DUKE ENERGY.

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February 26, 2019

VIA ELECTRONIC FILING

Ms. M. Lynn Jarvis
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

RE: Duke Energy Carolinas, LLC's Fuel Charge Adjustment Proceeding
Docket No. E-7, Sub 1190

Dear Ms. Jarvis:

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 Kimberly D. McGee, Eric S. Grant, Regis T. Repko, Kevin Y. Houston, and Stephen D. Capps, which collectively contain the information required in NCUC Rule R8-55.

Information contained in Stephen D. Capps Exhibit 1 is confidential because it contains sensitive information regarding DEC's future nuclear outage schedule. Information contained in Eric S. Grant Exhibit 3 is confidential because it contains spot gas supply cost information and public disclosure could hinder DEC from obtaining the most cost-effective energy to meet the needs of its customers. Therefore, I will deliver 15 copies filed under seal pursuant to N.C. Gen. Stat. § 62-132.11, and one copy with the confidential information redacted, to the Clerk's Office by close of business on February 27, 2019. These confidential documents should only be shared with the Commission and Commission Staff. Parties to the docket may contact DEC regarding obtaining copies pursuant to an appropriate confidentiality agreement.

Please contact me if you have any questions.

Sincerely,

Jack E. Jirak

Enclosure
cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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

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

1. The Applicant's general offices are located at 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 name and address of Applicant's attorney are:

Jack E. Jirak
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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 2018.

4. In Docket No. E-7, Sub 1163, 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 - 1.7983¢ per kWh
Commercial - 1.9382¢ per kWh
Industrial - 2.0233¢ per kWh

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

Residential - 1.7943¢ per kWh
Commercial - 1.9529¢ per kWh
Industrial - 1.9313¢ 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 - 0.1108¢ per kWh

Commercial - 0.0632¢ per kWh
Industrial - 0.1476¢ per kWh

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

Residential - 1.9051¢ per kWh
Commercial - 2.0161¢ per kWh
Industrial - 2.0789¢ per kWh

The new fuel factors would have an effective date of September 1, 2019.

6. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Eric S. Grant, Regis T. Repko, Kevin Y. Houston, Stephen D. Capps, and Kimberly McGee, 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 (90.21%) 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 -	1.9519¢ per kWh	1.9212¢ per kWh
Commercial -	2.0501¢ per kWh	2.0300¢ per kWh
Industrial -	2.1032¢ per kWh	2.0917¢ 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 -	1.9051¢ per kWh
Commercial -	2.0161¢ per kWh
Industrial -	2.0789¢ per kWh

Respectfully submitted this 26th day of February , 2019.

By: Jack Jirak

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ATTORNEYS FOR DUKE ENERGY CAROLINAS, LLC

STATE OF NORTH CAROLINA)
)
COUNTY OF MECKLENBURG)

VERIFICATION

Kimberly McGee, being first duly sworn, deposes and says:

That she is RATES MANAGER for DUKE ENERGY CAROLINAS, LLC, applicant in the above-titled action; that she 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, she believes it to be true.

Kimberly McGee

Kimberly McGee

Sworn to and subscribed before
me this the 22nd day of February, 2019.

Aloma M. Felder

Notary Public Aloma M. Felder

My Commission expires: July 21, 2020

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF KIMBERLY MCGEE 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 Kimberly McGee. 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 graduated from the University of North Carolina at Charlotte with a Bachelor of Science degree in Accountancy. I am a certified public accountant licensed in the State of North Carolina. I began my career in 1989 with Deloitte and Touche, LLP as a staff auditor. In 1992, I began working with DEC (formerly known as Duke Power Company) as a staff accountant and have held a variety of positions in the finance organization. From 1997 until 2009, I worked for Wachovia Bank (now known as Wells Fargo) in a variety of finance and regulatory positions. I rejoined DEC in January 2009 as a Lead Accountant in Financial Reporting. I joined the Rates Department in 2011 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 and wholesale rates, and 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 testified before the North Carolina Utilities Commission ("NCUC" or the "Commission") in DEP's general rate case proceeding supporting the base fuel factors in Docket No. E-2, Sub 1142 and provided testimony in DEC's general rate case proceeding supporting the base fuel factors in Docket No. E-7, Sub 1146. I also testified supporting cost recovery in the 2013 Demand Side Management and Energy Efficiency Rider in Docket No. E-7, Sub 1031. I submitted testimony in DEC's fuel and fuel-related cost recovery proceeding E-7, Subs 1163 and 1129 and DEP's fuel and fuel-related cost recovery proceedings in Docket No. E-2, Subs 1045, 1069 and 1107.

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 McGee 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, 2018 ("test period"), and the billing period is September 1, 2019 through August 31, 2020 ("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 MCGEE 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 92.95% proposed nuclear capacity factor and projected megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 92.95% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 90.21% 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 2018 Monthly Fuel Reports.

1) December 2018 Monthly Fuel Report required by NCUC Rule R8-52.

2) December 2018 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

Q. PLEASE EXPLAIN MCGEE EXHIBIT 1.

A. McGee 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 1.9051¢, 2.0161¢, and 2.0789¢ per kWh, respectively, to be reflected in rates during the billing period. The factors DEC proposes in this proceeding incorporate a 92.95% nuclear capacity factor as testified to by Company witness Capps, projected fossil fuel costs as testified to by Company witness Grant, projected nuclear fuel costs as testified to by Company witness Houston, and projected reagents costs as testified to by Company witness Repko. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on McGee 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	1.7943	1.9529	1.9313	1.8901
EMF Increment (Decrement)	0.1108	0.0632	0.1476	0.0994
Net Fuel and Fuel Related Costs Factors	1.9051	2.0161	2.0789	1.9895

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 1.01% increase on customers' bills. The table below shows both the proposed and existing fuel and fuel-related costs factors.

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Proposed Total Fuel Factor	1.9051	2.0161	2.0789	1.9895
Existing Total Fuel Factor	1.7983	1.9382	2.0233	1.9059

Q. WHAT ARE THE KEY DRIVERS IMPACTING THE PROPOSED FUEL AND FUEL-RELATED COSTS FACTORS?

A. The increase in the proposed net fuel and fuel-related costs factors for all customer classes is primarily driven by an increase in coal commodity prices. An increase in gas generation due to lower gas prices partially offsets higher coal-related fuel cost. In addition, the under-collection of $57.7 million for the current test period is lower than the under-collection of $73.3 million included in setting fuel rates during the 2018 annual fuel proceeding, thus reducing the total rate increase.

Company witness Houston explains that the billing period price of 0.6115¢ per kWh for nuclear fuel is lower than experienced during the test period and lower than the prices reflected in current rates. As discussed by Company witness Grant, the proposed fuel and fuel-related costs factors include an average delivered cost for coal for the billing period of $66.80 per ton, which is 13% lower than the average delivered cost of coal per ton during the test period and lower than prices reflected in current rates. In addition, Company witness Grant notes a decrease in natural gas prices as evidenced by the Henry Hub[1] forward price of $2.75 per Million British Thermal Units ("MMBtu") used in the proposed fuel rates, compared to $3.09 per MMBtu in the test period.

[1] "Henry Hub" pipeline is the location used for physical settlement of the New York Mercantile Exchange futures contracts.

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 MCGEE 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 92.95%, and provides the forecasted MWh sales for the billing period on which system generation and costs are based.

Schedule 2 also uses the proposed capacity factor of 92.95% 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 90.21%. This capacity factor is based on the 2013 through 2017 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 production plant, which is the same allocation methodology used in the latest general rate case in Docket E-7, Sub 1146.

Page 3 of Exhibit 2, Schedules 1, 2, and 3 shows the allocation of system fuel costs to 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 MCGEE 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 McGee Exhibit 2, Schedule 1. For purposes of this filing, as a proxy for generation dispatch modeling, McGee 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 increased 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 an 90.21% NERC nuclear capacity factor compared to the proposed 92.95% nuclear capacity factor.

Q. MCGEE 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. McGee Exhibit 3, Pages 1 through 4, demonstrates that for the test period, DEC experienced an under-recovery for the residential, general service/lighting and industrial customer classes of $24.4 million, $14.8 million, and $18.4 million, respectively. There were two adjustments included in the calculation of the under-recovery balance at December 31, 2018. The first adjustment relates to the months of January 2018 through March 2018 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 (over)/under recovery for the months of January 2018 through March 2018 when computing the current EMF factors. Secondly, included in the test period (over)/under calculation is the under collection related to the coal inventory rider established in Ordering Paragraph 27 of the Commission's June 22, 2018 *Order Accepting Stipulation, Deciding Contested Issue and Requiring Revenue*

Reduction in Docket No. E-7, Sub 1146. The coal inventory rider was terminated from rates effective for service on and after December 1, 2018. DEC is not recovering any additional coal inventory rider costs beyond October 2018 when the termination requirements were met, but due to the timing of receiving final coal inventory reports, the rider was terminated at the end of November 2018. All amounts collected after October 2018 through January 2019 have been used to reduce the under-collected balance as of the end of October 2018. Interest has been accrued on the under-collected balance through August 2019.

Including these two adjustments results in under-collected EMF increments of 0.1108¢, 0.0632¢ and 0.1476¢ per kWh, respectively, for the residential, general service/lighting, and industrial customer classes based on normalized test period sales by customer class.

The over/(under) collection 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 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 MCGEE EXHIBIT 4.

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), McGee 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. McGee 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, McGee Exhibit 4 shows the test period peak demand for the system and for North Carolina retail customer classes.

Q. PLEASE EXPLAIN MCGEE EXHIBIT 5.

A. McGee 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 McGee Exhibit 6, DEC's test year actual fuel and fuel-related costs were 1.8969¢ 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 Repko discusses the performance of the fossil and hydro fleet, as well as the use of chemicals for reducing emissions. Company witness Grant 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), and (6) of N.C. Gen. Stat. § 62-133.2(a1). Subdivision (4) includes purchased power non-capacity costs subject to economic curtailment or dispatch. Subdivision (5) includes cogeneration and independent power producer capacity costs. Subdivision (6) includes renewable capacity costs. The allocation methods for subdivisions (4), (5), and (6) are the same as used in DEC's latest general rate case, Docket No. E-7, Sub 1146 and are as follows:

(a) Capacity-related purchased power costs in Subdivision (5) and (6) are allocated based upon the production plant allocator from the latest annual cost of service study.

(b) Subdivision (4) costs and non-capacity related costs in Subdivision (6) 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 NC retail jurisdiction based on jurisdictional sales, with consideration given to any fuel and fuel-related costs or benefits that should be directly assigned. Costs are further allocated among customer classes using the uniform percentage average bill adjustment methodology in setting fuel rates in this fuel proceeding. DEC proposes to use the same uniform percentage average bill adjustment methodology to adjust its fuel rates to reflect a proposed increase in fuel and fuel-related costs as it did in its 2018 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1163.

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

A. McGee 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 1.05% was calculated by dividing the fuel and fuel-related cost increase of $48,252,245 for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $4,609,002,994. The cost increase of $48,252,245 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 increase 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 McGee Exhibit 2, Schedule 1), the proposed composite EMF increment rate (as computed on McGee Exhibit 3, page 1). This results in a uniform bill percentage change of 1.05%. McGee 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 MCGEE EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. McGee 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 McGee 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 projected billing period sales for each class 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 McGee Exhibit 3, Page 2, 3, and 4) to derive the prospective component for each customer class. This breakdown is shown on McGee 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), AND (6) 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 — **McGee Exhibit 1**

North Carolina Annual Fuel and Fuel Related Expense
Summary Comparison of Fuel and Fuel Related Cost Factors
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

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 1163)					
1	Approved Fuel and Fuel Related Costs Factors	Input	1.7003	1.8314	1.8020	1.7769
2	EMF Increment	Input	0.0980	0.1068	0.2213	0.1290
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	**1.7983**	**1.9382**	**2.0233**	**1.9059**
	Fuel and Fuel Related Cost Factors Required by Rule R8-55					
5	Proposed Nuclear Capacity Factor of 92.95% and Normalized Test Period Sales	Exh 2 Sch 2 pg 2	**1.9212**	**2.0300**	**2.0917**	**2.0045**
6	NERC 5 Year Average Nuclear Capacity Factor of 90.21% and Projected Period Sales	Exh 2 Sch 3 pg 2	**1.9519**	**2.0501**	**2.1032**	**2.0261**
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 92.95%					
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	1.7460	1.9278	1.9105	1.8574
8	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.0483	0.0251	0.0208	0.0327
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	1.7943	1.9529	1.9313	1.8901
10	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.1108	0.0632	0.1476	0.0994
11	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.0000	0.0000	0.0000	0.0000
12	Net Fuel and Fuel Related Costs Factors cents/kWh	Sum	**1.9051**	**2.0161**	**2.0789**	**1.9895**

Note: Fuel factors exclude regulatory fee

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 92.95%
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	58,459,031	0.6115	357,497,468
2	Coal	Workpaper 3 & 4	18,355,203	3.1057	570,050,837
3	Gas CT and CC	Workpaper 3 & 4	20,821,617	2.4166	503,184,086
4	Reagents and Byproducts	Workpaper 9			24,959,649
5	Total Fossil	Sum	39,176,820		1,098,194,572
6	Hydro	Workpaper 3	4,839,425		
7	Net Pumped Storage	Workpaper 3	(3,874,211)		
8	Total Hydro	Sum	965,214		
9	Solar Distributed Generation	Workpaper 3	184,444		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	98,785,509		1,455,692,040
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(878,400)		(18,112,976)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,888,880)		(91,061,695)
13	Net Generation	Sum Lines 10-12	83,018,229		1,346,517,369
14	Purchased Power	Workpaper 3 & 4	9,280,339	3.1771	294,841,746
15	JDA Savings Shared	Workpaper 5			19,972,407
16	Total Purchased Power		9,280,339		314,814,153
17	Total Generation and Purchased Power	Line 13 + Line 16	92,298,568	1.8000	1,661,331,522
18	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(687,755)	2.4698	(16,986,301)
19	Line losses and Company use	Line 21-Line 17-Line 18	(4,366,969)		-
20	System Fuel Expense for Fuel Factor	Lines 17 + 18 + 19			1,644,345,221
21	Projected System MWh Sales for Fuel Factor	Workpaper 7	87,243,844		87,243,844
22	Fuel and Fuel Related Costs cents/kWh	Line 20 / Line 21 / 10			1.8848

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 92.95%
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7	21,397,068	23,381,644	12,939,285	57,717,997
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,295,654
3	QF Purchased Power - Capacity	Workpaper 4				14,874,084
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 28,169,738
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input				67.04%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 18,884,001
7	Production Plant Allocation Factors	Input	54.68%	31.06%	14.26%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 10,325,952	$ 5,864,785	$ 2,693,265	$ 18,884,001
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0483	0.0251	0.0208	0.0327
	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	1.7460	1.9278	1.9105	1.8574
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0483	0.0251	0.0208	0.0327
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.7943	1.9529	1.9313	1.8901
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.1108	0.0632	0.1476	0.0994
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	1.9051	2.0161	2.0789	1.9895

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 92.95%
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

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 1163	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)	McGee Exhibit 1	E + F = G
1	Residential	21,397,068	$ 2,183,285,633	$ 22,857,098	1.05%	0.1068	1.7983	1.9051
2	General Service/Lighting	23,381,644	1,738,716,194	18,202,843	1.05%	0.0779	1.9382	2.0161
3	Industrial	12,939,285	687,001,167	7,192,304	1.05%	0.0556	2.0233	2.0789
4	NC Retail	57,717,997	$ 4,609,002,994	$ 48,252,245	1.05%			

Total Proposed Composite Fuel Rate:

5	Total Fuel Costs for Allocation	Workpaper 7	$ 1,648,542,239
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	28,169,738
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,620,372,501
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7	87,243,844
9	NC Retail Projected Billing Period MWh Sales	Line 4	57,717,997
10	Allocation %	Line 9 / Line 8	66.16%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,072,038,447
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 1, Page 2	18,884,001
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,090,922,448
14	NC Retail Projected Billing Period MWh Sales	Line 4	57,717,997
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.8901
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.0994
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	1.9895

Total Current Composite Fuel Rate - Docket E-7 Sub 1163:

19	Current composite Fuel Rate cents/kWh	McGee Exhibit 1	1.7769
20	Current composite EMF Rate cents/kWh	McGee Exhibit 1	0.1290
21	Current composite EMF Interest Rate cents/kWh	McGee Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.9059
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.0836
24	NC Retail Projected Billing Period MWh Sales	Line 4	57,717,997
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 48,252,245

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 92.95% and Normalized Test Period Sales
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	58,459,031	0.6115	357,497,468
2	Coal	Calculated	19,630,442	3.1057	609,655,475
3	Gas CT and CC	Workpaper 3 & 4	20,821,617	2.4166	503,184,086
4	Reagents and Byproducts	Workpaper 9	-		24,959,649
5	Total Fossil	Sum	40,452,059		1,137,799,210
6	Hydro	Workpaper 3	4,839,425		
7	Net Pumped Storage	Workpaper 3	(3,874,211)		
8	Total Hydro	Sum	965,214		
9	Solar Distributed Generation		184,444		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	100,060,748		1,495,296,678
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(878,400)		(18,112,976)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,888,880)		(91,061,695)
13	Net Generation	Sum	84,293,468		1,386,122,007
14	Purchased Power	Workpaper 3 & 4	9,280,339		294,841,746
15	JDA Savings Shared	Workpaper 5	-		19,972,407
16	Total Purchased Power	Sum	9,280,339		314,814,153
17	Total Generation and Purchased Power	Line 13 + Line 16	93,573,807		1,700,936,160
18	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(687,755)		(16,986,301)
19	Line losses and Company use		(4,366,969)		-
20	System Fuel Expense for Fuel Factor	Lines 17 + 18 + 19			1,683,949,859
21	Normalized Test Period MWh Sales	Exhibit 4, Workpaper 7a	88,519,083		88,519,083
22	Fuel and Fuel Related Costs cents/kWh	Line 20 / Line 21 / 10			1.9024

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 92.95% and Normalized Test Period Sales
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Normalized Test Period MWh Sales	Exhibit 4	22,043,791	23,487,580	12,454,944	57,986,315
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,295,654
3	QF Purchased Power - Capacity	Workpaper 4				14,874,084
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 28,169,738
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input				67.04%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 18,884,001
7	Production Plant Allocation Factors	Input	54.68%	31.06%	14.26%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 10,325,952	$ 5,864,785	$ 2,693,265	$ 18,884,001
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0468	0.0250	0.0216	0.0326
	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	1.7636	1.9418	1.9225	1.8725
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0468	0.0250	0.0216	0.0326
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.8104	1.9668	1.9441	1.9051
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.1108	0.0632	0.1476	0.0994
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	1.9212	2.0300	2.0917	2.0045

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 92.95% and Normalized Test Period Sales
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

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 1163	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)	McGee Exhibit 1	E + F = G
1	Residential	22,043,791	$ 2,183,285,633	$ 27,083,575	1.24%	0.1229	1.7983	1.9212
2	General Service/Lighting	23,487,580	$ 1,738,716,194	21,568,708	1.24%	0.0918	1.9382	2.0300
3	Industrial	12,454,944	$ 687,001,167	8,522,223	1.24%	0.0684	2.0233	2.0917
4	NC Retail	57,986,315	$ 4,609,002,994	$ 57,174,506				

Total Proposed Composite Fuel Rate:

Line #	Description	Source	Amount
5	Total Fuel Costs for Allocation	Workpaper 7a	$ 1,688,146,877
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	28,169,738
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,659,977,139
8	Normalized Test Period System MWh Sales for Fuel Factor	Workpaper 7a	88,648,222
9	NC Retail Normalized Test Period MWh Sales	Exhibit 4	57,986,315
10	Allocation %	Line 9 / Line 8	65.41%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,085,791,046
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 2, Page 2	18,884,001
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,104,675,048
14	NC Retail Normalized Test Period MWh Sales	Line 4	57,986,315
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.9051
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.0994
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	2.0045
	Total Current Composite Fuel Rate - Docket E-7 Sub 1163:		
19	Current composite Fuel Rate cents/kWh	McGee Exhibit 1	1.7769
20	Current composite EMF Rate cents/kWh	McGee Exhibit 1	0.1290
21	Current composite EMF Interest Rate cents/kWh	McGee Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.9059
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.0986
24	NC Retail Normalized Test Period MWh Sales	Exhibit 4	57,986,315
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 57,174,506

