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February 23, 2021

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell, 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 1250

Dear Ms. Campbell:

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, Steve Immel 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.

Respectfully submitted,

Jack E. Jirak

Enclosures
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 1250, 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 23rd day of February, 2021.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**DUKE ENERGY CAROLINAS,**
R8-55 Relating to Fuel and Fuel-Related	)	**LLC'S APPLICATION**
Charge Adjustments for Electric Utilities	)	

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 550 South Tryon Street, Charlotte, North Carolina, and its mailing address is:

Duke Energy Carolinas, LLC
P. O. Box 1006
Charlotte, North Carolina 28201-1006

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 2020.

4. In Docket No. E-7, Sub 1228, 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 -	1.6391 ¢ per kWh
Commercial -	1.8249 ¢ per kWh
Industrial -	1.9310 ¢ per kWh

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

Residential -	1.4755¢ per kWh
Commercial -	1.7254¢ per kWh
Industrial -	1.7589¢ 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 - (0.0259)¢ per kWh
Commercial - (0.0207)¢ per kWh
Industrial - 0.0770¢ 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 - (0.0040)¢ per kWh
Commercial - (0.0032)¢ per kWh
Industrial - 0.0000¢ per kWh

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

Residential - 1.4456¢ per kWh
Commercial - 1.7015¢ per kWh
Industrial - 1.8359¢ per kWh

The new fuel factors would have an effective date of September 1, 2021.

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, Steve Immel 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 (91.95%) 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 -	1.4613¢ per kWh	1.4459¢ per kWh
Commercial -	1.7115¢ per kWh	1.6872¢ per kWh
Industrial -	1.8437¢ per kWh	1.8254¢ 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 -	1.4456¢ per kWh
Commercial -	1.7015¢ per kWh
Industrial -	1.8359¢ per kWh

Respectfully submitted this 23rd day of February, 2021.

By: ____________________

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ATTORNEYS FOR DUKE ENERGY CAROLINAS, LLC

VERIFICATION

STATE OF NORTH CAROLINA)
) DOCKET NO. E-7, SUB 1250
COUNTY OF MECKLENBURG)

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

That he is RATES MANAGER for DUKE ENERGY CAROLINAS, LLC, applicant in the above-titled action; 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: 2-5-2021

Peggy Holton
Official Signature of Notary

(Official Seal) PEGGY HOLTON NOTARY PUBLIC WAKE COUNTY, NC

Peggy Holton, Notary Public
Notary's printed or typed name

My commission expires: 12/22/2021

I signed this notarial certificate on 2-5-2021 according to the emergency video notarization requirements contained in G.S. 10B-25.

Notary Public location during video notarization: Wake County

Stated physical location of principal during video notarization: Mecklenburg County

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am Rates Manager 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 started 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.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES MANAGER 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 provided testimony in Docket Nos. E-7, Sub 1231 and E-2, Sub 1254 regarding Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's compliance reports and applications for approval of their respective CPRE cost recovery riders in 2020.

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, 2020 ("test period"), and the billing period is September 1, 2021 through August 31, 2022 ("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 93.21% proposed nuclear capacity factor and projected megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 93.21% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 91.95% 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 2020 Monthly Fuel Reports.

1) December 2020 Monthly Fuel Report required by NCUC Rule R8-52.

2) December 2020 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 1.4456¢, 1.7015¢, and 1.8359¢ per kWh, respectively, to be reflected in rates during the billing period. The factors DEC proposes in this proceeding incorporate a 93.21% 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 Immel. 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	1.4755	1.7254	1.7589	1.6414
EMF Increment (Decrement)	(0.0259)	(0.0207)	0.0770	(0.0033)
EMF Interest (Decrement)	(0.0040)	(0.0032)	-	(0.0029)
Net Fuel and Fuel Related Costs Factors	1.4456	1.7015	1.8359	1.6352

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 a 1.89% decrease 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	1.4456	1.7015	1.8359	1.6352
Existing Total Fuel Factor	1.6391	1.8249	1.9310	1.7791
Decrease in Fuel Factor	(0.1935)	(0.1234)	(0.0951)	

Q. WHAT ARE THE KEY DRIVERS IMPACTING THE PROPOSED FUEL

AND FUEL-RELATED COSTS FACTORS?

A. The decrease in the proposed net fuel and fuel-related costs factors is primarily driven by a $2 million over-recovery in the current test period compared to a $57 million under-recovery included in current rates. In addition, estimated system fuel costs in the billing period are lower due to lower kilowatt-hour sales and lower 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 93.21% 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. The purchased and generated power costs associated with this generation are included in the Company's Rider CPRE filing in Docket No. E-7, Sub 1247.

Schedule 2 also uses the proposed capacity factor of 93.21% 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 91.95%. This capacity factor is based on the 2015 through 2019 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 peak demand, a proxy for the production plant allocator since the annual cost of service study is not available at the timing of filing.

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 91.95% NERC nuclear capacity factor compared to the proposed 93.21% 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 over-recovery for the residential and general service/lighting customer classes of $6.0 million and $4.8 million, respectively, and an under-recovery for the industrial customer class of $8.9 million. There are two adjustments included in the calculation of the over-recovery balance at December 31, 2020. The first adjustment relates to the months of January 2020 through March 2020, which were included in the fuel rate approved in the last fuel and fuel-related cost recovery proceeding and are included for Commission review in the current proceeding. The Company has excluded the amount of over-recovery for the months of January 2020 through March 2020 that was included in the EMF approved in Docket E-7, Sub 1228 when computing the proposed EMF factors. For purposes of computing interest on amounts to be refunded to residential and general service customers in this proceeding, a second adjustment is being made. The Company has adjusted the over-recovery amount to exclude customer credits for payments the Company received related to purchased power contract terms. Such amounts are not considered a refund of amounts advanced by customers and accordingly are not included in the computation of interest on over-recovery.

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.

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 1146) 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. Finally, Sykes Exhibit 4 shows the test period peak demand for the system and for North Carolina retail customer classes.

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 1.7305¢ 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) lower natural gas prices; (3) the high capacity factors of its nuclear fleet; and (4) 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 Immel 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 peak demand, a proxy for the production plant allocator since the annual cost of service study is not available at the timing of filing from the latest annual cost of service study.

(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 decrease in fuel and fuel-related costs as it did in its 2020 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1228.

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 (1.89%) was calculated by dividing the fuel and fuel-related cost decrease of $83,415,574 for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $4,419,603,081. The cost decrease of $83,415,574 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 (1.89)%. 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 WORKPAPERS 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, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

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 1228)					
1	Approved Fuel and Fuel Related Costs Factors	Input	1.6027	1.7583	1.6652	1.6816
2	EMF Increment	Input	0.0364	0.0666	0.2658	0.0975
3	EMF Interest Decrement cents/kWh	Input	0.0000	0.0000	0.0000	0.0000
4	Approved Net Fuel and Fuel Related Costs Factors	Sum	**1.6391**	**1.8249**	**1.9310**	**1.7791**
	Fuel and Fuel Related Cost Factors Required by Rule R8-55					
5	Proposed Nuclear Capacity Factor of 93.21% and Normalized Test Period Sales	Exh 2 Sch 2 pg 2	**1.4459**	**1.6872**	**1.8254**	**1.6255**
6	NERC 5 Year Average Nuclear Capacity Factor of 91.95% and Projected Period Sales	Exh 2 Sch 3 pg 2	**1.4613**	**1.7115**	**1.8437**	**1.6469**
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 93.21%					
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	1.4394	1.6997	1.7368	1.6125
8	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.0361	0.0257	0.0221	0.0289
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	1.4755	1.7254	1.7589	1.6414
10	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	(0.0259)	(0.0207)	0.0770	(0.0033)
11	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	(0.0040)	(0.0032)	0.0000	(0.0029)
12	Net Fuel and Fuel Related Costs Factors cents/kWh	Sum	**1.4456**	**1.7015**	**1.8359**	**1.6352**

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 93.21%
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	58,622,085	0.6057	355,077,645
2	Coal	Workpaper 3 & 4	18,691,906	2.3444	438,222,003
3	Gas CT and CC	Workpaper 3 & 4	22,065,718	2.2833	503,828,581
4	Reagents and Byproducts	Workpaper 9			25,707,869
5	Total Fossil	Sum	40,757,624		967,758,453
6	Hydro	Workpaper 3	4,030,270		
7	Net Pumped Storage	Workpaper 3	(2,872,983)		
8	Total Hydro	Sum	1,157,287		-
9	Solar Distributed Generation	Workpaper 3	367,302		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	100,904,299		1,322,836,098
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(16,986,285)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,848,200)		(89,940,492)
13	Fuel expense recovered through reimbursement	Workpaper 4			(6,522,205)
14	Net Generation	Sum Lines 10-13	85,180,099		1,209,387,117
15	Purchased Power	Workpaper 3 & 4	8,109,496	3.0679	248,794,545
16	JDA Savings Shared	Workpaper 5			7,856,711
17	Total Purchased Power		8,109,496		256,651,255
18	Total Generation and Purchased Power	Line 14 + Line 17	93,289,595	1.5715	1,466,038,372
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,789,852)	1.6030	(28,691,221)
20	Line losses and Company use	Line 22-Line 18-Line 19	(3,809,747)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,437,347,151
22	Projected System MWh Sales for Fuel Factor	Workpaper 7	87,689,996		87,689,996
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.6391

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 93.21%
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7	21,803,077	24,128,419	12,036,241	57,967,737
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,866,978
3	QF Purchased Power - Capacity	Workpaper 4				11,169,971
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 25,036,948
5	NC Portion - Jursidicational % based on Peak Demand Allocator	Input				66.90%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 16,749,046
7	Peak Demand Allocation Factors	Input	47.00%	37.09%	15.91%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Peak Demand	Line 6 * Line 7	$ 7,872,063	$ 6,212,405	$ 2,664,577	$ 16,749,046
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0361	0.0257	0.0221	0.0289
	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	1.4394	1.6997	1.7368	1.6125
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0361	0.0257	0.0221	0.0289
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.4755	1.7254	1.7589	1.6414
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	(0.0259)	(0.0207)	0.0770	(0.0033)
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	(0.0040)	(0.0032)	-	(0.0029)
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	1.4456	1.7015	1.8359	1.6352

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 93.21%
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

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 1228	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	21,803,077	$ 2,235,509,347	$ (42,192,996)	-1.89%	(0.1935)	1.6391	1.4456
2	General Service/Lighting	24,128,419	1,577,855,414	(29,780,438)	-1.89%	(0.1234)	1.8249	1.7015
3	Industrial	12,036,241	606,238,320	(11,442,140)	-1.89%	(0.0951)	1.9310	1.8359
4	NC Retail	57,967,737	$ 4,419,603,081	$ (83,415,574)	-1.89%			

Total Proposed Composite Fuel Rate:

Line #	Description	Source	Amount
5	Total Fuel Costs for Allocation	Workpaper 7	$ 1,441,525,237
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	25,036,948
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,416,488,289
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7	87,848,058
9	NC Retail Projected Billing Period MWh Sales	Line 4	57,967,737
10	Allocation %	Line 9 / Line 8	65.99%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 934,740,622
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 1, Page 2	16,749,046
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 951,489,668
14	NC Retail Projected Billing Period MWh Sales	Line 4	57,967,737
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.6414
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	(0.0033)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	(0.0029)
18	Total Proposed Composite Fuel Rate	Sum	1.6352

Total Current Composite Fuel Rate - Docket E-7 Sub 1228:

Line #	Description	Source	Amount
19	Current composite Fuel Rate cents/kWh	Sykes Exhibit 1	1.6816
20	Current composite EMF Rate cents/kWh	Sykes Exhibit 1	0.0975
21	Current composite EMF Interest Rate cents/kWh	Sykes Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.7791
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	(0.1439)
24	NC Retail Projected Billing Period MWh Sales	Line 4	57,967,737
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ (83,415,574)

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 93.21% and Normalized Test Period Sales
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	58,622,085	0.6057	355,077,645
2	Coal	Calculated	17,565,881	2.3444	411,822,928
3	Gas CT and CC	Workpaper 3 & 4	22,065,718	2.2833	503,828,581
4	Reagents and Byproducts	Workpaper 9	-		25,707,869
5	Total Fossil	Sum	39,631,599		941,359,378
6	Hydro	Workpaper 3	4,030,270		
7	Net Pumped Storage	Workpaper 3	(2,872,983)		
8	Total Hydro	Sum	1,157,287		
9	Solar Distributed Generation		367,302		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	99,778,273		1,296,437,023
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(16,986,285)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,848,200)		(89,940,492)
13	Fuel expense recovered through reimbursement	Workpaper 4			(6,522,205)
14	Net Generation	Sum	84,054,073		1,182,988,041
15	Purchased Power	Workpaper 3 & 4	8,109,496		248,794,545
16	JDA Savings Shared	Workpaper 5	-		7,856,711
17	Total Purchased Power	Sum	8,109,496		256,651,255
18	Total Generation and Purchased Power	Line 14 + Line 17	92,163,570		1,439,639,297
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,789,852)		(28,691,221)
20	Line losses and Company use	Line 22 - Line 19 - Line 18	(3,809,747)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,410,948,076
22	Normalized Test Period MWh Sales	Exhibit 4	86,563,971		86,563,971
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.6299

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 93.21% and Normalized Test Period Sales
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Normalized Test Period MWh Sales	Exhibit 4	23,329,575	23,102,975	11,570,060	58,002,609
Calculation of Renewable Purchased Power Capacity Rate by Class						Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,866,978
3	QF Purchased Power - Capacity	Workpaper 4				11,169,971
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 25,036,948
5	NC Portion - Jursidicational % based on Peak Demand Allocator	Input				66.90%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 16,749,046
7	Peak Demand Allocation Factors	Input	47.00%	37.09%	15.91%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Peak Demand	Line 6 * Line 7	$ 7,872,063	$ 6,212,405	$ 2,664,577	$ 16,749,046
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0337	0.0269	0.0230	0.0289
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	1.4421	1.6842	1.7254	1.6028
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0337	0.0269	0.0230	0.0289
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.4758	1.7111	1.7484	1.6317
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	(0.0259)	(0.0207)	0.0770	(0.0033)
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	(0.0040)	(0.0032)	-	(0.0029)
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	1.4459	1.6872	1.8254	1.6255

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 93.21% and Normalized Test Period Sales
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

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 1228	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	23,329,575	$ 2,235,509,347	$ (45,064,232)	-2.02%	(0.1932)	1.6391	1.4459
2	General Service/Lighting	23,102,975	$ 1,577,855,414	(31,806,998)	-2.02%	(0.1377)	1.8249	1.6872
3	Industrial	11,570,060	$ 606,238,320	(12,220,778)	-2.02%	(0.1056)	1.9310	1.8254
4	NC Retail	58,002,609	$ 4,419,603,081	$ (89,092,008)				

Line #	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
5	Total Fuel Costs for Allocation	Workpaper 7a	$ 1,415,126,162
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	25,036,948
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,390,089,213
8	Normalized Test Period System MWh Sales for Fuel Factor	Workpaper 7a	86,722,032
9	NC Retail Normalized Test Period MWh Sales	Exhibit 4	58,002,609
10	Allocation %	Line 9 / Line 8	66.88%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 929,691,666
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 2, Page 2	16,749,046
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 946,440,712
14	NC Retail Normalized Test Period MWh Sales	Line 9	58,002,609
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.6317
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	(0.0033)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	(0.0029)
18	Total Proposed Composite Fuel Rate	Sum	1.6255
	Total Current Composite Fuel Rate - Docket E-7 Sub 1228:		
19	Current composite Fuel Rate cents/kWh	Sykes Exhibit 1	1.6816
20	Current composite EMF Rate cents/kWh	Sykes Exhibit 1	0.0975
21	Current composite EMF Interest Rate cents/kWh	Sykes Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.7791
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	(0.1536)
24	NC Retail Normalized Test Period MWh Sales	Exhibit 4	58,002,609
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ (89,092,008)

