
NC Actual $ (Calc)	$ 6,081,374	$ 6,623,322	$ 5,689,753	$ 5,473,813	$ 6,510,923	$ 6,318,516	$ 6,380,877	$ 7,799,377	$ 6,047,486	$ 6,392,544	$ 6,625,865	$ 9,485,733	$ 79,429,582
Billed rate (¢/kWh):	0.1533	0.1533	0.1533	0.1533	0.1533	0.1533	0.1533	0.1533	0.1689	0.1689	0.1689	0.1689	
Billed $:	$ 7,356,944	$ 7,438,905	$ 6,774,334	$ 6,146,611	$ 5,729,584	$ 6,814,720	$ 8,249,278	$ 8,706,344	$ 8,689,317	$ 7,030,008	$ 8,055,859	$ 6,953,473	$ 87,945,377
(Over)/ Under $:	$ (1,275,570)	$ (815,583)	$ (1,084,581)	$ (672,798)	$ 781,339	$ (496,204)	$ (1,868,401)	$ (906,967)	$ (2,641,831)	$ (637,464)	$ (1,429,993)	$ 2,532,260	$ (8,515,795)
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ 430,619	$ 430,619	$ 215,310	$ 215,310	$ 322,964	$ 1,399,512	$ 3,229,644	$ 3,229,644	$ 645,929	$ 215,310	$ 215,310	$ 215,310	$ 10,765,481
System Actual $ - Capacity component of Purchased Power for REPS Compliance	645,345	680,159	573,260	641,154	778,381	625,715	2,302,254	2,743,308	2,223,872	1,950,062	637,418	610,344	$ 14,411,272
System Actual $ - Capacity component of HB589 Purpa QF purchases	264,275	306,973	236,219	277,976	283,502	204,320	1,125,235	1,384,219	1,116,138	1,010,084	297,176	256,193	$ 6,762,310
System Actual $ - Capacity component of SC DERP	1,869	1,868	12,351	6,569	4,675	15,765	4,866	18,466	9,471	10,816	8,919	5,142	$ 100,777
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 1,342,109	$ 1,419,619	$ 1,037,140	$ 1,141,008	$ 1,389,523	$ 2,245,312	$ 6,661,999	$ 7,375,637	$ 3,995,410	$ 3,186,272	$ 1,158,823	$ 1,086,989	$ 32,039,840
NC Actual $ (Calc) (1)	$ 906,558	$ 958,914	$ 700,560	$ 770,720	$ 938,585	$ 1,521,128	$ 4,513,293	$ 4,996,760	$ 2,706,763	$ 2,158,598	$ 785,065	$ 736,399	$ 21,693,343
Billed rate (¢/kWh):	0.0327	0.0327	0.0327	0.0327	0.0327	0.0327	0.0327	0.0327	0.0328	0.0328	0.0328	0.0328	
Billed $:	$ 1,570,139	$ 1,587,631	$ 1,445,797	$ 1,311,826	$ 1,222,823	$ 1,454,416	$ 1,760,583	$ 1,858,131	$ 1,686,991	$ 1,364,844	$ 1,564,008	$ 1,349,985	$ 18,177,174
(Over)/Under $:	$ (663,581)	$ (628,718)	$ (745,237)	$ (541,106)	$ (284,239)	$ 66,712	$ 2,752,710	$ 3,138,628	$ 1,019,773	$ 793,755	$ (778,942)	$ (613,586)	$ 3,516,169
TOTAL (Over)/ Under $:	**$ (1,939,151)**	**$ (1,444,300)**	**$ (1,829,818)**	**$ (1,213,904)**	**$ 497,100**	**$ (429,492)**	**$ 884,309**	**$ 2,231,661**	**$ (1,622,059)**	**$ 156,290**	**$ (2,208,936)**	**$ 1,918,674**	**$ (4,999,624)**

Note: The billed rate for September and October are pro-rated based on number of billing days in cycle on new rate schedules.
(1) January - May NC actual capacity shown herein is adjusted to reflect use of 2019 production plant allocation factor. Actual true-up related to allocator was made as prior period adjustment in June 2020 of Schedule 4.

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Actual Sales by Jursidiction - Subject to Weather
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1263

Sykes Workpaper 11

Line #	Description	Reference	MWhs NORTH CAROLINA	SOUTH CAROLINA	TOTAL COMPANY	% NC	% SC
1	Residential	Company Records	22,424,524	6,819,677	29,244,200	76.68	23.32
2	Total General Service	Company Records	23,396,396	5,297,993	28,694,389		
3	less Lighting and Traffic Signals		249,725	50,082	299,807		
4	General Service subject to weather		23,146,672	5,247,911	28,394,582	81.52	18.48
5	Industrial	Company Records	12,247,042	8,363,794	20,610,836	59.42	40.58
6	Total Retail Sales	1+2+5	58,067,962	20,481,464	78,549,426		
7	Total Retail Sales subject to weather	1+4+5	57,818,237	20,431,382	78,249,619	73.89	26.11

This does not exclude Greenwood and includes the impact of SC DERP net metering generation
rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1263

Line #	Description	REFERENCE	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Total Residential		442,226	76.68	339,099	23.32	103,127
	General Service						
2	Total General Service		55,501	81.52	45,245	18.48	10,257
	Industrial						
3	Total Industrial		48,942	59.42	29,081	40.58	19,861
4	Total Retail	L1+ L2+ L3	546,669		413,425		133,245
5	Wholesale		49,334				
6	Total Company	L4 + L5	596,003		413,425		133,245

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment by Class by Month
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1263

	Residential	Commercial	Industrial	
2021	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	
JAN	(32,231)	(6,216)	-	
FEB	76,342	6,207	5,074	
MAR	(28,114)	-	-	
APR	87,225	-	-	
MAY	22,994	7,646	8,603	
JUN	5,003	2,379	1,202	
JUL	132,023	60,904	22,835	
AUG	115,041	51,399	31,162	
SEP	(100,540)	(54,870)	(24,544)	
OCT	(63,328)	(35,264)	(17,356)	
NOV	37,621	7,905	21,965	
DEC	190,190	15,412	-	
Total	**442,226**	**55,501**	**48,942**	**546,669**

Wholesale

2021	**TOTAL MWH ADJUSTMENT**
JAN	(3,420)
FEB	5,335
MAR	(1,081)
APR	-
MAY	992
JUN	495
JUL	14,107
AUG	10,393
SEP	(4,390)
OCT	(983)
NOV	8,219
DEC	19,667
Total	**49,334**

Note:	**The Resale customers include:**
1	Concord[1]
2	Dallas
3	Forest City
4	Kings Mountain[1]
5	Due West
6	Prosperity[2]
7	Lockhart
8	Western Carolina University
9	City of Highlands
10	Haywood
11	Piedmont
12	Rutherford
13	Blue Ridge
14	Greenwood[1]

[1]Wholesale load is no longer being served by Duke as of December 2018.
[2]Wholesale load is no longer being served by Duke as of December 2019.