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor of 90.21% and Projected Period Sales
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 2	56,739,499	0.6115	346,981,926
2	Coal	Calculated	19,636,789	3.1057	609,852,590
3	Gas CT and CC	Workpaper 3 & 4	20,821,617	2.4166	503,184,086
4	Reagents and Byproducts	Workpaper 9	-		24,959,649
5	Total Fossil	Sum	40,458,406		1,137,996,325
6	Hydro	Workpaper 3	4,839,425		
7	Net Pumped Storage	Workpaper 3	(3,874,211)		
8	Total Hydro	Sum	965,214		
9	Solar Distributed Generation	Workpaper 3	184,444		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	98,347,563		1,484,978,251
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(878,400)		(18,112,976)
12	Less Catawba Joint Owners	Calculated	(14,450,934)		(88,383,179)
13	Net Generation	Sum	83,018,229		1,378,482,097
14	Purchased Power	Workpaper 3 & 4	9,280,339		294,841,746
15	JDA Savings Shared	Workpaper 5	-		19,972,407
16	Total Purchased Power	Sum	9,280,339		314,814,153
17	Total Generation and Purchased Power	Line 13 + Line 16	92,298,568		1,693,296,250
18	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(687,755)		(16,986,301)
19	Line losses and Company use		(4,366,969)		-
20	System Fuel Expense for Fuel Factor	Lines 17 + 18 + 19			1,676,309,949
21	Projected System MWh Sales for Fuel Factor	Workpaper 7b	87,243,844		87,243,844
22	Fuel and Fuel Related Costs cents/kWh	Line 20 / Line 21 / 10			1.9214

DUKE ENERGY CAROLINAS
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 90.21% and Projected Period Sales
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7b	21,397,068	23,381,644	12,939,285	57,717,997
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 13,295,654
3	QF Purchased Power - Capacity	Workpaper 4				$ 14,874,084
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 28,169,738
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input				67.04%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 18,884,001
7	Production Plant Allocation Factors	Input	54.68%	31.06%	14.26%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 10,325,952	$ 5,864,785	$ 2,693,265	$ 18,884,001
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0483	0.0251	0.0208	0.0327
	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	1.7928	1.9618	1.9348	1.8940
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0483	0.0251	0.0208	0.0327
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	1.8411	1.9869	1.9556	1.9267
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.1108	0.0632	0.1476	0.0994
14	EMF Interest (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	1.9519	2.0501	2.1032	2.0261

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
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 90.21% and Projected Period Sales
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

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 1163	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)	McGee Exhibit 1	E + F = G
1	Residential	21,397,068	$ 2,183,285,633	$ 32,863,914	1.51%	0.1536	1.7983	1.9519
2	General Service/Lighting	23,381,644	$ 1,738,716,194	$ 26,172,031	1.51%	0.1119	1.9382	2.0501
3	Industrial	12,939,285	$ 687,001,167	$ 10,341,087	1.51%	0.0799	2.0233	2.1032
4	NC Retail	57,717,997	$ 4,609,002,994	$ 69,377,032				

Line #	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
5	Total Fuel Costs for Allocation	Workpaper 7b	$ 1,680,506,966
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	28,169,738
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,652,337,228
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7b	87,243,844
9	NC Retail Projected Billing Period MWh Sales	Line 4	57,717,997
10	Allocation %	Line 9 / Line 8	66.16%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,093,186,310
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 3, Page 2	18,884,001
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,112,070,311
14	NC Retail Projected Billing Period MWh Sales	Line 4	57,717,997
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	1.9267
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.0994
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	2.0261
	Total Current Composite Fuel Rate - Docket E-7 Sub 1163:		
19	Current composite Fuel Rate cents/kWh	McGee Exhibit 1	1.7769
20	Current composite EMF Rate cents/kWh	McGee Exhibit 1	0.1290
21	Current composite EMF Interest Rate cents/kWh	McGee Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	1.9059
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.1202
24	NC Retail Projected Billing Period MWh Sales	Line 4	57,717,997
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 69,377,032

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

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 2018			5,733,820	$	70,210,460
2	February			5,031,181	$	(21,289,748)
3	March(1)			4,190,094	$	4,767,793
4	April(1)			4,416,566	$	(13,763,436)
5	May			4,252,750	$	6,136,829
6	June(1)			5,245,689	$	6,622,242
7	July(1)			5,639,361	$	14,497,484
8	August			5,409,821	$	13,507,110
9	September			6,212,764	$	(8,995,949)
10	October			4,141,212	$	11,156,943
11	November			4,314,713	$	11,789,339
12	December			4,892,732	$	16,666,116
13	**Total Test Period**			**59,480,703**	**$**	**111,305,183**
14	Adjustment to remove (Over) / Under Recovery - January - March 2018 [2]				$	53,688,503
15	Include Under Recovery related to Coal Inventory Rider				$	37,667
16	**Adjusted (Over)/ Under Recovery**				**$**	**57,654,346**
17	NC Retail Normalized Test Period MWh Sales			Exhibit 4		57,986,315
18	Experience Modification Increment (Decrement) cents/kWh					0.0994

[1] Prior period corrections not included in rate incurred but are included in over/(under) recovery total
[2] January - March 2018 filed in fuel Docket E-7, Sub 1163 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 (O)/ U on Line 16.
Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWH Sales (c)	Reported (Over)/ Under Recovery (d)
1	January 2018	2.2454	1.7919	2,747,953	$ 12,463,615
2	February	1.2214	1.7919	2,101,525	$ (11,989,284)
3	March[1]	1.8936	1.7919	1,546,024	$ 1,587,096
4	April[1]	1.5682	1.7919	1,557,073	$ (3,496,659)
5	May	2.2261	1.7919	1,361,386	$ 5,910,833
6	June[1]	1.9042	1.7919	1,940,879	$ 2,162,126
7	July[1]	1.9028	1.7919	2,227,922	$ 2,375,059
8	August	1.9776	1.7885	2,050,040	$ 3,875,805
9	September	1.7474	1.7894	2,200,376	$ (925,298)
10	October	2.0726	1.7983	1,554,551	$ 4,264,193
11	November	2.3435	1.7983	1,436,836	$ 7,833,590
12	December	1.9167	1.7983	2,038,462	$ 2,413,589
13	**Total Test Period**			**22,763,029**	**$ 26,474,665**
14	Test Period Wtd Avg. ¢/kWh	1.9096	1.7928		
15	Adjustment to remove (Over) / Under Recovery - January - March 2018 [2]				$ 2,061,427
16	Include Under Recovery related to Coal Inventory Rider				$ 14,415
17	**Adjusted (Over)/Under Recovery**				**$ 24,427,653**
18	NC Retail Normalized Test Period MWh Sales			Exhibit 4	22,043,791
19	Experience Modification Increment (Decrement) cents/kWh				0.1108

Notes:
[1] Prior period corrections not included in rate incurred but are included in over/(under) recovery total
[2] January - March 2018 filed in fuel Docket E-7, Sub 1163 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 (O)/ U on Line 17.
Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - GS/Lighting
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2018	3.5376	1.9253	2,053,224	$	33,104,497
2	February	1.5865	1.9253	1,899,154	$	(6,434,005)
3	March(1)	2.0122	1.9253	1,709,988	$	1,503,768
4	April(1)	1.5762	1.9253	1,819,014	$	(6,335,002)
5	May	1.9140	1.9253	1,860,965	$	(210,465)
6	June(1)	1.9786	1.9253	2,190,371	$	1,145,088
7	July(1)	2.1543	1.9253	2,291,796	$	5,295,453
8	August	2.1026	1.9219	2,244,902	$	4,054,944
9	September	1.6846	1.9256	2,660,685	$	(6,412,545)
10	October	2.1707	1.9382	1,727,851	$	4,018,244
11	November	2.1580	1.9382	1,824,017	$	4,009,350
12	December	2.4310	1.9382	1,880,041	$	9,264,795
13	**Total Test Period**			**24,162,007**	**$**	**43,004,122**
14	Test Period Wtd Avg. ¢/kWh	2.1057	1.9279			
15	Adjustment remove (Over) / Under Recovery - January - March 2018 (2)				$	28,174,260
16	Include Under Recovery related to Coal Inventory Rider				$	15,301
17	**Adjusted (Over)/ Under Recovery**				**$**	**14,845,163**
18	NC Retail Normalized Test Period MWh Sales			Exhibit 4		23,487,580
19	Experience Modification Increment (Decrement) cents/kWh					0.0632

Notes:

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

(2) January - March 2018 filed in fuel Docket E-7, Sub 1163 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 (O)/ U on Line 17.

Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Industrial
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2018	4.6719	2.0297	932,643	$	24,642,348
2	February	1.7515	2.0297	1,030,502	$	(2,866,460)
3	March[(1)]	2.2081	2.0297	934,082	$	1,676,929
4	April[(1)]	1.6509	2.0297	1,040,479	$	(3,931,775)
5	May	2.0721	2.0297	1,030,399	$	436,461
6	June[(1)]	2.3283	2.0297	1,114,438	$	3,315,028
7	July[(1)]	2.6319	2.0297	1,119,643	$	6,826,972
8	August	2.5265	2.0263	1,114,879	$	5,576,360
9	September	1.8991	2.0218	1,351,703	$	(1,658,106)
10	October	2.3580	2.0233	858,810	$	2,874,506
11	November	2.0182	2.0233	1,053,860	$	(53,600)
12	December	2.5353	2.0233	974,229	$	4,987,733
13	**Total Test Period**			**12,555,667**	**$**	**41,826,395**
14	Test Period Wtd Avg. ¢/kWh	2.3595	2.0271			
15	Adjustment to remove (Over) / Under Recovery - January - March 2018 [(2)]				$	23,452,816
16	Include Under Recovery related to Coal Inventory Rider				$	7,951
17	Adjusted (Over)/ Under Recovery				$	18,381,529
18	NC Retail Normalized Test Period MWh Sales			Exhibit 4		12,454,944
19	Experience Modification Increment (Decrement) cents/KWh					0.1476

Notes:
[(1)] Prior period corrections not included in rate incurred but are included in over/(under) recovery total
[(2)] January - March 2018 filed in fuel Docket E-7, Sub 1163 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 (O)/ U on Line 17.
Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Sales, Fuel Revenue, Fuel Expense and System Peak
Test Period Ended December 31, 2018
Billing Period September 2019 - August 2020
Docket E-7, Sub 1190

McGee 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)	90,487,628	59,480,703	22,763,029	24,162,007	12,555,667
2	Customer Growth MWh Adjustment	Workpaper 13 Pg 1	309,143	155,235	188,587	(37,644)	4,292
3	Weather MWh Adjustment	Workpaper 12	(2,277,688)	(1,649,623)	(907,825)	(636,783)	(105,015)
4	Total Normalized MWh Sales	Sum	88,519,083	57,986,315	22,043,791	23,487,580	12,454,944
5	Test Period Fuel and Fuel Related Revenue *		$ 1,691,073,964	$ 1,128,424,268			
6	Test Period Fuel and Fuel Related Expense *		$ 1,852,256,576	$ 1,239,729,451			
7	Test Period Unadjusted (Over)/Under Recovery		$ 161,182,612	$ 111,305,183			

		Winter Coincidental Peak (CP) kW
8	Total System Peak	18,871,786
9	NC Retail Peak	12,650,981
10	NC Residential Peak	6,917,677
11	NC General Service/Lighting Peak	3,929,002
12	NC Industrial Peak	1,804,302

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

DUKE ENERGY CAROLINAS **McGee Exhibit 5**

North Carolina Annual Fuel and Fuel Related Expense

Nuclear Capacity Ratings

Test Period Ended December 31, 2018

Billing Period September 2019 - August 2020

Docket E-7, Sub 1190

Unit	Rate Case Docket E-7, Sub 1146	Fuel Docket E-7, Sub 1163	Proposed Capacity Rating MW
Oconee Unit 1	847	847.0	847.0
Oconee Unit 2	848	848.0	848.0
Oconee Unit 3	859	859.0	859.0
McGuire Unit 1	1,158	1158.0	1158.0
McGuire Unit 2	1,158	1157.6	1157.6
Catawba Unit 1	1,160	1160.1	1160.1
Catawba Unit 2	1,150	1150.1	1150.1
Total Company	7,180	7,179.8	7,179.8

McGee Exhibit 6

DECEMBER 2018 MONTHLY FUEL FILING

DUKE ENERGY CAROLINAS
SUMMARY OF MONTHLY FUEL REPORT

Docket No. E-7, Sub 1161

Line No.		December 2018	12 Months Ended December 2018
1	Fuel and fuel-related costs	$ 167,457,560	$ 1,885,269,344
	MWH sales:		
2	Total system sales	7,718,637	92,433,072
3	Less intersystem sales	228,210	1,945,444
4	Total sales less intersystem sales	7,490,427	90,487,628
5	Total fuel and fuel-related costs (¢/KWH) (line 1/line 4)	2.2356	2.0835
6	Current fuel and fuel-related cost component (¢/KWH) (per Schedule 4, Line 2a Total)	1.8969	
	Generation Mix (MWH):		
	Fossil (by primary fuel type):		
7	Coal	1,366,724	22,653,740
8	Fuel Oil	12,042	232,515
9	Natural Gas - Combined Cycle	1,059,332	13,695,555
10	Natural Gas - Combustion Turbine	42,178	2,550,671
11	Natural Gas - Steam	127,536	187,574
12	Biogas	3,259	30,204
13	Total fossil	2,611,071	39,350,259
14	Nuclear 100%	4,981,169	59,936,028
15	Hydro - Conventional	368,610	2,877,050
16	Hydro - Pumped storage	(44,946)	(529,226)
17	Total hydro	323,664	2,347,824
18	Solar Distributed Generation	5,768	130,018
19	Total MWH generation	7,921,672	101,764,129
20	Less joint owners' portion - Nuclear	1,147,290	15,165,371
21	Less joint owners' portion - Combined Cycle	27,377	465,202
22	Adjusted total MWH generation	6,747,005	86,133,556

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 1161

Fuel and fuel-related costs:	December 2018	12 Months Ended December 2018
0501110 coal consumed - steam	$ 46,847,568	$ 675,888,074
0501222-0501223 biomass/test fuel consumed	-	
0501310 fuel oil consumed - steam	1,223,578	8,586,389
0501330 fuel oil light-off - steam	593,669	7,287,851
Total Steam Generation - Account 501	48,664,815	691,762,314
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	23,069,842	275,311,826
Other Generation - Account 547		
0547100, 0547124 - natural gas consumed - Combustion Turbine	2,272,971	98,161,049
0547100 natural gas consumed - Steam	5,696,114	8,633,545
0547101 natural gas consumed - Combined Cycle	31,773,516	373,047,230
0547106 biogas consumed - Combined Cycle	175,961	1,523,560
0547200 fuel oil consumed - Combustion Turbine	57,020	25,830,495
Total Other Generation - Account 547	39,975,582	507,195,879
Reagents		
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	1,549,134	27,110,200
Total Reagents	1,549,134	27,110,200
By-products		
Net proceeds from sale of by-products	583,525	6,085,203
Total By-products	583,525	6,085,203
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	113,842,898	1,507,465,422
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (economic)	211,474	10,514,290
Capacity component of purchased power (renewables)	594,915	13,300,661
Capacity component of purchased power (PURPA)	159,399	6,541,261
Fuel and fuel-related component of purchased power	59,686,689	434,709,945
Total Purchased Power and Net Interchange - Account 555	60,652,477	465,066,157
Less:		
Fuel and fuel-related costs recovered through intersystem sales	6,944,585	86,336,253
Fuel in loss compensation	92,474	925,224
Solar integration charge revenue	758	758
Total Fuel Credits - Accounts 447 /456	7,037,817	87,262,235
Total Fuel and Fuel-related Costs	$ 167,457,560	$ 1,885,269,344

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 2018

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Cherokee County Cogeneration Partners	$ 1,287,426	$ 211,474	27,369	$ 946,407	$ 129,545	
City of Kings Mountain	8,979	8,979	-	-	-	
DE Progress - Native Load Transfer	27,945,591	-	741,793	23,410,601	4,543,696	$ (8,706)
DE Progress - Native Load Transfer Benefit	1,156,134	-	-	1,156,134	-	
DE Progress - Fees	(156,964)	-	-	-	(156,964)	
Haywood Electric - Economic	40,903	20,630	336	12,367	7,906	
Macquarie Energy, LLC	6,826,931	-	146,439	4,164,428	2,662,503	
NCEMC - Economic	115,200	-	3,600	70,272	44,928	
NCMPA Instantaneous - Economic	1,813,810	-	53,310	1,088,467	725,343	
NTE Carolinas LLC	3,232,610	-	78,830	1,971,892	1,260,718	
Piedmont Municipal Power Agency	307,201	-	10,960	184,355	122,846	
PJM Interconnection, LLC.	11,214,935	-	313,334	6,841,110	4,373,825	
Southern Company Services, Inc.	250,370	-	9,167	152,726	97,644	
Tennesse Valley Authority	96,400	-	2,600	58,804	37,596	
Town of Dallas	584	584	-	-	-	
Town of Forest City	19,856	19,856	-	-	-	
	$ 54,159,966	**$ 261,523**	**1,387,738**	**$ 40,057,563**	**$ 13,849,586**	**$ (8,706)**
Renewable Energy						
REPS	$ 4,406,020	$ 594,902	77,027	$ -	$ 3,811,118	$ -
DERP - Purchased Power	149	13	3	-	136	
	$ 4,406,169	**$ 594,915**	**77,030**	**$ -**	**$ 3,811,254**	**$ -**
HB589 PURPA Purchases						
Qualifying Facilities	1,936,441	159,399	37,040		1,712,356	64,686
	$ 1,936,441	**$ 159,399**	**37,040**	**$ -**	**$ 1,712,356**	**$ 64,686**
Non-dispatchable						
Blue Ridge Electric Membership Corp.	$ 1,244,696	$ 724,668	26,268	$ 317,217		$ 202,811
Haywood Electric	351,238	152,148	7,201	121,445		77,645
Macquarie Energy, LLC	957,341	-	12,433	583,978		373,363
NCEMC - Other	4,398	4,398	-	-		-
NCMPA	155,400	-	1,110	94,794		60,606
Piedmont Electric Membership Corp.	592,764	346,426	11,904	150,266		96,072
Generation Imbalance	1,078,303	-	8,735	242,385		835,918
Energy Imbalance - Purchases	(277,960)	-	(11,956)	(169,556)		(108,404)
Energy Imbalance - Sales	(269,174)	-	-	(269,534)		360
Other Purchases	648	-	19	-		648
	$ 3,837,654	**$ 1,227,640**	**55,714**	**$ 1,070,995**	**$ -**	**$ 1,539,019**
Total Purchased Power	**$ 64,340,230**	**$ 2,243,477**	**1,557,522**	**$ 41,128,558**	**$ 19,373,196**	**$ 1,594,999**
Interchanges In						
Other Catawba Joint Owners	6,629,878	-	579,425	3,870,366		2,759,512
WS Lee Joint Owner	1,406,837		43,619	1,229,697		177,140
Total Interchanges In	8,036,714	-	623,044	5,100,063	-	2,936,651
						(1)
Interchanges Out						
Other Catawba Joint Owners	(7,985,890)	(134,209)	(695,363)	(4,647,804)		(3,203,877)
Catawba- Net Negative Generation	(66,943)	-	(2,964)	(51,150)		(15,793)
WS Lee Joint Owner	(1,402,174)		(42,514)	(1,216,174)		(186,000)
Total Interchanges Out	(9,455,007)	(134,209)	(740,841)	(5,915,128)	-	(3,405,670)
Net Purchases and Interchange Power	**$ 62,921,937**	**$ 2,109,268**	**1,439,725**	**$ 40,313,493**	**$ 19,373,196**	**$ 1,125,979**

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

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

DECEMBER 2018

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
SC Public Service Authority - Emergency	$ 19,312	-	475	$ 16,530	$ 2,782
SC Electric & Gas - Emergency	22,373	-	383	21,699	674
Market Based:					
NCMPA	110,344	$ 87,568	392	22,919	(143)
PJM Interconnection, LLC.	69	-	-	-	69
SC Electric & Gas	2,050	-	-	-	2,050
Other:					
DE Progress - Native Load Transfer Benefit	287,133	-	-	287,133	-
DE Progress - Native Load Transfer	8,259,541	-	225,840	6,529,920	1,729,621
Generation Imbalance	76,917	-	1,120	66,384	10,533
BPM Transmission	(67,517)	-			(67,517)
Total Intersystem Sales	**$ 8,710,222**	**$ 87,568**	**228,210**	**$ 6,944,585**	**$ 1,678,069**

* Sales for resale other than native load priority.