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 91.95% and Projected Period Sales
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 2	57,831,714	0.6057	350,290,320
2	Coal	Calculated	19,282,087	2.3444	452,058,499
3	Gas CT and CC	Workpaper 3 & 4	22,065,718	2.2833	503,828,581
4	Reagents and Byproducts	Workpaper 9	-		25,707,869
5	Total Fossil	Sum	41,347,805		981,594,949
6	Hydro	Workpaper 3	4,030,270		
7	Net Pumped Storage	Workpaper 3	(2,872,983)		
8	Total Hydro	Sum	1,157,287		
9	Solar Distributed Generation	Workpaper 3	367,302		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	100,704,109		1,331,885,268
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(16,986,285)
12	Less Catawba Joint Owners	Calculated	(14,648,010)		(88,727,875)
13	Fuel expense recovered through reimbursement	Workpaper 4			(6,522,205)
14	Net Generation	Sum	85,180,099		1,219,648,904
15	Purchased Power	Workpaper 3 & 4	8,109,496		248,794,545
16	JDA Savings Shared	Workpaper 5	-		7,856,711
17	Total Purchased Power	Sum	8,109,496		256,651,255
18	Total Generation and Purchased Power	Line 14 + Line 17	93,289,595		1,476,300,159
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,789,852)		(28,691,221)
20	Line losses and Company use	Line 22 - Line 19 - Line 18	(3,809,747)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			1,447,608,938
22	Projected System MWh Sales for Fuel Factor	Workpaper 7b	87,689,996		87,689,996
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			1.6508

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 91.95% and Projected Period Sales
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7b	21,803,077	24,128,419	12,036,241	57,967,737
Calculation of Renewable Purchased Power Capacity Rate by Class						Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,866,978
3	QF Purchased Power - Capacity	Workpaper 4				11,169,971
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 25,036,948
5	NC Portion - Jursidicational % based on Peak Demand Allocator	Input				66.90%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 16,749,046
7	Peak Demand Allocation Factors	Input	47.00%	37.09%	15.91%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Peak Demand	Line 6 * Line 7	$ 7,872,063	$ 6,212,405	$ 2,664,577	$ 16,749,046
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0361	0.0257	0.0221	0.0289
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	1.4551	1.7097	1.7446	1.6242
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0361	0.0257	0.0221	0.0289
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.4912	1.7354	1.7667	1.6531
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	(0.0259)	(0.0207)	0.0770	(0.0033)
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	(0.0040)	(0.0032)	-	(0.0029)
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	1.4613	1.7115	1.8437	1.6469

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 91.95% and Projected Period Sales
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

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 1228	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	21,803,077	$ 2,235,509,347	$ (38,762,432)	-1.73%	(0.1778)	1.6391	1.4613
2	General Service/Lighting	24,128,419	$ 1,577,855,414	$ (27,359,096)	-1.73%	(0.1134)	1.8249	1.7115
3	Industrial	12,036,241	$ 606,238,320	$ (10,511,820)	-1.73%	(0.0873)	1.9310	1.8437
4	NC Retail	57,967,737	$ 4,419,603,081	$ (76,633,348)				

Line	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
5	Total Fuel Costs for Allocation	Workpaper 7b	$ 1,451,787,024
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	25,036,948
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,426,750,076
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7b	87,848,058
9	NC Retail Projected Billing Period MWh Sales	Line 4	57,967,737
10	Allocation %	Line 9 / Line 8	65.99%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 941,512,375
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 3, Page 2	16,749,046
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 958,261,421
14	NC Retail Projected Billing Period MWh Sales	Line 4	57,967,737
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.6531
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	(0.0033)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	(0.0029)
18	Total Proposed Composite Fuel Rate	Sum	1.6469
	Total Current Composite Fuel Rate - Docket E-7 Sub 1228:		
19	Current composite Fuel Rate cents/kWh	Sykes Exhibit 1	1.6816
20	Current composite EMF Rate cents/kWh	Sykes Exhibit 1	0.0975
21	Current composite EMF Interest Rate cents/kWh	Sykes Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.7791
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	(0.1322)
24	NC Retail Projected Billing Period MWh Sales	Line 4	57,967,737
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ (76,633,348)

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, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line No.	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)		NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2020				4,799,050	$	(7,772,097)
2	February				4,852,515	$	(22,331,610)
3	March				4,419,005	$	(22,145,172)
4	April				4,009,531	$	(19,263,780)
5	May				3,737,498	$	(7,856,726)
6	June [(1)]				4,445,349	$	3,557,928
7	July				5,381,134	$	13,395,789
8	August				5,679,285	$	8,998,515
9	September				5,143,265	$	(11,722,010)
10	October				4,161,109	$	884,018
11	November				4,768,317	$	(13,335,325)
12	December [(1)]				4,115,807	$	23,445,876
13	**Total Test Period**				**55,511,864**	**$**	**(54,144,594)**
14	Adjustment to remove (Over)/Under Recovery - January-March 2020[(2)]					$	(52,248,875)
15	**Adjusted (Over)/Under Recovery**					**$**	**(1,895,719)**
16	NC Retail Normalized Test Period MWh Sales			Exhibit 4			58,002,609
17	**Experience Modification Increment (Decrement) cents/kWh**						**(0.0033)**
18	Adjusted (Over)/Under Recovery					$	(1,895,719)
19	Adjustment to remove customer credits for purchased power contract terms[(3)]					$	5,318
20	Amount of refund for interest computation					$	(1,890,402)
21	Annual Interest Rate						10%
22	Monthly Interest Rate						0.83%
23	Number of Months (August 15, 2020 - February 28, 2022)						18.5
24	Interest					$	(1,664,640)
25	**Experience Modification Increment (Decrement) cents/kWh**						**(0.0029)**

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

[(2)] January-March 2020 filed in fuel Docket E-7, Sub 1228 to update the EMF and included in 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.

[(3)] Purchased power contract term collections not considered a refund of amounts advanced by customers, therefore have been excluded from the computation of interest.

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, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWH Sales (c)	Reported (Over)/ Under Recovery (d)
1	January 2020	1.4459	1.8127	2,021,126	$ (7,413,792)
2	February	1.2613	1.8127	1,940,656	$ (10,701,007)
3	March	1.2791	1.8127	1,693,572	$ (9,037,706)
4	April	1.3789	1.8127	1,450,861	$ (6,293,969)
5	May	1.6559	1.8127	1,342,790	$ (2,105,593)
6	June [(1)]	1.8232	1.8127	1,700,445	$ 165,111
7	July	1.8123	1.8127	2,257,762	$ (8,998)
8	August	1.7591	1.8127	2,353,392	$ (1,262,025)
9	September	1.4671	1.7118	1,961,816	$ (4,800,324)
10	October	1.8861	1.6027	1,361,181	$ 3,858,149
11	November	1.7168	1.6027	1,406,770	$ 1,604,755
12	December [(1)]	1.7373	1.6027	1,905,668	$ 2,811,210
13	**Total Test Period**			**21,396,039**	**$ (33,184,189)**
14	Test Period Wtd Avg. ¢/kWh	1.6014	1.7576		
15	Adjustment to remove (Over)/Under Recovery - January-March 2020[(2)]				$ (27,152,504)
16	**Adjusted (Over)/Under Recovery**				**$ (6,031,685)**
17	NC Retail Normalized Test Period MWh Sales			Exhibit 4	23,329,575
18	**Experience Modification Increment (Decrement) cents/kWh**				**(0.0259)**
19	Adjusted (Over)/Under Recovery				$ (6,031,685)
20	Adjustment to remove customer credits for purchased power contract terms[(3)]				$ 2,419
21	Amount of refund for interest computation				$ (6,029,266)
22	Annual Interest Rate				10%
23	Monthly Interest Rate				0.83%
24	Number of Months (August 15, 2020 - February 28, 2022)				18.5
25	Interest				$ (929,511)
26	**Experience Modification Increment (Decrement) cents/kWh**				**(0.0040)**

Notes:

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

[(2)] January-March 2020 filed in fuel Docket E-7, Sub 1228 to update the EMF and included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 17.

[(3)] Purchased power contract term collections not considered a refund of amounts advanced by customers, therefore have been excluded from the computation of interest.

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, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2020	1.8136	1.9562	1,919,161	$	(2,736,820)
2	February	1.5188	1.9562	1,917,354	$	(8,385,934)
3	March	1.4558	1.9562	1,771,910	$	(8,865,883)
4	April	1.4000	1.9562	1,700,279	$	(9,457,058)
5	May	1.6578	1.9562	1,595,041	$	(4,759,228)
6	June (1)	1.9960	1.9562	1,845,527	$	724,468
7	July	2.2244	1.9562	2,167,855	$	5,814,650
8	August	2.1618	1.9562	2,253,716	$	4,633,072
9	September	1.6002	1.8611	2,126,565	$	(5,550,013)
10	October	1.6495	1.7583	1,844,555	$	(2,007,635)
11	November	1.3617	1.7583	2,116,483	$	(8,394,817)
12	December (1)	2.7101	1.7583	1,459,697	$	14,225,259
13	**Total Test Period**			**22,718,144**	**$**	**(24,759,939)**
14	Test Period Wtd Avg. ¢/kWh	1.7897	1.9001			
15	Adjustment to remove (Over)/Under Recovery - January-March 2020(2)					(19,988,636)
16	**Adjusted (Over)/Under Recovery**				**$**	**(4,771,302)**
17	NC Retail Normalized Test Period MWh Sales			Exhibit 4		23,102,975
18	**Experience Modification Increment (Decrement) cents/kWh**					**(0.0207)**
19	Adjusted (Over)/Under Recovery				$	(4,771,302)
20	Adjustment to remove customer credits for purchased power contract terms(3)				$	2,899
21	Amount of refund for interest computation				$	(4,768,404)
22	Annual Interest Rate					10%
23	Monthly Interest Rate					0.83%
24	Number of Months (August 15, 2020 - February 28, 2022)					18.5
25	Interest				$	(735,129)
26	**Experience Modification Increment (Decrement) cents/kWh**					**(0.0032)**

Notes:

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

(2) January-March 2020 filed in fuel Docket E-7, Sub 1228 to update the EMF and included in current EMF rate.
Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 17.

(3) Purchased power contract term collections not considered a refund of amounts advanced by customers, therefore have been excluded from the computation of interest.

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, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2020	2.1705	1.8935	858,763	$	2,378,515
2	February	1.5672	1.8935	994,505	$	(3,244,669)
3	March	1.4487	1.8935	953,523	$	(4,241,584)
4	April	1.4843	1.8935	858,390	$	(3,512,753)
5	May	1.7695	1.8935	799,666	$	(991,906)
6	June (1)	2.1907	1.8935	899,377	$	2,668,350
7	July	2.6878	1.8935	955,517	$	7,590,138
8	August	2.4184	1.8935	1,072,177	$	5,627,469
9	September	1.6538	1.7838	1,054,884	$	(1,371,673)
10	October	1.5640	1.6652	955,373	$	(966,497)
11	November	1.1395	1.6652	1,245,063	$	(6,545,263)
12	December (1)	2.5964	1.6652	750,442	$	6,409,407
13	**Total Test Period**			**11,397,681**	**$**	**3,799,534**
14	Test Period Wtd Avg. ¢/kWh	1.8627	1.8242			
15	Adjustment to remove (Over)/Under Recovery - January-March 2020[2]				$	(5,107,737)
16	**Adjusted (Over)/Under Recovery**				**$**	**8,907,271**
17	NC Retail Normalized Test Period MWh Sales			Exhibit 4		11,570,060
18	**Experience Modification Increment (Decrement) cents/KWh**					**0.0770**

Notes:

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

[2] January-March 2020 filed in fuel Docket E-7, Sub 1228 to update the EMF and included in 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, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

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)	82,983,046	55,511,864	21,396,039	22,718,144	11,397,681
2	Customer Growth MWh Adjustment	Workpaper 13 Pg 1	494,727	322,769	225,676	89,954	7,139
3	Weather MWh Adjustment	Workpaper 12	3,086,197	2,167,977	1,707,860	294,877	165,240
4	Total Normalized MWh Sales	Sum	86,563,971	58,002,609	23,329,575	23,102,975	11,570,060
5	Test Period Fuel and Fuel Related Revenue *		$ 1,571,170,278	$ 1,015,637,375			
6	Test Period Fuel and Fuel Related Expense *		$ 1,435,008,103	$ 961,492,783			
7	Test Period Unadjusted (Over)/Under Recovery		$ (136,162,175)	$ (54,144,594)			

Line #	Description	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.

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Nuclear Capacity Ratings
Test Period Ended December 31, 2020
Billing Period September 2021 - August 2022
Docket E-7, Sub 1250

Sykes Exhibit 5

Unit	Rate Case Docket E-7, Sub 1146	Fuel Docket E-7, Sub 1228	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	1,160.1
Catawba Unit 2	1,150.1	1,150.1	1,150.1
Total Company	7,179.8	7,179.8	7,179.8

Sykes Exhibit 6

DECEMBER 2020 MONTHLY FUEL FILING

DUKE ENERGY CAROLINAS
SUMMARY OF MONTHLY FUEL REPORT

Docket No. E-7, Sub 1234

Line No.		December 2020	12 Months Ended December 2020
1	Fuel and fuel-related costs	$ 139,993,351	$ 1,435,984,896
	MWH sales:		
2	Total system sales	6,362,066	84,193,171
3	Less intersystem sales	89,096	1,210,125
4	Total sales less intersystem sales	6,272,970	82,983,046
5	Total fuel and fuel-related costs (¢/KWH) (line 1/line 4)	2.2317	1.7305
6	Current fuel and fuel-related cost component (¢/KWH) (per Schedule 4, Line 7a Total)	1.6693	
	Generation Mix (MWH):		
	Fossil (by primary fuel type):		
7	Coal	1,371,448	14,738,937
8	Fuel Oil	8,702	64,807
9	Natural Gas - Combined Cycle	1,016,660	14,333,589
10	Natural Gas - Combined Heat and Power	39	5,300
11	Natural Gas - Combustion Turbine	97,325	775,879
12	Natural Gas - Steam	172,344	2,406,276
13	Biogas	2,622	25,709
14	Total fossil	2,669,140	32,350,497
15	Nuclear 100%	5,476,820	59,945,886
16	Hydro - Conventional	252,107	3,016,593
17	Hydro - Pumped storage	(48,524)	(505,461)
18	Total hydro	203,583	2,511,132
19	Solar Distributed Generation	10,105	148,719
20	Total MWH generation	8,359,648	94,956,234
21	Less joint owners' portion - Nuclear	1,413,968	15,631,285
22	Less joint owners' portion - Combined Cycle	82,982	1,319,907
23	Adjusted total MWH generation	6,862,698	78,005,042