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1263

Line	Estimation Method [1]	Rate Schedule	NC Proposed kWh [1] Adjustment	SC Proposed kWh Adjustment	Wholesale Proposed kWh Adjustment	Total Company
1	*Regression*	Residential	198,267,663	64,686,596		
2						
3		**General Service (Excluding Lighting):**				
4	*Customer*	General Service Small and Large	(239,177,414)	(13,727,966)		
5	*Regression*	Miscellaneous	395,553	897,831		
6		Total General	(238,781,861)	(12,830,135)		
7						
8		**Lighting:**				
9	*Regression*	T & T2 (GL/FL/PL/OL)[2]	(902,695)	(70,408)		
10	*Regression*	TS	461,758	193,341		
11		Total Lighting	(440,937)	122,933		
12						
13		**Industrial:**				
14	*Customer*	I - Textile	675,995	3,411,534		
15	*Customer*	I - Nontextile	17,186,010	23,274,269		
16		Total Industrial	17,862,005	26,685,803		
17						
18						
19		Total	(23,093,129)	78,665,196	73,414,740	128,986,807
					WP 13-2	

Notes:
[1] Two approved methods are used for estimating the growth adjustment depending on the class/schedule:
"Regression" refers to the use of Ordinary Least Squares Regression
"Customer" refers to the use of the Customer by Customer approach.
[2] T and T2 were combined due to North Carolina's FL & GL schedules being merged into OL & PL.
rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales-Wholesale
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1263

Sykes Workpaper 13
Page 2

Calculation of Customer Growth Adjustment to kWh Sales - Wholesale

Line No.		Reference	
1	Total System Resale (kWh Sales)	Company Records	9,405,969,890
2	Less Intersystem Sales	Exhibit 6, Sch 1	1,241,221,539
3	Total kWh Sales Excluding Intersystem Sales	L1 - L2	8,164,748,350
4	Residential Growth Factor	Line 8	0.8992
5	Adjustment to kWhs - Wholesale	L3 * L4 / 100	73,414,740
6	Total System Retail Residential kWh Sales	Company Records	29,244,200,232
7	2021 Proposed Adjustment kWh - Residential (NC+SC)	WP 13-1	262,954,259
8	Percent Adjustment	L7 / L6 * 100	0.8992

rounding differences may occur

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	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**KEVIN Y. HOUSTON FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY CAROLINAS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin Y. Houston and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Manager of Nuclear Fuel Supply for Duke Energy Carolinas, LLC ("DEC" or the "Company") and Duke Energy Progress, LLC ("DEP").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEC?

A. I am responsible for nuclear fuel procurement for the nuclear units owned and operated by DEC and DEP.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Florida with a Bachelor of Science degree in Nuclear Engineering, and from North Carolina State University with a Master's degree in Nuclear Engineering. I began my career with the Company in 1992 as an engineer and worked in Duke Energy's nuclear design group where I performed nuclear physics roles. I assumed my current role having commercial responsibility for purchasing uranium, conversion services, enrichment services, and fuel fabrication services in 2012.

I have served as Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use. I became a registered professional engineer in the state of North Carolina in 2003.

Q. **HAVE YOU FILED TESTIMONY OR TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDING?**

A. Yes. I filed testimony in the DEC fuel and fuel-related cost recovery proceedings in Docket E-7, Sub 1250.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to (1) provide information regarding DEC's nuclear fuel purchasing practices, (2) provide costs for the January 1, 2021 through December 31, 2021 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2022 through August 31, 2023 billing period ("billing period").

Q. **YOUR TESTIMONY INCLUDES TWO EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?**

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Houston Exhibit 1, which is a Graphical Representation of the Nuclear Fuel Cycle, and Houston Exhibit 2, which sets forth the Company's Nuclear Fuel Procurement Practices.

Q. **PLEASE DESCRIBE THE COMPONENTS THAT MAKE UP NUCLEAR FUEL.**

A. In order to prepare uranium for use in a nuclear reactor, it must be processed from an ore to a ceramic fuel pellet. This process is commonly broken into four distinct industrial stages: (1) mining and milling; (2) conversion; (3) enrichment; and (4) fabrication. This process is illustrated graphically in Houston Exhibit 1.

Uranium is often mined by either surface (*i.e.*, open cut) or underground mining techniques, depending on the depth of the ore deposit. The ore is then sent to a mill where it is crushed and ground-up before the uranium is extracted by leaching, the process in which either a strong acid or alkaline solution is used to dissolve the uranium. Once dried, the uranium oxide ("U_3O_8") concentrate – often referred to as yellowcake – is packed in drums for transport to a conversion facility. Alternatively, uranium may be mined by in situ leach ("ISL") in which oxygenated groundwater is circulated through a very porous ore body to dissolve the uranium and bring it to the surface. ISL may also use slightly acidic or alkaline solutions to keep the uranium in solution. The uranium is then recovered from the solution in a mill to produce U_3O_8.

After milling, the U_3O_8 must be chemically converted into uranium hexafluoride ("UF_6"). This intermediate stage is known as conversion and produces the feedstock required in the isotopic separation process.

Naturally occurring uranium primarily consists of two isotopes, 0.7% Uranium-235 ("U-235") and 99.3% Uranium-238. Most of this country's nuclear reactors (including those of the Company) require U-235 concentrations in the 3-5% range to operate a complete cycle of 18 to 24 months between refueling outages. The process of increasing the concentration of U-235 is known as enrichment. Gas centrifuge is the primary technology used by the commercial enrichment suppliers. This process first applies heat to the UF_6 to create a gas.

Then, using the mass differences between the uranium isotopes, the natural uranium is separated into two gas streams, one being enriched to the desired level of U-235, known as low enriched uranium, and the other being depleted in U-235, known as tails.

Once the UF_6 is enriched to the desired level, it is converted to uranium dioxide powder and formed into pellets. This process and subsequent steps of inserting the fuel pellets into fuel rods and bundling the rods into fuel assemblies for use in nuclear reactors is referred to as fabrication.

Q. PLEASE PROVIDE A SUMMARY OF DEC'S NUCLEAR FUEL PROCUREMENT PRACTICES.

A. As set forth in Houston Exhibit 2, DEC's nuclear fuel procurement practices involve 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.

For uranium concentrates, conversion, and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. Throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEC's exposure to price volatility. Diversifying fuel suppliers reduces DEC's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Q. PLEASE DESCRIBE DEC'S DELIVERED COST OF NUCLEAR FUEL DURING THE TEST PERIOD.

A. Staggering long-term contracts over time for each of the components of the nuclear fuel cycle means DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets. DEC mitigates the impact of market volatility on the portfolio of supply contracts by using a mixture of pricing mechanisms. Consistent with its portfolio approach to contracting, DEC entered into several long-term contracts during the test period.

DEC's portfolio of diversified contract pricing yielded an average unit cost of $39.49 per pound for uranium concentrates during the test period, representing a 16% decrease from the prior test period.

A majority of DEC's enrichment purchases during the test period were delivered under long-term contracts negotiated prior to the test period. The staggered portfolio approach has the effect of smoothing out DEC's exposure to price volatility. The average unit cost of DEC's purchases of enrichment services during the test period increased 12% to $116.60 per Separative Work Unit.

Delivered costs for fabrication and conversion services have a limited impact on the overall fuel expense rate given that the dollar amounts for these purchases represent a substantially smaller percentage – 16% and 5%, respectively, for the fuel batches recently loaded into DEC's reactors – of DEC's total direct fuel cost relative to uranium concentrates or enrichment, which are 44% and 35%, respectively.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN NUCLEAR FUEL MARKET CONDITIONS.

A. Prices in the uranium concentrate markets have increased due to production cutbacks and activity from financial investors. Industry consultants believe that recent production cutbacks have been warranted due to the previously existing oversupply conditions and that market prices need to further increase in the longer term to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements.

Market prices for conversion services have recently been stable primarily due to an increase in new production.

Market prices for enrichment services have recently increased primarily due to a reduction in available inventory supplies.

Fabrication is not a service for which prices are published; however, industry consultants expect fabrication prices will continue to generally trend upward.

Q. WHAT CHANGES DO YOU SEE IN DEC'S NUCLEAR FUEL COST IN THE BILLING PERIOD?

A. Because fuel is typically expensed over two to three operating cycles (roughly three to six years), DEC's nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period, as well as prior periods. The fuel residing in the reactors during the billing period will have been obtained under historical contracts negotiated in various market conditions. Each of these contracts contributes to a portion of the uranium, conversion, enrichment, and fabrication costs reflected in the total fuel expense.

The average fuel expense is expected to remain relatively flat, from 0.5726 cents per kWh incurred in the test period, to approximately 0.5773 cents per kWh in the billing period.

Q. WHAT STEPS IS DEC TAKING TO PROVIDE STABILITY IN ITS NUCLEAR FUEL COSTS AND TO MITIGATE PRICE INCREASES IN THE VARIOUS COMPONENTS OF NUCLEAR FUEL?