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

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

Twelve Months Ended December 2018

Purchased Power	Total	Capacity	Non-capacity			Not Fuel $
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel-related $
Cherokee County Cogeneration Partners	$ 31,713,488	$ 10,514,290	536,248	$ 18,602,696	$ 2,596,502	
City of Kings Mountain	107,748	107,748	-	-	-	
DE Progress - Native Load Transfer	194,410,960	-	5,426,920	174,475,494	19,671,245	$ 264,221
DE Progress - Native Load Transfer Benefit	13,751,828	-	-	13,751,828	-	
DE Progress - Fees	(1,093,167)	-	-	-	(1,093,167)	
EDF Trading North America, LLC.	76,115	-	3,005	46,430	29,685	
Exelon Generation Company, LLC.	118,087	-	4,060	72,034	46,053	
Haywood Electric - Economic	487,779	251,870	5,097	143,904	92,005	
Macquarie Energy, LLC	29,508,026	-	770,088	17,999,896	11,508,130	
Morgan Stanley Capital Group	24,839	-	1,112	15,152	9,687	
NCEMC	169,200	-	5,490	103,212	65,988	
NCMPA	4,490,834	-	71,519	3,053,238	1,437,596	
NCMPA Load Following Economic	16,007,553	-	506,485	10,121,981	5,885,572	
NTE Carolinas LLC	7,004,810	-	195,650	4,272,935	2,731,875	
Piedmont Municipal Power Agency	2,609,446	-	88,744	1,680,985	928,461	
PJM Interconnection, LLC.	51,171,173	-	864,902	31,214,417	19,956,756	
Rainbow Energy Marketing Corporation	87,525	-	3,285	53,390	34,135	
South Carolina Electric & Gas Company	212,527	-	4,600	127,811	84,716	
Southern Company Services, Inc.	1,289,556	-	45,702	786,630	502,926	
Tennesse Valley Authority	1,603,241	-	30,841	977,977	625,264	
The Energy Authority	38,483	-	1,167	23,475	15,008	
Town of Dallas	7,008	7,008	-	-	-	
Town of Forest City	238,272	238,272	-	-	-	
	$ 354,035,331	**$ 11,119,188**	**8,564,915**	**$ 277,523,485**	**$ 65,128,437**	**$ 264,221**
Renewable Energy						
REPS	$ 62,977,408	$ 13,300,096	976,170	$ -	$ 49,677,312	$ -
DERP - Purchased Power	2,713	565	49	-	2,148	
DERP - Net Metered Generation	43,550	7,964	15	-		35,586
	$ 63,023,671	**$ 13,308,625**	**$ 976,235**	**$ -**	**$ 49,679,460**	**$ 35,586**
HB589 PURPA Purchases						
Qualifying Facilities	33,208,999	6,541,261	549,098		$ 25,585,400	$ 1,082,338
	$ 33,208,999	**6,541,261**	**549,098**	**$ -**	**$ 25,585,400**	**$ 1,082,338**
Non-dispatchable						
Blue Ridge Electric Membership Corp.	$ 14,972,210	$ 8,136,773	295,129	$ 4,169,615		$ 2,665,822
Haywood Electric	4,206,307	1,935,370	80,216	1,385,271		885,666
Macquarie Energy, LLC	18,266,985	-	307,544	11,142,861		7,124,124
NCEMC - Other	647,276	52,776	6,570	362,645		231,855
NCMPA - Reliability	245,400	-	2,610	149,694		95,706
NTE Carolinas LLC	1,828,310	-	36,865	1,115,269		713,041
Piedmont Electric Membership Corp.	7,179,987	3,902,138	140,568	1,999,488		1,278,361
South Carolina Electric & Gas Company	131,734	-	1,400	80,358		51,376
Southern Company Services, Inc.	2,984,720	-	47,510	1,820,679		1,164,041
Generation Imbalance	3,782,664		82,265	1,893,961		1,888,703
Energy Imbalance - Purchases	2,199,376		25,123	1,350,748		848,628
Energy Imbalance - Sales	(1,765,005)		-	(6,529,253)		4,764,248
Other Purchases	12,518	-	352	-		12,518
	$ 54,692,482	**$ 14,027,057**	**1,026,152**	**$ 18,941,336**	**$ -**	**$ 21,724,089**
Total Purchased Power	**$ 504,960,483**	**$ 44,996,131**	**11,116,400**	**$ 296,464,821**	**$ 140,393,297**	**$ 23,106,234**
						-
Interchanges In						
Other Catawba Joint Owners	91,135,514	-	7,642,809	56,961,998		34,173,516
WS Lee Joint Owner	7,725,713	-	271,306	6,611,033		1,114,680
Total Interchanges In	98,861,227	-	7,914,116	63,573,032	-	35,288,195
Interchanges Out						
Other Catawba Joint Owners	(93,139,372)	(1,580,207)	(7,784,646)	(57,610,256)		(33,948,909)
Catawba- Net Negative Generation	(231,152)	-	(11,304)	(180,241)		(50,911)
WS Lee Joint Owner	(9,390,983)	-	(327,441)	(7,930,708)		(1,460,275)
Total Interchanges Out	(102,761,507)	(1,580,207)	(8,123,391)	(65,721,205)	-	(35,460,095)
Net Purchases and Interchange Power	**$ 501,060,203**	**$ 43,415,924**	**10,907,125**	**$ 294,316,648**	**$ 140,393,297**	**$ 22,934,334**

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

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

Twelve Months Ended DECEMBER 2018

Sales	Total $		Capacity $		Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:							
DE Progress - Emergency	$ 15,390		-		333	$ 13,113	$ 2,277
SC Public Service Authority - Emergency	2,315,135		$ 224,000		7,527	2,007,790	83,345
SC Electric & Gas - Emergency	103,368	**A**	-	**A**	1,974	87,826	15,542
Market Based:							
Central Electric Power Cooperative, Inc.	2,793,800	**B**	2,793,800	**B**	-	-	-
EDF Trading Company	2,600		-		50	1,976	624
Macquarie Energy, LLC	19,200		-		-	-	19,200
NCMPA	1,454,481		1,050,069		5,529	368,868	35,544
PJM Interconnection, LLC.	1,502,443		-		24,365	918,000	584,443
SC Electric & Gas	317,950	**A**	-	**A**	4,050	268,115	49,835
Tennessee Valley Authority	49,525		-		1,025	37,501	12,024
The Energy Authority	55,545		-		604	33,101	22,444
Other:							
DE Progress - Native Load Transfer Benefit	5,666,748		-		-	5,666,748	-
DE Progress - Native Load Transfer	78,027,793		-		1,883,308	74,808,327	3,219,466
Generation Imbalance	1,760,829		-		16,679	2,124,888	(364,059)
BPM Transmission	(245,056)		-			-	(245,056)
Total Intersystem Sales	**$ 93,839,751**		**$ 4,067,869**		**1,945,444**	**$ 86,336,253**	**$ 3,435,629**

* Sales for resale other than native load priority.

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

A - Twelve months ended December 2018 includes a correction to reclassify market sales for the month of October 2018 as an emergency sale. The October 2018 sales were as follows: Total dollars = $24,456, Non capacity MWH = 408, Non-capacity fuel dollars = $20,096, and Non-capacity non-fuel dollars = $3,550.

B - Twelve months ended December 2018 includes a correction to include market capacity sales for the period January 2018 - October 2018. Market capacity sales each month were as follows: Total dollars = $279,380, and capacity dollars= $279,380. Total market capacity sales dollars for the period January 2018 - October 2018 = $2,793,800.

Duke Energy Carolinas
(Over) / Under Recovery of Fuel Costs
December 2018

Line No.			Residential	Commercial	Industrial	Total
1	Actual System kWh sales	Input				7,490,426,895
2	DERP Net Metered kWh generation	Input				10,412,429
3	Adjusted System kWh sales	L1 + L2				7,500,839,324
4	N.C. Retail kWh sales	Input	2,038,461,729	1,880,040,961	974,229,470	4,892,732,160
5	NC kWh sales % of actual system kWh sales	L4 T / L1				65.32%
6	NC kWh sales % of adjusted system kWh sales	L4 T / L3				65.23%
7	Approved fuel and fuel-related rates (¢/kWh)					
	7a Billed rates by class (¢/kWh)	Input Annually	1.7983	1.9382	2.0233	1.8969
	7b Billed fuel expense	L7a * L4 / 100	$36,657,657	$36,438,954	$19,711,585	$92,808,196
8	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)					
	8a Docket E-7, Sub 1163 allocation factor	Input	35.64%	41.77%	22.59%	
	8b System incurred expense	Input				$166,830,104
	8c Incurred base fuel and fuel-related expense	L8b * L6 * 8a	$38,786,219	$45,458,159	$24,577,446	$108,821,824
	8d Incurred base fuel rates by class (¢/kWh)	L8c / L4 * 100	1.9027	2.4179	2.5228	2.2242
9	Incurred renewable purchased power capacity rates by class (¢/kWh)					
	9a NC retail production plant %	Input				67.56%
	9b Production plant allocation factors	Input	43.68%	37.64%	18.68%	100.00%
	9c System incurred expense	Input				$965,788
	9d Incurred renewable capacity expense	L9a * L9b * 9c	$285,027	$245,590	$121,872	$652,488
	9e Incurred renewable capacity rates by class (¢/kWh)	(L9a * L9c) * L9b / L4 * 100	0.0140	0.0131	0.0125	0.0133
10	Total incurred rates by class (¢/kWh)	L8d + L9e	1.9167	2.4310	2.5353	2.2375
11	Difference in ¢/kWh (incurred - billed)	L7c - L10	0.1184	0.4928	0.5120	0.3406
12	(Over) / under recovery [See footnote]	(L4 * L11) / 100	$2,413,589	$9,264,795	$4,987,733	$16,666,116
13	Prior period adjustments	Input				
14	Total (over) / under recovery [See footnote]	L12+ L13	$2,413,589	$9,264,795	$4,987,733	$16,666,116
15	Total system incurred expense	L8b + L9c				$167,795,892
16	Less: Jurisdictional allocation adjustment(s)	Input				338,332
17	Total Fuel and Fuel-related Costs per Schedule 2	L15 + L16				$167,457,560

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

	Year 2018	Total To Date	(Over) / Under Recovery Residential	Commercial	Industrial	Total Company
	January	$70,210,459	$12,463,615	$33,104,497	$24,642,348	$70,210,459
	February	48,920,711	($11,989,284)	($6,434,005)	($2,866,460)	(21,289,748)
_/1	March	53,688,504	$1,587,096	$1,503,768	$1,676,929	4,767,793
_/1	April	39,952,067	($3,469,659)	($6,335,002)	($3,931,775)	(13,736,437)
	May	46,088,897	$5,910,833	($210,465)	$436,461	6,136,830
	June	52,711,139	$2,162,126	$1,145,088	$3,315,028	6,622,242
_/2	July	67,208,623	$2,375,059	$5,295,453	$6,826,972	14,497,484
	August	80,715,732	$3,875,805	$4,054,944	$5,576,360	13,507,109
_/2	September	71,719,783	($925,298)	($6,412,545)	($1,658,106)	(8,995,949)
_/2	October	82,876,726	$4,264,193	$4,018,244	$2,874,506	11,156,943
	November	$94,666,066	$7,833,590	$4,009,350	($53,600)	$11,789,340
	December	$111,332,182	$2,413,589	$9,264,795	$4,987,733	$16,666,116
			$26,501,665	$43,004,122	$41,826,396	$111,332,182

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 2018

Description	Allen	Belews Creek	Buck	Catawba	Cliffside	Dan River	Lee	Lee	Lincoln	Marshall	McGuire	Mill Creek	Oconee	Rockingham	Current Month	Total 12 ME December 2018
	Steam	Steam	CC	Nuclear	Steam - Dual Fuel	CC	CC	Steam/CT	CT	Steam	Nuclear	CT	Nuclear	CT		
Cost of Fuel Purchased ($)																
Coal	$49,933	$17,907,637			$8,548,228					$22,079,739					$48,585,537	$657,498,215
Oil	143,133	1,082,966	-		273,156	-	-	-	-	-		-		-	1,499,256	48,634,501
Gas - CC			$13,103,055			$12,923,682	$6,858,257								32,884,994	384,692,206
Gas - CT								104,195	$110,569			$158,525		$1,899,682	2,272,971	98,161,049
Gas - Steam					5,695,205			909							5,696,114	8,633,545
Biogas			-			361,043	-								361,043	3,466,205
Total	$193,066	$18,990,604	$13,103,055		$14,516,590	$13,284,725	$6,858,257	$105,103	$110,569	$22,079,739		$158,525		$1,899,682	$91,299,914	$1,201,085,721
Average Cost of Fuel Purchased (¢/MBTU)																
Coal		555.02			687.75	-				399.01					485.71	324.71
Oil	1,321.84	172.99			692.52			-	-	-		-		-	221.68	1,358.88
Gas - CC			442.19			442.08	455.27								442.14	392.80
Gas - CT								532.70	467.48			510.56		457.22	464.11	343.97
Gas - Steam					445.73										-	410.58
Biogas			-		.	1,577.30	-								1,577.30	1,603.31
Weighted Average	1,782.98	492.94	442.19		567.03	450.90	455.27	532.60	467.48	399.01		510.56		457.22	459.65	358.68
Cost of Fuel Burned ($)																
Coal	$741,089	$19,525,109			$12,888,384	-	-	-		$13,692,987					$46,847,568	$675,888,074
Oil - CC			-			-	-								-	-
Oil - Steam/CT	163,523	1,219,227			286,271			25,472	$25,788	148,226		-		-	1,874,266	41,704,735
Gas - CC			$13,103,055			$12,923,682	$6,858,257								32,884,994	384,692,206
Gas - CT								$104,195	110,569			$158,525		$1,899,682	2,272,971	98,161,049
Gas - Steam					5,695,205			909							5,696,114	8,633,545
Biogas			-			361,043	-								361,043	3,466,205
Nuclear				$8,356,486							$10,990,838		$10,470,715		29,818,039	370,839,248
Total	$904,613	$20,744,336	$13,103,055	$8,356,486	$18,869,860	$13,284,725	$6,858,257	$130,575	$136,358	$13,841,212	$10,990,838	$158,525	$10,470,715	$1,899,682	$119,754,995	$1,583,385,062
Average Cost of Fuel Burned (¢/MBTU)																
Coal	359.55	352.99			354.20			-		341.94					350.11	315.40
Oil - CC															-	-
Oil - Steam/CT	1,564.97	1,487.41			1,505.97			12,245.96	1,521.44	1,620.84		-		-	1,530.31	1,604.54
Gas - CC			442.19			442.08	455.27								442.14	392.80
Gas - CT								532.70	467.48			510.56		457.22	464.11	343.97
Gas - Steam					445.73			-							-	410.58
Biogas			-			1,577.30	-								1,577.30	1,603.31
Nuclear				58.63							62.46		58.28		59.86	61.43
Weighted Average	417.71	369.55	442.19	58.63	382.33	450.90	455.27	654.77	537.96	344.86	62.46	510.56	58.28	457.22	165.17	166.78
Average Cost of Generation (¢/kWh)								1,287.30	632.18							
Coal	2.92	3.41			3.52	-	-	-	-	3.41					3.43	2.98
Oil - CC			-			-	-								-	-
Oil - Steam/CT	12.43	15.65			14.52	-	-	128.73	63.22	16.41		-		-	15.56	17.94
Gas - CC			3.06			3.11	3.19								3.10	2.81
Gas - CT								5.57	10.88			8.08		5.09	5.39	3.85
Gas - Steam					4.45				-						4.47	4.60
Biogas			-			11.08	-								11.08	11.48
Nuclear				0.59							0.62		0.59		0.60	0.62
Weighted Average	3.39	3.57	3.06	0.59	3.80	3.17	3.19	9.16	12.90	3.44	0.62	8.08	0.59	5.09	1.51	1.56
Burned MBTU's																
Coal	206,117	5,531,427			3,638,779			-		4,004,460					13,380,783	214,294,473
Oil - CC															-	-
Oil - Steam/CT	10,449	81,970			19,009			208	1,695	9,145		-		-	122,476	2,599,178
Gas - CC			2,963,222			2,923,367	1,506,423								7,393,012	97,936,802
Gas - CT								19,560	23,652			31,049		415,485	489,746	28,537,792
Gas - Steam					1,277,737		174								1,277,911	2,102,783
Biogas			-			22,890	-								22,890	216,190
Nuclear				14,252,377							17,596,869		17,965,994		49,815,240	603,676,564
Total	216,566	5,613,397	2,963,222	14,252,377	4,935,525	2,946,257	1,506,423	19,942	25,347	4,013,605	17,596,869	31,049	17,965,994	415,485	72,502,058	949,363,782

Schedule 5
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DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
DECEMBER 2018

Description	Allen Steam	Belews Creek Steam	Buck CC	Catawba Nuclear	Cliffside Steam - Dual Fuel	Dan River CC	Lee CC	Lee Steam/CT	Lincoln CT	Marshall Steam	McGuire Nuclear	Mill Creek CT	Oconee Nuclear	Rockingham CT	Current Month	Total 12 ME December 2018
Net Generation (mWh)																
Coal	25,397	573,052			366,421					401,855					1,366,724	22,653,740
Oil - CC															-	-
Oil - Steam/CT	1,315	7,791			1,972	-	-	20	41	903		-		-	12,042	232,515
Gas - CC			428,198			416,157	214,977	-							1,059,332	13,695,555
Gas - CT								1,871	1,016			1,961		37,330	42,178	2,550,671
Gas - Steam					128,002			(466)							127,536	187,574
Biogas			-			3,259	-								3,259	30,204
Nuclear 100%				1,420,722							1,778,199		1,782,248		4,981,169	59,936,028
Hydro (Total System)															323,664	2,347,824
Solar (Total System)															5,768	130,018
Total	26,712	580,843	428,198	1,420,722	496,394	419,416	214,977	1,425	1,057	402,758	1,778,199	1,961	1,782,248	37,330	7,921,672	101,764,129
Cost of Reagents Consumed ($)																
Ammonia		($46,049)	$14,280		$11,119	$8,043	$11,630								($977)	$4,077,078
Limestone	$24,711	467,587			478,632					$374,113					1,345,043	19,594,631
Sorbents	-	53,543								73,539					127,081	2,353,883
Urea	-									45,004					45,004	928,117
Re-emission Chemical		-													-	69,161
Dibasic Acid	-														-	-
Activated Carbon	34,464									-					34,464	170,782
Total	$59,175	$475,081	$14,280		489,751	$8,043	$11,630			$492,656					$1,550,615	$27,193,652

Notes:
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.