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

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS

Docket No. E-7, Sub 1234

Fuel and fuel-related costs:	December 2020	12 Months Ended December 2020
0501110 coal consumed - steam	$ 42,109,238	$ 509,419,250
0501310 fuel oil consumed - steam	181,852	3,355,663
0501330 fuel oil light-off - steam	305,196	3,287,490
Total Steam Generation - Account 501	42,596,286	516,062,403
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	22,919,977	256,442,658
Other Generation - Account 547		
0547100, 0547124 - natural gas consumed - Combustion Turbine	3,854,899	26,580,246
0547100 - Combustion Turbine - credit for inefficient fuel cost	(45,980)	(100,388)
0547100 natural gas consumed - Steam	6,405,649	73,118,890
0547101 natural gas consumed - Combined Cycle	24,719,752	281,739,819
0547101 natural gas consumed - Combined Heat and Power	25,323	566,869
0547106 biogas consumed - Combined Cycle	141,294	1,388,864
0547200 fuel oil consumed - Combustion Turbine	876,617	2,063,581
Total Other Generation - Account 547	35,977,554	385,357,881
Reagents		
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	1,608,993	17,555,512
Total Reagents	1,608,993	17,555,512
By-products		
Net proceeds from sale of by-products	1,169,523	7,934,796
Total By-products	1,169,523	7,934,796
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	104,272,333	1,183,353,250
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (economic)	215,310	10,765,481
Capacity component of purchased power (renewables)	615,486	14,501,806
Capacity component of purchased power (PURPA)	256,193	6,762,310
Fuel and fuel-related component of purchased power	37,895,970	248,287,490
Total Purchased Power and Net Interchange - Account 555	38,982,959	280,317,087
Less:		
Fuel and fuel-related costs recovered through intersystem sales	3,152,653	26,840,359
Fuel in loss compensation	85,032	755,898
Solar Integration Charge	-	3,864
Lincoln CT marginal fuel revenue	13,953	75,020
Miscellaneous Fees Collected	10,300	10,300
Total Fuel Credits - Accounts 447 /456	3,261,938	27,685,441
Total Fuel and Fuel-related Costs	$ 139,993,351	$ 1,435,984,896

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

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

DECEMBER 2020

Purchased Power	Total	Capacity	Non-capacity			Not Fuel $
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel-related $
Carolina Power Partners, LLC	$ 978,100	-	33,440	$ 596,641	$ 381,459	
Cherokee County Cogeneration Partners	1,521,127	$ 215,310	39,774	1,122,180	183,637	
Cube Yadkin Generation LLC	123,723	-	7,709	75,471	48,252	
DE Progress - Native Load Transfer	19,491,334	-	738,327	17,470,858	2,027,149	$ (6,673)
DE Progress - Native Load Transfer (Prior Period Adjust)	734	-	-	-	734	
DE Progress - Native Load Transfer Benefit	2,139,555	-	-	2,139,555	-	
Haywood Electric - Economic	24,989	20,230	109	2,903	1,856	
Macquarie Energy, LLC	3,675,222	-	86,739	2,241,885	1,433,337	
NCEMC - Economic	42,120	-	810	25,693	16,427	
NCMPA Instantaneous - Economic	838,428	-	34,370	484,444	353,984	
Piedmont Municipal Power Agency	285,149	-	12,007	164,759	120,390	
PJM Interconnection, LLC.	230,674	-	6,200	140,711	89,963	
Southern Company Services, Inc.	63,004	-	2,688	38,432	24,572	
Tennesse Valley Authority	237,512	-	7,094	144,882	92,630	
Town of Dallas	584	584	-	-	-	
Town of Forest City	19,856	19,856	-	-	-	
	$ 29,672,111	**$ 255,980**	**969,267**	**$ 24,648,415**	**$ 4,774,389**	**$ (6,673)**
Renewable Energy						
REPS	$ 4,701,460	$ 610,344	84,946	$ -	$ 4,091,116	$ -
DERP - Purchased Power	54,261	5,142	910	-	37,283	11,836
	$ 4,755,721	**$ 615,486**	**85,856**	**$ -**	**$ 4,128,399**	**$ 11,836**
HB589 PURPA Purchases						
CPRE - Purchased Power	(10,000)	-	-			(10,000)
Qualifying Facilities	2,895,926	256,193	57,308		2,568,618	71,115
	$ 2,885,926	**$ 256,193**	**57,308**	**$ -**	**$ 2,568,618**	**$ 61,115**
Non-dispatchable / Other						
Blue Ridge Electric Membership Corp.	$ 1,020,170	$ 619,257	25,417	$ 244,557		$ 156,356
Carolina Power Partners, LLC	597,600	-	18,000	364,536		233,064
DE Progress - As Available Capacity	3,826	3,826	-	-		-
Exelon Generation Company, LLC.	38,430	-	1,098	23,442		14,988
Haywood Electric	227,559	116,898	5,409	67,503		43,158
Macquarie Energy, LLC	1,260,096	-	32,084	768,659		491,437
Morgan Stanley Capital Group	36,138	-	1,277	22,044		14,094
NCEMC - Other	4,021	4,021	-	-		-
Piedmont Electric Membership Corp.	461,013	267,253	11,904	118,193		75,566
Southern Company Services, Inc.	56,000	-	2,000	34,160		21,840
Generation Imbalance	141,567	-	3,780	55,654		85,913
Energy Imbalance - Purchases	12,166	-	(8,729)	10,443		1,723
Energy Imbalance - Sales	(288,704)	-	-	(278,165)		(10,539)
Other Purchases	356	-	14	-		356
	$ 3,570,237	**$ 1,011,255**	**92,254**	**$ 1,431,026**	**$ -**	**$ 1,127,956**
Total Purchased Power	**$ 40,883,995**	**$ 2,138,914**	**1,204,685**	**$ 26,079,441**	**$ 11,471,406**	**$ 1,194,234**
Interchanges In						
Other Catawba Joint Owners	7,508,569	-	711,873	4,285,824		3,222,745
WS Lee Joint Owner	1,210,914		42,903	1,034,072		176,842
Total Interchanges In	8,719,483	-	754,776	5,319,897	-	3,399,586
Interchanges Out						
Other Catawba Joint Owners	(7,361,777)	(134,209)	(693,224)	(4,174,593)		(3,052,975)
Catawba- Net Negative Generation	-	-	-	-		-
WS Lee Joint Owner	(957,875)		(33,340)	(800,181)		(157,694)
Total Interchanges Out	(8,319,652)	(134,209)	(726,564)	(4,974,774)	-	(3,210,669)
Net Purchases and Interchange Power	**$ 41,283,826**	**$ 2,004,705**	**1,232,897**	**$ 26,424,564**	**$ 11,471,406**	**$ 1,383,151**

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

DECEMBER 2020

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
DE Progress - Emergency	$ 100,774	$ -	1,180	$ 92,137	$ 8,638
Market Based:					
Macquarie Energy, LLC	-	-	-	2,699	(2,699)
NCMPA	106,134	87,500	270	20,014	(1,381)
PJM Interconnection, LLC.	(3)	-	-	-	(3)
Other:					
DE Progress - Native Load Transfer Benefit	297,225	-	-	297,225	-
DE Progress - Native Load Transfer	2,809,592	-	85,741	2,691,167	118,425
Generation Imbalance	61,927	-	1,905	49,411	12,516
BPM Transmission	3,092	-			3,092
Total Intersystem Sales	**$ 3,378,741**	**$ 87,500**	**89,096**	**$ 3,152,653**	**$ 138,588**

* Sales for resale other than native load priority.

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

Feb 23 2021 OFFICIAL COPY

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

Twelve Months Ended DECEMBER 2020

Purchased Power	Total	Capacity	Non-capacity			Not Fuel $
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel-related $
Carolina Power Partners, LLC	$ 2,224,380	-	86,400	$ 1,356,872	$ 867,508	
Cherokee County Cogeneration Partners	20,600,437	$ 10,765,481	351,406	8,109,001	1,725,955	
Cube Yadkin Generation LLC	123,723	-	7,709	75,471	48,252	
DE Progress - Native Load Transfer	100,976,135	-	5,911,217	92,233,427	8,497,582	$ 245,126
DE Progress - Native Load Transfer (Prior Period Adjust)	734	-	-	-	734	
DE Progress - Native Load Transfer Benefit	12,958,040	-	-	12,958,040	-	
DE Progress - Fees	6,036	-	-	-	6,036	
EDF Trading North America, LLC.	3,120	-	240	1,903	1,217	
Exelon Generation Company, LLC.	76,305	-	2,685	46,546	29,759	
Haywood Electric - Economic	274,796	256,136	607	11,383	7,277	
Macquarie Energy, LLC	6,590,892	-	196,775	4,020,444	2,570,448	
NCEMC	42,120	-	810	25,693	16,427	
NCMPA Load Following Economic	7,491,216	-	459,359	4,377,196	3,114,020	
NTE Carolinas LLC	820,801	-	37,325	500,688	320,113	
Piedmont Municipal Power Agency	2,978,297	-	193,184	1,751,386	1,226,911	
PJM Interconnection, LLC.	422,946	-	13,872	257,998	164,948	
Rainbow Energy Marketing Corporation	7,548	-	300	4,604	2,944	
South Carolina Electric & Gas Company / Dominion Energy	13,450	-	400	7,930	5,520	
Southern Company Services, Inc.	427,836	-	25,491	260,980	166,856	
Tennesse Valley Authority	559,698	-	23,066	341,416	218,281	
The Energy Authority	8,244	-	229	5,029	3,215	
Town of Dallas	7,008	7,008	-	-	-	
Town of Forest City	238,272	238,272	-	-	-	
	$ 156,852,034	**$ 11,266,897**	**7,311,075**	**$ 126,346,007**	**$ 18,994,003**	**$ 245,126**
Renewable Energy						
REPS	$ 70,245,371	$ 14,411,272	1,145,873	$ -	$ 55,834,100	$ -
DERP - Purchased Power	966,899	90,534	16,567	-	679,995	196,370
DERP - Net Metered Generation	56,012	10,243	1,297	-		45,769
	$ 71,268,282	**$ 14,512,049**	**1,163,736**	**$ -**	**$ 56,514,095**	**$ 242,139**
HB589 PURPA Purchases						
CPRE - Purchased Power	$ (2,244,000)	$ -	-			$ (2,244,000)
Qualifying Facilities	38,695,060	6,762,310	681,954		$ 30,908,248	1,024,502
	$ 36,451,060	**$ 6,762,310**	**681,954**	**$ -**	**$ 30,908,248**	**$ (1,219,498)**
Non-dispatchable / Other						
Carolina Power & Light (DE Progress) - Emergency	$ 49,412	$ -	569	$ 30,141		$ 19,271
Blue Ridge Electric Membership Corp.	13,522,047	7,488,673	305,808	3,680,359		2,353,015
Carolina Power Partners, LLC	1,509,240	-	46,800	920,636		588,604
DE Progress - As Available Capacity	149,077	149,077	-	-		-
Exelon Generation Company, LLC.	38,430	-	1,098	23,442		14,988
Haywood Electric	2,872,965	1,494,026	63,271	841,155		537,784
Macquarie Energy, LLC	5,754,063	-	146,648	3,509,979		2,244,084
Morgan Stanley Capital Group	36,138	-	1,277	22,044		14,094
NCEMC - Other	364,189	51,816	6,049	190,548		121,825
NCMPA - Reliability	57,240	-	1,080	34,916		22,324
Piedmont Electric Membership Corp.	6,391,828	3,524,179	140,544	1,749,265		1,118,383
PJM Interconnection, LLC - Other	3,744	-	175	2,284		1,460
Southern Company Services, Inc.	364,619	-	7,011	222,418		142,201
Generation Imbalance	1,307,904		56,424	565,036		742,868
Energy Imbalance - Purchases	668,581		(1,430)	518,790		149,791
Energy Imbalance - Sales	(1,008,321)		-	(948,806)		(59,515)
Other Purchases	8,268	-	258	-		8,268
	$ 32,089,423	**$ 12,707,771**	**775,582**	**$ 11,362,207**	**$ -**	**$ 8,019,445**
Total Purchased Power	**$ 296,660,799**	**$ 45,249,027**	**9,932,347**	**$ 137,708,214**	**$ 106,416,346**	**$ 7,287,211**
Interchanges In						
Other Catawba Joint Owners	74,998,623	-	7,867,637	43,384,153		31,614,472
WS Lee Joint Owner	11,295,227	-	500,924	9,242,716		2,052,512
Total Interchanges In	86,293,850	-	8,368,561	52,626,868	-	33,666,984
Interchanges Out						
Other Catawba Joint Owners	(71,597,673)	(1,584,537)	(7,454,361)	(41,125,471)		(28,887,665)
Catawba- Net Negative Generation	(188,590)	-	(9,707)	(129,579)		(59,011)
WS Lee Joint Owner	(9,029,429)	-	(395,030)	(7,208,892)		(1,820,537)
Total Interchanges Out	(80,815,692)	(1,584,537)	(7,859,098)	(48,463,942)	-	(30,767,213)
Net Purchases and Interchange Power	**$ 302,138,957**	**$ 43,664,490**	**10,441,810**	**$ 141,871,140**	**$ 106,416,346**	**$ 10,186,982**

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
DECEMBER 2020

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
DE Progress - Emergency	$ 125,188	-	2,322	$ 113,626	$ 11,563
SC Public Service Authority - Emergency	11,678	-	456	9,389	2,289
SC Electric & Gas / Dominion Energy - Emergency	16,079	-	653	29,063	(12,984)
Market Based:					
Central Electric Power Cooperative, Inc.	5,546,611	$ 4,809,000	23,372	694,954	42,657
EDF Trading Company	64,800	-	2,050	40,370	24,430
Evergy Kansas Central (BPM)	83,610	-	2,664	49,921	33,689
Exelon Generation Company, LLC.	29,085	-	1,680	27,783	1,302
Macquarie Energy, LLC	1,479,310	-	51,940	1,030,403	448,907
NCMPA	1,201,597	1,050,003	5,572	170,190	(18,597)
PJM Interconnection, LLC.	181,650	-	8,552	182,675	(1,025)
SC Electric & Gas / Dominion Energy	391,427	-	12,300	235,047	156,380
Southern Company	54,834	-	6,730	95,407	(40,573)
Tennesse Valley Authority	22,500	-	450	15,720	6,780
The Energy Authority	260,242	-	10,148	161,253	98,989
Other:					
DE Progress - Native Load Transfer Benefit	3,387,778	-	-	3,387,778	-
DE Progress - Native Load Transfer	21,570,376	-	1,062,405	20,142,840	1,427,536
Generation Imbalance	411,383	-	18,831	453,940	(42,557)
BPM Transmission	(195,265)	-		-	(195,265)
Total Intersystem Sales	**$ 34,642,883**	**$ 5,859,003**	**1,210,125**	**$ 26,840,359**	**$ 1,943,521**

* 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
December 2020

Line No.			Residential	Commercial	Industrial	Total
1	Actual System kWh sales	Input				6,272,969,895
2	DERP Net Metered kWh generation	Input				10,483,803
3	Adjusted System kWh sales	L1 + L2				6,283,453,698
4	N.C. Retail kWh sales	Input	1,905,668,087	1,459,697,098	750,442,212	4,115,807,397
5	NC kWh sales % of actual system kWh sales	L4 T / L1				65.61%
6	NC kWh sales % of adjusted system kWh sales	L4 T / L3				65.50%
7	Approved fuel and fuel-related rates (¢/kWh)					
	7a Billed rates by class (¢/kWh)	Input Annually	1.6027	1.7583	1.6652	1.6693
	7b Billed fuel expense	L7b * L4 / 100	$30,542,142	$25,665,854	$12,496,364	$68,704,360
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	35.85%	42.97%	21.18%	
	8b System incurred expense	Input				$139,569,050
	8c Incurred base fuel and fuel-related expense	L8b * L6 * 8a	$32,774,892	$39,280,050	$19,366,012	$91,420,954
	8d Incurred base fuel rates by class (¢/kWh)	L8c / L4 * 100	1.7199	2.6910	2.5806	2.2212
9	Incurred renewable purchased power capacity rates by class (¢/kWh)					
	9a NC retail production plant %	Input				67.09%
	9b Production plant allocation factors	Input	45.45%	38.36%	16.20%	100.00%
	9c System incurred expense	Input				$1,086,989
	9d Incurred renewable capacity expense	L9a * L9b * 9c	$331,423	$279,724	$118,135	$729,282
	9e Incurred renewable capacity rates by class (¢/kWh)	(L9a * L9c) * L9b / L4 * 100	0.0174	0.0192	0.0157	0.0177
10	Total incurred rates by class (¢/kWh)	L8d + L9e	1.7373	2.7101	2.5964	2.2389
11	Difference in ¢/kWh (incurred - billed)	L7a - L10	0.1346	0.9518	0.9312	0.5697
12	(Over) / under recovery [See footnote]	(L4 * L11) / 100	$2,564,173	$13,893,920	$6,987,783	$23,445,876
13	Prior period adjustments	Input	247,037	331,339	(578,376)	0
14	Total (over) / under recovery [See footnote]	L12+ L13	$2,811,210	$14,225,259	$6,409,407	$23,445,876
15	Total system incurred expense	L8b + L9c				$140,656,039
16	Less: Jurisdictional allocation adjustment(s)	Input				662,688
17	Total Fuel and Fuel-related Costs per Schedule 2	L15 + L16				$139,993,351

Feb 23 2021

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Duke Energy Carolinas
(Over) / Under Recovery of Fuel Costs
December 2020

Line No.