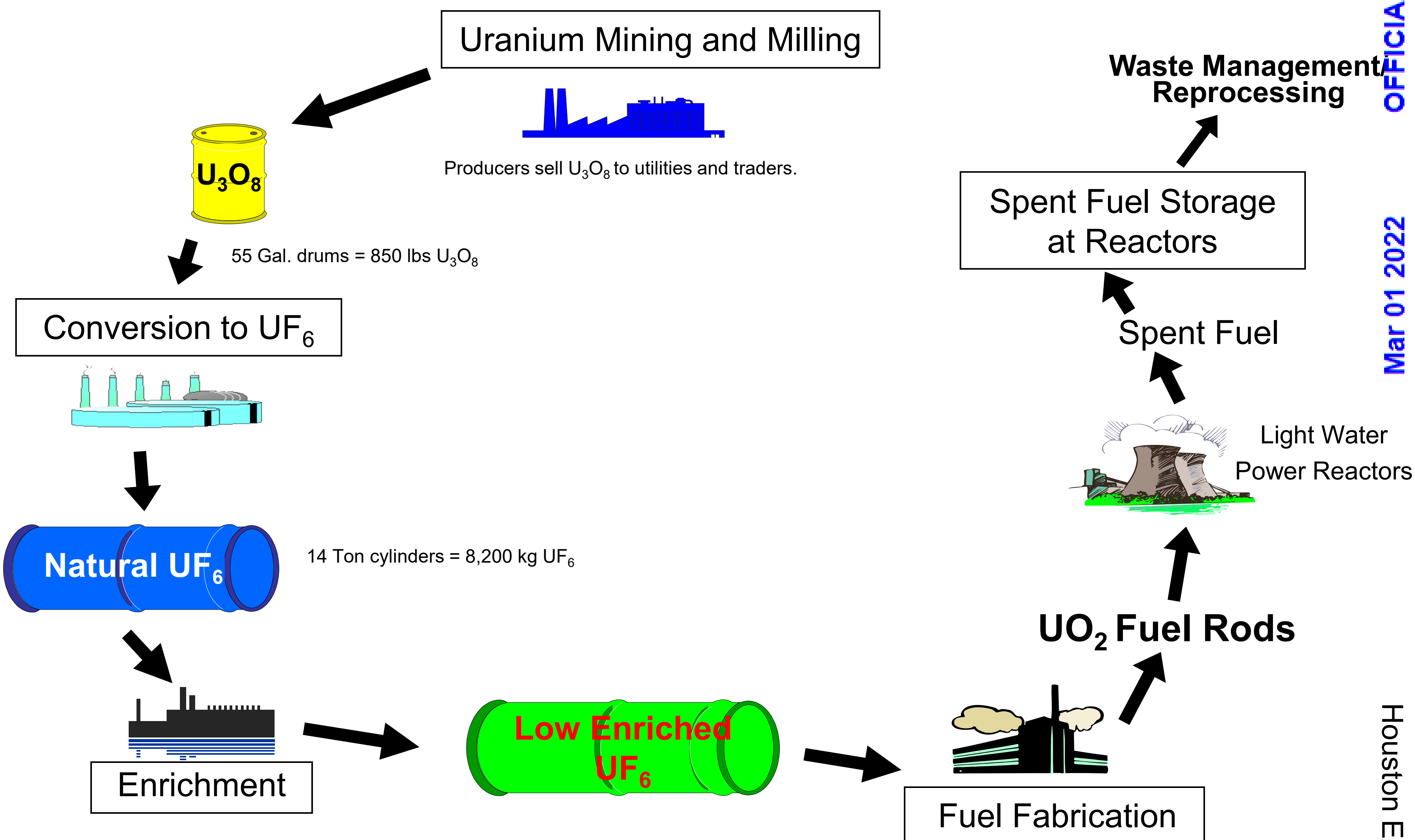
A. As I discussed earlier and as described in Houston Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEC relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating a range of pricing mechanisms, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEC's exposure to price volatility.

Although costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a cents per kWh basis will likely continue to be a fraction of the cents per kWh cost of fossil fuel. Therefore, customers will continue to benefit from DEC's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

The Nuclear Fuel Cycle



Duke Energy Carolinas, LLC Nuclear Fuel Procurement Practices

The Company's nuclear fuel procurement practices are summarized below:

- Near and long-term consumption forecasts are computed based on factors such as: nuclear system operational projections given fleet outage/maintenance schedules, adequate fuel cycle design margins to key safety licensing limitations, and economic tradeoffs between required volumes of uranium and enrichment necessary to produce the required volume of enriched uranium.
- Nuclear system inventory targets are determined and designed to provide: reliability, insulation from market volatility, and sensitivity to evolving market conditions. Inventories are monitored on an ongoing basis.
- On an ongoing basis, existing purchase commitments are compared with consumption and inventory requirements to ascertain additional needs.
- Qualified suppliers are invited to make proposals to satisfy additional or future contract needs.
- Contracts are awarded based on the most attractive evaluated offer, considering factors such as price, reliability, flexibility and supply source diversification/portfolio security of supply.
- For uranium concentrates, conversion and enrichment services, long term supply contracts are relied upon to fulfill the largest portion of forward requirements. By staggering long-term contracts over time, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Due to the technical complexities of changing suppliers, fabrication services are generally sourced to a single domestic supplier on a plant-by-plant basis using multi-year contracts.
- Spot market opportunities are evaluated from time to time to supplement long-term contract supplies as appropriate based on comparison to other supply options.
- Delivered volumes of nuclear fuel products and services are monitored against contract commitments. The quality and volume of deliveries are confirmed by the delivery facility to which the Company has instructed delivery. Payments for such delivered volumes are made after the Company's receipt of such delivery facility confirmations.

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	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**JOHN A. VERDERAME FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY CAROLINAS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John A. Verderame. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Vice President, Fuels & Systems Optimization for Duke Energy Corporation ("Duke Energy"). In that capacity, I lead the organization responsible for the purchase and delivery of coal, natural gas, fuel oil, and reagents to Duke Energy's regulated generation fleet, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas," "DEC," or the "Company") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"). In addition, I manage the fleet's power trading, system optimization, energy supply analytics, and contract administration functions.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics from the University of Rochester in 1983, and a Master's in Business Administration in Finance from Rutgers University in 1985. I have worked in the energy industry for 20 years. Prior to that, from 1986 to 2001, I was a Vice President in the United States (US) Government Bond Trading Groups at the Chase Manhattan Bank and Cantor Fitzgerald. My responsibilities as a US Government Securities Trader included acting as the Firm's market maker in US Government Treasury securities. I joined Progress Energy, in 2001, as a Real-Time Energy Trader. My responsibilities as a Real-Time Energy Trader included managing the real-time energy position of the Progress Energy regulated utilities. In 2005, I was promoted to Manager of the Power Trading group. My role as manager included responsibility for the short-term capacity and energy position of the Progress Energy regulated utilities in the Carolinas and Florida.

In 2012, upon consummation of the merger between Duke Energy Corp. and Progress Energy, Progress Energy became Duke Energy Progress and I was named Managing Director, Trading and Dispatch. As Managing Director, Trading and Dispatch I was responsible for Power and Natural Gas Trading and Generation Dispatch on behalf of Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I assumed my current position in November 2019.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDING?

A. Yes. I testified in support of DEC's 2020 fuel and fuel-related cost recovery application in Docket No. E-7, Sub 1250 and in DEP's 2020 fuel and fuel-related cost recovery application in Docket No. E-2, Sub 1272.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe DEC's fossil fuel purchasing practices, provide actual fossil fuel costs for the period January 1, 2021 through December 31, 2021 ("test period") versus the period January 1, 2020 through December 31, 2020 ("prior test period"), and describe changes projected for the billing period of September 1, 2022 through August, 31 2023 ("billing period").