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED CONSUMPTION AND INVENTORY REPORT
DECEMBER 2018

Description	Allen	Belews Creek	Buck	Cliffside	Dan River	Lee	Lee	Lincoln	Marshall	Mill Creek	Rockingham	Current Month	Total 12 ME December 2018
	Steam	Steam	CC	Steam - Dual Fuel	CC	CC	Steam/CT	CT	Steam	CT	CT		
Coal Data:													
Beginning balance	196,674	741,379		565,251			-		448,731			1,952,035	2,321,844
Tons received during period	-	221,261		95,812					262,988			580,061	8,353,369
Inventory adjustments	(16,000)	(91,871)		(46,501)			-		(41,785)			(196,158)	(171,512)
Tons burned during period	8,841	221,660		146,683			-		158,816			536,000	8,703,762
Ending balance	171,833	649,109		467,879			-		511,118			1,799,939	1,799,939
MBTUs per ton burned	23.31	24.95		24.81			-		25.21			24.96	24.62
Cost of ending inventory ($/ton)	83.82	88.09		87.87			-		86.22			87.09	87.09
Oil Data:													
Beginning balance	90,694	221,182	-	236,089	-	-	714,747	9,834,797	312,274	4,366,782	3,238,190	19,014,755	16,962,536
Gallons received during period	75,652	578,080	-	144,399	-	-	-	-	-	-	-	798,131	21,144,157
Miscellaneous adjustments	448	(35,415)	-	(11,633)	-	-	(9,425)	-	-	-	-	(57,379)	(352,297)
Gallons burned during period	75,879	596,667		137,943	-	-	1,520	12,305	66,449	-	-	889,408	18,888,297
Ending balance	90,915	167,180	-	230,912	-	-	703,802	9,822,492	245,825	4,366,782	3,238,190	18,866,098	18,866,098
Cost of ending inventory ($/gal)	2.16	1.99	-	2.08	-	-	2.33	2.10	2.23	2.47	2.17	2.20	2.20
Natural Gas Data:													
Beginning balance													
MCF received during period			2,880,290	1,244,450	2,818,207	1,473,258	19,360	23,206		30,487	400,698	8,889,956	125,135,402
MCF burned during period			2,880,290	1,244,450	2,818,207	1,473,258	19,360	23,206		30,487	400,698	8,889,956	125,135,402
Ending balance													
Biogas Data:													
Beginning balance													
MCF received during period			-		22,062	-						22,062	210,727
MCF burned during period			-		22,062	-						22,062	210,727
Ending balance													
Limestone Data:													
Beginning balance	23,869	38,673		34,190					37,083			133,815	169,322
Tons received during period	-	6,707		7,615					12,836			27,159	444,242
Inventory adjustments	(2,996)	(4,910)		-					(7,085)			(14,991)	(14,991)
Tons consumed during period	527	11,600		9,514					9,187			30,828	483,419
Ending balance	20,346	28,870		32,292					33,647			115,155	115,155
Cost of ending inventory ($/ton)	46.89	39.54		39.44					40.72			41.16	41.16
												Qtr Ending December 2018	Total 12 ME December 2018
Ammonia Data:													
Beginning balance		1,315										1,315	1,159
Tons received during period		901										901	4,715
Tons consumed during period		583										583	4,241
Ending balance		1,633										1,633	1,633
Cost of ending inventory ($/ton)		620.44										620.44	620.44

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit and terminal activity.
Gas is burned as received; therefore, inventory balances are not maintained.

Schedule 6

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DUKE ENERGY CAROLINAS

ANALYSIS OF COAL PURCHASED

DECEMBER 2018

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ALLEN	SPOT	-	$ -	$ -
	CONTRACT	-	-	-
	ADJUSTMENTS	-	49,933	-
	TOTAL	-	49,933	-
BELEWS CREEK	SPOT	-	11,982	-
	CONTRACT	221,261	17,706,037	80.02
	ADJUSTMENTS	-	189,618	-
	TOTAL	221,261	17,907,637	80.93
CLIFFSIDE	SPOT	-	-	-
	CONTRACT	95,812	7,221,379	75.37
	ADJUSTMENTS	-	1,326,849	-
	TOTAL	95,812	8,548,228	89.22
MARSHALL	SPOT	96,525	8,181,703	84.76
	CONTRACT	166,463	13,355,663	80.23
	ADJUSTMENTS	-	542,373	-
	TOTAL	262,988	22,079,739	83.96
ALL PLANTS	SPOT	96,525	8,193,685	84.89
	CONTRACT	483,536	38,283,079	79.17
	ADJUSTMENTS	-	2,108,773	-
	TOTAL	580,061	$ 48,585,537	$ 83.76

DUKE ENERGY CAROLINAS

ANALYSIS OF COAL QUALITY RECEIVED

DECEMBER 2018

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
BELEWS CREEK	6.91	10.15	12,468	1.58
CLIFFSIDE	8.48	7.60	12,603	2.35
MARSHALL	6.73	10.02	12,508	1.73

DUKE ENERGY CAROLINAS
ANALYSIS OF OIL PURCHASED
DECEMBER 2018

	ALLEN	BELEWS CREEK	CLIFFSIDE
VENDOR	HighTowers	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract	Contract
SULFUR CONTENT %	0	0	0
GALLONS RECEIVED	75,652	578,080	144,399
TOTAL DELIVERED COST	$ 143,133	$ 1,082,966	$ 273,156
DELIVERED COST/GALLON	$ 1.89	$ 1.87	$ 1.89
BTU/GALLON	138,000	138,000	138,000

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2018 - December, 2018
Nuclear Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Oconee 1	6,745,635	847	90.91	89.94
Oconee 2	7,581,168	848	102.06	100.00
Oconee 3	6,967,442	859	92.59	92.12
McGuire 1	10,359,250	1,158	102.12	99.56
McGuire 2	9,502,818	1,158	93.68	91.80
Catawba 1	9,510,487	1,160	93.59	92.99
Catawba 2	9,269,228	1,150	92.01	91.84

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January, 2018 through December, 2018
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Buck CC	11	1,463,456	206	81.10	88.68
Buck CC	12	1,471,968	206	81.57	89.09
Buck CC	ST10	2,237,637	312	81.87	96.78
Buck CC	Block Total	5,173,061	724	81.57	92.29
Dan River CC	8	1,433,925	199	82.26	86.38
Dan River CC	9	1,410,200	199	80.90	85.84
Dan River CC	ST7	2,118,133	320	75.56	91.38
Dan River CC	Block Total	4,962,258	718	78.90	88.46
WS Lee CC	11	1,030,538	223	70.01	75.09
WS Lee CC	12	1,090,492	223	74.08	77.05
WS Lee CC	ST10	1,402,639	337	63.05	76.36
WS Lee CC	Block Total	3,523,669	783	68.17	76.19

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, 2018 through December, 2018

Baseload Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Belews Creek 1	4,793,474	1,110	49.30	88.06
Belews Creek 2	3,227,943	1,110	33.20	69.66
Marshall 3	3,176,205	658	55.10	89.31
Marshall 4	3,675,692	660	63.58	88.48

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, 2018 through December, 2018

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Cliffside 6	4,311,369	844	58.31	75.32
Marshall 1	958,416	380	28.79	88.74
Marshall 2	675,957	380	20.31	68.31

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, 2018 through December, 2018
Other Cycling Steam Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Allen	1	71,408	167	4.88	83.17
Allen	2	86,505	167	5.91	84.03
Allen	3	158,113	270	6.68	80.91
Allen	4	178,336	267	7.62	89.89
Allen	5	325,399	259	14.34	85.49
Cliffside	5	1,243,104	546	25.99	61.63
Lee	3	54,152	173	3.57	36.34

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, 2018 through December, 2018
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Lee CT	79,514	96	84.70
Lincoln CT	82,484	1,565	93.72
Mill Creek CT	201,194	735	99.23
Rockingham CT	2,325,235	895	90.19

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, 2018 through December, 2018
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Conventional Hydroelectric Stations:			
Bear Creek	37,232	9.5	86.90
Bridgewater	117,680	31.5	95.52
Bryson	4,632	0.9	85.69
Cedar Cliff	27,610	6.8	92.39
Cedar Creek	178,151	45.0	81.91
Cowans Ford	312,212	324.0	58.69
Dearborn	222,145	42.0	97.55
Fishing Creek	203,570	50.0	88.41
Franklin	3,726	1.0	58.90
Gaston Shoals	14,686	4.5	96.65
Great Falls	-92	12.0	100.00
Keowee	98,064	152.0	99.21
Lookout Shoals	162,927	27.0	99.26
Mission	5,388	1.8	51.83
Mountain Island	207,502	62.0	90.56
Nantahala	270,145	50.0	99.03
Ninety-Nine Islands	83,267	15.2	91.67
Oxford	107,478	40.0	38.56
Queens Creek	4,621	1.4	99.89
Rhodhiss	119,297	33.5	94.18
Rocky Creek	-73	3.0	0.00
Tennessee Creek	48,111	9.8	93.76
Thorpe	96,019	19.7	93.15
Tuckasegee	7,077	2.5	85.11
Tuxedo	33,861	6.4	96.21
Wateree	336,004	85.0	81.96
Wylie	175,810	72.0	55.96
Pumped Storage Hydroelectric Stations:			
Gross Generation			
Bad Creek	1,447,036	1,360.0	65.67
Jocassee	1,204,730	780.0	92.99
Energy for Pumping			
Bad Creek	-1,838,591		
Jocassee	-1,342,401		
Net Generation			
Bad Creek	-391,555		
Jocassee	-137,671		

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 2018 through December 2018
Pre-commercial Combined Cycle Units

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

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
January 2018					
Lee	11	-10	n/a	n/a	n/a
Lee	12	-11	n/a	n/a	n/a
Lee	ST10	0	n/a	n/a	n/a
Lee	Block Total	-21	n/a	n/a	n/a
February 2018					
Lee	11	-1,575	n/a	n/a	n/a
Lee	12	-1,120	n/a	n/a	n/a
Lee	ST10	0	n/a	n/a	n/a
Lee	Block Total	-2,695	n/a	n/a	n/a
March 2018					
Lee	11	25,973	n/a	n/a	n/a
Lee	12	14,939	n/a	n/a	n/a
Lee	ST10	-1,349	n/a	n/a	n/a
Lee	Block Total	39,563	n/a	n/a	n/a
April 1 - 4					
Lee	11	14,158	n/a	n/a	n/a
Lee	12	6,771	n/a	n/a	n/a
Lee	ST10	8,994	n/a	n/a	n/a
Lee	Block Total	29,923	n/a	n/a	n/a
Total		66,771			

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

Duke Energy Carolinas
Base Load Power Plant Performance Review Plan

Period: December, 2018

Station	Unit	Date of Outage	Duration of Outage	Scheduled / Unscheduled	Cause of Outage	Reason Outage Occurred	Remedial Action Taken
Oconee	1	11/30/2018 - 12/08/2018	177.87	Unscheduled	1B2 reactor coolant pump seal leakage	Failure of reactor coolant pump seal	Replaced reactor coolant pump seal
	2	None					
	3	None					
McGuire	1	None					
	2	None					
Catawba	1	11/17/2018 - 12/11/2018	255.70	Scheduled	End-of-cycle 24 refueling outage	Planned refueling outage	Refueling outage in progress
	2	None					

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
December 2018

Belews Creek Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
1	12/3/2018 5:37:00 PM To 12/6/2018 5:07:00 AM	Unsch	1070	Second Reheater Leaks	HRH Leak on 9th floor. P17 Tube 7,8,9,10,11 and 12, P18 Tubes 10,11 and 12.	
1	12/22/2018 6:00:00 PM To 12/23/2018 2:55:00 PM	Sch	1000	Furnace Wall Leaks	Furnace wall leak on 6th floor.	
1	12/26/2018 7:00:00 AM To 1/1/2019 12:00:00 AM	Sch	8110	Wet Scrubber - Spray Nozzles	1B Absorber agitator and mist eliminator header repairs.	
2	9/8/2018 3:00:00 AM To 12/8/2018 12:00:00 AM	Sch	4520	Gen. Stator Windings; Bushings; And Terminals	Unit 2 fall outage for SSH replacement, LP Generator rewind and CCP final ties.	
2	12/8/2018 12:00:00 AM To 12/13/2018 3:23:00 AM	Sch	3999	Other Miscellaneous Balance Of Plant Problems	Fuel oil fire from replaced accumulator, 2B SAH Rub from new seals,200-2 not wired.	
2	12/14/2018 10:41:00 AM To 12/16/2018 11:54:00 PM	Unsch	8499	Other Miscellaneous Wet Scrubber Problems	FGD Stack doors left open and could not be closed online.	
2	12/27/2018 9:34:00 PM To 12/31/2018 9:30:00 PM	Sch	1492	Air Heater Fouling (Tubular)	Unit 2 PAH plugged and unable to make mill temps.	

Buck Combined Cycle Station

No Outages at Baseload Units During the Month.

Dan River Combined Cycle Station

No Outages at Baseload Units During the Month.

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
December 2018

Marshall Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
4	12/7/2018 9:58:00 PM To 12/15/2018 4:00:00 PM	Sch	1493	Air Heater Fouling (Regenerative)	APH Wash.	
4	12/18/2018 8:00:00 AM To 12/20/2018 5:00:00 PM	Sch	0890	Bottom Ash Systems (Wet or Dry)	Bottom Ash Hopper Seal Trough Repairs.	

WS Lee Combined Cycle

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
WS Lee CC ST 10	12/3/2018 7:05:00 PM To 12/20/2018 5:00:00 PM	Unsch	4289	Turbine - Other Lube Oil System Problems	Trip due to low lube oil in reservoir.	
WS Lee CC ST 10	12/22/2018 12:10:00 AM To 12/22/2018 1:00:00 AM	Unsch	4289	Turbine - Other Lube Oil System Problems	EBOP fail to start.	
WS Lee CC ST 10	12/22/2018 1:53:00 AM To 12/22/2018 11:00:00 AM	Unsch	4289	Turbine - Other Lube Oil System Problems	EBOP fail to start.	
WS Lee CC ST 10	12/22/2018 11:42:00 AM To 12/22/2018 2:00:00 PM	Unsch	4289	Turbine - Other Lube Oil System Problems	EBOP fail to start.	
WS Lee CC GT 11	12/3/2018 7:05:00 PM To 12/20/2018 5:00:00 PM	Unsch	3430	Feedwater Regulating (Boiler Level Control) Valve	Trip due to IP drum level.	
WS Lee CC GT 11	12/21/2018 6:30:00 AM To 12/21/2018 10:00:00 AM	Sch	3352	Feedwater Chemistry	Shut down due to water chemistry/vac.	
WS Lee CC GT 12	12/3/2018 7:05:00 PM To 12/20/2018 5:00:00 PM	Unsch	3430	Feedwater Regulating (Boiler Level Control) Valve	Trip due to IP drum level.	

Notes:

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- Data is reflected at 100% ownership.

Duke Energy Carolinas
Base Load Power Plant Performance Review Plan

December 2018
Oconee Nuclear Station

	Unit 1		Unit 2		Unit 3	
(A) MDC (mW)	847		848		859	
(B) Period Hours	744		744		744	
(C) Net Gen (mWh) and Capacity Factor (%)	481,371	76.39	648,846	102.84	652,031	102.02
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00	0	0.00	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00	0	0.00	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	150,653	23.91	0	0.00	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-1,856	-0.30	-17,934	-2.84	-12,935	-2.02
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00	0	0.00
(J) Net mWh Possible in Period	630,168	100.00%	630,912	100.00%	639,096	100.00%
(K) Equivalent Availability (%)		75.43		100.00		100.00
(L) Output Factor (%)		100.39		102.84		102.02
(M) Heat Rate (BTU/NkWh)		10,230		10,050		10,001

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant Performance Review Plan

December 2018
McGuire Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	1158		1158	
(B) Period Hours	744		744	
(C) Net Gen (mWh) and Capacity Factor (%)	891,451	103.47	886,748	102.92
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-29,899	-3.47	-25,196	-2.92
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00
(J) Net mWh Possible in Period	861,552	100.00%	861,552	100.00%
(K) Equivalent Availability (%)		100.00		100.00
(L) Output Factor (%)		103.47		102.92
(M) Heat Rate (BTU/NkWh)		9,869		9,923

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant Performance Review Plan

December 2018
Catawba Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	1160		1150	
(B) Period Hours	744		744	
(C) Net Gen (mWh) and Capacity Factor (%)	552,976	64.07	867,746	101.42
(D) Net mWh Not Gen due to Full Schedule Outages	296,612	34.37	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	13,307	1.54	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	145	0.02	-12,146	-1.42
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00
(J) Net mWh Possible in Period	863,040	100.00%	855,600	100.00%
(K) Equivalent Availability (%)		63.35		100.00
(L) Output Factor (%)		97.63		101.42
(M) Heat Rate (BTU/NkWh)		10,134		9,967

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
December 2018

Belews Creek Station

	Unit 1	Unit 2
(A) MDC (mW)	1,110	1,110
(B) Period Hrs	744	744
(C) Net Generation (mWh)	404,610	176,233
(D) Capacity Factor (%)	48.99	21.34
(E) Net mWh Not Generated due to Full Scheduled Outages	175,287	429,921
(F) Scheduled Outages: percent of Period Hrs	21.23	52.06
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	66,045	67,951
(J) Forced Outages: percent of Period Hrs	8.00	8.23
(K) Net mWh Not Generated due to Partial Forced Outages	3,159	45,010
(L) Forced Derates: percent of Period Hrs	0.38	5.45
(M) Net mWh Not Generated due to Economic Dispatch	176,739	106,725
(N) Economic Dispatch: percent of Period Hrs	21.40	12.92
(O) Net mWh Possible in Period	825,840	825,840
(P) Equivalent Availability (%)	70.39	34.26
(Q) Output Factor (%)	85.98	54.19
(R) Heat Rate (BTU/NkWh)	9,236	10,647

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
December 2018

Buck Combined Cycle Station

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	206	206	312	724
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	129,223	129,215	169,760	428,198
(D) Capacity Factor (%)	84.31	84.31	73.13	79.49
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	5,952	5,952
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	2.56	1.10
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	24,041	24,049	56,416	104,506
(N) Economic Dispatch: percent of Period Hrs	15.69	15.69	24.30	19.40
(O) Net mWh Possible in Period	153,264	153,264	232,128	538,656
(P) Equivalent Availability (%)	100.00	100.00	97.44	98.90
(Q) Output Factor (%)	85.29	86.03	73.13	80.21
(R) Heat Rate (BTU/NkWh)	9,945	9,739	1,661	6,599

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
December 2018

Dan River Combined Cycle Station

	Unit 8	Unit 9	Unit ST07	Block Total
(A) MDC (mW)	199	199	320	718
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	130,730	122,378	166,308	419,416
(D) Capacity Factor (%)	88.30	82.66	69.85	78.51
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	17,326	25,678	71,772	114,776
(N) Economic Dispatch: percent of Period Hrs	11.70	17.34	30.15	21.49
(O) Net mWh Possible in Period	148,056	148,056	238,080	534,192
(P) Equivalent Availability (%)	100.00	100.00	100.00	100.00
(Q) Output Factor (%)	89.45	88.83	71.12	81.01
(R) Heat Rate (BTU/NkWh)	10,412	10,566	1,784	7,036

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
December 2018

Marshall Station

	Unit 3	Unit 4
(A) MDC (mW)	658	660
(B) Period Hrs	744	744
(C) Net Generation (mWh)	250,510	51,399
(D) Capacity Factor (%)	51.17	10.47
(E) Net mWh Not Generated due to Full Scheduled Outages	0	160,402
(F) Scheduled Outages: percent of Period Hrs	0.00	32.67
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	239,042	279,239
(N) Economic Dispatch: percent of Period Hrs	48.83	56.87
(O) Net mWh Possible in Period	489,552	491,040
(P) Equivalent Availability (%)	100.00	67.33
(Q) Output Factor (%)	51.17	46.92
(R) Heat Rate (BTU/NkWh)	9,867	10,142