18 (Over) / under recovery for each month of the current calendar year [See footnote]

	Year 2020	Total To Date	(Over) / Under Recovery Residential	Commercial	Industrial	Total Company
	January	($7,772,097)	($7,413,792)	($2,736,820)	$2,378,515	($7,772,097)
	February	(30,103,707)	($10,701,007)	($8,385,934)	($3,244,669)	($22,331,610)
	March	(52,248,879)	($9,037,706)	($8,865,883)	($4,241,584)	($22,145,172)
	April	(71,512,659)	($6,293,969)	($9,457,058)	($3,512,753)	($19,263,780)
	May	(79,369,385)	($2,105,593)	($4,759,228)	($991,906)	($7,856,726)
_/1	June	(75,811,457)	$165,111	$724,468	$2,668,350	$3,557,928
	July	(62,415,668)	($8,998)	$5,814,650	$7,590,138	$13,395,789
	August	(53,417,153)	($1,262,025)	$4,633,072	$5,627,469	$8,998,515
_/2	September	(65,139,163)	($4,800,324)	($5,550,013)	($1,371,673)	($11,722,010)
_/2	October	(64,255,145)	$3,858,149	($2,007,635)	($966,497)	$884,018
	November	($77,590,470)	$1,604,755	($8,394,817)	($6,545,263)	($13,335,325)
_/1	December	($54,144,594)	$2,811,210	$14,225,259	$6,409,407	$23,445,876
			($33,184,189)	($24,759,939)	$3,799,534	($54,144,594)

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 prior period 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 2020

Description	Buck CC	Dan River CC	Lee CC	Clemson CHP	Lee Steam/CT	Lincoln CT	(A) Lincoln (Unit17) CT	Mill Creek CT	Rockingham CT
Cost of Fuel Purchased ($)									
Coal									
Oil	-	-	-		-	-	-	-	-
Gas - CC	$10,899,040	$4,337,175	$10,892,051						
Gas - CHP				$25,323					
Gas - CT					$33,260	$178,930	$373,904	$379,803	$2,843,021
Gas - Steam					264				
Biogas	395,748	(263)	-						
Total	$11,294,788	$4,336,912	$10,892,051	$25,323	$33,524	$178,930	$373,904	$379,803	$2,843,021
Average Cost of Fuel Purchased (¢/MBTU)									
Coal		-							
Oil					-	-	-	-	-
Gas - CC	359.39	363.23	364.04						
Gas - CHP				4,841.94					
Gas - CT					638.06	370.11	319.96	361.44	361.68
Gas - Steam					332.60				
Biogas	2,174.44	-	-						
Weighted Average	370.22	363.21	364.04	4,841.94	638.06	370.11	319.96	361.44	361.68
Cost of Fuel Burned ($)									
Coal		-	-		-				
Oil - CC	-	-	-						
Oil - Steam/CT					$0	4,736	-	694,987	176,893
Gas - CC	$10,899,040	$4,337,175	$10,892,051						
Gas - CHP				$25,323					
Gas - CT					33,260	$178,930	$373,904	$379,803	$2,843,021
Gas - Steam					264				
Biogas	395,748	(263)	-						
Nuclear									
Total	$11,294,788	$4,336,912	$10,892,051	$25,323	$33,524	$183,667	$373,904	$1,074,791	$3,019,914
Average Cost of Fuel Burned (¢/MBTU)									
Coal					-				
Oil - CC									
Oil - Steam/CT					-	1,518.09	-	1,794.07	1,552.24
Gas - CC	359.39	363.23	364.04						
Gas - CHP				4,841.94					
Gas - CT					638.06	370.11	319.96	361.44	361.68
Gas - Steam					332.60				
Biogas	2,174.44	-	-						
Nuclear									
Weighted Average	370.22	363.21	364.04	4,841.94	638.06	377.48	319.96	747.32	378.70
Average Cost of Generation (¢/kWh)									
Coal		-	-		-	-	-		
Oil - CC	-	-	-						
Oil - Steam/CT		-	-		-	16.67	-	23.46	16.67
Gas - CC	2.49	2.60	2.64						
Gas - CHP				65.60					
Gas - CT					8.34	5.90	3.41	4.63	3.81
Gas - Steam					-	-	-		
Biogas	15.10	-	-						
Nuclear									
Weighted Average	2.57	2.60	2.64	65.60	209.52	6.00	3.41	9.62	3.99
Burned MBTU's									
Coal					-				
Oil - CC									
Oil - Steam/CT					-	312	-	38,738	11,396
Gas - CC	3,032,651	1,194,065	2,991,957						
Gas - CHP				523					
Gas - CT					5,213	48,345	116,859	105,081	786,050
Gas - Steam					41				
Biogas	18,200	-	-						
Nuclear									
Total	3,050,851	1,194,065	2,991,957	523	5,254	48,657	116,859	143,819	797,446
Net Generation (mWh)									
Coal									
Oil - CC									
Oil - Steam/CT		-	-		-	28	-	2,963	1,061
Gas - CC	436,836	167,022	412,802		-				
Gas - CHP				39					
Gas - CT					399	3,031	10,971	8,208	74,717
Gas - Steam					(383)				
Biogas	2,622	-	-						
Nuclear 100%									
Hydro (Total System)									
Solar (Total System)									
Total	439,458	167,022	412,802	39	16	3,059	10,971	11,171	75,778

Description	Buck CC	Dan River CC	Lee CC
Cost of Reagents Consumed ($)			
Ammonia	$18,886	$5,818	$0
Limestone			
Sorbents			
Urea			
Re-emission Chemical			
Dibasic Acid			
Activated Carbon			
Lime (water emissions)			
Total	$18,886	$5,818	$0

Notes:

(A) Lincoln (Unit 17) fuel and fuel related costs represents pre-commercial generation during an extended testing and validation period.

(B) Solar Net Generation (mWh) for the month of December includes pre-commercial 225 mWh for Gaston Solar and 621 mWh for Maiden Creek Solar.

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 2020

Description	Allen	Marshall	Belews Creek	Cliffside	Catawba	McGuire	Oconee	Current Month	Total 12 ME December 2020
	Steam	Steam - Dual Fuel	Steam - Dual Fuel	Steam - Dual Fuel	Nuclear	Nuclear	Nuclear		
Cost of Fuel Purchased ($)									
Coal	$1,577,477	$1,754,302	$11,470,966	$10,418,928				$25,221,674	$524,924,279
Oil	185,282	184,358	-	128,100				497,740	7,111,516
Gas - CC								26,128,266	296,014,769
Gas - CHP								25,323	566,869
Gas - CT								3,808,918	26,479,858
Gas - Steam		658,574	920,601	4,826,210				6,405,649	73,118,890
Biogas								395,485	3,886,168
Total	$1,762,760	$2,597,234	$12,391,568	$15,373,238				$62,483,056	$932,102,349
Average Cost of Fuel Purchased (¢/MBTU)									
Coal	146.33	120.66	387.31	248.05				260.18	363.32
Oil	1,111.33	1,114.19	-	1,123.87				1,115.60	964.95
Gas - CC								360.47	291.63
Gas - CHP								4,841.94	900.44
Gas - CT								363.61	293.34
Gas - Steam		361.83	356.40	366.63				364.63	296.70
Biogas				.				2,173.00	2,121.55
Weighted Average	161.03	157.17	384.83	278.09				315.66	332.14
Cost of Fuel Burned ($)									
Coal	3,571,288	$22,581,995	$1,720,310	$14,235,645				$42,109,238	$509,419,250
Oil - CC								-	-
Oil - Steam/CT	169,845	214,154	-	103,049				1,363,664	8,706,734
Gas - CC								26,128,266	296,014,769
Gas - CHP								25,323	566,869
Gas - CT								3,808,918	26,479,858
Gas - Steam		658,574	920,601	4,826,210				6,405,649	73,118,890
Biogas								395,485	3,886,168
Nuclear					$10,059,697	$9,693,332	$11,290,556	31,043,585	348,551,598
Total	$3,741,133	$23,454,723	$2,640,912	$19,164,904	$10,059,697	$9,693,332	$11,290,556	$111,280,130	$1,266,744,136
Average Cost of Fuel Burned (¢/MBTU)									
Coal	275.63	321.64	397.94	293.77				309.75	351.15
Oil - CC								-	-
Oil - Steam/CT	1,025.94	1,080.66	-	999.12				1,403.93	1,155.30
Gas - CC								360.47	291.63
Gas - CHP								4,841.94	900.44
Gas - CT								363.61	293.34
Gas - Steam		361.83	356.40	366.63				364.63	296.70
Biogas								2,173.00	2,121.55
Nuclear					57.67	55.09	57.72	56.86	57.73
Weighted Average	285.09	324.73	382.41	310.49	57.67	55.09	57.72	142.03	143.14
Average Cost of Generation (¢/kWh)									
Coal	3.00	3.21	7.14	2.72				3.07	3.46
Oil - CC								-	-
Oil - Steam/CT	11.13	10.78	-	9.05				15.67	13.43
Gas - CC								2.57	2.07
Gas - CHP								3.72	3.04
Gas - CT								3.91	3.41
Gas - Steam		3.36	3.44	3.82				3.72	3.04
Biogas								15.09	15.12
Nuclear					0.57	0.55	0.58	0.57	0.58
Weighted Average	3.11	3.23	5.19	2.94	0.57	0.55	0.58	1.33	1.33
Burned MBTU's									
Coal	1,295,699	7,020,964	432,300	4,845,845				13,594,808	145,073,739
Oil - CC								-	-
Oil - Steam/CT	16,555	19,817	-	10,314				97,132	753,636
Gas - CC								7,218,673	101,505,115
Gas - CHP								523	62,955
Gas - CT								1,061,547	9,026,942
Gas - Steam		182,011	258,305	1,316,385				1,756,742	24,644,417
Biogas								18,200	183,176
Nuclear					17,442,554	17,596,486	19,560,447	54,599,487	603,725,817
Total	1,312,254	7,222,792	690,605	6,172,544	17,442,554	17,596,486	19,560,447	78,347,113	884,975,797
Net Generation (mWh)									
Coal	118,909	704,337	24,083	524,119				1,371,448	14,738,937
Oil - CC								-	-
Oil - Steam/CT	1,526	1,986	-	1,138				8,702	64,807
Gas - CC								1,016,660	14,333,589
Gas - CHP								39	5,300
Gas - CT								97,325	775,879
Gas - Steam		19,579	26,799	126,349				172,344	2,406,276
Biogas								2,622	25,709
Nuclear 100%					1,750,957	1,771,352	1,954,511	5,476,820	59,945,886
Hydro (Total System)								203,583	2,511,132
Solar (Total System)								10,105 (B)	148,719 (B)
Total	120,435	725,902	50,882	651,606	1,750,957	1,771,352	1,954,511	8,359,648	94,956,234
Cost of Reagents Consumed ($)									
Ammonia			$12,439	$94,070				$131,214	$2,132,769
Limestone	$80,787	$492,369	23,042	645,650				1,241,849	13,486,306
Sorbents	-	182,384	-					182,384	1,346,201
Urea	(1)	50,675						50,674	492,740
Re-emission Chemical		-	-	-				-	345,138
Dibasic Acid	-							-	-
Activated Carbon	-	-						-	25,493
Lime (water emissions)	-	3,613	-					3,613	91,162
Total	80,785	729,042	$35,481	$739,721				$1,609,734	$17,919,809

Notes:

(A) Lincoln (Unit 17) fuel and fuel related costs represents pre-commercial generation during an extended testing and validation period.

(B) Solar Net Generation (mWh) for the month of December includes pre-commercial 225 mWh for Gaston Solar and 621 mWh for Maiden Creek Solar.

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 CONSUMPTION AND INVENTORY REPORT
DECEMBER 2020

Description	Buck CC	Dan River CC	Lee CC	Clemson CHP	Lee Steam/CT	Lincoln CT	(A) Lincoln (Unit17) CT	Mill Creek CT	Rockingham CT	Allen Steam	Marshall Steam - Dual Fuel	Belews Creek Steam - Dual Fuel	Cliffside Steam - Dual Fuel	Current Month	Total 12 ME December 2020
Coal Data:															
Beginning balance					-					186,382	960,652	674,515	423,558	2,245,107	2,127,823
Tons received during period										24,160	13,819	165,159	175,477	378,615	5,798,126
Inventory adjustments					-					25,626	47,206	(46,502)	(6,803)	19,527	18,845
Tons burned during period					-					54,063	281,367	17,310	201,962	554,702	5,856,247
Ending balance					-					182,105	740,309	775,862	390,270	2,088,547	2,088,547
MBTUs per ton burned					-					23.97	24.95	24.97	23.99	24.51	24.77
Cost of ending inventory ($/ton)					-					73.92	80.26	99.38	70.49	84.98	84.98
Oil Data:															
Beginning balance	-	-	-		725,202	9,685,581	401,963	4,200,018	2,936,025	100,642	234,223	92,835	164,992	18,541,481	18,531,066
Gallons received during period	-	-	-		-	-	-	-	-	120,812	119,901	-	82,595	323,308	5,340,477
Miscellaneous adjustments	-	-	-		-	-	-	-	0	489	-	(9,364)	(8,443)	(16,647)	(261,532)
Gallons burned during period		-	-		-	2,260	-	281,445	81,500	120,205	144,160	-	75,144	705,385	5,467,254
Ending balance	-	-	-		725,202	9,683,321	401,963	3,918,573	2,854,525	101,738	209,964	83,471	164,000	18,142,757	18,142,757
Cost of ending inventory ($/gal)	-	-	-		1.87	2.10	1.21	2.47	2.17	1.42	1.49	1.28	1.37	2.14	2.14
Natural Gas Data:															
Beginning balance															
MCF received during period	2,929,844	1,153,862	2,900,531	508	5,107	47,415	112,706	101,805	759,266		176,538	249,500	1,273,001	9,710,083	131,051,615
MCF burned during period	2,929,844	1,153,862	2,900,531	508	5,107	47,415	112,706	101,805	759,266		176,538	249,500	1,273,001	9,710,083	131,051,615
Ending balance															
Biogas Data:															
Beginning balance															
MCF received during period	17,583	-	-											17,583	177,457
MCF burned during period	17,583	-	-											17,583	177,457
Ending balance															
Limestone Data:															
Beginning balance										27,056	77,766	48,347	30,212	183,382	175,919
Tons received during period										-	-	-	-	-	292,356
Inventory adjustments										1,771	(6,843)	4,700	(2,299)	(2,670)	(2,671)
Tons consumed during period										1,774	12,100	624	11,785	26,283	311,176
Ending balance										27,054	58,823	52,423	16,128	154,428	154,428
Cost of ending inventory ($/ton)										45.54	40.69	36.92	44.42	40.65	40.65
														Qtr Ending December 2020	Total 12 ME December 2020
Ammonia Data:															
Beginning balance	1,834													1,834	1,405
Tons received during period	-													-	2,738
Tons consumed during period	26													26	2,334
Ending balance	1,808													1,808	1,808
Cost of ending inventory ($/ton)	485.71													485.71	485.71

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.
Schedule excludes in-transit and terminal activity.
Gas is burned as received; therefore, inventory balances are not maintained.