Q. YOUR TESTIMONY INCLUDES THREE EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND

UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Verderame Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Verderame Exhibit 2, which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases for the test period and prior test period, and Verderame Confidential Exhibit 3, which summarizes the annual fuels related transactional activity between DEC and Piedmont Natural Gas Company, Inc. ("Piedmont") for spot commodity transactions during the test period, as required by the Merger Agreement between Duke Energy and Piedmont.

Q. PLEASE PROVIDE A SUMMARY OF DEC'S FOSSIL FUEL PROCUREMENT PRACTICES.

A. A summary of DEC's fossil fuel procurement practices is set out in Verderame Exhibit 1.

Q. PLEASE DESCRIBE THE COMPANY'S APPROACH TO UNIT COMMITMENT AND DISPATCH OF ITS GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS.

A. Both DEC and DEP perform the same detailed daily process to determine the unit commitment plan that economically and reliably meets the Company's projected system needs over the next seven days. The Company utilizes a production cost model to determine an optimal unit commitment plan to economically and reliably meet system requirements. The model minimizes the production costs needed to serve the projected customer demand within reliability and other system constraints over a period of time. Inputs to the model include, but are not limited to, the following: (1) forecasted customer energy demand; (2) the latest forecasted fuel prices, reflective of market supply chain dynamics; (3) variable transportation rates; (4) planned maintenance and refueling outages at the generating units; (5) generating unit performance parameters; (6) reliability constraints such as units run to maintain day-ahead planning reserves or units required to run for transmission or voltage support; and (7) expected market conditions associated with power purchases and off-system sales opportunities. The production cost model output produces the optimized hourly unit commitment plan for the 7-day forecast period. This unit commitment plan also provides the starting point for dispatch, but dispatch is then also subject to real time adjustments due to changing system conditions including management of natural gas transportation constraints. The unit commitment plan is prepared daily and adjusted, as needed, throughout any given day to respond to changing real time system conditions.

Q. PLEASE DESCRIBE THE COMPANY'S DELIVERED COST OF COAL AND NATURAL GAS DURING THE TEST PERIOD.

A. The Company's average delivered cost of coal per ton for the test period was \$78.22 per ton, compared to \$90.53 per ton in the prior test period, representing a decrease of approximately 14%. The cost of delivered coal 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, representing a decrease of approximately 10%. 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, representing an increase of approximately 44%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

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, representing a decrease of 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, representing an increase of approximately 40%.

Changes in coal and natural gas burns were primarily driven by increased demand from the economic rebound experienced following the COVID-19 shutdowns in 2020. Rapidly escalating coal commodity prices in the latter half of 2021 off-set the overall increase in natural gas prices reducing gas to coal switching. Gas burns are also impacted by the inclusion of natural gas generation at Belews Creek Unit 2 and Marshall Units 3 & 4 as a result of the dual fuel conversions being commercially available in early 2021.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN COAL AND NATURAL GAS MARKET CONDITIONS.

A. 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 from the new administration 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) uncertainty surrounding regulations for mining operations; (6) tightening access to investor financing coupled with deteriorating credit quality is increasing the overall costs of financing for coal producers; (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. Producers were unable to respond to this rapid rise in demand due to capacity constraints resulting from labor and resource shortages. These factors combined to drive both domestic and export coal prices in 2021 to record levels.

Declining demand for coal in the utility sector has also driven rail transportation providers to modify their business models to be less dependent on coal related transportation revenues. Although rail transportation providers are required to provide rail service, the Company's rail transportation providers have limited resources to adapt to significant changes in scheduling demand resulting from the Company's burn volatility, specifically in higher than forecasted coal burn scenarios. In 2021, the Company experienced increased delivery delays created by rail transportation labor and resource shortages.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years as producers enhanced production techniques, enhance efficiencies, and lowered production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in

2021, such dynamics were influenced primarily by growth in export demand, stable production, lower than average storage inventory balances and seasonal weather demand. While there continues to be adequate natural gas production capacity there is a growing need for natural gas pipeline infrastructure to serve increased market demand. Conversely, pipeline infrastructure permitting and regulatory process approval efforts are increasingly challenged and taking longer due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing. The Federal Energy Regulatory Commission ("FERC") is in the process of developing policy for additional project requirements to include an analysis of environmental and social impacts on new pipeline infrastructure.

Over the longer term planning horizon, natural gas supply has the ability to respond to changing demand while the pipeline infrastructure needed to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico is highly uncertain.

Q. WHAT ARE THE PROJECTED COAL AND NATURAL GAS CONSUMPTIONS AND COSTS FOR THE BILLING PERIOD?

A. 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. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. 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 increase in delivered costs is primarily driven by increased coal commodity costs due to limited coal supply and increased domestic and international demand. 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. This projected delivered 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 despite DEC's strong contract compliance monitoring process; 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.

DEC's current natural gas burn projection for the billing period is approximately 242.0 million MBtu, which is an increase from the 189.6 million MBtu consumed during the test period. The net increase in DEC's overall natural gas burn projections for the billing period versus the test period is primarily driven by coal to gas switching as a result of 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 current average forward Henry Hub price for the billing period is $$3.60 per MMBtu, compared to $3.84 per MMBtu in the test period.

The Company now expects projected natural gas burn volumes to be reduced based on delays in anticipated lower cost gas supply coming into the portfolio.

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.

Q. WHAT STEPS IS DEC TAKING TO ENSURE A COST-EFFECTIVE RELIABLE FUEL SUPPLY?

A. The Company 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. With respect to coal procurement, the Company's procurement strategy includes: (1) having an appropriate mix of term contract and spot purchases for coal; (2) staggering coal contract expirations in order to limit exposure to forward market price changes; and (3) diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels. Additionally, the Company negotiates coal transportation contracts that support secure, reliable deliveries in a lower coal burn environment.

The Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply. These procurement practices include contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption. 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.

Lastly, DEC procures long-term firm interstate and intrastate transportation to provide natural gas to their generating facilities. Given the Company's limited amount of contracted firm interstate transportation, the Company purchases shorter term firm interstate pipeline capacity as available from the capacity release market. The Company's firm transportation ("FT") provides the underlying framework for the Company to manage the natural gas supply needed for reliable cost-effective generation. First, it allows the Company access to lower cost natural gas supply from Transco Zone 3 and Zone 4 and the ability to transport gas to Zone 5 for delivery to the Carolinas' generation fleet. Second, the Company's FT allows it to manage intraday supply adjustments on the pipeline through injections or withdrawals of natural gas supply from storage, including on weekends and holidays when the gas markets are closed. Third, it allows the Company to mitigate imbalance penalties associated with Transco pipeline restrictions, which can be significant. The Company's customers receive the benefit of each of these aspects of the Company's FT: access to lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Duke Energy Carolinas, LLC Fossil Fuel Procurement Practices

Coal

- Near and long-term coal consumption is forecasted based on inputs such as load projections, fleet maintenance and availability schedules, coal quality and cost, non-coal commodity and emission prices, environmental permit and emissions constraints, projected renewable energy production, and wholesale energy imports and exports.
- Station and system inventory targets are developed to provide generational reliability, insulation from short-term market volatility, and adaptability to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to determine changes in supply needs.
- All qualified suppliers are invited to participate in Request for Proposals to satisfy additional supply needs.
- Spot market solicitations are conducted on an on-going basis to supplement existing purchase commitments.
- Contracts are awarded based on the highest customer value, considering factors such as price, quality, transportation, reliability and flexibility.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on certified scale weights and coal quality analysis meeting ASTM standards as established by ASTM International.