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
December 2018

WS Lee Combined Cycle

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	223	223	337	783
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	65,805	67,050	82,122	214,977
(D) Capacity Factor (%)	39.66	40.41	32.75	36.90
(E) Net mWh Not Generated due to Full Scheduled Outages	781	0	0	781
(F) Scheduled Outages: percent of Period Hrs	0.47	0.00	0.00	0.13
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	90,519	90,519	140,922	321,961
(J) Forced Outages: percent of Period Hrs	54.56	54.56	56.21	55.27
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	8,807	8,343	27,684	44,834
(N) Economic Dispatch: percent of Period Hrs	5.31	5.03	11.04	7.70
(O) Net mWh Possible in Period	165,912	165,912	250,728	582,552
(P) Equivalent Availability (%)	44.97	45.44	43.79	44.60
(Q) Output Factor (%)	91.32	94.95	83.12	89.03
(R) Heat Rate (BTU/NkWh)	9,815	9,566	2,061	6,775

Notes:

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

Duke Energy Carolinas
Intermediate Power Plant Performance
Review Plan
December 2018

		Cliffside Station
		Cliffside 6
(A)	**MDC (mW)**	844
(B)	**Period Hrs**	744
(C)	**Net Generation (mWh)**	383,291
(D)	**Net mWh Possible in Period**	627,936
(E)	**Equivalent Availability (%)**	87.46
(F)	**Output Factor (%)**	69.10
(G)	**Capacity Factor (%)**	61.04

Notes:

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

Duke Energy Carolinas
Peaking Power Plant Performance
Review Plan
December 2018

		Cliffside Station
		Unit 5
(A)	**MDC (mW)**	546
(B)	**Period Hrs**	744
(C)	**Net Generation (mWh)**	113,103
(D)	**Net mWh Possible in Period**	406,224
(E)	**Equivalent Availability (%)**	80.73
(F)	**Output Factor (%)**	74.07
(G)	**Capacity Factor (%)**	27.84

Notes:

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

Duke Energy Carolinas
Base Load Power Plant Performance Review Plan

January 2018 - December 2018
Oconee Nuclear Station

	Unit 1		Unit 2		Unit 3	
(A) MDC (mW)	847		848		859	
(B) Period Hours	8760		8760		8760	
(C) Net Gen (mWh) and Capacity Factor (%)	6,745,635	90.91	7,581,168	102.06	6,967,442	92.59
(D) Net mWh Not Gen due to Full Schedule Outages	524,378	7.07	0	0.00	582,288	7.74
* (E) Net mWh Not Gen due to Partial Scheduled Outages	29,529	0.40	347	0.00	46,294	0.62
(F) Net mWh Not Gen due to Full Forced Outages	184,787	2.49	0	0.00	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-64,608	-0.87	-153,035	-2.06	-71,184	-0.95
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00	0	0.00
(J) Net mWh Possible in Period	7,419,720	100.00%	7,428,480	100.00%	7,524,840	100.00%
(K) Equivalent Availability (%)		89.94		100.00		92.12
(L) Output Factor (%)		100.52		102.06		100.36
(M) Heat Rate (BTU/NkWh)		10,233		10,127		10,102

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant Performance Review Plan

January 2018 - December 2018
McGuire Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	1158		1158	
(B) Period Hours	8760		8760	
(C) Net Gen (mWh) and Capacity Factor (%)	10,359,250	102.12	9,502,818	93.68
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00	791,628	7.80
* (E) Net mWh Not Gen due to Partial Scheduled Outages	796	0.01	28,506	0.28
(F) Net mWh Not Gen due to Full Forced Outages	34,991	0.34	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-250,957	-2.47	-178,872	-1.76
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00
(J) Net mWh Possible in Period	10,144,080	100.00%	10,144,080	100.00%
(K) Equivalent Availability (%)		99.56		91.80
(L) Output Factor (%)		102.47		101.61
(M) Heat Rate (BTU/NkWh)		9,957		10,015

*** Estimate**
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant Performance Review Plan

January 2018 - December 2018
Catawba Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	1160		1150	
(B) Period Hours	0		8760	
(C) Net Gen (mWh) and Capacity Factor (%)	9,510,487	102.28	9,269,228	92.01
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00	777,783	7.72
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00	76,740	0.76
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	0	0.00	-49,751	-0.49
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00
(J) Net mWh Possible in Period	0	100.00%	10,074,000	100.00%
(K) Equivalent Availability (%)		95.52		91.84
(L) Output Factor (%)		100.33		99.71
(M) Heat Rate (BTU/NkWh)		10,098		10,048

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
January, 2018 through December, 2018

Belews Creek Station

	Unit 1	Unit 2
(A) MDC (mW)	1,110	1,110
(B) Period Hrs	8,760	8,760
(C) Net Generation (mWh)	4,793,474	3,227,943
(D) Capacity Factor (%)	49.30	33.20
(E) Net mWh Not Generated due to Full Scheduled Outages	747,659	2,689,881
(F) Scheduled Outages: percent of Period Hrs	7.69	27.66
(G) Net mWh Not Generated due to Partial Scheduled Outages	1,040	740
(H) Scheduled Derates: percent of Period Hrs	0.01	0.01
(I) Net mWh Not Generated due to Full Forced Outages	311,892	173,216
(J) Forced Outages: percent of Period Hrs	3.21	1.78
(K) Net mWh Not Generated due to Partial Forced Outages	100,192	86,443
(L) Forced Derates: percent of Period Hrs	1.03	0.89
(M) Net mWh Not Generated due to Economic Dispatch	3,769,344	3,545,377
(N) Economic Dispatch: percent of Period Hrs	38.76	36.46
(O) Net mWh Possible in Period	9,723,600	9,723,600
(P) Equivalent Availability (%)	88.06	69.66
(Q) Output Factor (%)	73.99	67.36
(R) Heat Rate (BTU/NkWh)	9,305	9,599

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
January, 2018 through December, 2018

Buck Combined Cycle Station

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	206	206	312	724
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,463,456	1,471,968	2,237,637	5,173,061
(D) Capacity Factor (%)	81.10	81.57	81.87	81.57
(E) Net mWh Not Generated due to Full Scheduled Outages	61,021	56,502	58,692	176,215
(F) Scheduled Outages: percent of Period Hrs	3.38	3.13	2.15	2.78
(G) Net mWh Not Generated due to Partial Scheduled Outages	139,166	139,968	28,219	307,353
(H) Scheduled Derates: percent of Period Hrs	7.71	7.76	1.03	4.85
(I) Net mWh Not Generated due to Full Forced Outages	4,003	354	806	5,163
(J) Forced Outages: percent of Period Hrs	0.22	0.02	0.03	0.08
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	277	277
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.01	0.00
(M) Net mWh Not Generated due to Economic Dispatch	136,914	135,768	407,489	680,170
(N) Economic Dispatch: percent of Period Hrs	7.59	7.52	14.91	10.72
(O) Net mWh Possible in Period	1,804,560	1,804,560	2,733,120	6,342,240
(P) Equivalent Availability (%)	88.68	89.09	96.78	92.29
(Q) Output Factor (%)	84.66	84.85	84.14	84.49
(R) Heat Rate (BTU/NkWh)	10,221	9,937	2,440	6,774

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
January, 2018 through December, 2018

Dan River Combined Cycle Station

	Unit 8	Unit 9	Unit ST07	Block Total
(A) MDC (mW)	199	199	320	718
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,433,925	1,410,200	2,118,133	4,962,258
(D) Capacity Factor (%)	82.26	80.90	75.56	78.90
(E) Net mWh Not Generated due to Full Scheduled Outages	97,347	105,218	156,480	359,045
(F) Scheduled Outages: percent of Period Hrs	5.58	6.04	5.58	5.71
(G) Net mWh Not Generated due to Partial Scheduled Outages	132,928	132,170	5,760	270,858
(H) Scheduled Derates: percent of Period Hrs	7.63	7.58	0.21	4.31
(I) Net mWh Not Generated due to Full Forced Outages	7,068	9,462	11,920	28,450
(J) Forced Outages: percent of Period Hrs	0.41	0.54	0.43	0.45
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	67,418	67,418
(L) Forced Derates: percent of Period Hrs	0.00	0.00	2.41	1.07
(M) Net mWh Not Generated due to Economic Dispatch	71,972	86,190	443,489	601,650
(N) Economic Dispatch: percent of Period Hrs	4.13	4.94	15.82	9.57
(O) Net mWh Possible in Period	1,743,240	1,743,240	2,803,200	6,289,680
(P) Equivalent Availability (%)	86.38	85.84	91.38	88.46
(Q) Output Factor (%)	87.94	87.41	80.83	84.62
(R) Heat Rate (BTU/NkWh)	10,614	10,673	2,397	7,123

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
January, 2018 through December, 2018

Marshall Station

	Unit 3	Unit 4
(A) MDC (mW)	658	660
(B) Period Hrs	8,760	8,760
(C) Net Generation (mWh)	3,176,205	3,675,692
(D) Capacity Factor (%)	55.10	63.58
(E) Net mWh Not Generated due to Full Scheduled Outages	372,746	501,545
(F) Scheduled Outages: percent of Period Hrs	6.47	8.67
(G) Net mWh Not Generated due to Partial Scheduled Outages	2,091	12,896
(H) Scheduled Derates: percent of Period Hrs	0.04	0.22
(I) Net mWh Not Generated due to Full Forced Outages	95,739	81,433
(J) Forced Outages: percent of Period Hrs	1.66	1.41
(K) Net mWh Not Generated due to Partial Forced Outages	145,499	69,994
(L) Forced Derates: percent of Period Hrs	2.52	1.21
(M) Net mWh Not Generated due to Economic Dispatch	1,971,800	1,440,040
(N) Economic Dispatch: percent of Period Hrs	34.21	24.91
(O) Net mWh Possible in Period	5,764,080	5,781,600
(P) Equivalent Availability (%)	89.31	88.48
(Q) Output Factor (%)	68.89	75.74
(R) Heat Rate (BTU/NkWh)	9,553	9,406

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
January, 2018 through December, 2018

WS Lee Combined Cycle

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	223	223	337	783
(B) Period Hrs	6,601	6,601	6,601	6,601
(C) Net Generation (mWh)	1,030,538	1,090,492	1,402,639	3,523,669
(D) Capacity Factor (%)	70.01	74.08	63.05	68.17
(E) Net mWh Not Generated due to Full Scheduled Outages	200,652	187,320	291,168	679,140
(F) Scheduled Outages: percent of Period Hrs	13.63	12.73	13.09	13.14
(G) Net mWh Not Generated due to Partial Scheduled Outages	27,459	28,514	67,117	123,090
(H) Scheduled Derates: percent of Period Hrs	1.87	1.94	3.02	2.38
(I) Net mWh Not Generated due to Full Forced Outages	138,565	122,014	167,641	428,220
(J) Forced Outages: percent of Period Hrs	9.41	8.29	7.54	8.29
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	74,809	43,683	295,972	414,464
(N) Economic Dispatch: percent of Period Hrs	5.08	2.97	13.30	8.02
(O) Net mWh Possible in Period	1,472,023	1,472,023	2,224,537	5,168,583
(P) Equivalent Availability (%)	75.09	77.05	76.36	76.19
(Q) Output Factor (%)	96.75	98.41	85.00	92.16
(R) Heat Rate (BTU/NkWh)	10,365	10,240	1,646	6,855

Notes:

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

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan
January 2018 through December 2018

Pre-Commercial
Lee Combined Cycle Station

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)				
(B) Period Hrs				
(C) Net Generation (mWh)	38,546	20,580	7,645	66,771
(D) Capacity Factor (%)				
(E) Net mWh Not Generated due to Full Scheduled Outages				
(F) Scheduled Outages: percent of Period Hrs				
(G) Net mWh Not Generated due to Partial Scheduled Outages				
(H) Scheduled Derates: percent of Period Hrs				
(I) Net mWh Not Generated due to Full Forced Outages				
(J) Forced Outages: percent of Period Hrs				
(K) Net mWh Not Generated due to Partial Forced Outages				
(L) Forced Derates: percent of Period Hrs				
(M) Net mWh Not Generated due to Economic Dispatch				
(N) Economic Dispatch: percent of Period Hrs				
(O) Net mWh Possible in Period				
(P) Equivalent Availability (%)				
(Q) Output Factor (%)				
(R) Heat Rate (BTU/NkWh)				

Note: The Power Plant Performance Data reports are limited to capturing data beginning the first month a station is in commercial operation. Lee CC began commercial operations April 5, 2018.

Duke Energy Carolinas
Intermediate Power Plant
Performance Review Plan
January, 2018 through December, 2018

Cliffside Station

Units	**Unit 6**
(A) MDC (mW)	844
(B) Period Hrs	8,760
(C) Net Generation (mWh)	4,311,369
(D) Net mWh Possible in Period	7,393,440
(E) Equivalent Availability (%)	75.32
(F) Output Factor (%)	79.29
(G) Capacity Factor (%)	58.31

Notes:

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

Duke Energy Carolinas
Peaking Power Plant
Performance Review Plan
January, 2018 through December, 2018

Cliffside Station

Units	**Unit 5**
(A) MDC (mW)	546
(B) Period Hrs	8,760
(C) Net Generation (mWh)	1,243,104
(D) Net mWh Possible in Period	4,782,960
(E) Equivalent Availability (%)	60.18
(F) Output Factor (%)	71.78
(G) Capacity Factor (%)	25.99

Notes:

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

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

McGee Workpaper 1

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs	9,270,870	9,127,064	10,021,874	9,249,360	7,252,338	6,692,637	6,844,888	58,459,031
Cost (Gross of Joint Owners)	$ 57,728,557	$ 58,001,149	$ 60,167,863	$ 56,622,253	$ 46,212,440	$ 38,923,889	$ 39,841,317	357,497,468
$/MWh	6.2269	6.3549	6.0037	6.1217	6.3721	5.8159	5.8206	
Avg $/MWh		**6.1154**						
Cents per kWh		**0.6115**						

			Sept 2019 - August 2020
MDC			
CATA_UN01	Catawba	MW	1,160.1
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
			7,179.8
Hours in month			8,760
Generation GWHs			
CATA_UN01	Catawba	GWh	9,271
CATA_UN02	Catawba	GWh	9,127
MCGU_UN01	McGuire	GWh	10,022
MCGU_UN02	McGuire	GWh	9,249
OCON_UN01	Oconee	GWh	7,252
OCON_UN02	Oconee	GWh	6,693
OCON_UN03	Oconee	GWh	6,845
			58,459
	Proposed Nuclear Capacity Factor		92.95%

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

McGee Workpaper 2

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs with NERC applied	9,098,465	9,020,036	9,081,995	9,078,858	6,785,334	6,793,345	6,881,466	56,739,499
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	89.53%	89.53%	89.53%	89.53%	91.45%	91.45%	91.45%	90.21%
Cost	$ 55,640,302	$ 55,160,685	$ 55,539,582	$ 55,520,397	$ 41,494,696	$ 41,543,686	$ 42,082,578	$ 346,981,926

Avg $/MWh	**6.1154**
Cents per kWh	**0.6115**

2013-2017	Capacity Rating	NCF Rating	Weighted Average	
Oconee 1	847.0	91.45	10.79%	
Oconee 2	848.0	91.45	10.80%	
Oconee 3	859.0	91.45	10.94%	
McGuire 1	1158.0	89.53	14.44%	
McGuire 2	1157.6	89.53	14.43%	
Catawba 1	1160.1	89.53	14.47%	
Catawba 2	1150.1	89.53	14.34%	
	7179.8		**90.21%**	Wtd Avg on Capacity Rating

DUKE ENERGY CAROLINAS | **McGee Workpaper 3**

North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation and Purchased Power in MWhs
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

Resource Type	Sept 2019 - August 2020	
NUC Total (Gross)	58,459,031	
COAL Total	18,355,203	
Gas CT and CC total (Gross)	20,821,617	
Run of River	4,839,425	
Net pumped Storage	(3,874,211)	
Total Hydro	965,214	
Catawba Joint Owners	(14,888,880)	
Lee CC Joint Owners	(878,400)	
DEC owned solar	184,444	
Total Generation		83,018,229
Purchases for REPS Compliance	1,204,212	
Qualifying Facility Purchases - Non-REPS compliance	1,275,248	
Other Purchases	66,854	
Allocated Economic Purchases	319,079	
Joint Dispatch Purchases	6,414,946	
	9,280,339	
Total Generation and Purchased Power		92,298,568
Fuel Recovered Through intersystem Sales	(687,755)	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected Fuel and Fuel Related Costs
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

McGee Workpaper 4

Resource Type	Sept 2019 - August 2020	
Nuclear Total (Gross)	$ 357,497,468	
COAL Total	570,050,837	
Gas CT and CC total (Gross)	503,184,086	
Catawba Joint Owner costs	(91,061,695)	
CC Joint Owner costs	(18,112,976)	
Reagents and gain/loss on sale of By-Products	24,959,649	Workpaper 9
Purchases for REPS Compliance - Energy	63,867,566	
Purchases for REPS Compliance Capacity	13,295,654	
Purchases of Qualifying Facilities - Energy	58,754,197	
Purchases of Qualifying Facilities - Capacity	14,874,084	
Other Purchases	2,029,948	
JDA Savings Shared	19,972,407	Workpaper 5
Allocated Economic Purchase cost	9,109,705	Workpaper 5
Joint Dispatch purchases	132,910,592	Workpaper 6
Total Purchases	314,814,153	
Fuel Expense recovered through intersystem sales	(16,986,301)	Workpaper 5
Total System Fuel and Fuel Related Costs	**$ 1,644,345,221**	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected Joint Dispatch Fuel Impacts
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

McGee 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**
9/1/2019	$ 475,131	$ 665,890	$ (169,265)	$ (112,397)	$ (10,444,194)	$ 10,444,194	$ (1,053,331)	$ 1,053,331
10/1/2019	$ 414,456	$ 591,080	$ (4,395)	$ (67,808)	$ (7,750,156)	$ 7,750,156	$ (1,182,598)	$ 1,182,598
11/1/2019	$ 950,625	$ 1,370,649	$ (419,575)	$ (61,033)	$ (15,340,171)	$ 15,340,171	$ (2,955,441)	$ 2,955,441
12/1/2019	$ 479,370	$ 692,032	$ (371,479)	$ (59,958)	$ (12,761,635)	$ 12,761,635	$ (1,792,678)	$ 1,792,678
1/1/2020	$ 730,828	$ 1,011,856	$ (1,806,953)	$ (2,697,340)	$ (1,005,527)	$ 1,005,527	$ 626,965	$ (626,965)
2/1/2020	$ 463,058	$ 655,004	$ (1,255,361)	$ (1,044,487)	$ (2,708,449)	$ 2,708,449	$ (215,029)	$ 215,029
3/1/2020	$ 426,687	$ 608,794	$ (409,836)	$ (356,416)	$ (9,719,397)	$ 9,719,397	$ (1,442,087)	$ 1,442,087
4/1/2020	$ 459,023	$ 693,091	$ (291,103)	$ (49,201)	$ (10,408,733)	$ 10,408,733	$ (2,336,142)	$ 2,336,142
5/1/2020	$ 531,216	$ 804,769	$ (483,810)	$ (86,028)	$ (13,269,047)	$ 13,269,047	$ (2,608,123)	$ 2,608,123
6/1/2020	$ 345,100	$ 504,336	$ (265,478)	$ (113,940)	$ (13,397,425)	$ 13,397,425	$ (2,137,472)	$ 2,137,472
7/1/2020	$ 587,846	$ 827,961	$ (399,661)	$ (463,252)	$ (12,439,738)	$ 12,439,738	$ (3,016,091)	$ 3,016,091
8/1/2020	$ 483,920	$ 684,244	$ (327,024)	$ (196,140)	$ (11,987,821)	$ 11,987,821	$ (1,860,381)	$ 1,860,381
Sept 19 - Aug 20		$ 9,109,705		$ (5,308,001)		$ 121,232,293		$ 19,972,407

$ 132,910,592	Workpaper 6 - Transfer - Purchases
$ (11,678,300)	Workpaper 6 - Transfer - Sales
$ 121,232,293	Sept 19-Aug 20 Net Fuel Transfer Payment
$ (11,678,300)	Workpaper 6 - Transfer - Sales
$ (5,308,001)	Sept 19-Aug 20 Economic Sales Cost
$ (16,986,301)	**Total Fuel expense recovered through intersystem sales**