DUKE ENERGY CAROLINAS

ANALYSIS OF COAL PURCHASED

DECEMBER 2020

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ALLEN	SPOT	-	$ -	$ -
	CONTRACT	24,160	1,516,810	62.78
	FIXED TRANSPORTATION / ADJUSTMENTS	-	0	-
	TOTAL	24,160	1,516,810	62.78
BELEWS CREEK	SPOT	38,357	2,540,568	66.23
	CONTRACT	126,802	8,274,865	65.26
	FIXED TRANSPORTATION / ADJUSTMENTS	-	2,209	-
	TOTAL	165,159	10,817,642	65.50
CLIFFSIDE	SPOT	-	24,564	-
	CONTRACT	175,477	9,973,775	56.84
	FIXED TRANSPORTATION / ADJUSTMENTS	-	0	-
	TOTAL	175,477	9,998,339	56.98
MARSHALL	SPOT	13,819	853,067	61.73
	CONTRACT	-	27,580	-
	FIXED TRANSPORTATION / ADJUSTMENTS	-	49,600	-
	TOTAL	13,819	930,247	67.32
ALL PLANTS	SPOT	52,176	3,418,199	65.51
	CONTRACT	326,439	19,793,030	60.63
	FIXED TRANSPORTATION / ADJUSTMENTS	-	51,809	-
	TOTAL	378,615	23,263,038	$ 61.44

DUKE ENERGY CAROLINAS

ANALYSIS OF COAL QUALITY RECEIVED

DECEMBER 2020

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
ALLEN	6.26	12.74	12,212	0.91
BELEWS CREEK	7.13	9.90	12,480	1.26
CLIFFSIDE	9.20	7.48	12,451	1.78
MARSHALL	7.05	13.03	11,913	0.72

DUKE ENERGY CAROLINAS
ANALYSIS OF OIL PURCHASED
DECEMBER 2020

	ALLEN	CLIFFSIDE	MARSHALL
VENDOR	HighTowers	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract	Contract
SULFUR CONTENT %	0	0	0
GALLONS RECEIVED	120,812	82,595	119,901
TOTAL DELIVERED COST	$ 185,282	$ 128,100	$ 184,358
DELIVERED COST/GALLON	$ 1.53	$ 1.55	$ 1.54
BTU/GALLON	138,000	138,000	138,000

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2020 - December, 2020
Nuclear Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Oconee 1	6,859,973	847	92.20	90.88
Oconee 2	7,670,158	848	102.97	99.99
Oconee 3	7,012,136	859	92.93	91.89
McGuire 1	9,434,118	1,158	92.75	90.65
McGuire 2	9,612,830	1,158	94.50	93.32
Catawba 1	9,235,519	1,160	90.64	89.94
Catawba 2	10,121,151	1,150	100.19	99.78

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2020 through December, 2020
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Buck CC	11	1,134,065	206	62.67	75.42
Buck CC	12	1,134,559	206	62.70	75.10
Buck CC	ST10	1,598,203	312	58.32	80.85
Buck CC	Block Total	3,866,827	724	60.80	77.67
Dan River CC	8	1,311,548	199	75.03	83.79
Dan River CC	9	1,297,690	199	74.24	83.04
Dan River CC	ST7	1,847,499	320	65.73	91.85
Dan River CC	Block Total	4,456,737	718	70.66	87.17
WS Lee CC	11	1,739,314	240	82.50	88.86
WS Lee CC	12	1,853,394	240	87.92	93.53
WS Lee CC	ST10	2,443,026	313	88.86	94.57
WS Lee CC	Block Total	6,035,734	793	86.65	92.53

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.

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2020 through December, 2020

Baseload Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Belews Creek 1	2,691,806	1,110	27.61	58.99
Belews Creek 2	2,649,126	1,110	27.17	64.73
Marshall 3	2,074,332	658	35.89	61.51
Marshall 4	2,202,419	660	37.99	65.19

Notes:

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

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2020 through December, 2020

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Cliffside 6	4,194,682	849	56.25	79.37
Marshall 1	852,998	380	25.55	89.00
Marshall 2	956,682	380	28.66	89.62

Notes:

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

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2020 through December, 2020
Other Cycling Steam Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Allen	1	7,133	167	0.49	81.63
Allen	2	11,024	167	0.75	94.17
Allen	3	57,542	270	2.43	95.94
Allen	4	238,290	267	10.16	95.80
Allen	5	205,583	259	9.04	88.47
Cliffside	5	1,064,746	546	22.20	69.22
Lee	3	-4,725	173	0.00	100.00

Notes:

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

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2020 through December, 2020
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Clemson CHP	5,300	16	39.33
Lee CT	1,711	96	95.49
Lincoln CT	15,767	1,565	95.96
Mill Creek CT	70,332	756	99.68
Rockingham CT	656,571	895	88.88

Notes:

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

Duke Energy Carolinas
Power Plant Performance Data

Twelve Month Summary
January, 2020 through December, 2020
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Conventional Hydroelectric Stations:			
Bear Creek	33,970	9.5	72.33
Bridgewater	101,362	31.5	98.91
Cedar Cliff	14,360	6.8	64.07
Cedar Creek	195,060	45.0	66.54
Cowans Ford	345,561	324.0	95.00
Dearborn	167,286	42.0	86.33
Fishing Creek	236,761	50.0	86.00
Great Falls	-71	12.0	0.00
Keowee	111,177	152.0	96.63
Lookout Shoals	174,141	27.0	98.63
Mountain Island	227,649	62.0	64.49
Nantahala	281,167	50.0	91.68
Ninety-Nine Islands	80,306	15.2	76.52
Oxford	183,279	40.0	86.37
Queens Creek	6,292	1.4	93.68
Rhodhiss	119,034	33.4	98.18
Tennessee Creek	-12	9.8	0.00
Thorpe	118,015	19.7	99.49
Tuckasegee	5,018	2.5	66.71
Wateree	401,240	85.0	81.19
Wylie	214,998	72.0	69.12
Total Conventional Hydroelectric Stations:	3,016,593		
Pumped Storage Hydroelectric Stations:			
Gross Generation			
Bad Creek	1,602,907	1,360.0	67.95
Jocassee	1,138,239	780.0	81.85
Energy for Pumping			
Bad Creek	-2,004,346		
Jocassee	-1,242,261		
Net Generation			
Bad Creek	-401,439		
Jocassee	-104,022		

Notes:

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

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2020 through December, 2020
Pre-commercial Combustion Turbine Stations

Note: The Power Plant Performance Data reports are limited to capturing data beginning the first full month a station is in commercial operation. During the months identified, Lincoln Unit 17 produced pre-commercial generation.

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
December 2020			
Lincoln Unit 17	10,971	n/a	n/a
November 2020			
Lincoln Unit 17	8,337	n/a	n/a
October 2020			
Lincoln Unit 17	11,198	n/a	n/a
September 2020			
Lincoln Unit 17	8,471	n/a	n/a
August 2020			
Lincoln Unit 17	-221	n/a	n/a
July 2020			
Lincoln Unit 17	-24	n/a	n/a
June 2020			
Lincoln Unit 17	1,805	n/a	n/a
May 2020			
Lincoln Unit 17	-657	n/a	n/a
Total	39,880		

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 2021 through August 2022
Docket E-7, Sub 1250

Sykes Workpaper 1

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs	9,330,730	9,921,566	9,278,272	9,189,043	7,233,820	6,758,803	6,909,851	58,622,085
Cost (Gross of Joint Owners)	$ 56,313,089	$ 62,379,795	$ 53,463,594	$ 53,190,353	$ 48,378,152	$ 40,167,441	$ 41,185,222	$ 355,077,645
$/MWh	6.0352	6.2873	5.7622	5.7885	6.6878	5.9430	5.9604	
Avg $/MWh		**6.0571**						
Cents per kWh		**0.6057**						

			Sept 2021 - August 2022
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	9,331
CATA_UN02	Catawba	GWh	9,922
MCGU_UN01	McGuire	GWh	9,278
MCGU_UN02	McGuire	GWh	9,189
OCON_UN01	Oconee	GWh	7,234
OCON_UN02	Oconee	GWh	6,759
OCON_UN03	Oconee	GWh	6,910
			58,622
	Proposed Nuclear Capacity Factor		93.21%

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period September 2021 through August 2022
Docket E-7, Sub 1250

Sykes Workpaper 2

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs with NERC applied	9,296,633	9,216,497	9,279,804	9,276,599	6,885,500	6,893,629	6,983,052	57,831,714
Hours	8760	8760	8760	8760	8760	8760	8760	8760
MDC	1160.1	1150.1	1158.0	1157.6	847.0	848.0	859.0	7179.8
Capacity factor	91.48%	91.48%	91.48%	91.48%	92.80%	92.80%	92.80%	91.95%
Cost	$ 56,310,290	$ 55,824,898	$ 56,208,357	$ 56,188,942	$ 41,705,906	$ 41,755,146	$ 42,296,781	$ 350,290,320

Avg $/MWh	**6.0571**
Cents per kWh	**0.6057**

2015-2019	Capacity Rating	NCF Rating	Weighted Average	
Oconee 1	847.0	92.80	10.95%	
Oconee 2	848.0	92.80	10.96%	
Oconee 3	859.0	92.80	11.10%	
McGuire 1	1158.0	91.48	14.75%	
McGuire 2	1157.6	91.48	14.75%	
Catawba 1	1160.1	91.48	14.78%	
Catawba 2	1150.1	91.48	14.65%	
	7179.8		**91.95%**	Wtd Avg on Capacity Rating

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation and Purchased Power in MWhs
Billing Period September 2021 through August 2022
Docket E-7, Sub 1250

Sykes Workpaper 3

Resource Type	**Sept 2021 - August 2022**	
NUC Total (Gross)	58,622,085	
COAL Total	18,691,906	
Gas CT and CC total (Gross)	22,065,718	
Run of River	4,030,270	
Net pumped Storage	(2,872,983)	
Total Hydro	1,157,287	
Catawba Joint Owners	(14,848,200)	
Lee CC Joint Owners	(876,000)	
DEC owned solar	367,302	
Total Generation		85,180,099
Purchases for REPS Compliance	1,259,059	
Qualifying Facility Purchases - Non-REPS compliance	2,257,343	
Other Purchases	36,100	
Allocated Economic Purchases	371,115	
Joint Dispatch Purchases	4,185,880	
	8,109,496	
Total Generation and Purchased Power		93,289,595
Fuel Recovered Through Intersystem Sales	(1,789,852)	

rounding differences may occur

Duke Energy Carolinas, LLC **Sykes Workpaper 4**
North Carolina Annual Fuel and Fuel Related Expense
Projected Fuel and Fuel Related Costs
Billing Period September 2021 through August 2022
Docket E-7, Sub 1250

Resource Type	Sept 2021 - August 2022	
Nuclear Total (Gross)	$ 355,077,645	
COAL Total	438,222,003	
Gas CT and CC total (Gross)	503,828,581	
Catawba Joint Owner costs	(89,940,492)	
CC Joint Owner costs	(16,986,285)	
Non-Economic Fuel Expense Recovered through Reimbursement	(6,522,205)	
Reagents and gain/loss on sale of By-Products	25,707,869	Workpaper 9
Purchases for REPS Compliance - Energy	62,808,851	
Purchases for REPS Compliance - Capacity	13,866,978	
Purchases of Qualifying Facilities - Energy	53,822,291	
Purchases of Qualifying Facilities - Capacity	11,169,971	
Other Purchases	2,586,674	
JDA Savings Shared	7,856,711	Workpaper 5
Allocated Economic Purchase cost	11,091,651	Workpaper 5
Joint Dispatch purchases	93,448,130	Workpaper 6
Total Purchases	256,651,255	
Fuel Expense recovered through intersystem sales	(28,691,221)	Workpaper 5
Total System Fuel and Fuel Related Costs	**$ 1,437,347,151**	

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Joint Dispatch Fuel Impacts
Billing Period September 2021 through August 2022
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Sykes Workpaper 5

Positive numbers represent costs to Rate Payers, 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**
9/1/2021	$ 1,054,985	$ 1,489,274	$ (122,675)	$ (197,587)	$ (3,762,312)	$ 3,762,312	$ (217,149)	$ 217,149
10/1/2021	$ 812,687	$ 1,199,637	$ (74,159)	$ (94,918)	$ (7,376,689)	$ 7,376,689	$ (1,612,598)	$ 1,612,598
11/1/2021	$ 968,558	$ 721,584	$ (159,041)	$ (93,475)	$ (14,155,044)	$ 14,155,044	$ (3,467,413)	$ 3,467,413
12/1/2021	$ 944,127	$ 232,432	$ (406,595)	$ (267,257)	$ (9,163,715)	$ 9,163,715	$ (625,497)	$ 625,497
1/1/2022	$ 1,900,927	$ 2,723,940	$ (1,113,145)	$ (1,836,243)	$ 68,261	$ (68,261)	$ 2,086,357	$ (2,086,357)
2/1/2022	$ 938,420	$ 1,350,167	$ (608,729)	$ (802,795)	$ (499,296)	$ 499,296	$ 1,440,906	$ (1,440,906)
3/1/2022	$ 358,236	$ 246,158	$ (286,289)	$ (322,285)	$ (5,264,225)	$ 5,264,225	$ (508,772)	$ 508,772
4/1/2022	$ 451,814	$ 346,300	$ (220,333)	$ (19,608)	$ (8,735,414)	$ 8,735,414	$ (1,848,386)	$ 1,848,386
5/1/2022	$ 386,367	$ 562,877	$ (194,707)	$ (94,039)	$ (6,413,312)	$ 6,413,312	$ (1,011,472)	$ 1,011,472
6/1/2022	$ 1,606,722	$ 448,861	$ (172,585)	$ (147,466)	$ (5,686,849)	$ 5,686,849	$ (731,894)	$ 731,894
7/1/2022	$ 935,253	$ 647,767	$ (218,665)	$ (213,920)	$ (5,407,444)	$ 5,407,444	$ (1,418,613)	$ 1,418,613
8/1/2022	$ 783,070	$ 1,122,655	$ (114,647)	$ (199,370)	$ (2,649,832)	$ 2,649,832	$ 57,821	$ (57,821)
Sept 21 - Aug 22		$ 11,091,651		$ (4,288,963)		$ 69,045,871		$ 7,856,711

$ 93,448,130	Workpaper 6 - Transfer - Purchases
$ (24,402,258)	Workpaper 6 - Transfer - Sales
$ 69,045,871	Sept 21-Aug 22 Net Fuel Transfer Payment
$ (24,402,258)	Workpaper 6 - Transfer - Sales
$ (4,288,963)	Sept 21-Aug 22 Economic Sales Cost
$ (28,691,221)	**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 2021 through August 2022
Docket E-7, Sub 1250