Gas

- Near and long-term natural gas consumption is forecasted based on inputs such as load projections, commodity and emission prices, projected renewable energy production, and fleet maintenance and availability schedules.
- Physical procurement targets are developed to procure a cost effective and reliable natural gas supply.
- Natural gas supply is contracted utilizing a portfolio of long term, short term, spot market and physical call option agreements
- Short-term and long-term Requests for Proposals and market solicitations are conducted with potential suppliers, as needed, to procure the cost competitive, secure, and reliable natural gas supply, firm transportation, and storage capacity needed to meet forecasted gas usage.
- Short-term and spot purchases are conducted on an on-going basis to supplement term natural gas supply.
- On a continuous basis, existing purchases are compared against forecasted gas usage to determine changes in supply and transportation needs.
- Natural gas transportation for the generation fleet is obtained through a mix of long-term firm transportation agreements, and shorter-term pipeline capacity purchases.
- A targeted percentage of the natural gas fuel price exposure is managed via a rolling 60-month structured financial natural gas hedging program.

- Through the Asset Management and Delivered Supply Agreement between Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC implemented on January 1, 2103, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for the combined Carolinas gas fleet.

Fuel Oil

- No. 2 fuel oil is burned primarily for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All No. 2 fuel oil is moved via pipeline to applicable terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, the Company relies on a combination of inventory, responsive suppliers with access to multiple terminals, and trucking agreements to manage its needs. Replenishment of No. 2 fuel oil inventories at the applicable plant facilities is done on an "as needed basis" and coordinated between fuel procurement and station personnel.
- Formal solicitations for supply may be conducted as needed with an emphasis on maintaining a network of reliable suppliers at a competitive market price in the region of our generating assets.

DUKE ENERGY CAROLINAS
Summary of Coal Purchases
Twelve Months Ended December 31, 2021 & 2020
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
1	January 2021	323,175	272,905	596,079
2	February	178,088	352,765	530,853
3	March	307,174	179,526	486,700
4	April	244,734	259,026	503,760
5	May	214,001	267,134	481,135
6	June	167,453	305,774	473,227
7	July	408,398	114,825	523,222
8	August	477,986	126,407	604,393
9	September	405,691	50,464	456,155
10	October	276,793	140,002	416,795
11	November	75,126	75,590	150,716
12	December	150,700	89,983	240,683
13	**Total** (Sum L1:L12)	**3,229,319**	**2,234,401**	**5,463,718**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
14	January 2020	719,300	39,752	759,052
15	February	377,885	130,203	508,088
16	March	511,418	51,906	563,324
17	April	454,145	23,566	477,712
18	May	203,960	12,873	216,833
19	June	306,915	11,563	318,478
20	July	395,057	50,851	445,908
21	August	548,061	25,831	573,892
22	September	400,170	99,692	499,862
23	October	531,876	52,647	584,523
24	November	360,487	111,351	471,838
25	December	326,439	52,176	378,615
26	**Total (Sum L14:L25)**	**5,135,713**	**662,411**	**5,798,125**

DUKE ENERGY CAROLINAS
Summary of Gas Purchases
Twelve Months Ended December 31, 2021 & 2020
MBTUs

Line No.	Month	MBTUs
1	January 2021	15,219,115
2	February	10,438,520
3	March	10,115,378
4	April	8,394,699
5	May	10,080,567
6	June	13,869,501
7	July	23,083,528
8	August	21,334,474
9	September	17,254,822
10	October	17,385,461
11	November	22,756,045
12	December	19,657,646
13	**Total (Sum L1:L12)**	**189,589,756**

Line No.	Month	MBTUs
14	January 2020	13,098,158
15	February	13,151,481
16	March	13,043,284
17	April	6,893,840
18	May	10,414,617
19	June	9,651,972
20	July	13,975,803
21	August	12,871,773
22	September	11,262,855
23	October	11,076,024
24	November	9,927,112
25	December	10,055,686
26	**Total (Sum L14:L25)**	**135,422,605**

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	)

JOHN A. VERDERAME CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

MARCH 1, 2022

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	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**BRYAN WALSH FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY CAROLINAS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bryan Walsh and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy and am the Vice President ("VP") of Central Operational Services and Oversight.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from The Catholic University of America with a Bachelor of Mechanical Engineering degree. I also graduated from the Georgia Institute of Technology with a Master of Science in Mechanical Engineering. I am a registered Professional Engineer in the State of North Carolina. My career began with Duke Energy as part of Duke / Fluor Daniel in 1999 as an associate engineer assisting in the design and commissioning of new combined-cycle power plants. I transferred to Duke Power in 2003 and worked in the Technical Services group for Fossil-Hydro. Since that time, I have held various roles of increasing responsibility in the generation engineering, operations areas, and project management, including the role of technical manager at DEC's Marshall Steam Station, and also station manager at Duke Energy Indiana's Gallagher Station & Markland Hydro Station. I was also the Midwest Regional Manager from 2012 to 2015, with overall responsibility for the Midwest Gas Turbine Fleet and various coal-fired facilities in Indiana and Kentucky. I was named General Manager for Outages & Projects in the Carolinas in 2015. Next, I became the General Manager of Fossil-Hydro Organizational Effectiveness in 2017. I assumed my current role in 2019.

Q. WHAT ARE YOUR CURRENT DUTIES AS VP OF CENTRAL OPERATIONAL SERVICES AND OVERSIGHT?

A. In this role, I am responsible for providing engineering, environmental compliance planning, technical services, and maintenance services, for Duke Energy's fleet of fossil, hydroelectric, and solar (collectively, "Fossil/Hydro/Solar") facilities.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before the North Carolina Utilities Commission on behalf of the Company in its Duke Energy Progress fuel case in Docket No E-2, Sub 1250.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (1) describe DEC's Fossil/Hydro/Solar generation portfolio and changes made since the 2021 fuel and fuel-related cost recovery proceeding, as well as those expected in the near term, (2) discuss the performance of DEC's Fossil/Hydro/Solar facilities during the test period of January 1, 2021 through December 31, 2021 (the "test period"), (3) provide information on significant Fossil/Hydro/Solar outages that occurred during the test period, and (4) provide information concerning environmental compliance efforts.

Q. PLEASE DESCRIBE DEC'S FOSSIL/HYDRO/SOLAR GENERATION PORTFOLIO.

A. The Company's Fossil/Hydro/Solar generation portfolio consists of approximately 14,274 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	6,087 MWs
Hydro -	3,354 MWs
Combustion Turbines ("CT") -	2,633 MWs
Combined Cycle Turbines ("CC")-	2,116 MWs
Solar -	71 MWs
Combined Heat and Power ("CHP") -	13 MWs

The coal-fired assets consist of four generating stations with a total of 10 units. These units are equipped with emissions control equipment, including selective catalytic or selective non-catalytic reduction ("SCR" or "SNCR") equipment for removing nitrogen oxides ("NO_x"), and flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"). In addition, all 10 coal-fired units are equipped with low NO_x burners.

The Company has a total of 31 simple cycle CT units, of which 29 are considered the larger group providing approximately 2,549 MWs of capacity. These 29 units are located at Lincoln, Mill Creek, and Rockingham Stations, and are equipped with water injection systems that reduce NO_x and/or have low NO_x burner equipment in use. The Lee CT facility includes two units with a total capacity of 84 MWs equipped with fast-start ability in support of DEC's Oconee Nuclear Station. The Company has 2,116 MWs of CC turbines, comprised of the Buck CC, Dan River CC and W.S. Lee CC facilities. These facilities are equipped with technology for emissions control, including SCRs, low NO_x burners, and carbon monoxide/volatile organic compounds catalysts. The Company's hydro fleet includes two pumped storage facilities with four units each that provide a total capacity of 2,300 MWs, along with conventional hydro assets consisting of 59 units providing approximately 1,054 MWs of capacity. The 71 MWs of solar capacity are made up of 17 rooftop solar sites providing 3 MWs of relative summer dependable capacity, the Mocksville solar facility providing 6 MWs of relative summer dependable capacity, the Monroe solar facility providing 22 MWs of relative summer dependable capacity, Woodleaf solar facility providing 2 MWs of relative summer dependable capacity, Gaston solar facility providing 10 MW of relative summer dependable capacity and Maiden Creek solar facility providing 28 MW of relative summer dependable capacity. Finally, the Company has the Clemson CHP that provides 13 MW of capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEC'S 2021 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. Allen Unit 3 was retired on 3/31/2021, and Allen Units 2 and 4 were retired on 12/31/2021. Bad Creek Unit 1 was uprated to bring an additional 80MW to the grid. W.S. Lee Unit 3 was placed in inactive reserve and will be retired 3/31/2022.