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected Merger Payments
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

McGee Workpaper 6

	Transfer Projection		Purchase Allocation Delta		Adjusted Transfer		Fossil Gen Cost		Pre-Net Payments	
					purchase	sale			sale	purchase
	PECtoDEC	**DECtoPEC**	**PEC**	**DEC**	**PECtoDEC**	**DECtoPEC**	**PEC**	**DEC**	**PECtoDEC**	**DECtoPEC**
9/1/2019	464,096	14,623	10,534	(10,534)	474,630	14,623	$ 22.64	$ 20.60	$ 301,261	$ 10,745,454
10/1/2019	406,906	75,054	8,370	(8,370)	415,276	75,054	$ 22.10	$ 19.03	$ 1,427,980	$ 9,178,136
11/1/2019	675,108	1,571	33,083	(33,083)	708,192	1,571	$ 21.71	$ 20.01	$ 31,436	$ 15,371,607
12/1/2019	564,868	22,814	2,716	(2,716)	567,583	22,814	$ 23.37	$ 22.13	$ 504,795	$ 13,266,429
1/1/2020	207,223	163,501	(7,592)	7,592	207,223	171,093	$ 25.26	$ 24.72	$ 4,228,626	$ 5,234,152
2/1/2020	232,255	123,728	(8,963)	8,963	232,255	132,692	$ 24.98	$ 23.30	$ 3,092,324	$ 5,800,773
3/1/2020	468,979	12,017	7,840	(7,840)	476,820	12,017	$ 20.80	$ 16.50	$ 198,232	$ 9,917,629
4/1/2020	580,234	41,238	(4,789)	4,789	580,234	46,027	$ 19.35	$ 17.80	$ 819,312	$ 11,228,046
5/1/2020	666,200	17,354	14,825	(14,825)	681,026	17,354	$ 19.93	$ 17.44	$ 302,581	$ 13,571,628
6/1/2020	739,202	5,870	4,470	(4,470)	743,672	5,870	$ 18.15	$ 16.50	$ 96,828	$ 13,494,252
7/1/2020	672,958	24,313	(279)	279	672,958	24,592	$ 19.09	$ 16.62	$ 408,669	$ 12,848,407
8/1/2020	642,936	17,040	12,142	(12,142)	655,079	17,040	$ 18.71	$ 15.63	$ 266,256	$ 12,254,078
Sept 19 - Aug 20	6,320,965	519,122	72,358	(72,358)	6,414,946	540,745			$ 11,678,300	$ 132,910,592
									Net Pre-Net Payments	$ 121,232,293

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 92.95%
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

McGee Workpaper 7

Fall 2018 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	21,397,068		21,397,068
	General	23,127,702		23,127,702
	Industrial	12,939,285		12,939,285
	Lighting	253,942		253,942
	NC RETAIL	57,717,997	-	57,717,997
South Carolina:				
	Residential	6,427,468	78,602	6,506,070
	General	5,801,262	49,849	5,851,111
	Industrial	9,500,669	688	9,501,357
	Lighting	42,373	-	42,373
	SC RETAIL	21,771,772	129,139	21,900,911
Total Retail Sales				
	Residential	27,824,536	78,602	27,903,138
	General	28,928,964	49,849	28,978,813
	Industrial	22,439,954	688	22,440,642
	Lighting	296,315	-	296,315
	Retail Sales	79,489,769	129,139	79,618,908
	Wholesale	7,624,936	-	7,624,936
	Projected System MWH Sales for Fuel Factor	87,114,705	129,139	87,243,844
	NC as a percentage of total	**66.26%**		**66.16%**
	SC as a percentage of total	24.99%		25.10%
	Wholesale as a percentage of total	8.75%		8.74%
		100.00%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	129,139
Marginal fuel rate per MWh for SC NEM	$ 32.50
Fuel benefit to be directly assigned to SC Retail	$ 4,197,018

System Fuel Expense	$ 1,644,345,221	McGee Exhibit 2 Schdule 1 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,197,018	
Total Fuel Costs for Allocation	$ 1,648,542,239	

Reconciliation

	System	NC Retail Customers	Wholesale	South Carolina Retail	
Total system fuel expense from McGee Exhibit 2 Schedule 1 Page 1	$ 1,644,345,221				
QF and REPS Compliance Purchased Power - Capacity	$ 28,169,738				
Other fuel costs	$ 1,616,175,484				
SC Net Metering Fuel Allocation adjustment	$ 4,197,018				
Jurisdictional fuel costs after adj.	$ 1,620,372,501				
Allocation to states/classes		66.16%	8.74%	25.10%	
Jurisdictional fuel costs	$ 1,620,372,501	$ 1,072,038,447	$ 141,620,557	$ 406,713,498	67.04% Capacity Allocator
Direct Assignment of Fuel benefit to SC Retail	$ (4,197,018)		$ -	$ (4,197,018)	
Total system actual fuel costs	$ 1,616,175,484	$ 1,072,038,447	$ 141,620,557	$ 402,516,480	
QF and REPS Compliance Purchased Power - Capacity	28,169,738	18,884,001			
Total system fuel expense from McGee Exhibit 2 Schedule 1 Page 1	$ 1,644,345,221	**$ 1,090,922,448**			
		Exh.2, Sch. 1 page 3			

DUKE ENERGY CAROLINAS — **Revised McGee Workpaper 7a**

North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 92.95% and Normalized Test Period Sales
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

Fall 2018 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
North Carolina:						
	NC RETAIL	59,480,703	155,235	(1,649,623)	-	57,986,315
South Carolina:						
	SC RETAIL	21,918,532	72,754	(507,334)	129,139	21,613,091
	Wholesale	9,088,393	81,154	(120,731)	-	9,048,816
	Normalized System MWH Sales for Fuel Factor	90,487,628	309,143	(2,277,688)	129,139	88,648,222
	NC as a percentage of total	**65.73%**				**65.41%**
	SC as a percentage of total	24.22%				24.38%
	Wholesale as a percentage of total	10.04%				10.21%
		100.00%				100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	129,139
Marginal fuel rate per MWh for SC NEM	$ 32.50
Fuel benefit to be directly assigned to SC Retail	$ 4,197,018

System Fuel Expense	$ 1,683,949,859	McGee Exhibit 2 Schedule 2 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,197,018	
Total Fuel Costs for Allocation	$ 1,688,146,877	

Reconciliation

	System	NC Retail Customers	Wholesale	South Carolina Retail
Total system fuel expense from McGee Exhibit 2 Schedule 2 Page 1	$ 1,683,949,859			
QF and REPS Compliance Purchased Power - Capacity	$ 28,169,738			
Other fuel costs	$ 1,655,780,122			
SC Net Metering Fuel Allocation adjustment	$ 4,197,018			
Jurisdictional fuel costs after adj.	$ 1,659,977,139			
Allocation to states/classes		65.41%	10.21%	24.38%
Jurisdictional fuel costs	$ 1,659,977,139	$ 1,085,791,047	$ 169,483,666	$ 404,702,427
Direct Assignment of Fuel benefit to SC Retail	$ (4,197,018)		$ -	$ (4,197,018)
Total system actual fuel costs	$ 1,655,780,122	$ 1,085,791,047	$ 169,483,666	$ 400,505,409
QF and REPS Compliance Purchased Power - Capacity	28,169,738	18,884,001		
Total system fuel expense from McGee Exhibit 2 Schedule 2 Page 1	$ 1,683,949,859	**$ 1,104,675,048**		
		Exh. 2, Sch 2 page 3		

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
NERC 5 Year Average Nuclear Capacity Factor of 90.21%
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

McGee Workpaper 7b

Fall 2018 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	21,397,068		21,397,068
	General	23,127,702		23,127,702
	Industrial	12,939,285		12,939,285
	Lighting	253,942		253,942
	NC RETAIL	57,717,997	-	57,717,997
South Carolina:				
	Residential	6,427,468	78,602	6,506,070
	General	5,801,262	49,849	5,851,111
	Industrial	9,500,669	688	9,501,357
	Lighting	42,373	0	42,373
	SC RETAIL	21,771,772	129,139	21,900,911
Total Retail Sales				
	Residential	27,824,536	78,602	27,903,138
	General	28,928,964	49,849	28,978,813
	Industrial	22,439,954	688	22,440,642
	Lighting	296,315	-	296,315
	Retail Sales	79,489,769	129,139	79,618,908
	Wholesale	7,624,936	-	7,624,936
	Projected System MWh Sales for Fuel Factor	87,114,705	129,139	87,243,844
	NC as a percentage of total	**66.26%**		**66.16%**
	SC as a percentage of total	24.99%		25.10%
	Wholesale as a percentage of total	8.75%		8.74%
		100.00%		100.00%

SC Net Metering allocation adjustment		
Total projected SC NEM MWhs	129,139	
Marginal fuel rate per MWh for SC NEM	$ 32.50	
Fuel benefit to be directly assigned to SC Retail	$ 4,197,018	
System Fuel Expense	$ 1,676,309,949	McGee Exhibit 2 Schedule 3 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,197,018	
Total Fuel Costs for Allocation	$ 1,680,506,966	McGee Exhibit 2 Schedule 3 Page 3 of 3, Line 5

Reconciliation

	System	NC Retail Customers	Wholesale	South Carolina Retail
Total system fuel expense from McGee Exhibit 2 Schedule 3 Page 1	$ 1,676,309,949			
QF and REPS Compliance Purchased Power - Capacity	$ 28,169,738			
Other fuel costs	$ 1,648,140,211			
SC Net Metering Fuel Allocation adjustment	$ 4,197,018			
Jurisdictional fuel costs after adj.	$ 1,652,337,229			
Allocation to states/classes		66.16%	8.74%	25.10%
Jurisdictional fuel costs	$ 1,652,337,229	$ 1,093,186,310	$ 144,414,274	$ 414,736,644
Direct Assignment of Fuel benefit to SC Retail	$ (4,197,018)		$ -	$ (4,197,018)
Total system actual fuel costs	$ 1,648,140,211	$ 1,093,186,310	$ 144,414,274	$ 410,539,627
QF and REPS Compliance Purchased Power - Capacity	28,169,738	18,884,001		
Total system fuel expense from McGee Exhibit 2 Schedule 3 Page 1	$ 1,676,309,949	**$ 1,112,070,311**		
		Exh. 2, Sch.3 page 3		

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Annualized Revenue
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

	January 2019 Actuals			Normalized Sales	
	Revenue	**KWH Sales**	**Cents/ kwh**	**McGee EX 4**	**Total Annualized Revenues**
	(a)	(b)	(a) / (b) *100 = (c)	(d)	(c) * (d) * 10
Residential	$ 217,323,443.93	2,194,230,798	9.9043	22,043,791	$ 2,183,285,633
General	$ 143,353,269.17	1,936,498,544	7.4027	23,487,580	$ 1,738,716,194
Industrial	$ 49,109,115.03	890,320,580	5.5159	12,454,944	$ 687,001,167
Total	$ 409,785,828.13	5,021,049,922		57,986,315	$ 4,609,002,994

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Projected Reagents and ByProducts
Billing Period Sept 2019 through Aug 2020
Docket E-7, Sub 1190

McGee Workpaper 9

Reagent and ByProduct projections

Date	Ammonia	Urea	Limestone	Magnesium hydroxide	Calcium Carbonate	**Reagent Cost**	**Gypsum (Gain)/ Loss**	**Ash (Gain)/Loss**	**Sale of By-Products (Gain)/Loss**
9/1/2019	$ 342,265	$ 77,914	$ 1,644,941	$ 215,442	$ 119,083	**$ 2,399,645**	$ 347,807	$ (20,361)	**$ 327,447**
10/1/2019	$ 203,263	$ 46,271	$ 976,890	$ 96,653	$ 59,479	**$ 1,382,556**	$ 222,691	$ (500)	**$ 222,191**
11/1/2019	$ 295,673	$ 67,308	$ 1,421,021	$ 141,587	$ 80,226	**$ 2,005,816**	$ 307,158	$ (14,173)	**$ 292,986**
12/1/2019	$ 280,685	$ 63,896	$ 1,348,984	$ 200,980	$ 105,495	**$ 2,000,040**	$ 253,684	$ (31,440)	**$ 222,244**
1/1/2020	$ 480,295	$ 109,336	$ 2,308,323	$ 235,514	$ 119,285	**$ 3,252,753**	$ 448,822	$ (51,070)	**$ 397,752**
2/1/2020	$ 455,643	$ 103,724	$ 2,189,841	$ 224,812	$ 115,218	**$ 3,089,236**	$ 426,261	$ (54,924)	**$ 371,337**
3/1/2020	$ 280,833	$ 63,929	$ 1,349,695	$ 197,989	$ 96,692	**$ 1,989,138**	$ 249,549	$ (49,646)	**$ 199,903**
4/1/2020	$ 112,329	$ 25,571	$ 539,858	$ 73,146	$ 41,882	**$ 792,786**	$ 114,210	$ (7,717)	**$ 106,493**
5/1/2020	$ 127,830	$ 29,100	$ 614,359	$ 89,834	$ 50,633	**$ 911,756**	$ 128,869	$ (9,205)	**$ 119,664**
6/1/2020	$ 116,620	$ 26,548	$ 560,481	$ 93,291	$ 51,598	**$ 848,537**	$ 114,157	$ (8,031)	**$ 106,126**
7/1/2020	$ 252,434	$ 57,465	$ 1,213,211	$ 193,957	$ 106,887	**$ 1,823,954**	$ 246,905	$ (18,748)	**$ 228,157**
8/1/2020	$ 228,139	$ 51,934	$ 1,096,445	$ 180,818	$ 101,250	**$ 1,658,586**	$ 225,313	$ (14,765)	**$ 210,548**
	$ 3,176,009	$ 722,995	$ 15,264,049	$ 1,944,022	$ 1,047,728	**$ 22,154,802**	$ 3,085,428	$ (280,581)	**$ 2,804,847**

Total Reagent cost and Sale of By-products **$ 24,959,649**

DUCE ENERGY CAROLINAS

North Carolina Annual Fuel and Fuel Related Expense

2.5% calculation test

Twelve Months Ended December 31, 2017

Billing Period Sept 2019 through Aug 2020

Docket E-7, Sub 1190

McGee Workpaper 10

Line No.	Description	Forecast $	(over)/under Collection $	Total $
1	Amount in current docket	107,380,554	72,488,427	179,868,981
2	Amount in Sub 1163, prior year docket	129,739,014	25,206,674	154,945,688
3	Increase/(Decrease)	(22,358,461)	47,281,753	24,923,292
4	2.5% of 2018 NC revenue of $4,895,869,250.56			122,396,731
	Excess of purchased power growth over 2.5% of Revenue			0

	E-7 Sub 1190			
WP 4	Purchases for REPS Compliance - Energy	63,867,566	66.16%	42,254,782
WP 4	Purchases for REPS Compliance Capacity	13,295,654	67.04%	8,912,938
WP 4	Purchases	2,029,948	66.16%	1,343,014
WP 4	QF Energy	58,754,197	66.16%	38,871,777
WP 4	QF Capacity	14,874,084	67.04%	9,971,063
WP 4	Allocated Economic Purchase cost	9,109,705	66.16%	6,026,981
		161,931,154		107,380,554

E-7 Sub 1163			
Purchases for REPS Compliance	76,265,967	65.58%	50,015,221
Purchases for REPS Compliance Capacity	16,389,786	66.39%	10,881,179
Purchases	1,354,014	65.58%	887,962
QF Energy	59,741,306	65.58%	39,178,348
QF Capacity	13,954,158	66.39%	9,264,165
Allocated Economic Purchase cost	29,753,184	65.58%	19,512,138
	197,458,415		129,739,014

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
2.5% calculation test
Twelve Months Ended December 31, 2018
Docket E-7, Sub 1190

McGee Workpaper 10a

2018	**Jan18**	**Feb18**	**Mar18**	**Apr18**	**May18**	**June 18**	**Jul18**	**Aug18**	**Sep18**	**Oct18**	**Nov18**	**Dec18**	**12 ME**
System KWH Sales - Sch 4, Adjusted	8,703,429,931	7,459,691,118	6,449,998,012	6,590,329,093	6,591,233,338	8,009,317,385	8,486,873,480	8,267,869,991	9,507,963,860	6,345,056,567	6,681,164,890	7,500,839,324	90,593,766,989
NC Retail KWH Sales - Sch 4	5,733,819,698	5,031,181,342	4,190,094,169	4,416,566,036	4,252,750,024	5,245,688,511	5,639,360,853	5,409,821,248	6,212,763,717	4,141,211,581	4,314,713,247	4,892,732,160	59,480,702,586
NC Retail % of Sales, Adjusted (Calc)	65.88%	67.44%	64.96%	67.02%	64.52%	65.49%	66.45%	65.43%	65.34%	65.27%	64.58%	65.23%	65.66%
NC retail production plant %	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%	67.56%
<u>Fuel and Fuel related component of purchased power</u>													
System Actual $ - Sch 3 Fuel$:	$ 54,851,829	$ 19,768,561	$ 11,751,953	$ 8,971,622	$ 7,588,225	$ 7,853,735	$ 25,151,873	$ 24,971,461	$ 21,908,434	$ 27,821,901	$ 26,826,328	$ 40,057,563	$ 277,523,485
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	18,300,781	2,407,886	1,331,655	1,356,382	1,684,418	1,881,586	2,920,154	3,759,304	6,703,809	4,827,502	6,105,374	13,849,586	$ 65,128,437
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	3,057,332	3,239,022	2,726,561	3,894,992	4,543,762	4,545,750	4,893,476	4,813,048	4,818,507	3,635,758	4,331,202	3,811,118	$ 48,310,528
System Actual$ - Sch 3 Fuel-related$; SC DERP	122	125	134	163	218	223	232	223	213	203	157	136	$ 2,149
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	1,692,902	2,049,413	2,053,505	2,531,173	2,424,811	2,829,385	2,716,750	2,487,659	2,471,326	2,042,872	2,089,973	1,712,356	$ 27,102,125
Total System Economic & QF$	77,902,966	27,465,007	17,863,808	16,754,332	16,241,434	17,110,679	35,682,485	36,031,695	35,902,289	38,328,236	39,353,034	59,430,759	418,066,724
<u>Less:</u>													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 30,897,067	$ 15,346,230	$ 7,372,650	$ 7,540,311	$ 5,735,851	$ 6,332,102	$ 23,572,626	$ 21,641,030	$ 15,422,513	$ 23,414,464	$ 20,577,089	$ 28,953,467	$ 206,805,400
Total System Economic $ without Native Load Transfers	$ 47,005,899	$ 12,118,777	$ 10,491,158	$ 9,214,021	$ 10,505,583	$ 10,778,577	$ 12,109,859	$ 14,390,665	$ 20,479,776	$ 14,913,772	$ 18,775,945	$ 30,477,292	$ 211,261,324
NC Actual $ (Calc)	$ 30,967,487	$ 8,173,497	$ 6,815,342	$ 6,174,856	$ 6,778,340	$ 7,059,410	$ 8,046,764	$ 9,416,080	$ 13,382,046	$ 9,733,733	$ 12,125,553	$ 19,880,072	$ 138,553,178
Billed rate (¢/kWh):	0.0868	0.0868	0.0868	0.0868	0.0868	0.0868	0.0868	0.0868	0.1631	0.1921	0.1922	0.1922	
Billed $:	$ 4,979,550	$ 4,369,342	$ 3,638,897	$ 3,835,577	$ 3,693,311	$ 4,555,631	$ 4,897,517	$ 4,698,172	$ 10,132,031	$ 7,954,367	$ 8,291,468	$ 9,402,231	$ 70,448,093
(Over)/ Under $:	$ 25,987,937	$ 3,804,155	$ 3,176,444	$ 2,339,278	$ 3,085,029	$ 2,503,779	$ 3,149,247	$ 4,717,908	$ 3,250,015	$ 1,779,366	$ 3,834,085	$ 10,477,841	$ 68,105,086
<u>Capacity component of purchased power</u>													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ 422,948	$ 422,948	$ 211,474	$ 211,474	$ 317,211	$ 1,374,581	$ 3,172,110	$ 3,116,270	$ 630,852	$ 211,474	$ 211,474	$ 211,474	$ 10,514,290
System Actual $ - Capacity component of Purchased Power for REPS Compliance	486,469	465,590	421,064	517,448	539,749	567,326	2,279,476	2,238,065	2,451,979	1,649,703	659,013	594,902	$ 12,870,784
System Actual $ - Capacity component of HB589 Purpa QF purchases	316,410	362,951	415,622	397,922	232,512	271,686	1,225,424	1,199,461	1,251,154	924,601	242,932	159,399	$ 7,000,074
System Actual $ - Capacity component of SC DERP	57	37	64	28	13	21	78	84	72	79	19	13	$ 565
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 1,225,884	$ 1,251,526	$ 1,048,224	$ 1,126,872	$ 1,089,485	$ 2,213,614	$ 6,677,088	$ 6,553,880	$ 4,334,057	$ 2,785,857	$ 1,113,438	$ 965,788	$ 30,385,713
NC Actual $ (Calc) (1)	$ 828,210	$ 845,534	$ 708,183	$ 761,317	$ 736,059	$ 1,495,523	$ 4,511,056	$ 4,427,817	$ 2,928,099	$ 1,882,131	$ 752,241	$ 652,488	$ 20,528,657
Billed rate (¢/kWh):	0.0241	0.0241	0.0241	0.0241	0.0241	0.0241	0.0241	0.0241	0.0289	0.0353	0.0353	0.0353	
Billed $:	$ 1,383,962	$ 1,214,368	$ 1,011,356	$ 1,066,019	$ 1,026,479	$ 1,266,143	$ 1,361,163	$ 1,305,759	$ 1,795,614	$ 1,462,023	$ 1,524,125	$ 1,728,304	$ 16,145,316
(Over)/Under $:	$ (555,752)	$ (368,834)	$ (303,173)	$ (304,702)	$ (290,420)	$ 229,380	$ 3,149,893	$ 3,122,057	$ 1,132,485	$ 420,108	$ (771,884)	$ (1,075,816)	$ 4,383,341
TOTAL (Over)/ Under $:	**$ 25,432,185**	**$ 3,435,322**	**$ 2,873,271**	**$ 2,034,577**	**$ 2,794,608**	**$ 2,733,159**	**$ 6,299,140**	**$ 7,839,965**	**$ 4,382,500**	**$ 2,199,474**	**$ 3,062,201**	**$ 9,402,025**	**$ 72,488,427**

Note: The billed rate for September and October are pro-rated based on number of billing days in cycle on new rate schedules.