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
9/1/2021	251,617	116,444	(16,971)	16,971	251,617	133,415	$ 23.22	$ 15.60	$ 2,081,261	$ 5,843,573
10/1/2021	376,590	63,669	(3,893)	3,893	376,590	67,563	$ 22.20	$ 14.58	$ 984,937	$ 8,361,626
11/1/2021	600,895	7,749	18,605	(18,605)	619,500	7,749	$ 23.00	$ 12.20	$ 94,541	$ 14,249,585
12/1/2021	415,829	156,683	14,190	(14,190)	430,020	156,683	$ 25.97	$ 12.79	$ 2,003,858	$ 11,167,572
1/1/2022	150,297	279,321	(23,059)	23,059	150,297	302,380	$ 27.95	$ 14.12	$ 4,268,785	$ 4,200,524
2/1/2022	147,663	241,402	(22,785)	22,785	147,663	264,187	$ 26.96	$ 13.18	$ 3,481,557	$ 3,980,853
3/1/2022	335,731	129,422	(1,475)	1,475	335,731	130,897	$ 21.25	$ 14.28	$ 1,868,782	$ 7,133,007
4/1/2022	515,174	84,533	(4,391)	4,391	515,174	88,924	$ 19.71	$ 15.96	$ 1,419,191	$ 10,154,604
5/1/2022	402,086	90,810	(9,503)	9,503	402,086	100,312	$ 19.77	$ 15.31	$ 1,535,300	$ 7,948,612
6/1/2022	327,890	81,463	13,381	(13,381)	341,270	81,463	$ 20.42	$ 15.73	$ 1,281,202	$ 6,968,052
7/1/2022	352,486	138,198	(4,362)	4,362	352,486	142,559	$ 22.01	$ 16.50	$ 2,352,080	$ 7,759,524
8/1/2022	263,445	162,770	(18,986)	18,986	263,445	181,756	$ 21.56	$ 16.67	$ 3,030,764	$ 5,680,597
Sept 21 - Aug 22	4,139,703	1,552,465	(59,249)	59,249	4,185,880	1,657,890			$ 24,402,258	$ 93,448,130
									Net Pre-Net Payments	$ 69,045,871

rounding differences may occur

Duke Energy Carolinas, LLC **Sykes Workpaper 7**
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 93.21%
Billing Period September 2021 through August 2022
Docket E-7, Sub 1250

Fall 2020 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	21,803,077		21,803,077
	General	23,889,192		23,889,192
	Industrial	12,036,241		12,036,241
	Lighting	239,227		239,227
	NC RETAIL	57,967,737	-	57,967,737
South Carolina:				
	Residential	6,549,429	102,353	6,651,782
	General	5,992,271	55,281	6,047,552
	Industrial	8,837,609	428	8,838,037
	Lighting	39,918	-	39,918
	SC RETAIL	21,419,227	158,062	21,577,289
Total Retail Sales				
	Residential	28,352,506	102,353	28,454,859
	General	29,881,464	55,281	29,936,744
	Industrial	20,873,850	428	20,874,278
	Lighting	279,145	-	279,145
	Retail Sales	79,386,965	158,062	79,545,026
	Wholesale	8,303,032	-	8,303,032
	Projected System MWH Sales for Fuel Factor	87,689,996	158,062	87,848,058
	NC as a percentage of total	**66.11%**		**65.99%**
	SC as a percentage of total	24.43%		24.56%
	Wholesale as a percentage of total	9.47%		9.45%
		100.00%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs		158,062
Marginal fuel rate per MWh for SC NEM	$	26.43
Fuel benefit to be directly assigned to SC Retail	$	4,178,086

System Fuel Expense	$ 1,437,347,151	Sykes Exhibit 2 Schedule 1 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,178,086	
Total Fuel Costs for Allocation	$ 1,441,525,237	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	$ 1,437,347,151				
QF and REPS Compliance Purchased Power - Capacity	$ 25,036,948				
Other fuel costs	$ 1,412,310,202				
SC Net Metering Fuel Allocation adjustment	$ 4,178,086				
Jurisdictional fuel costs after adj.	$ 1,416,488,289				
Allocation to states/classes		65.99%	9.45%	24.56%	
Jurisdictional fuel costs	$ 1,416,488,289	$ 934,740,622	$ 133,858,143	$ 347,889,524	66.90%
Direct Assignment of Fuel benefit to SC Retail	$ (4,178,086)		$ -	$ (4,178,086)	
Total system actual fuel costs	$ 1,412,310,202	$ 934,740,622	$ 133,858,143	$ 343,711,437	
QF and REPS Compliance Purchased Power - Capacity	25,036,948	16,749,046			
Total system fuel expense from Sykes Exhibit 2 Schedule 1 Page 1	$ 1,437,347,151	**$ 951,489,668**			
		Exh.2, Sch. 1 page 3, Line 13			

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 93.21% and Normalized Test Period Sales
Billing Period September 2021 through August 2022
Docket E-7, Sub 1250

Fall 2020 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	55,511,864	322,769	2,167,977	-	58,002,610
SC RETAIL	19,994,535	92,599	710,925	158,062	20,956,121
Wholesale	7,476,647	79,360	207,295	-	7,763,302
Normalized System MWH Sales for Fuel Factor	82,983,046	494,727	3,086,197	158,062	86,722,032
NC as a percentage of total	**66.90%**				**66.88%**
SC as a percentage of total	24.09%				24.16%
Wholesale as a percentage of total	9.01%				8.95%
	100.00%				100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	158,062
Marginal fuel rate per MWh for SC NEM	$ 26.43
Fuel benefit to be directly assigned to SC Retail	$ 4,178,086

System Fuel Expense	$ 1,410,948,076	Sykes Exhibit 2 Schedule 2 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,178,086	
Total Fuel Costs for Allocation	$ 1,415,126,162	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	$ 1,410,948,076			
QF and REPS Compliance Purchased Power - Capacity	$ 25,036,948			
Other fuel costs	$ 1,385,911,127			
SC Net Metering Fuel Allocation adjustment	$ 4,178,086			
Jurisdictional fuel costs after adj.	$ 1,390,089,213			
Allocation to states/classes		66.88%	8.95%	24.16%
Jurisdictional fuel costs	$ 1,390,089,213	$ 929,691,666	$ 124,412,985	$ 335,845,554
Direct Assignment of Fuel benefit to SC Retail	$ (4,178,086)		$ -	$ (4,178,086)
Total system actual fuel costs	$ 1,385,911,127	$ 929,691,666	$ 124,412,985	$ 331,667,468
QF and REPS Compliance Purchased Power - Capacity	25,036,948	16,749,046		
Total system fuel expense from Sykes Exhibit 2 Schedule 2 Page 1	$ 1,410,948,076	**$ 946,440,712**		
		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 91.95%
Billing Period September 2021 through August 2022
Docket E-7, Sub 1250

Sykes Workpaper 7b

Fall 2020 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	21,803,077		21,803,077
	General	23,889,192		23,889,192
	Industrial	12,036,241		12,036,241
	Lighting	239,227		239,227
	NC RETAIL	57,967,737	-	57,967,737
South Carolina:				
	Residential	6,549,429	102,353	6,651,782
	General	5,992,271	55,281	6,047,552
	Industrial	8,837,609	428	8,838,037
	Lighting	39,918	0	39,918
	SC RETAIL	21,419,227	158,062	21,577,289
Total Retail Sales				
	Residential	28,352,506	102,353	28,454,859
	General	29,881,464	55,281	29,936,745
	Industrial	20,873,850	428	20,874,278
	Lighting	279,145	-	279,145
	Retail Sales	79,386,964	158,062	79,545,026
	Wholesale	8,303,032	-	8,303,032
	Projected System MWh Sales for Fuel Factor	87,689,996	158,062	87,848,058
	NC as a percentage of total	**66.11%**		**65.99%**
	SC as a percentage of total	24.43%		24.56%
	Wholesale as a percentage of total	9.47%		9.45%
		100.01%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	158,062	
Marginal fuel rate per MWh for SC NEM	$ 26.43	
Fuel benefit to be directly assigned to SC Retail	$ 4,178,086	
System Fuel Expense	$ 1,447,608,938	Sykes Exhibit 2 Schedule 3 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,178,086	
Total Fuel Costs for Allocation	$ 1,451,787,024	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	$ 1,447,608,938			
QF and REPS Compliance Purchased Power - Capacity	$ 25,036,948			
Other fuel costs	$ 1,422,571,989			
SC Net Metering Fuel Allocation adjustment	$ 4,178,086			
Jurisdictional fuel costs after adj.	$ 1,426,750,076			
Allocation to states/classes		65.99%	9.45%	24.56%
Jurisdictional fuel costs	$ 1,426,750,076	$ 941,512,375	$ 134,827,882	$ 350,409,819
Direct Assignment of Fuel benefit to SC Retail	$ (4,178,086)		$ -	$ (4,178,086)
Total system actual fuel costs	$ 1,422,571,989	$ 941,512,375	$ 134,827,882	$ 346,231,732
QF and REPS Compliance Purchased Power - Capacity	25,036,948	16,749,046		
Total system fuel expense from Sykes Exhibit 2 Schedule 3 Page 1	$ 1,447,608,938	**$ 958,261,421**		
		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 2021 through August 2022
Docket E-7, Sub 1250

Sykes Workpaper 8

	January 2021 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	$ 232,627,628.37	2,427,681,062	9.5823	23,329,575	$ 2,235,509,347
General	$ 151,922,584.38	2,224,452,001	6.8297	23,102,975	$ 1,577,855,414
Industrial	$ 59,399,180.48	1,133,633,489	5.2397	11,570,060	$ 606,238,320
Total	$ 443,949,393.23	5,785,766,552		58,002,609	$ 4,419,603,081

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Reagents and ByProducts
Billing Period September 2021 through August 2022
Docket E-7, Sub 1250

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**
9/1/2021	$ 254,001	$ 58,683	$ 1,606,144	$ 153,447	$ 92,068	$ 71,486	**$ 2,235,829**	$ 439,597	$ (39,130)	$ (180,111)	**$ 220,355**
10/1/2021	$ 175,836	$ 40,624	$ 1,111,877	$ 111,351	$ 66,811	$ 71,486	**$ 1,577,984**	$ 290,188	$ (5,710)	$ (177,793)	**$ 106,685**
11/1/2021	$ 221,414	$ 51,154	$ 1,400,085	$ 126,904	$ 76,142	$ 71,486	**$ 1,947,185**	$ 406,119	$ (79,173)	$ (175,470)	**$ 151,477**
12/1/2021	$ 280,366	$ 64,774	$ 1,772,861	$ 151,011	$ 90,607	$ 71,486	**$ 2,431,105**	$ 523,636	$ (101,577)	$ (173,288)	**$ 248,772**
1/1/2022	$ 401,963	$ 92,867	$ 2,541,766	$ 202,788	$ 121,673	$ 71,486	**$ 3,432,543**	$ 770,470	$ (161,638)	$ (171,363)	**$ 437,470**
2/1/2022	$ 383,066	$ 88,501	$ 2,422,272	$ 193,244	$ 115,947	$ 71,486	**$ 3,274,516**	$ 746,552	$ (176,072)	$ (169,522)	**$ 400,957**
3/1/2022	$ 188,873	$ 43,636	$ 1,194,314	$ 112,076	$ 67,246	$ 71,486	**$ 1,677,631**	$ 358,963	$ (71,356)	$ (167,765)	**$ 119,842**
4/1/2022	$ 107,105	$ 24,745	$ 677,266	$ 36,643	$ 21,986	$ 71,486	**$ 939,231**	$ 202,655	$ (10,545)	$ (166,307)	**$ 25,802**
5/1/2022	$ 102,555	$ 23,694	$ 648,496	$ 36,188	$ 21,713	$ 71,486	**$ 904,131**	$ 193,396	$ (11,011)	$ (165,442)	**$ 16,943**
6/1/2022	$ 159,812	$ 36,922	$ 1,010,553	$ 63,671	$ 38,203	$ 71,486	**$ 1,380,647**	$ 303,841	$ (29,602)	$ (164,681)	**$ 109,558**
7/1/2022	$ 218,501	$ 50,481	$ 1,381,667	$ 90,984	$ 54,590	$ 71,486	**$ 1,867,709**	$ 431,038	$ (63,783)	$ (163,942)	**$ 203,314**
8/1/2022	$ 211,283	$ 48,813	$ 1,336,022	$ 84,644	$ 50,786	$ 71,486	**$ 1,803,034**	$ 415,929	$ (57,573)	$ (163,207)	**$ 195,149**
	$ 2,704,776	$ 624,892	$ 17,103,321	$ 1,362,953	$ 817,772	$ 857,831	**$ 23,471,545**	$ 5,082,384	$ (807,169)	$ (2,038,892)	**$ 2,236,324**

Total Reagent cost and Sale of By-products **$ 25,707,869**

rounding differences may occur

Duke Energy Carolinas, LLC **Sykes Workpaper 10**
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Twelve Months Ended December 31, 2020
Billing Period September 2021 through August 2022
Docket E-7, Sub 1250

Line No.	**Description**	**Forecast $**	**(over)/under Collection $**	**Total $**
1	Amount in current docket	102,740,263	(4,999,624)	97,740,638
2	Amount in Sub 1228, prior year docket	101,750,258	1,617,020	103,367,278
3	Increase/(Decrease)	990,005	(6,616,645)	(5,626,640)
4	2.5% of 2020 NC retail revenue of $4,632,028,605			115,800,715
	Excess of purchased power growth over 2.5% of revenue			0

	E-7 Sub 1250			
WP 4	Purchases for REPS Compliance - Energy	62,808,851	65.99%	41,447,561
WP 4	Purchases for REPS Compliance - Capacity	13,866,978	66.90%	9,276,635
WP 4	Purchases	2,586,674	65.99%	1,706,946
WP 4	QF Energy	53,822,291	65.99%	35,517,330
WP 4	QF Capacity	11,169,971	66.90%	7,472,410
WP 4	Allocated Economic Purchase cost	11,091,651	65.99%	7,319,380
		155,346,415		102,740,263

E-7 Sub 1228			
Purchases for REPS Compliance	63,001,495	66.02%	41,593,587
Purchases for REPS Compliance Capacity	13,122,631	67.55%	8,863,980
Purchases	1,628,569	66.02%	1,075,181
QF Energy	56,445,045	66.02%	37,265,019
QF Capacity	12,285,396	67.55%	8,298,450
Allocated Economic Purchase cost	7,049,441	66.02%	4,654,041
	153,532,577		101,750,258

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 1250

Sykes Workpaper 10a

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
2.5% Calculation Test
Twelve Months Ended December 31, 2019
Docket E-7, Sub 1250