Q. WHAT ARE DEC'S OBJECTIVES IN THE OPERATION OF ITS FOSSIL/HYDRO/SOLAR FACILITIES?

A. The primary objective of DEC's Fossil/Hydro/Solar generation department is to provide safe, reliable and cost-effective electricity to DEC's customers. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with procedures, guidelines, and a standard operating model.

The Company complies with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability for customers. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power options for DEC's customers. Equipment inspection and maintenance outages are generally scheduled during the spring and fall months when customer demand is reduced due to milder temperatures. These outages are well-planned and executed in order to prepare the unit for reliable operation until the next planned outage in order to maximize value for customers.

Q. WHAT IS HEAT RATE, AND WHAT WAS THE HEAT RATE FOR DEC'S COAL-FIRED AND COMBINED CYCLE UNITS DURING THE REVIEW PERIOD?

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the review period, the Company's ten coal units produced 55% of the Fossil/Hydro/Solar generation, with the average heat rate for the coal-fired units being 9,736 Btu/kWh. The most active station during this period was Belews Creek, providing 43% of the coal generation for the DEC fleet with a heat rate of 9,685 Btu/kWh. During the review period, the Company's three combined cycle power blocks produced 38% of the Fossil/Hydro/Solar generation, with an average heat rate of 7,099 Btu/kWh.

Q. HOW MUCH GENERATION DID EACH TYPE OF FOSSIL/HYDRO/SOLAR GENERATING FACILITY PROVIDE FOR THE TEST PERIOD?

A. The Company's system generation was approximately 99 million MW hours ("MWhs") for the test period. The Fossil/Hydro/Solar fleet provided 38 million MWhs, or approximately 39% of the total generation. As a percentage of the total system generation, 21% was produced from coal-fired stations and approximately 15% from CC operations, 1% from CTs, 1% from hydro facilities, and 0.3% from solar.

Q. HOW DID DEC COST EFFECTIVELY DISPATCH ITS DIVERSE MIX OF GENERATING UNITS DURING THE TEST PERIOD?

A. The Company's portfolio includes a diverse mix of units that, along with additional nuclear capacity, allows DEC to meet the dynamics of customer load requirements in a cost-effective manner. Additionally, DEC has utilized the Joint Dispatch Agreement, which allows generating resources for DEC and DEP to be dispatched as a single system to enhance dispatching by allowing DEC customers to benefit from the lowest cost resources available. The cost and operational characteristics of each unit generally determine the type of customer load situation (*e.g.,* base and peak load requirements) that a unit would be called upon, or dispatched, to support.

At Belews Creek, Cliffside, and Marshall, dual fuel capabilities also promote efficiency, fuel flexibility and reduced cost. The units equipped with dual fuel capability can be economically dispatched based on need and cost, and the ability to switch fuels can allow the units to avoid forced outages if there is an issue with a fuel system or supply.

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DEC'S FOSSIL/HYDRO/SOLAR FLEET DURING THE TEST PERIOD.

A. The Company's generating units operated efficiently and reliably during the test period. The following key measures are used to evaluate the 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[1] 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

[1] Derated hours are hours the unit operation was less than full capacity.

a year during which the unit is unavailable because of forced outages and forced deratings.

The following chart provides operation results, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Availability Brochure ("NERC Brochure") representing the period 2016 through 2020 and is categorized by generator type. The NERC data reported represents an average of comparable units based on capacity rating. The data in the chart reflects DEC results compared to the NERC five-year averages.

Generator Type	Measure	Review Period	2016-2020	Number of Units
		DEC Operational Results	NERC Average	
Coal Fired Test Period	EAF	71.7%	76.1%	626
	EFOR	11.4%	10.2%	
	EFOF	6.9%	n/a	
Coal Fired Summer Peak	EAF	79.8%	n/a	n/a
Total CC Average	EAF	87.4%	84.9%	345
	NCF	74.0%	54.3%	
	EFOR	0.3%	5.0%	
	EFOF	0.3%	n/a	
Total CT Average	EAF	83.0%	86.6%	709
	SR	99.8%	98.5%	
Hydro	EAF	74.9%	79.4%	1059

Q. PLEASE DISCUSS SIGNIFICANT OUTAGES OCCURRING AT DEC'S FOSSIL/HYDRO/SOLAR FACILITIES DURING THE TEST PERIOD.

A. In general, planned maintenance outages for all fossil and larger hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most of these units had at least one small planned outage during this test period to inspect and maintain plant equipment.

In the first half of 2021, Cliffside Unit 6 completed an outage to perform a boiler inspection, make repairs to the submerged flight conveyor, and perform maintenance on the baghouse. Marshall Unit 3 performed an outage to perform turbine and generator rotor inspections. Marshall Unit 4 completed an outage to perform a Mercury and Air Toxic Standards (MATS) inspection. Dan River CC completed an outage to perform a borescope inspection.

In the second half of 2021, Cliffside Unit 5 completed an outage to complete precipitator inspection/repairs, wash pre-heaters, repair cooling tower fans and replace the steam seal header relief valve. Belews Creek Unit 1 completed an outage to inspect/repair/replace portions of the turbine, perform repairs on the FGD overflow tank, and replace the rappers on the fly ash precipitator. Cliffside Unit 6 performed an outage to replace the SCR catalyst, install new pin mixers on the ash silo, and perform Balance of Plant maintenance. Marshall Unit 1 and Unit 2 completed outages for dual fuel gas installation and tie in. Lincoln CT Units 15 and Unit 16 both completed outages to upgrade protective relays for generators and transformers. Rockingham CT Unit 2 performed a hot gas path inspection.

Q. HOW DOES DEC ENSURE EMISSIONS REDUCTIONS FOR ENVIRONMENTAL COMPLIANCE?

A. The Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for NO_x and SO_2 emissions. The SCR technology that DEC currently operates on the coal-fired units uses ammonia or urea for NO_x removal. The SNCR technology employed at Allen Station and Marshall Units 1, 2 and 4 injects urea into the boiler for NO_x removal. All DEC coal units have wet scrubbers installed that use crushed limestone for SO_2 removal. Cliffside Unit 6 has a state-of-the-art SO_2 reduction system that couples a wet scrubber (*e.g.*, limestone) and dry scrubber (*e.g.*, quicklime). SCR equipment is also an integral part of the design of the Buck, Dan River and Lee CC Stations in which aqueous ammonia is introduced for NO_x removal.

Overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emissions reduction required. The Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. Overall, the goal is to effectively comply with emissions regulations and provide the optimal total-cost solution for the operation of the unit. The Company will continue to leverage new technologies and chemicals to meet both present and future state and federal emission requirements including the MATS rule. MATS chemicals that DEC uses when required to reduce emissions include, but may not be limited to, activated carbon, mercury oxidation chemicals, and mercury re-emission prevention chemicals. Company witness Sykes provides the cost information for DEC's chemical use and forecast.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

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	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**STEVEN D. CAPPS FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY CAROLINAS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven D. Capps and my business address is 13225 Hagers Ferry Road, Huntersville, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy") with direct executive accountability for Duke Energy's South Carolina nuclear plants, including Duke Energy Carolinas, LLC's ("DEC" or the "Company") Catawba Nuclear Station ("Catawba") in York County, South Carolina, the Oconee Nuclear Station ("Oconee") in Oconee County, South Carolina, and Duke Energy Progress, LLC's ("DEP") Robinson Nuclear Plant, located in Darlington County, South Carolina.

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AS SENIOR VICE PRESIDENT OF NUCLEAR OPERATIONS?