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
2.5% calculation test
Twelve Months Ended December 31, 2017
Docket E-7, Sub 1190

McGee Workpaper 10b

2017	**Jan17**	**Feb17**	**Mar17**	**Apr17**	**May17**	**June 17**	**Jul17**	**Aug17**	**Sep17**	**Oct17**	**Nov17**	**Dec17**	**12 ME**
System KWH Sales - Sch 4, Adjusted	7,537,708,015	6,554,206,632	6,358,740,783	7,141,766,120	5,899,728,291	7,386,182,606	8,217,318,035	8,246,356,880	7,636,553,967	6,672,440,753	6,414,671,902	7,061,789,900	85,127,463,884
NC Retail KWH Sales - Sch 4	4,974,781,160	4,409,516,555	4,161,725,776	4,712,572,814	3,804,926,476	4,858,493,561	5,393,164,464	5,434,256,910	5,082,625,773	4,373,336,154	4,193,859,450	4,613,039,595	56,012,298,688
NC Retail % of Sales, Adjusted (Calc)	66.00%	67.28%	65.45%	65.99%	64.49%	65.78%	65.63%	65.90%	66.56%	65.54%	65.38%	65.32%	65.80%
NC retail production plant %	67.09%	67.09%	67.09%	67.09%	67.09%	67.09%	67.09%	67.09%	67.09%	67.09%	67.09%	67.09%	67.09%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 14,477,669	$ 16,876,907	$ 10,096,048	$ 8,192,583	$ 9,721,355	$ 10,071,142	$ 12,026,892	$ 14,840,029	$ 18,993,838	$ 17,656,690	$ 22,489,529	$ 25,927,577	$ 181,370,259
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	2,015,378	1,988,183	1,423,270	946,815	1,094,013	1,076,835	1,880,095	2,503,480	1,906,962	2,121,832	2,815,382	3,654,363	$ 23,426,608
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	2,453,055	2,550,377	3,307,695	4,043,976	3,816,768	4,301,618	4,300,868	4,332,085	3,902,317	3,805,061	3,655,861	2,991,972	$ 43,461,653
System Actual$ - Sch 3 Fuel-related$; SC DERP								(8,513)	242	225	208	147	$ (7,691)
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases								2,942,527	2,459,473	2,447,053	2,384,629	2,150,732	$ 12,384,414
Total System Economic & QF$	18,946,102	21,415,467	14,827,013	13,183,374	14,632,136	15,449,595	18,207,855	24,609,608	27,262,832	26,030,861	31,345,609	$ 34,724,791	260,635,243
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 10,063,655	$ 13,734,418	$ 7,330,149	$ 6,099,895	$ 7,828,909	$ 6,973,202	$ 9,283,031	$ 11,761,966	$ 17,022,958	$ 15,515,603	$ 18,675,689	$ 20,326,204	$ 144,615,679
Total System Economic $ without Native Load Transfers	$ 8,882,447	$ 7,681,049	$ 7,496,864	$ 7,083,479	$ 6,803,227	$ 8,476,393	$ 8,924,824	$ 12,847,642	$ 10,239,874	$ 10,515,258	$ 12,669,920	$ 14,398,587	$ 116,019,564
NC Actual $ (Calc)	$ 5,862,290	$ 5,167,630	$ 4,906,615	$ 4,674,111	$ 4,387,622	$ 5,575,614	$ 5,857,513	$ 8,466,452	$ 6,815,306	$ 6,892,044	$ 8,283,489	$ 9,405,725	$ 76,294,410
Billed rate (¢/kWh):	0.1074	0.1074	0.1074	0.1074	0.1074	0.1074	0.1074	0.1074	0.0868	0.0868	0.0868	0.0868	
Billed $:	$ 5,343,741	$ 4,736,553	$ 4,470,385	$ 5,062,086	$ 4,087,123	$ 5,218,829	$ 5,793,154	$ 5,837,295	$ 4,414,019	$ 3,798,034	$ 3,642,167	$ 4,006,205	$ 56,409,592
(Over)/ Under $:	$ 518,549	$ 431,076	$ 436,230	$ (387,975)	$ 300,499	$ 356,785	$ 64,358	$ 2,629,158	$ 2,401,287	$ 3,094,010	$ 4,641,322	$ 5,399,519	$ 19,884,818
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ 419,234	$ 419,233	$ 209,616	$ 209,616	$ 314,425	$ 1,362,507	$ 3,144,246	$ 3,144,246	$ 628,850	$ 209,616	$ 209,616	$ 209,616	$ 10,480,821
System Actual $ - Capacity component of Purchased Power for REPS Compliance	392,592	412,586	456,453	533,339	443,290	522,270	2,084,627	2,035,395	1,896,602	1,684,518	519,390	374,434	$ 11,355,496
System Actual $ - Capacity component of HB589 Purpa QF purchases							-	1,341,938	1,167,715	1,069,000	326,098	234,918	$ 4,139,669
System Actual $ - Capacity component of SC DERP								(4,510)	99	101	37	22	$ (4,251)
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 811,826	$ 831,819	$ 666,069	$ 742,955	$ 757,715	$ 1,884,777	$ 5,228,873	$ 6,517,069	$ 3,693,266	$ 2,963,235	$ 1,055,141	$ 818,990	$ 25,971,735
NC Actual $ (Calc)	$ 544,694	$ 558,108	$ 446,898	$ 498,485	$ 508,388	$ 1,264,590	$ 3,508,308	$ 4,372,622	$ 2,477,994	$ 1,988,180	$ 707,946	$ 549,501	$ 17,425,714
Billed rate (¢/kWh):	0.0204	0.0204	0.0204	0.0204	0.0204	0.0204	0.0204	0.0204	0.0241	0.0241	0.0241	0.0241	
Billed $:	$ 1,014,183	$ 898,945	$ 848,429	$ 960,728	$ 775,691	$ 990,476	$ 1,099,476	$ 1,107,854	$ 1,226,785	$ 1,055,585	$ 1,012,265	$ 1,113,442	$ 12,103,858
(Over)/Under $:	$ (469,489)	$ (340,837)	$ (401,531)	$ (462,243)	$ (267,302)	$ 274,114	$ 2,408,832	$ 3,264,768	$ 1,251,209	$ 932,595	$ (304,319)	$ (563,941)	$ 5,321,856
TOTAL (Over)/ Under $:													**$ 25,206,674**

DUKE ENERGY CAROLINAS **McGee Workpaper 11**

North Carolina Annual Fuel and Fuel Related Expense
Actual Sales by Jursidication - Subject to Weather
Twelve Months Ended December 31, 2018
Docket E-7, Sub 1190
MWhs

Line #	Description	Reference	NORTH CAROLINA	SOUTH CAROLINA	Retail TOTAL COMPANY	% NC	% SC
1	Residential	Company Records	22,763,029	6,953,474	29,716,503	76.60	23.40
2	Total General Service	Company Records	24,162,007	5,800,354	29,962,361		
3	less Lighting and Traffic Signals		261,740	44,385	306,125		
4	General Service subject to weather		23,900,267	5,755,969	29,656,236	80.59	19.41
5	Industrial	Company Records	12,555,667	9,164,704	21,720,370	57.81	42.19
6	Total Retail Sales	1+2+5	59,480,703	21,918,532	81,399,234		
7	Total Retail Sales subject to weather	1+4+5	59,218,963	21,874,146	81,093,109	73.03	26.97

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

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment
Twelve Months Ended December 31, 2018
Docket E-7, Sub 1190

Line #	Description	REFERENCE	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Total Residential		(1,185,150)	76.60	(907,825)	23.40	(277,325)
	General Service						
2	Total General Service		(790,151)	80.59	(636,783)	19.41	(153,368)
	Industrial						
3	Total Industrial		(181,656)	57.81	(105,015)	42.19	(76,641)
4	Total Retail	L1+ L2+ L3	(2,156,957)		(1,649,623)		(507,334)
5	Wholesale		(120,731)				
6	Total Company	L4 + L5	(2,277,688)		(1,649,623)		(507,334)

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment by Class by Month
Twelve Months Ended December 31, 2018
Docket E-7, Sub 1190

	Residential	Commercial	Industrial	
2018	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	
JAN	(218,136)	(35,856)	-	
FEB	(21,771)	(2,405)	(1,317)	
MAR	297,124	-	-	
APR	(74,206)	(16,924)	41,146	
MAY	7,286	(10,553)	3,908	
JUN	(349,703)	(195,436)	(108,358)	
JUL	(226,914)	(108,742)	(35,233)	
AUG	51,266	25,765	13,164	
SEP	(130,432)	(533,537)	(522,476)	
OCT	(295,132)	119,399	432,355	
NOV	(13,417)	(2,573)	(4,846)	
DEC	(211,114)	(29,290)	-	
Total	**(1,185,150)**	**(790,151)**	**(181,656)**	**(2,156,957)**

Wholesale

2018	**TOTAL MWH ADJUSTMENT**	Note:	**The Resale customers include:**
JAN	(60,423)	1	Concord
FEB	54,716	2	Dallas
MAR	(36,354)	3	Forest City
APR	4,476	4	Kings Mountain
MAY	(9,856)	5	Due West
JUN	(30,811)	6	Prosperity
JUL	(5,051)	7	Lockhart
AUG	8,937	8	Western Carolina University
SEP	(26,557)	9	City of Highlands
OCT	1,983	10	Haywood
NOV	(390)	11	Piedmont
DEC	(21,401)	12	Rutherford
		13	Blue Ridge
Total	**(120,731)**	14	Greenwood

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales
Twelve Months Ended December 31, 2018
Docket E-7, Sub 1190

Line	Estimation Method [1]	Rate Schedule	NC Proposed KWH [1] Adjustment	SC Proposed KWH Adjustment	Wholesale Proposed KWH Adjustment	Total Company
1	*Regression*	Residential	188,586,837	70,684,402		
2						
3		**General Service (excluding lighting):**				
4	*Customer*	General Service Small and Large	(36,464,624)	(6,608,226)		
	Regression	T2 Flood Lighting/Outdoor Lighting	-	-		
5	*Regression*	Miscellaneous	(127,805)	272,435		
6		Total General	(36,592,429)	(6,335,791)		
7						
8		**Lighting:**				
9	*Regression*	T & T2 (GL/FL/PL/OL)[2]	(1,092,054)	1,005,314		
10	*Regression*	TS	40,545	(8,749)		
11		Total Lighting	(1,051,509)	996,565		
12						
13		**Industrial:**				
14	*Customer*	I - Textile	4,245,005	4,245,005		
15	*Customer*	I - Nontextile	47,195	3,163,678		
16		Total Industrial	4,292,201	7,408,683		
17						
18						
19		Total	155,235,100	72,753,859	81,154,151	309,143,111
					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. See ND330 for further explanation

[2] T and T2 were combined due to North Carolina's FL & GL schedules being merged into OL & PL during the 12 month period.

DUCE ENERGY CAROLINAS

North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales-Wholesale
Twelve Months Ended December 31, 2018
Docket E-7, Sub 1190

Calculation of Customer Growth Adjustment to KWH Sales - Wholesale

Line No.		Reference	
1	Total System Resale (kWh Sales)	Company Records	11,246,967,907
2	Less Intersystem Sales	Schedule 1	1,945,444,289
3	Total KWH Sales Excluding Intersystem Sales	L1 - L2	9,301,523,618
4	Residential Growth Factor	Line 8	0.8725
5	Adjustment to KWH's - Wholesale	L3 * L4 / 100	81,154,151
6	Total System Retail Residential kWh Sales	Company Records	29,716,502,591
7	2018 Proposed Adjustment KWH - Residential (NC+SC)	WP 13 1	259,271,239
8	Percent Adjustment	L7 / L6 * 100	0.8725

"RAC001": CarolinasOperating Revenue Report

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Coal Inventory Rider True-up Calculation
Docket E-7, Sub 1190

Workpaper 14

Line No.			2018 *August*	2018 *September*	2018 *October*	2018 *November*	2018 *December*	2019 *January*	*Total to Date*
1	Full Load Burn 35 day supply	Input	2,209,515	2,209,515	2,209,515				
2	Beginning Actual tons on hand (including Terminals and In-transit) - actual	Input	2,349,694	2,356,042	2,244,622				
3	Ending Actual tons on hand (including Terminals and In-transit) - actual	Input	2,356,042	2,244,622	2,347,399				
4	Average tons on hand	(L2 + L3)/2	2,352,868	2,300,332	2,296,010				
5	Coal tons in excess of 35 days	L4 - L1	143,353	90,817	86,495				
6	Price per ton	Input	$ 73.23	$ 73.23	$ 73.23				
7	Dollars in excess of 35 day supply	L5 * L6	$ 10,497,741	$ 6,650,537	$ 6,334,064				
8	Number of days supply	L4 / 63,129 tons	37	36	36				
9	Carrying cost percentage 8/1/2018-12/31/2018 (a) (b)		0.745623%	0.745623%	0.745623%				
10	Total system amount to recover	L7 * L9	$ 78,274	$ 49,588	$ 47,228				$ 175,090
11	NC allocation percentage	Input	66.6244%	66.6244%	66.6244%				66.6244%
12	Total NC retail amount to recover	L10 * L11	$ 52,149	$ 33,038	$ 31,466				$ 116,653
13	NC Actual $ Collected	Input	$ 8,997	$ 24,938	$ 18,962	$ 17,250	$ 11,647	$ 33	$ 81,827
14	GRT & Reg. Fee percentage	Input	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%	0.14%
15	GRT and Reg Fee $'s To Back Out	L13 * L14	$ 13	$ 35	$ 26	$ 24	$ 16	$ 0	$ 114
16	Rider Excluding GRT & Reg Fee	L13 - L15	$ 8,984	$ 24,903	$ 18,936	$ 17,226	$ 11,631	$ 33	$ 81,712
17	(Over)/Under Collected - at current tax rate	L12 - L16	$ 43,165	$ 8,135	$ 12,530	$ (17,226)	$ (11,631)	$ (33)	$ 34,940
18	**(Over)/Under Collected - at future tax rate**	L19*(1-CTR)/(1-FTR)	**$ 43,016**	**$ 8,107**	**$ 12,486**	**$ (17,166)**	**$ (11,590)**	**$ (33)**	**$ 34,820**

Notes:

(a) Carrying costs exclude gross receipts tax and regulatory fee.

(b) Revised to reflect current state income tax apportionment percentages.

	(OVER)/UNDER BALANCE	CUMULATIVE BASIS FOR COMPUTING RETURN	MONTHLY DEFERRED INCOME TAX 0410.11 - (Current Tax Rate)	CUMULATIVE DEFERRED INCOME TAX	NET DEFERRED BALANCE AFTER-TAX	MONTHLY AFTER-TAX RETURN ON DEFERRAL (Interest)	CUMULATIVE AFTER-TAX INTEREST INCOME	GROSS UP OF "AFTER-TAX RETURN ON DEFERRAL" TO PRETAX STATUS 0421.64	CUMULATIVE GROSS PRETAX RETURN
Rate Case			**0.236686**			**0.005691**		**0.763314**	
Rates 1/01/2018 - 12/31/18			**0.236149**			**0.005692**		**0.763851**	
Rates 1/1/19 - current			**0.233503**			**0.005697**		**0.766498**	
BEGINNING BAL.	0	0	0			0	0	0	0
Aug-18	43,165	43,165	10,193	10,193	32,972	94	94	123	123
Sep-18	8,135	51,300	1,921	12,114	39,186	205	299	267	390
Oct-18	12,530	63,830	2,959	15,073	48,757	250	549	326	716
Nov-18	(17,226)	46,604	(4,068)	11,005	35,599	240	789	313	1,029
Dec-18	(11,631)	34,973	(2,747)	8,258	26,715	177	966	231	1,260
Jan-19	(33)	34,940	(8)	8,250	26,690	152	1,118	198	1,459
Feb-19	0	34,940	0	8,250	26,690	152	1,270	198	1,657
Mar-19	0	34,940	0	8,250	26,690	152	1,422	198	1,855
Apr-19	0	34,940	0	8,250	26,690	152	1,574	198	2,054
May-19	0	34,940	0	8,250	26,690	152	1,726	198	2,252
Jun-19	0	34,940	0	8,250	26,690	152	1,878	198	2,451
Jul-19	0	34,940	0	8,250	26,690	152	2,030	198	2,649
Aug-19	0	34,940	0	8,250	26,690	152	2,182	198	2,847
ENDING BALANCE	34,940	34,940	8,250	8,250	26,690	2,182	2,182	2,847	2,847

Total Under-Collection 37,667

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**ERIC S. GRANT 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 Eric S. Grant. 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 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 have a Bachelor of Science degree in Electrical Engineering from North Carolina State University. I joined Progress Energy in 1990, as an engineer in the Nuclear Engineering Department. From 2000-2006, I held a variety of management positions within Progress Energy's System Planning and Operations Department, including managing system operations for what is now DEP and Duke Energy Florida (DEF). In 2007, I became General Manager for the DEF Combine Cycle and Combustion Turbine Generation Fleet. I joined Duke Energy in July 2012 as the Managing Director of System Optimization, the position which I held until April 2017. I assumed my current position in April 2017. I am also a licensed professional engineer in the state of North

Carolina.

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

A. Yes. I filed testimony in DEC's 2018 North Carolina fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1163 and in DEP's 2018 North Carolina fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1173.