Sykes Workpaper 10b

2019	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	12 ME
System KWH Sales - Sch 4, Adjusted	7,570,888,821	7,430,788,664	6,521,808,145	6,367,436,322	6,726,545,218	7,552,455,357	8,316,260,504	8,548,800,472	8,292,133,918	7,019,132,212	6,533,297,016	7,161,497,356	88,041,044,005
NC Retail KWH Sales - Sch 4	5,021,049,922	5,026,972,376	4,366,363,694	4,263,829,687	4,421,389,704	5,029,188,554	5,524,188,997	5,710,820,956	5,512,226,874	4,692,561,973	4,299,808,753	4,774,119,609	58,642,521,099
NC Retail % of Sales, Adjusted (Calc)	66.32%	67.65%	66.95%	66.96%	65.73%	66.59%	66.43%	66.80%	66.48%	66.85%	65.81%	66.66%	66.61%
NC retail production plant %	67.56%	67.56%	67.56%	67.56%	67.75%	67.75%	67.75%	67.75%	67.75%	67.75%	67.75%	67.75%	67.72%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 23,687,311	$ 57,492,154	$ 14,514,026	$ 14,125,368	$ 6,227,781	$ 7,986,019	$ 9,392,534	$ 7,209,102	$ 18,620,321	$ 13,793,051	$ 15,085,734	$ 17,891,442	$ 206,024,843
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	10,050,079	26,532,896	2,706,430	4,264,779	908,542	640,701	1,230,088	1,129,642	1,974,692	1,539,252	2,340,043	2,634,380	$ 55,951,524
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	3,283,437	4,116,642	3,779,240	5,137,202	5,251,425	5,598,653	5,193,633	5,586,738	5,216,879	4,899,454	4,069,122	3,963,969	$ 56,096,394
System Actual$ - Sch 3 Fuel-related$; SC DERP	102	14,377	8,659	21,097	25,363	30,158	22,270	26,481	26,351	26,014	17,072	15,590	$ 233,534
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	1,367,422	1,711,969	1,557,910	2,135,075	2,259,422	2,837,912	2,660,982	2,749,375	2,583,768	2,605,902	2,204,650	2,090,407	$ 26,764,794
Total System Economic & QF$	38,388,351	89,868,038	22,566,265	25,683,521	14,672,533	17,093,443	18,499,507	16,701,338	28,422,011	22,863,673	23,716,621	26,595,788	345,071,089
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 11,884,171	$ 71,766,352	$ 8,909,559	$ 10,043,093	$ 3,969,493	$ 6,657,925	$ 7,676,184	$ 5,446,589	$ 17,997,075	$ 13,185,756	$ 12,864,226	$ 15,502,723	$ 185,903,146
Total System Economic $ without Native Load Transfers	$ 26,504,180	$ 18,101,686	$ 13,656,706	$ 15,640,428	$ 10,703,040	$ 10,435,518	$ 10,823,323	$ 11,254,749	$ 10,424,936	$ 9,677,917	$ 10,852,395	$ 11,093,065	$ 159,167,943
NC Actual $ (Calc)	$ 17,577,699	$ 12,245,897	$ 9,143,192	$ 10,473,308	$ 7,035,158	$ 6,949,023	$ 7,189,539	$ 7,518,465	$ 6,930,015	$ 6,470,063	$ 7,142,370	$ 7,395,049	$ 106,069,779
Billed rate (¢/kWh):	0.1922	0.1922	0.1922	0.1922	0.1922	0.1922	0.1922	0.1922	0.1759	0.1535	0.1533	0.1533	
Billed $:	$ 9,650,458	$ 9,661,841	$ 8,392,151	$ 8,195,081	$ 8,497,911	$ 9,666,100	$ 10,617,491	$ 10,976,198	$ 9,696,007	$ 7,203,083	$ 6,591,607	$ 7,318,725	$ 106,466,653
(Over)/ Under $:	$ 7,927,242	$ 2,584,056	$ 751,041	$ 2,278,227	$ (1,462,753)	$ (2,717,077)	$ (3,427,952)	$ (3,457,733)	$ (2,765,992)	$ (733,020)	$ 550,763	$ 76,323	$ (396,874)
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ 426,732	$ 426,732	$ 213,366	$ 213,366	$ 320,050	$ 1,386,879	$ 3,200,490	$ 3,200,490	$ 640,098	$ 213,366	$ 213,366	$ 213,366	$ 10,668,301
System Actual $ - Capacity component of Purchased Power for REPS Compliance	608,844	738,655	747,764	827,415	781,129	817,587	2,308,343	2,605,889	2,449,375	2,179,103	611,944	591,922	$ 15,267,970
System Actual $ - Capacity component of HB589 Purpa QF purchases	240,541	314,914	229,175	301,405	216,488	298,037	1,151,852	1,312,758	1,272,900	1,184,456	259,220	187,603	$ 6,969,349
System Actual $ - Capacity component of SC DERP	32	4,343	4,209	5,850	3,530	4,199	3,177	3,738	3,716	3,670	2,375	2,168	$ 41,006
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 1,276,149	$ 1,484,644	$ 1,194,514	$ 1,348,036	$ 1,321,197	$ 2,506,702	$ 6,663,862	$ 7,122,875	$ 4,366,089	$ 3,580,594	$ 1,086,905	$ 995,058	$ 32,946,626
NC Actual $ (Calc) (1)	$ 862,169	$ 1,003,029	$ 807,016	$ 910,736	$ 895,069	$ 1,698,211	$ 4,514,555	$ 4,825,522	$ 2,957,887	$ 2,425,739	$ 736,343	$ 674,120	$ 22,310,397
Billed rate (¢/kWh):	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0353	0.0342	0.0327	0.0327	0.0327	
Billed $:	$ 1,773,631	$ 1,775,723	$ 1,542,370	$ 1,506,151	$ 1,561,807	$ 1,776,506	$ 1,951,359	$ 2,017,285	$ 1,886,955	$ 1,535,934	$ 1,406,799	$ 1,561,982	$ 20,296,502
(Over)/Under $:	$ (911,461)	$ (772,694)	$ (735,354)	$ (595,415)	$ (666,739)	$ (78,295)	$ 2,563,196	$ 2,808,237	$ 1,070,932	$ 889,805	$ (670,455)	$ (887,863)	$ 2,013,895
TOTAL (Over)/ Under $:	**$ 7,015,780**	**$ 1,811,363**	**$ 15,688**	**$ 1,682,813**	**$ (2,129,491)**	**$ (2,795,372)**	**$ (864,756)**	**$ (649,496)**	**$ (1,695,060)**	**$ 156,785**	**$ (119,692)**	**$ (811,539)**	**$ 1,617,020**

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 2018 production plant allocation factor. Actual true-up related to allocator was made as prior period adjustment in May 2019 of Schedule 4.

rounding differences may occur

Duke Energy Carolinas, LLC **Sykes Workpaper 11**
North Carolina Annual Fuel and Fuel Related Expense
Actual Sales by Jursidication - Subject to Weather
Twelve Months Ended December 31, 2020
Docket E-7, Sub 1250

			MWhs				
Line #	Description	Reference	NORTH CAROLINA	SOUTH CAROLINA	TOTAL COMPANY	% NC	% SC
1	Residential	Company Records	21,396,039	6,566,946	27,962,984	76.52	23.48
2	Total General Service	Company Records	22,718,144	5,231,956	27,950,100		
3	less Lighting and Traffic Signals		262,966	50,594	313,560		
4	General Service subject to weather		22,455,178	5,181,362	27,636,541	81.25	18.75
5	Industrial	Company Records	11,397,681	8,195,633	19,593,314	58.17	41.83
6	Total Retail Sales	1+2+5	55,511,864	19,994,535	75,506,399		
7	Total Retail Sales subject to weather	1+4+5	55,248,898	19,943,941	75,192,839	73.48	26.52

This does not exclude Greenwood and includes the impact of SC DERP net metering generation

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment
Twelve Months Ended December 31, 2020
Docket E-7, Sub 1250

Line #	Description	REFERENCE	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Total Residential		2,231,913	76.52	1,707,860	23.48	524,053
	General Service						
2	Total General Service		362,925	81.25	294,877	18.75	68,048
	Industrial						
3	Total Industrial		284,064	58.17	165,240	41.83	118,824
4	Total Retail	L1+ L2+ L3	2,878,902		2,167,977		710,925
5	Wholesale		207,295				
6	Total Company	L4 + L5	3,086,197		2,167,977		710,925

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment by Class by Month
Twelve Months Ended December 31, 2020
Docket E-7, Sub 1250

2020	Residential TOTAL MWH ADJUSTMENT	Commercial TOTAL MWH ADJUSTMENT	Industrial TOTAL MWH ADJUSTMENT	
JAN	372,371	57,492	-	
FEB	481,279	42,012	32,140	
MAR	50,667	-	-	
APR	58,532	-	-	
MAY	182,541	35,968	51,277	
JUN	352,469	129,088	70,502	
JUL	241,887	90,967	28,531	
AUG	(64,182)	(25,605)	(12,663)	
SEP	(101,503)	(50,296)	(24,943)	
OCT	40,044	16,706	10,880	
NOV	299,438	50,431	128,339	
DEC	318,368	16,162	-	
Total	**2,231,913**	**362,925**	**284,064**	**2,878,902**

Wholesale

2020	TOTAL MWH ADJUSTMENT
JAN	38,620
FEB	25,594
MAR	2,376
APR	-
MAY	12,541
JUN	32,517
JUL	24,554
AUG	(4,972)
SEP	(4,242)
OCT	(1,717)
NOV	43,289
DEC	38,735
Total	**207,295**

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]

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales
Twelve Months Ended December 31, 2020
Docket E-7, Sub 1250

Sykes Workpaper 13
Page 1

Line	Estimation Method [1]	Rate Schedule	NC Proposed KWH [1] Adjustment	SC Proposed KWH Adjustment	Wholesale Proposed KWH Adjustment	Total Company
1	*Regression*	Residential	225,676,100	64,516,912		
2						
3		**General Service (excluding lighting):**				
4	*Customer*	General Service Small and Large	86,782,288	12,388,860		
5	*Regression*	Miscellaneous	535,920	517,444		
6		Total General	87,318,208	12,906,304		
7						
8		**Lighting:**				
9	*Regression*	T & T2 (GL/FL/PL/OL)2	2,624,981	1,258,859		
10	*Regression*	TS	10,497	(100,713)		
11		Total Lighting	2,635,478	1,158,146		
12						
13		**Industrial:**				
14	*Customer*	I - Textile	3,467,746	-		
15	*Customer*	I - Nontextile	3,671,273	14,017,455		
16		Total Industrial	7,139,019	14,017,455		
17						
18						
19		Total	322,768,805	92,598,817	79,359,686	494,727,308
					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 during the 12 month period.

rounding differences may occur

Duke Energy Carolinas, LLC **Sykes Workpaper 13**
North Carolina Annual Fuel and Fuel Related Expense **Page 2**
Customer Growth Adjustment to kWh Sales-Wholesale
Twelve Months Ended December 31, 2020
Docket E-7, Sub 1250

Calculation of Customer Growth Adjustment to kWh Sales - Wholesale

Line No.		Reference	
1	Total System Resale (kWh Sales)	Company Records	8,857,220,265
2	Less Intersystem Sales	Schedule 1	1,210,124,770
3	Total kWh Sales Excluding Intersystem Sales	L1 - L2	7,647,095,495
4	Residential Growth Factor	Line 8	1.0378
5	Adjustment to kWhs - Wholesale	L3 * L4 / 100	79,359,686
6	Total System Retail Residential kWh Sales	Company Records	27,962,984,454
7	2020 Proposed Adjustment kWh - Residential (NC+SC)	WP 13 1	290,193,012
8	Percent Adjustment	L7 / L6 * 100	1.0378

"RAC001": CarolinasOperating Revenue Report

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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 19 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. No.

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, 2020 through December 31, 2020 ("test period") versus the period January 1, 2019 through December 31, 2019 ("prior test period"), and describe changes projected for the billing period of September 1, 2021 through August, 31 2022 ("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. HOW DOES DEC OPERATE ITS PORTFOLIO OF GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS?

A. Both DEC and DEP utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider factors that include, but are not limited to, the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

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 $90.53 per ton, compared to $82.11 per ton in the prior test period, representing an increase of approximately 10%. The cost of delivered coal includes an average transportation cost of $35.07 per ton in the test period, compared to $28.33 per ton in the prior test period, representing an increase of approximately 24% and also includes $24.8 million in costs associated with the mitigation of coal contract obligations related to COVID-19 load losses, as is described in more detail below. The Company's average price of gas purchased for the test period was $2.94 per Million British Thermal Units ("MMBtu"), compared to $3.40 per MMBtu in the prior test period, representing a decrease of approximately 14%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEC's coal burn for the test period was 5.9 million tons, compared to a coal burn of 8.1 million tons in the prior test period, representing a decrease of 28%. The Company's natural gas burn for the test period was 135.4 MMBtu, compared to a gas burn of 123.9 MMBtu in the prior test period, representing an increase of approximately 9%.

As a result of load reduction from the COVID-19 pandemic, extremely low natural gas prices, and mild winter weather, the Company experienced a significant shift in generation from coal to natural gas. The COVID-19 pandemic had an unprecedented and unanticipated impact on forecasted load in 2020, which in turn reduced coal demand and required inventory mitigation beyond the Company's typical no-cost mitigation measures. Influenced by the operational realities from the pandemic, DEC burned significantly less coal than anticipated, and customers benefited from greater utilization of lower-cost natural gas.

Given the reduction in actual and forecasted coal usage for the balance of 2020, the Company was required to evaluate alternatives to reduce its coal contract obligations for 2020 that exceeded its consumption and storage capabilities. The Company exercised and exhausted its rights to flex down contractual obligations, defer tons, and optimize off-site storage opportunities at no additional cost to the customer in order to address the excess coal due to significant declines in demand related to COVID-19 related shut-downs. After exhausting all of its no-cost contract mitigation options, it was necessary to determine whether to force run coal generation or continue to maximize customers savings by burning natural gas while negotiating to buy out for the remaining balance of its excess 2020 coal obligations. The Company determined through its production cost analysis that pursuing contractual buyouts would result in projected customer savings of approximately $22 million as compared with force running coal generation.

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 due to declining demand for coal stemming from accelerated coal retirements and overall declines in coal generation demand resulting from the impacts of COVID-19 economic shutdowns in 2020; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening access to investor financing coupled with deteriorating credit quality is increasing the overall costs of financing for coal producers; and, (7) corrections in production levels in an attempt to bring coal supply in balance with demand.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in the short term, such dynamics are influenced primarily by seasonal weather demand and overall storage inventory balances. While there continues to be adequate natural gas production capacity to serve increased market demand, pipeline infrastructure permitting and regulatory process approval efforts are challenged due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing. Specifically, cancellation of the Atlantic Coast Pipeline which was terminated July 5, 2020 will limit the Company's access to low cost natural gas resources.

Over the longer term planning horizon, natural gas supply is projected to continue to increase 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 6.9 million tons, compared to 5.9 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. While coal burns are projected to increase, they remain well below historic coal burns due to coal to gas switching resulting from changes in the coal rail transportation rate structure forecasted to go into effect April 1, 2021. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $63.95 per ton for the billing period compared to $90.53 per ton in the test period. This includes an average projected total transportation cost of $26.67 per ton for the billing period, compared to $35.07 per ton in the test period. 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 non-Central Appalachian coal DEC is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

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

Q. WHAT STEPS IS DEC TAKING TO MANAGE PORTFOLIO FUEL COSTS?

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.

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. Lastly, 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, 2020 & 2019
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
1	January 2020	719,300	39,752	759,052
2	February	377,885	130,203	508,088
3	March	511,418	51,906	563,324
4	April	454,145	23,566	477,712
5	May	203,960	12,873	216,833
6	June	306,915	11,563	318,478
7	July	395,057	50,851	445,908
8	August	548,061	25,831	573,892
9	September	400,170	99,692	499,862
10	October	531,876	52,647	584,523
11	November	360,487	111,351	471,838
12	December	326,439	52,176	378,615
13	**Total** (Sum L1:L12)	**5,135,713**	**662,411**	**5,798,125**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
14	January 2019	467,830	111,867	579,698
15	February	555,624	64,276	619,900
16	March	551,679	112,937	664,616
17	April	476,648	227,914	704,562
18	May	549,400	152,538	701,938
19	June	647,313	140,296	787,609
20	July	692,046	77,088	769,134
21	August	732,253	115,963	848,217
22	September	469,275	204,304	673,579
23	October	471,409	231,850	703,259
24	November	397,228	239,441	636,669
25	December	560,959	202,536	763,494
26	**Total (Sum L14:L25)**	**6,571,664**	**1,881,010**	**8,452,675**

DUKE ENERGY CAROLINAS
Summary of Gas Purchases
Twelve Months Ended December 31, 2020 & 2019
MBTUs

Line No.	Month	MBTUs
1	January 2020	13,098,158
2	February	13,151,481
3	March	13,043,284
4	April	6,893,840
5	May	10,414,617
6	June	9,651,972
7	July	13,975,803
8	August	12,871,773
9	September	11,262,855
10	October	11,076,024
11	November	9,927,112
12	December	10,055,686
13	**Total (Sum L1:L12)**	**135,422,605**

Line No.	Month	MBTUs
14	January 2019	11,540,233
15	February	11,895,973
16	March	8,829,116
17	April	7,309,473
18	May	12,448,810
19	June	10,195,827
20	July	12,505,061
21	August	12,104,186
22	September	12,459,839
23	October	8,409,940
24	November	5,772,711
25	December	10,423,250
26	**Total (Sum L14:L25)**	**123,894,419**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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

FEBRUARY 23, 2021

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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 1228.

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, 2020 through December 31, 2020 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2021 through August 31, 2022 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 $47.06 per pound for uranium concentrates during the test period, representing a 4.6% increase 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 decreased 9.6% to $104.04 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 4%, 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 46% and 34%, respectively.