A. As Senior Vice President of Nuclear Operations, I am responsible for providing executive oversight for the safe and reliable operation of Duke Energy's three South Carolina operating nuclear stations. I am also involved in the operations of Duke Energy's other nuclear stations, including DEC's McGuire Nuclear Station ("McGuire") located in Mecklenburg County, North Carolina.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a B.S. in Mechanical Engineering from Clemson University and have over 34 years of experience in the nuclear field in various roles with increasing responsibilities. I joined Duke Energy in 1987 as a field engineer at Oconee. During my time at Oconee, I served in a variety of leadership positions at the station, including Senior Reactor Operator, Shift Technical Advisor, and Mechanical and Civil Engineering Manager. In 2008, I transitioned to McGuire as the Engineering Manager. I later became plant manager and was named Vice President of McGuire in 2012. In December 2017, I was named Senior Vice President of Nuclear Corporate for Duke with direct executive accountability for Duke Energy's nuclear corporate functions, including nuclear corporate engineering, nuclear major projects, corporate governance and operation support and organizational effectiveness. I assumed my current role in October 2018.

Q. HAVE YOU TESTIFIED OR SUBMITTED TESTIMONY BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I provided testimony and appeared before the Commission in DEC's fuel and fuel related cost recovery proceeding in Docket No. E-7, Sub 1163 and provided testimony in DEC's fuel and fuel related cost recovery proceedings in Docket No. E-7, Sub 1190, Docket No. E-7, Sub 1228, and Docket No. E-7, Sub 1250.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe and discuss the performance of DEC's nuclear fleet during the period of January 1, 2021 through December 31, 2021 ("test period"). I provide information about refueling outages completed during the period and also discuss the nuclear capacity factor being proposed by DEC for use in this proceeding in determining the fuel factor to be reflected in rates during the billing period of September 1, 2022 through August 31, 2023 ("billing period").

Q. PLEASE DESCRIBE EXHIBIT 1 INCLUDED WITH YOUR TESTIMONY.

A. Exhibit 1 is a confidential exhibit outlining the planned schedule for refueling outages for DEC's nuclear units through the billing period. This exhibit represents DEC's current plan, which is subject to adjustment due to changes in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEC'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 5,389 megawatts ("MWs") of generating capacity, made up as follows:

Oconee -	2,554 MWs
McGuire -	2,316 MWs
Catawba -	519 MWs

The three generating stations summarized above are comprised of a total of seven units. Oconee began commercial operation in 1973 and was the first nuclear station designed, built, and operated by DEC. It has the distinction of being the second nuclear station in the country to have its license, originally issued for 40 years, renewed for up to an additional 20 years by the NRC. The license renewal, which was obtained in 2000, extends operations to 2033, 2033, and 2034 for Oconee Units 1, 2, and 3, respectively. The Company submitted a subsequent license renewal (SLR) application for the Oconee units in June 2021, and the application is currently under review by the Nuclear Regulatory Commission. If approved, the Oconee units would be licensed to operate for an additional 20 years. In 2019, the Company publicly announced intention to seek SLR for all 11 units operated by Duke Energy.

McGuire began commercial operation in 1981, and Catawba began commercial operation in 1985. In 2003, the NRC renewed the licenses for McGuire and Catawba for up to an additional 20 years each. This renewal extends operations until 2041 for McGuire Unit 1, and 2043 for McGuire Unit 2 and Catawba Units 1 and 2. The Company jointly owns Catawba with North Carolina Municipal Power Agency Number One, North Carolina Electric Membership Corporation, and Piedmont Municipal Power Agency.

Q. WHAT ARE DEC'S OBJECTIVES IN THE OPERATION OF ITS NUCLEAR GENERATION ASSETS?

A. The primary objective of DEC's nuclear generation department is to safely provide reliable and cost-effective electricity to DEC's customers in North and South Carolina. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees receive extensive, comprehensive training and execute their responsibilities to the highest standards in accordance with detailed procedures that are continually updated to ensure best practices. The Company maintains station equipment and systems reliably, and ensures timely implementation of work plans and projects that enhance the performance of systems, equipment, and personnel. Station refueling and maintenance outages are conducted through the execution of well-planned, well-executed, and high-quality work activities, which ensure that the plant is prepared for operation until the next planned outage.

Q. PLEASE DISCUSS THE PERFORMANCE OF DEC'S NUCLEAR FLEET DURING THE TEST PERIOD.

A. The Company operated its nuclear stations in a reasonable and prudent manner during the test period, providing approximately 61% of the total power generated by DEC. During 2021, DEC's seven nuclear units collectively achieved a fleet capacity factor of 96.12%, marking the 22nd consecutive year in which DEC's nuclear fleet exceeded a system capacity factor of 90%. During the test period, McGuire Unit 1, Oconee Unit 1, and the Oconee station established new annual net generation records. The Company continued successful Covid-19 mitigation protocols and executed four refueling outages and achieved strong operational performance during the year. Catawba Unit 2 and Oconee Unit 2 entered their 2021 refueling outages after completing breaker-to-breaker continuous cycle runs. Catawba Unit 1 established a new Duke Energy refueling outage duration record. The 18.8-day refueling outage also established a new U.S. duration record for ice condenser pressurized water reactors.

Q. HOW DOES DEC'S NUCLEAR FLEET COMPARE TO INDUSTRY AVERAGES?

A. The Company's nuclear fleet has a history of performance that consistently exceeds industry averages. The most recently published North American Electric Reliability Council's ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") indicates an average capacity factor of 92.07% for the period 2016 through 2020 for comparable units. The Company's 2021 capacity factor of

96.12% and 2-year average[1] of 95.58% both exceed the NERC average of 92.07%.

Industry benchmarking efforts are a principal technique used by the Company to ensure best practices, and Duke Energy's nuclear fleet continues to rank among the top performers when compared to the seven-other large domestic nuclear fleets using Key Performance Indicators ("KPIs") in the areas of personal safety, radiological dose, capacity factor, forced loss rate, industry performance index, and total operating cost. 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. By continually assessing the Company's performance as compared with industry benchmarks, the Company continues to ensure the overall safety, reliability and cost-effectiveness of DEC's nuclear units.

The superior performance of DEC's nuclear fleet has resulted in substantial benefits to customers. DEC's nuclear fleet has produced approximately 50.9 million MWhs of additional, emissions-free generation over the past 22 years (as compared with production at a capacity factor of 90%), which is equivalent to an additional 10.5 months of output from DEC's nuclear fleet (based on DEC's average annual generation for the same 22-year period). These performance results demonstrate DEC's continuing success in achieving high performance without compromising safety and reliability.

[1] This represents the simple average for the current and prior 12-month test periods.

Q. WHAT IMPACTS A UNIT'S AVAILABILITY AND WHAT IS DEC'S PHILOSOPHY FOR SCHEDULING REFUELING AND MAINTENANCE OUTAGES?

A. In general, refueling, maintenance, and NRC required testing and inspections impact the availability of DEC's nuclear system.

Prior to a planned outage, DEC develops a detailed schedule for the outage and for major tasks to be performed, including sub-schedules for particular activities. The Company's scheduling philosophy is to strive for the best possible outcome for each outage activity within the outage plan. For example, if the "best ever" time an outage task was performed is 12 hours, then 12 hours becomes the goal for that task in each subsequent outage. Those individual aspirational goals are incorporated into an overall outage schedule. The Company then aggressively works to meet, and measures itself against, that aspirational schedule. To minimize potential impacts to outage schedules due to unforeseen maintenance requirements, "discovery activities" (walk-downs, inspections, etc.) are scheduled at the earliest opportunities so that any maintenance or repairs identified through those activities can be promptly incorporated into the outage plan.

As noted, the schedule is utilized for measuring outage preparation and execution and driving continuous improvement efforts. However, for planning purposes, particularly with the dispatch and system operating center functions, DEC also develops an allocation of outage time that incorporates reasonable schedule losses. The development of each outage allocation is dependent on maintenance and repair activities included in the outage, as well as major projects to be implemented during the outage. Both schedule and allocation are set aggressively to drive continuous improvement in outage planning and execution.