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, 2018 through December 31, 2018 ("test period") versus the period January 1, 2017 through December 31, 2017 ("prior test period"), and describe changes projected for the billing period of September 1, 2019 through August, 31 2020 ("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 Grant Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Grant 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 Grant 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 Grant 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 $78.71 per ton, compared to $74.90 per ton in the prior test period, representing an increase of approximately 5%. This includes an average transportation cost of $29.58 per ton in the test period, compared to $26.46 per ton in the prior test period, representing an increase of approximately 12%. The Company's average price of gas purchased for the test period was $3.84 per Million British Thermal Units ("MMBtu"), compared to $3.65 per MMBtu in the prior test period, representing an increase of approximately 5%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEC's coal burn for the test period was 8.7 million tons, compared to a coal burn of 9.7 million tons in the prior test period, representing a decrease of 10%. The Company's natural gas burn for the test period was 128.8 MMBtu, compared to a gas burn of 80.8 MMBtu in the prior test period, representing an increase of approximately 59%. The net increase in DEC's overall natural gas burn was primarly driven by the addition of the new Lee combined cycle facility, which became commercially available in April 2018. An additional contributing factor to changes in coal and natural gas burns were commodity prices.

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

A. Coal markets continue to be in a state of flux due to a number of factors, including: (1) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) strong global market demand for both steam and metallurgical coal; (4) uncertainty surrounding regulations for mining operations; and (5) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

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. In addition, there continues to be growth in the natural gas pipeline infrastructure needed to serve increased market demand. However, pipeline infrastructure permitting and regulatory process approval efforts are taking longer due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing.

Over the longer term planning horizon, natural gas supply is projected to continue to increase along with the needed pipeline infrastructure to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico.

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 6.5 million tons, compared to 8.7 million tons consumed during the test period. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $66.80 per ton for the billing period compared to $77.13 per ton in the test period. The lower projected cost is due, in part, to newly negotiated rail transportation contracts that go into effect in early spring 2019. 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 147.2 MMBtu, which is an increase from the 128.8 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 driven by the inclusion of natural gas generation at Cliffside, Belews Creek, and Marshall Units 3 & 4 as a result of the dual fuel conversions being commercial available over the course of the billing period. The current average forward Henry Hub price for the billing period is $2.75 per MMBtu, compared to $3.09 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.

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, environmental permit and emissions considerations, projected renewable capacity, and wholesale energy imports and exports.
- Station and system inventory targets are developed to provide reliability, insulation from short-term market volatility, and sensitivity 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 additional needs.
- All qualified suppliers are invited to participate in proposals to satisfy additional or contract needs.
- Spot market solicitations are conducted on an on-going basis to supplement contract purchases.
- Contracts are awarded based on the lowest evaluated offer, 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 capacity, and fleet maintenance and availability schedules.
- Physical procurement targets are developed to procure a cost effective and reliable natural gas supply.
- Over time, short-term and long-term Requests for Proposals and market solicitations are conducted with potential suppliers 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 ascertain additional 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 36-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, 2018 & 2017
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
1	January 2018	453,756	60,390	514,146
2	February	770,299	-	770,299
3	March	818,185	48,963	867,148
4	April	728,025	13,269	741,294
5	May	712,466	11,116	723,582
6	June	683,250	37,208	720,458
7	July	717,234	149,366	866,600
8	August	678,523	221,949	900,470
9	September	564,680	218,860	783,537
10	October	387,121	95,651	482,771
11	November	349,180	53,825	403,003
12	December	483,536	96,525	580,061
13	**Total** (Sum L1:L12)	**7,346,255**	**1,007,122**	**8,353,369**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales(Tons)	Total (Tons)
14	January 2017	492,404	285,634	778,038
15	February	769,679	34,968	804,647
16	March	797,907	47,438	845,345
17	April	762,700	122,152	884,852
18	May	616,088	196,451	812,539
19	June	587,819	212,158	799,977
20	July	824,226	96,829	921,055
21	August	807,076	179,219	986,295
22	September	678,951	105,441	784,392
23	October	505,295	95,857	601,152
24	November	415,136	58,617	473,753
25	December	593,868	47,389	641,257
26	**Total (Sum L14:L25)**	**7,851,149**	**1,482,153**	**9,333,302**

DUKE ENERGY CAROLINAS
Summary of Gas Purchases
Twelve Months Ended December 31, 2018 & 2017
MBTUs

Line No.	Month	MBTUs
1	January 2018	6,638,156
2	February	6,512,143
3	March	10,050,310
4	April	10,537,626
5	May	10,067,211
6	June	12,715,364
7	July	15,647,875
8	August	12,892,804
9	September	12,377,677
10	October	10,303,322
11	November	11,867,520
12	December	9,183,559
13	**Total (Sum L1:L12)**	**128,793,567**

Line No.	Month	MBTUs
14	January 2017	6,197,082
15	February	6,087,279
16	March	6,952,395
17	April	4,229,605
18	May	6,556,798
19	June	6,420,642
20	July	7,915,859
21	August	7,227,606
22	September	6,912,715
23	October	7,406,015
24	November	8,220,853
25	December	6,709,366
26	**Total (Sum L14:L26)**	**80,836,215**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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	)

ERIC S. GRANT CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

FEBRUARY 26, 2019

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**REGIS REPKO 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 Regis Repko 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 and Chief Fossil/Hydro Officer for Duke Energy Carolinas, LLC ("DEC" or the "Company").

Q. WHAT ARE YOUR CURRENT DUTIES AS SENIOR VICE PRESIDENT AND CHIEF FOSSIL/HYDRO OFFICER?

A. In this role, I am responsible for the operations of the Company's regulated fleet of fossil, hydroelectric, and solar (collectively, "Fossil/Hydro/Solar") generating facilities in six states, including outage and maintenance services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Pennsylvania State University with a Bachelor of Science degree in Nuclear Engineering. I also have completed the Institute of Nuclear Power Operations (INPO) Senior Nuclear Plant Manager Course. My career began with Duke Energy in 1995 as an engineer at Oconee Nuclear Station. I have held various roles of increasing responsibility including nuclear shift supervisor, operations shift manager, engineering supervisor, maintenance rotating equipment manager and superintendent of operations, where I had responsibility for the operations of Oconee Nuclear Station and Keowee Hydro Station. I have also served as engineering manager for Catawba Nuclear Station and station manager for McGuire Nuclear Station. I became the Senior Vice President and Chief Fossil/Hydro Officer in 2016.

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

A. Yes. I testified before this Commission in the DEP NC 2015 Fuel Hearing Docket E-2, Sub 1069.

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 2018 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, 2018 through December 31, 2018 (the "test period"), (3) provide information on significant Fossil/Hydro/Solar outages that occurred during the test period, and (4) provide information concerning environmental compliance efforts.

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

A. The Company's Fossil/Hydro/Solar generation portfolio consists of approximately 14,991 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	6,764 MWs
Steam Natural Gas -	170 MWs
Hydro -	3,245 MWs
Combustion Turbines -	2,665 MWs
Combined Cycle Turbines -	2,116 MWs

Solar - 31 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 – W.S. Lee Station ("Lee") Unit 3 – is considered to be a peaking unit.

The Company has a total of 31 simple cycle combustion turbine ("CT") units, of which 29 are considered the larger group providing approximately 2,581 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 combined cycle turbines ("CC"), comprised of the Buck CC, Dan River CC and 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 2,140 MWs, along with conventional hydro assets consisting of 72 units providing approximately 1,104 MWs of capacity. The 31 MWs of solar capacity are made up of 18 roof top solar sites providing 3 MWs of relative summer dependable capacity, the Mocksville solar site providing 5 MWs of relative summer dependable capacity, the Monroe solar site providing 21 MWs of relative summer dependable capacity and Woodleaf providing 2 MWs of relative summer dependable capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEC'S 2017 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. DEC added Lee CC in April 2018, which added 786 MWs of capacity. The Hydro Fleet retired the Rocky Creek Station, units at Great Falls in May 2018 and two units at Ninety-Nine Islands in December 2018. Cliffside Station was upgraded to allow for dual fuel operation, allowing utilization of coal and natural gas. DEC completed the Woodleaf solar facility in December 2018. This facility has 6 MWs of nameplate capacity which provide 2 MWs of relative summer dependable capacity.

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 9,468 Btu/kWh. Based on operating performance data for 2017 that was published in the June 2018 issue of *Power Engineering* magazine, DEC's Rogers Energy Complex ("Cliffside"), Belews Creek Steam Station ("Belews Creek"), and Marshall Steam Station ("Marshall") ranked as the second, fourth, and eighth most efficient coal-fired generating stations in the nation with heat rates of 9,055 Btu/kWh, 9,167 Btu/kWh, and 9,495 Btu/kWh, respectively. These results compare favorably to the average heat rate of 10,476 Btu/kWh for North American coal generators, also reported in the above noted magazine. For the test period, the Marshall units provided 37% of coal-fired generation for DEC, with the Belews Creek units providing 35% and Cliffside providing 24%.

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 101.8 million MW hours ("MWhs") for the test period. The Fossil/Hydro/Solar fleet provided 41.8 million MWhs, or approximately 41% of the total generation. As a percentage of the total generation, 22% was produced from coal-fired stations and approximately 13% from CC operations, 3% from CTs, 2% from hydro facilities, and .13% 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 the 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.

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

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 2013 through 2017, and is categorized by generator type. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating. The data in the chart reflects DEC results compared to the NERC five-year comparisons.

Generator Type	Measure	Review Period	2013-2017	Nbr of Units
		DEC Operational Results	NERC Average	
Coal-Fired Test Period	EAF	79.5%	78.4%	752
	NCF	38.3%	56.4%	
	EFOR	7.5%	8.7%	
Coal-Fired Summer Peak	EAF	95.8%	n/a	n/a
Total CC Average	EAF	86.2%	85.0%	338
	NCF	76.7%	52.7%	
	EFOR	3.32%	5.3%	
Total CT Average	EAF	83.3%	87.8%	776
	SR	99.4%	98.1%	
Hydro	EAF	76.3%	80.4%	1,113

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.

Bad Creek hydro completed a major outage in Spring 2018, which included spherical valve overhauls and inspections of the intake and penstock to prepare for the Bad Creek uprate project, which will begin in Fall 2019. Lincoln

CT Unit 1 and Unit 2 completed an outage in Spring 2018 to upgrade the turbine control system. The CC fleet performed planned outages at Dan River CC and Buck CC in Spring 2018. The primary purpose of the Dan River CC outage was to perform a CT borescope inspection and a heat recovery steam generator inspection. The primary purpose of the Buck CC outage was to perform a borescope inspection on each combustion turbine.

In Fall 2018, Belews Creek Unit 2 preformed a boiler outage. The primary purpose of the outage was to replace the secondary superheater in the boiler and rewind the LP generator. Marshall Unit 2 completed an outage in Fall 2018. The primary purpose of this outage was to replace the HP and LP turbine rotors. Cliffside Unit 5 and Unit 6 completed an outage for the dual fuel conversion to allow the units to burn coal and natural gas. Lincoln CT Units 3-8 completed an outage in Fall 2018 to upgrade the turbine control systems.

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 Mercury and Air Toxics Standards ("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 McGee provides the cost information for DEC's chemical use and forecast.

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

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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 serve 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 1163.

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, 2018 through December 31, 2018 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2019 through August 31, 2020 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 $45.06 per pound for uranium concentrates during the test period, representing an increase of 15% per pound 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 2% to $118.62 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 44% and 36%, respectively.

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

A. Prices in the uranium concentrate markets remain relatively low with the continued lack of demand due to the March 2011 event at Fukushima. Industry consultants, however, believe market prices need to increase from current levels in order to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements.

Market prices for enrichment services have continued to decline primarily due to reduced demand and increased supplier inventories following the Fukushima event. Additionally, the transition by enrichment suppliers from gaseous diffusion technology to the more cost efficient gas centrifuge technology was a market driver.

Fabrication is not a service for which prices are published; however, industry consultants expect fabrication prices will continue to generally trend upward. For conversion services, market prices have increased during the test period.

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

A. The Company anticipates a decrease in nuclear fuel costs on a cents per kilowatt hour ("kWh") basis through the next billing period. 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 decrease from 0.6149 cents per kWh incurred in the test period, to approximately 0.6115 cents per kWh in the billing period. This change reflects the discharge of fuel with a higher cost basis from the reactors and its replacement with fuel procured under new contracts negotiated in lower markets.

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.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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 had over 31 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.

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, 2018 through December 31, 2018 ("test period"). I provide information about refueling outages for the test 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, 2019 through August 31, 2020 ("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 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.

[1] Reflects DEC's 19.246% ownership of Catawba Nuclear Station

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 59% of the total power generated by DEC. During 2018, DEC's seven nuclear units achieved the third highest annual net generation in the Company's history, falling just below record output achieved in 2016 and 2017 despite the fact that there was one additional refueling outage in 2018 as compared to the two prior years. The average capacity factor in 2018 for the Company's nuclear fleet was 95.29%, thereby marking the 19th consecutive year in which DEC's nuclear fleet achieved a system capacity factor exceeding 90%. All five of the Company's refueling outages in 2018 were completed within the scheduled allocation durations. McGuire Unit 1 established a new net generation record during 2018, and McGuire Unit 2 operated continuously during the operating cycle leading up to the September 2018 refueling outage. Catawba Unit 1 operated continuously during the cycle leading into the November 2018 refueling outage, and established a new record for the highest net generation for 9 months during the year. Catawba Unit 2 also achieved a continuous cycle run leading into that unit's March 2018 refueling outage, which represented the second shortest refueling outage for the unit. During the peak summer demand, the Oconee station achieved the highest 3rd quarter output in the station's history, and, over the course of entire year, recorded the third best annual generation performance.

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 90.21% for the period 2013 through 2017 for comparable units (pressurized water reactors on a capacity-rated basis with capacity ratings at and above 800 MWs). The Company's 2018 capacity factor of 95.29% and 2-year average[2] of 95.58% both exceed the NERC average of 90.21%.

[2] This represents the simple average for the current test period and prior test period of 12 months ended December 2016 for the DEC nuclear fleet.

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, manual and automatic shutdowns, capacity factor, forced loss rate, industry performance index, and total operating cost. On a larger industry basis using early release data for 2018 from the Electric Utility Cost Group, all three of DEC's nuclear plants rank in the top quartile in total operating cost among the 60 U.S. operating nuclear plants. By continually assessing the Company's performance as compared with industry benchmarks, the Company continues to ensure the overall safety, reliability and cost-effectiveness of DEC's nuclear units.

The superior performance of DEC's nuclear fleet has resulted in substantial benefits to customers. DEC's nuclear fleet has produced approximately 39 million MWhs of additional, carbon-free generation over the past 19 years (as compared with production at a capacity factor of 90%), which is equivalent to an additional 8 months of output from DEC's nuclear fleet (based on DEC's average annual generation for the same 19-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 or less 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 planning 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 or to defer work 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 AND MAINTENANCE AT DEC'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. There were five refueling outages completed during the test period. All five outages were completed within the duration allocation windows, and the combined O&M outage costs for the five refueling outages totaled $143[3] million compared to the combined budget for the five outages of $146.8 million.

The Catawba Unit 2 refueling outage began on March 17, 2018. In addition to refueling, reliability and safety enhancing maintenance was completed. Major pump and motor work included the replacement of the 2A stator coolant

[3] The combined outage cost and budget is inclusive of Catawba's joint owners' share.

pump, 2A condensate booster pump motor, 2B residual heat removal pump and motor, and the 2B2 component cooling pump and motor. Electrical work included installation of a new governor, with slow start capability, on the 2A emergency diesel generator ("EDG"), and rebuild of the 2B EDG battery charger. The first phase of the emergency supplemental power source electrical tie-ins was completed, adding additional emergency power resources and increasing maintenance flexibility on the EDGs. The distributed control system was upgraded and the open phase detection modification was completed on Unit 2. Fifty-three control rod drive mechanism cables and associated connectors were replaced. Repairs were completed on the 2A low pressure turbine rotor and robotic inspections were completed on eight welds associated with four nozzles on the reactor head. After refueling, maintenance, and modifications were completed, the unit returned to service on April 14, 2018, for a total outage duration of 27.9 days compared to a schedule allocation of 30 days. Following restart from the refueling outage, the turbine was disconnected for 6.2 hours to complete turbine overspeed trip testing.

After completing operating cycle 29, Oconee Unit 3 shut down on April 20, 2018 for refueling. In addition to refueling activities, major work included installation of new protective relaying on the main transformer, auxiliary transformer, and generator. Power circuit breaker 30 and numerous molded case breakers were replaced. Main step-up transformer work included the replacement of three high side bushings. Eddy Current testing was completed on all tubes in both steam generators. The 3A2 high pressure injection line thermal sleeve was replaced and preventative maintenance was completed on the 3C low pressure turbine rotor. After refueling, maintenance, and modifications were completed, the outage successfully completed on May 19, 2018. The outage duration was 28.2 days compared to a schedule allocation of 29 days.

McGuire Unit 2 shut down for refueling on September 15, 2018. In addition to refueling, major pump and motor work included the 2C2 heater drain pump motor replacement, 2A2 component cooling pump motor replacement, 2B chemical and volume control system pump motor replacement, and the rebuild of the 2B nuclear service water pump. Electrical work included replacement of the 2B main step-up transformer, and installation, testing, and tie-in of the emergency supplemental power supply ("ESPS") diesel generators. The ESPS installations provide an additional source of backup power and allow additional flexibility to complete maintenance on the station's emergency diesel generators. The open phase detection modification was also installed. Other work performed included repair of the 2A low pressure turbine #4 bearing, turning gear replacement, and steam generator secondary separator inspections and repair. Insulation was replaced on the reactor vessel head and digital rod position indication head cables and coil stacks were replaced. After refueling, inspections, maintenance, and modifications completed, the unit returned to service on October 13, 2018. The outage completed in 28.5 days compared to a schedule allocation of 29 days.

On October 19, 2018, Oconee Unit 1 was removed from service to begin a refueling outage. In addition to refueling activities, the Unit 1 switchyard power circuit breaker 18, main step-up transformer, and numerous molded case circuit breakers were replaced. The 1B2 reactor coolant pump ("RCP") rotating assembly was replaced and the 1B1 RCP motor bearing was repaired. Eddy

Current testing was completed on all tubes in both steam generators. Turbine work included inspections and maintenance for the 1B low pressure turbine. After refueling, maintenance, testing, and modifications were completed, the unit returned to service on November 14, 2018, for a duration of 25.7 days compared to a schedule allocation of 31.75 days. After the conclusion of the refueling outage, the turbine was disconnected for 1.3 hours for turbine overspeed testing.

The fifth and final refueling outage of the year began on November 17, 2018 when Catawba Unit 1 entered its fall refueling outage. In addition to refueling activities, the station completed inspections, maintenance, and modifications that improved safety margins and strengthened reliability. Major reliability pump and motor work included replacement of the 1A nuclear service water pump and motor, the 1C hotwell pump and motor, and the 1A condensate booster pump motor. Modifications completed included the installation of the open phase detection system and emergency diesel generator governor modifications that added slow start capabilities. Both modifications improve safety margins related to offsite and backup power. Turbine and feedwater work included inspections of the 1B low pressure turbine, the 1A main feedwater pump turbine, and inspections of the 1A auxiliary feedwater pump turbine and jet plug repair. Other significant inspections included Eddy Current testing on the Unit 1 steam generator, control rod guide tube and Alloy 600 auxiliary head adapter encoded inspections. After inspections, maintenance, and modifications completed, the unit returned to service on December 11, 2018. The duration of the outage was 24.5 days compared to a schedule allocation of 28 days.

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 92.95% 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 McGee and exceeds the five-year industry weighted average capacity factor of 90.21% for comparable units as reported in the NERC Brochure during the period of 2013 to 2017.

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

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1190

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 26, 2019

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's Fuel Charge Adjustment Proceeding, in Docket No. E-7, Sub 1190, 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 26th day of February, 2019.

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