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

A. Prices in the uranium concentrate markets have recently increased due to production cutbacks; however, prices remain relatively low. Industry consultants believe that 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 enrichment and conversion 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 increase from 0.5814 cents per kWh incurred in the test period, to approximately 0.6057 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?

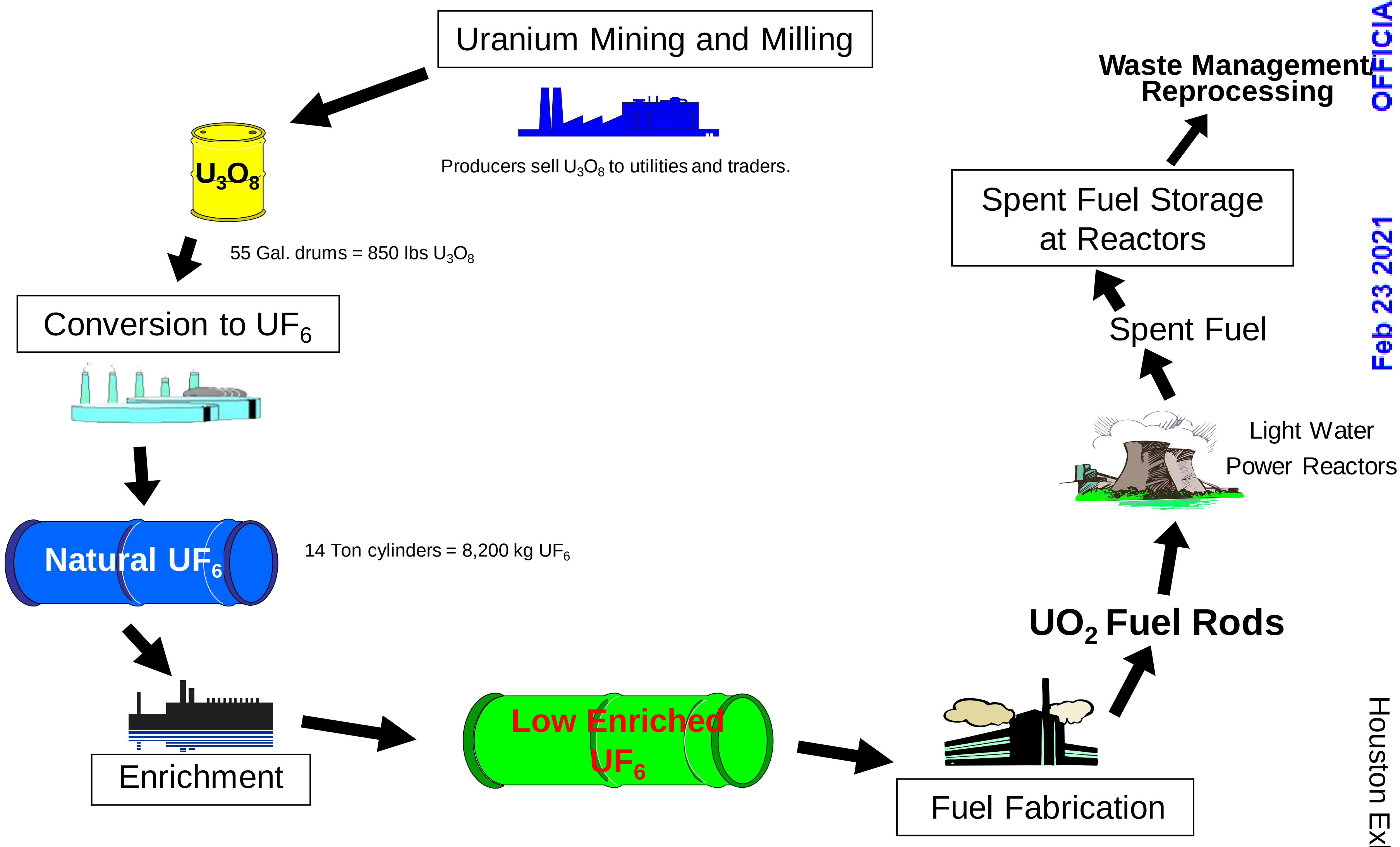
A. As I discussed earlier and as described in Houston Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEC relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating 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



Houston Exhibit 2

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.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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 526 South Church Street, Charlotte, 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 33 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 and Docket No. E-7, Sub 1228.

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, 2020 through December 31, 2020 ("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, 2021 through August 31, 2022 ("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 [1]

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.

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

[1] Reflects DEC's ownership of Catawba Nuclear Station.

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 63% of the total power generated by DEC. During 2020, DEC's seven nuclear units collectively achieved a fleet capacity factor of 95.05%, marking the 21st consecutive year in which DEC's nuclear fleet exceeded a system capacity factor of 90%. With comprehensive and successful Covid-19 mitigation protocols, the Company successfully executed five refueling outages with no impact to schedule or planned scope. All refueling outages were completed within budget and four of the five refueling outages completed under the scheduled allocation. McGuire Unit 2 entered its 2020 refueling outage after completing a breaker-to-breaker continuous cycle run, and Oconee Unit 2 established a new annual net generation record during 2020.

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 91.95% for the period 2015 through 2019 for comparable units. The Company's 2020 capacity factor of 95.05% and 2-year average[2] of 96.07% both exceed the NERC average of 91.95%.

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 2020 from the Electric Utility Cost Group, all three of DEC's nuclear plants rank in the top quartile in total operating cost among the 56 U.S. operating nuclear

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

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 47.1 million MWhs of additional, emissions-free generation over the past 21 years (as compared with production at a capacity factor of 90%), which is equivalent to an additional 9.8 months of output from DEC's nuclear fleet (based on DEC's average annual generation for the same 21-year period). These performance results demonstrate DEC's continuing success in achieving high performance without compromising safety and reliability.

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 five refueling outages completed during the test period: McGuire Unit 2, Oconee Unit 3, and Catawba Unit 1 in the spring of 2020, followed by McGuire Unit 1 and Oconee Unit 1 in the fall. All five outages were completed within budget, and all outage scope completion goals were met. The combined O&M outage costs for the five refueling outages totaled $132.9 million compared to the combined budget for the five outages of $136.4 million. Total days offline for refueling during the test period totaled 146.9 days compared to a total scheduled allocation of 151.5 days. Four of the five refueling outages were completed under allocation. The McGuire Unit 1 refueling outage extended 4 days beyond allocation.

After completing a continuous cycle run of 524.5 days, McGuire Unit 2 entered a spring refueling outage on March 21, 2020. In addition to refueling, safety and reliability enhancing maintenance, inspections and testing were completed. Maintenance work included the replacement of the 2D reactor coolant pump seal, and preventive maintenance on the 2A nuclear service work pump, 2A chemical and volume control motor, and 2A containment spray motor. Both the 2A and 2B component cooling heat exchangers were cleaned. Inspections on the reactor vessel head, 2B low pressure turbine, and thrust bearings were completed. After refueling, maintenance, and inspections and testing were completed, the unit returned to service on April 13, 2020, for a total duration of 23.4 days compared to a 25-day schedule allocation. The outage was accomplished with the lowest dose in the station's history.

Oconee Unit 3 shut down for refueling on April 10, 2020. During the outage, the unit's low-pressure turbines were replaced. Safety enhancements included the replacement of the standby shutdown letdown line. Reliability enhancements included the replacements of the 3A high pressure injection motor, 3B reactor building cooling unit motor, 3D1 heater drain pump and motor, 3B1 reactor coolant pump seal, and 20 air operated valve positioners. Preventive maintenance was completed on the 3A and 3B feedwater pumps, main transformer, 3TB switchgear and breaker, and the 3X8 load center. Inspections and testing completed included radiography tests on the high-pressure injection nozzle thermal sleeve and valves, condenser waterbox and discharge piping inspections, and 3TC switchgear inspections. After refueling, maintenance, testing and inspections completed, the unit returned to service on May 9, 2020. The outage duration was 28.97 days compared to a schedule allocation of 34.5 days.

Catawba Unit 1 shut down on May 2, 2020 for refueling. In addition to refueling activities, safety and reliability enhancements, testing and inspections were completed. Replacement of the unit's low-pressure turbines were completed. Other maintenance activities included replacement of the 1C reactor coolant pump motor, replacement of the 1A, 1C, and 1D reactor coolant pump seal packages, and replacement of the 1B reactor coolant charging pump motor. The 1B component cooling water heat exchanger tubes were replaced with new stainless-steel tubes. Volumetric inspection of the reactor vessel head and all head welds, and inspections and testing of seven motor-control centers were completed. After refueling, maintenance, inspections, and testing completed, the unit returned to service on June 1, 2020, for a total duration of 30.2 days compared to a 31-day schedule allocation.

McGuire Unit 1 was removed from the grid on September 19, 2020 to begin refueling. Along with routine refueling activities, safety and reliability enhancements and inspections were completed. Reliability enhancements completed during the refueling outage included replacement of the 1A reactor coolant pump seal and the 1B1 component cooling pump motor. Valve work and modifications completed included valve and valve actuator replacements in the heater drain, safety injection, nuclear service water and station air systems. Inspections completed included the reactor vessel 10-year in-service inspection, material reliability program upper and lower internals inspection, and inspection of the reactor coolant hot and cold leg nozzles. An 8-year reactor coolant pump switchgear inspection and testing of the 1A engineered safety features was also completed. The unit's turbine driven auxiliary feedpump turbine and 1C low pressure turbine were also inspected. With the exception of duration, all outage goals were met. The outage extended four days beyond the scheduled allocation due to challenges with reactor vessel inspection equipment performance and an emergent repair on a cold leg accumulator outlet check valve. Once work activities, testing and inspections were completed, the unit returned to service on October 21, 2020. The total outage duration was 32.1 days compared to a 28-day scheduled allocation.

The fifth and final refueling outage executed during the test period began on October 16, 2020 when Oconee Unit 1 shutdown for refueling. In addition to refueling, safety and reliability enhancements, testing and inspections were completed. Significant outage scope included the replacement of the unit's low-pressure turbine rotors, completing a multi-year project to replace the aging low-pressure turbines on all three Oconee units. The replacement of the low-pressure turbine rotors improves reliability, and reduces maintenance expense and inspection requirements during future refueling outages. Other reliability enhancements included replacement of the 1B1 reactor coolant pump motor, 1A1 and 1B2 reactor coolant pump seals, 1D2 heater drain pump and 1A high pressure injection pump motor. Replacement of the unit 1 standby shutdown facility reactor coolant letdown line also completed a multi-year station project; with this work now completed on all three Oconee units. Electrical work completed included main power relaying upgrade and preventive maintenance on the Unit 1 main transformer and various switchgear and breakers. Inspection activities included steam generator Eddy Current and reactor vessel materials reliability program inspections. After refueling, maintenance, inspections and testing completed, the unit returned to service on November 18, 2020, for a total duration of 32.2 days compared to a 33-day schedule allocation.

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 93.21% 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 91.95% for comparable units as reported in the NERC Brochure during the period of 2015 to 2019.

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

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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

FEBRUARY 23, 2021

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**STEVE IMMEL 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 Steve Immel 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 Fleet Transition Strategy.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of Kentucky with a Bachelor of Science degree in Civil Engineering and a Masters of Business Administration from Queens College. My career began with Duke Energy (d/b/a Duke Power) in 1980 as an Associate Design Engineer. Since that time, I have held various roles of increasing responsibility in corporate facilities, investment recovery, supply chain, and operations areas, including the role of Hydro Manager; Station Manager at Duke Energy Carolinas, LLC's ("DEC" or the "Company") Allen Steam Station and then Marshall Steam Station. I was named VP of Duke Energy Indiana's Midwest Regulated Operations in 2012 and VP of Outage and Project Services in 2014. In 2016, I was named to VP of Carolinas Coal Generation for the Company and Duke Energy Progress, LLC. I assumed my current role in 2020.

Q. WHAT ARE YOUR CURRENT DUTIES AS VP OF FLEET TRANSITION STRATEGY?

A. In this role, I am responsible for developing strategies to address various integrated resource plan ("IRP") scenarios and related plans for the Fossil/Hydro/Solar workforce.

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 most recent general rate case in Docket No E-7, Sub 1214.

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 2020 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, 2020 through December 31, 2020 (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 15,043 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	6,764 MWs
Steam Natural Gas -	170 MWs
Hydro -	3,277 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 13 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 13 coal-fired units are equipped with low NO_x burners. The steam natural gas unit – Lee Station ("Lee") Unit 3 – is considered to be a peaking unit.

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 2,220 MWs, along with conventional hydro assets consisting of 59 units providing approximately 1,057 MWs of capacity. The 71 MWs of solar capacity are made up of 17 roof top 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 12.5 MW of capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEC'S 2019 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. Marshall Unit 3 was upgraded in November 2020 to allow for co-fired operation, allowing utilization of coal and natural gas. Gaston solar facility went into service in December 2020 and will provide the DEC territory with 10 MW of capacity. Maiden Creek solar facility went into service in January 2021 and will provide the DEC territory with 28 MW of capacity. Bad Creek Unit 2 was upgraded in October 2020, increasing the unit's capacity by 80 MWs.

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?

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.

Q. WHAT HAS BEEN THE HEAT RATE OF DEC'S COAL UNITS DURING THE TEST PERIOD?

A. Over the test period, the average heat rate for DEC's coal fleet was 9,865 Btu/kWh. DEC's Rogers Energy Complex ("Cliffside"), Belews Creek Steam Station ("Belews Creek"), and Marshall Steam Station ("Marshall") have typically ranked as some of the most efficient coal-fired generating stations in the nation, with heat rates of 9,519, Btu/kWh, 9,871 Btu/kWh, and 9,941 Btu/kWh, respectively. For the test period, the Marshall units provided 35% of coal-fired generation for DEC, with the Belews Creek units providing 31% and Cliffside providing 31%.

Q. HOW MUCH GENERATION DID EACH TYPE OF FOSSIL/HYDRO/SOLAR GENERATING FACILITY PROVIDE FOR THE TEST PERIOD AND HOW DOES DEC UTILIZE EACH TYPE OF GENERATING FACILITY TO SERVE CUSTOMERS?

A. The Company's system generation totaled 95 million MW hours ("MWhs") for the test period. The Fossil/Hydro/Solar fleet provided 35 million MWhs, or approximately 37% of the total generation. As a percentage of the total generation, 16% was produced from coal-fired stations and approximately 15% from CC operations, 1% from CTs, 2.5% from hydro facilities, and 0.16% from solar.

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.

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

A. The Company, like other utilities across the U.S., has experienced a change in the dispatch order for each type of generating facility due to continued favorable economics resulting from low pricing of natural gas. Further, the addition of new

CC units within the Carolinas' portfolio in recent years has provided DEC with additional natural gas resources that feature state-of-the-art technology for increased efficiency and significantly reduced emissions. These factors promote the use of natural gas and provide real benefits in cost of fuel and reduced emissions for customers.

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; and (4) starting reliability ("SR"), which represents the percentage of successful starts. For 2021,

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

the Company is including another measure to assess plant reliability—equivalent forced outage factor ("EFOF")—which quantifies the number of period hours in 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 2015 through 2019 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 DEC Operational Results	2015 - 2019 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	72.3%	76.5%	705
	EFOR	15.1%	9.6%	
	EFOF	7.0%	n/a	
Coal-Fired Summer Peak	EAF	78.7%	n/a	n/a
Total CC Average	EAF	86.1%	84.9%	350
	NCF	73.1%	54.8%	
	EFOR	0.55%	4.9%	
	EFOF	0.48%	n/a	
Total CT Average	EAF	83.5%	86.9%	746
	SR	99.0%	98.4%	
Hydro	EAF	77.4%	79.9%	1,060

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

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

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.