Q. HOW DOES DEC HANDLE OUTAGE EXTENSIONS AND FORCED OUTAGES?

A. If an unanticipated issue that has the potential to become an on-line reliability challenge is discovered while a unit is off-line for a scheduled outage and repair cannot be completed within the planned work window, the outage is extended when in the best interest of customers to perform necessary maintenance or repairs prior to returning the unit to service. The decision to extend an outage is based on numerous factors, including reliability risk assessments, system power demands, and the availability of resources to address the emergent challenge. In general, if an issue poses a credible risk to reliable operations until the next scheduled outage, the issue is repaired prior to returning the unit to service. This approach enhances reliability and results in longer continuous run times and fewer forced outages, thereby reducing fuel costs for customers in the long run. In the event that a unit is forced off-line, every effort is made to safely perform the repair and return the unit to service as quickly as possible.

Q. DOES DEC PERFORM POST OUTAGE CRITIQUES AND CAUSE ANALYSES FOR INTERNAL IMPROVEMENT EFFORTS?

A. Yes. DEC applies self-critical analysis to each outage and, using the benefit of hindsight, identifies every potential cause of an outage delay or event resulting in a forced or extended outage, and applies lessons learned to drive continuous improvement. The Company also evaluates the performance of each function and discipline involved in outage planning and execution to identify areas in which it can utilize self-critical observation for improvement efforts.

Q. IS SUCH ANALYSES INTENDED TO ASSESS OR MAKE A DETERMINATION REGARDING THE PRUDENCE OR REASONABLENESS OF A PARTICULAR ACTION OR DECISION?

A. No. Given this focus on identifying opportunities for improvement, these critiques and cause analyses are not intended to document the broader context of the outage nor do they make any attempt to assess whether the actions taken were reasonable in light of what was known at the time of the events in question. Instead, the reports utilize hindsight (*e.g.*, subsequent developments or information not known at the time) to identify every potential cause of the incident in question. However, such a review is quite different from evaluating whether the actions or decisions in question were reasonable given the circumstances that existed at that time.

Q. WHAT OUTAGES WERE REQUIRED FOR REFUELING AT DEC'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. There were four refueling outages completed during the test period: Catawba Unit 2 in the spring of 2021, followed by McGuire Unit 2, Catawba Unit 1, and Oconee Unit 2 in the fall. Total days offline for refueling during the test period totaled 111.1 days compared to a total scheduled allocation of 114 days. Three of the four refueling outages were completed under allocation. The Catawba Unit 2 refueling outage extended 5.3 days beyond allocation due to an emergent weld overlay repair required on a reactor head penetration nozzle.

After completing a unit record 535-day continuous cycle run, Catawba Unit 2 was removed from service on March 27, 2021, for refueling. In addition to refueling, safety and reliability enhancing maintenance, inspections and testing were completed. The unit's three low-pressure turbines were replaced during the outage. The new turbines improve reliability and reduce required inspections and maintenance requirements. Other reliability enhancements included the replacement of the 2C reactor coolant pump seal, refurbishment of the 2A chemical injection pump seals, gear drive and motor, and refurbishment of the 2A2 component cooling water pump and motor. Other maintenance activities included tube replacements in the 2A component cooling water heat exchanger and corrective maintenance on the 2A moisture separator reheater tubes. The Unit 2 core exit thermocouple replacement project was completed. Steam generator activities included secondary side cleaning and primary side Eddy Current testing. Other testing and inspections completed during the outage included containment integrated leak rate testing and a volumetric reactor head inspection. The reactor head inspections identified a defect in one nozzle penetration necessitating a weld overlay repair. This emergent repair extended the outage by 5.3 days beyond the scheduled allocation. After refueling, maintenance, and inspections and testing were completed, the unit returned to service on May 3, 2021, for a total outage duration of 37.3 days.

McGuire Unit 2 was removed from the grid on September 11, 2021, for refueling. Large pump and motor reliability enhancements completed during the refueling outage included the 2A and 2C reactor coolant pump seals, the 2B2 component cooling pump motor, and the 2B nuclear service water motor replacements. Valve and actuator maintenance and replacements were completed on components of the safety injection, chemical volume control, instrument air, residual heat removal, and reactor coolant systems. The aging condenser cleaning system was also upgraded. Inspections completed included the reactor vessel 10-year in-service and material reliability program upper and lower internals inspections, and disassembly and inspection of the 2C low pressure turbine. Steam generator Eddy Current and 2B engineered safety features testing was completed. Once work activities, testing and inspections were completed, the unit returned to service on October 11, 2021. The total outage duration was 30.26 days compared to a 32-day scheduled allocation.

Catawba Unit 1 shut down for refueling on October 16, 2021. Along with routine refueling activities, safety and reliability enhancements and inspections were completed. Reliability enhancements completed during the outage included refurbishment of the 1A1 component cooling water pump and rewinding of the 1B hotwell pump motor. A modification on the Unit 1 main generator flexible links improved fit-up, current capacity, and cooling flow, permanently addressing a reliability challenge experienced earlier in the year. The Unit 1 digital fault recorder was replaced, and full functionality of the Unit 1 core exit thermocouples was restored with the replacement of 3 connectors. Inspections were completed on the number 2 main turbine control and number 1 combined intercept valves. After refueling, maintenance activities and inspections were completed, the unit returned to service on November 3, 2021. The 18.8-day refueling outage established a new refueling outage record for the Duke Energy fleet, low dose record for a Catawba refueling outage, and also established a U.S. industry record for refueling duration for ice condenser pressurized water reactors. The scheduled outage duration allocation was 25 days.

After completing a continuous cycle run of 701 days, Oconee Unit 2 shut down for refueling on November 12, 2021. Along with routine refueling activities, safety and reliability enhancements and inspections were completed. Large pump and motor reliability enhancing maintenance included the replacements of the 2A1 reactor coolant pump seals, 2A high pressure injection pump motor, 2B condensate booster pump motor, and 2B turbine electrohydraulic controls (EHC) pump. Other mechanical maintenance included the replacement of multiple feedwater system relief valves. Electrical work included bushing replacements on the CT-2 start-up transformer, and preventive maintenance on the Unit 2 main transformer, main feeder bus number 1, and multiple motor control centers. Upper core barrel bolt, CT2 4160-volt bus, 2TD 4160-volt switchgear, and condenser circulating water waterbox and inlet piping were among inspections completed during the outage. Testing activities included steam generator Eddy Current testing. After refueling, maintenance, inspections and testing completed, the unit returned to service on December 7, 2021, for a total duration of 24.75 days compared to a 25-day schedule allocation.

Q. WHAT OTHER OUTAGES OCCURRED DURING THE TEST PERIOD?

A. The fleet experienced 8.3 days of forced outages during the test period. McGuire Unit 2 was forced offline for just under 3 days due to oil contamination in the turbine lube oil, Catawba Unit 1 was forced offline for 2.8 days related to the main generator isolated bus phase flexible links, and Oconee Unit 2 experienced a 2.5-day forced outage after a reactor protection system actuation due to a signal spike.

Q. WHAT CAPACITY FACTOR DOES DEC PROPOSE TO USE IN DETERMINING THE FUEL FACTOR FOR THE BILLING PERIOD?

A. The Company proposes to use a 93.94% capacity factor, which is a reasonable value for use in this proceeding based upon the operational history of DEC's nuclear units and the number of planned outage days scheduled during the billing period. This proposed percentage is reflected in the testimony and exhibits of Company witness Sykes and exceeds the five-year industry weighted average capacity factor of 92.07% for comparable units as reported in the NERC Brochure during the period of 2016 to 2020.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

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	)

STEVEN D. CAPPS CONFIDENTIAL EXHIBIT 1

FILED UNDER SEAL

MARCH 1, 2022