ALLEN LAW OFFICES, PLLC

DWIGHT W. ALLEN
ATTORNEY

June 11, 2019

VIA ELECTRONIC FILING AND HAND DELIVERY

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

RE: Docket No. E-2, Sub 1204
Duke Energy Progress, LLC's Fuel Charge Adjustment Proceeding

Dear Ms. Jarvis:

Enclosed for filing with the North Carolina Utilities Commission ("NCUC" or the "Commission") is the Application of Duke Energy Progress, LLC ("DEP") 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, exhibits, and workpapers of Dana M. Harrington, and the testimony and exhibits of Regis Repko, Kenneth D. Church, Kelvin Henderson and Brett Phipps containing the information required in NCUC Rule R8-55. I will deliver fifteen (15) paper copies of the filing to the Clerk's Office by close of business on June 12, 2019.

Information contained in Brett Phipp's Exhibit 3 is confidential because it contains costs to purchase spot gas supply, and public disclosure could hinder DEP from obtaining the most cost-effective energy to meet the needs of its customers. Information contained in Kelvin Henderson's Exhibit 1 is confidential because it contains sensitive information regarding DEP's future nuclear outage schedule. For that reason, it is being filed under seal pursuant to N.C. Gen. Stat. § 132-1.2. This confidential document should only be shared with the Commission and Commission Staff. Parties to the docket may contact DEP regarding obtaining copies pursuant to an appropriate confidentiality agreement.

Please contact me if you have any questions.

Respectfully submitted,

Dwight W. Allen

Enclosures
cc: Parties of Record

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of Application of Duke Energy Progress, LLC R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	))))	**DUKE ENERGY PROGRESS LLC'S APPLICATION**

Duke Energy Progress, LLC ("DEP," "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 410 South Wilmington Street, Raleigh, North Carolina, and its mailing address is:

Duke Energy Progress, LLC
P. O. Box 1551
Raleigh, North Carolina 27602

2. The name and address of Applicant's attorney is:

Dwight W. Allen
Allen Law Offices, PLLC
1514 Glenwood Avenue, Suite 200
Raleigh, North Carolina 27608
Tel: (919) 838-0529
dallen@theallenlawoffices.com

Copies of all pleadings, testimony, orders, and correspondence in this proceeding should be served upon the attorney 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 DEP and requires that the Company use a test period of 12 months ended March 31. Therefore, the test period used in this Application for these proceedings is April 1, 2018 – March 31, 2019 ("test period").

4. In Docket No. E-2, Sub 1173, DEP's last fuel case, the Commission approved the following fuel and fuel-related costs factors (excluding the Experience Modification Factor ("EMF") and regulatory fee):

Residential	2.311¢ per kWh
Small General Service	2.556¢ per kWh
Medium General Service	2.477¢ per kWh
Large General Service	1.757¢ per kWh
Lighting	2.251¢ per kWh

5. In this Application, DEP proposes fuel and fuel-related costs factors (excluding EMF and regulatory fee) of:

Residential	2.355¢ per kWh
Small General Service	2.469¢ per kWh
Medium General Service	2.432¢ per kWh
Large General Service	2.099¢ per kWh
Lighting	2.121¢ per kWh

In addition, these factors should be adjusted for the EMF by an increment/(decrement) (excluding regulatory fee) of:

Residential	0.252¢ per kWh
Small General Service	0.120¢ per kWh
Medium General Service	0.170¢ per kWh
Large General Service	0.557¢ per kWh
Lighting	0.435¢ per kWh

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

Residential	2.607¢ per kWh
Small General Service	2.589¢ per kWh
Medium General Service	2.602¢ per kWh

Large General Service	2.656¢ per kWh
Lighting	2.556¢ per kWh

The new fuel factors should become effective for service on or after December 1, 2019.

6. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Kenneth D. Church, Kelvin Henderson, Brett Phipps, Regis Repko, and the testimony, exhibits, and workpapers of Dana M. Harrington, 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 average nuclear capacity factor of 91.8% using projected billing period sales, and based on the proposed nuclear capacity factor of 94.62% using normalized test period sales. These base fuel and fuel-related costs factors are:

	NERC Average	Normalized Sales
Residential	2.650¢ per kWh	2.604¢ per kWh
Small General Service	2.639¢ per kWh	2.614¢ per kWh
Medium General Service	2.635¢ per kWh	2.615¢ per kWh
Large General Service	2.678¢ per kWh	2.643¢ per kWh
Lighting	2.645¢ per kWh	2.515¢ per kWh

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

Residential	2.607¢ per kWh
Small General Service	2.589¢ per kWh
Medium General Service	2.602¢ per kWh
Large General Service	2.656¢ per kWh

Lighting 2.556¢ per kWh

Respectfully submitted this 11th day of June, 2019.

By: */s/ Dwight W. Allen*

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ATTORNEY FOR DUKE ENERGY PROGRESS, LLC

STATE OF NORTH CAROLINA	)	
	)	VERIFICATION
COUNTY OF MECKLENBURG	)	

Dana M. Harrington, bring first duly sworn, deposes and says:

That she is Rates Manager for Duke Energy Progress, LLC; 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.

Dana M. Harrington

Dana M. Harrington

Sworn to and subscribed before me this 4 day of June, 2019.

THOMAS J. REED-HALL NOTARY PUBLIC GASTON COUNTY, NC

Notary Public

My Commission expires: 7-30-2022

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of)
Application of Duke Energy Progress, LLC)
Pursuant to G.S. 62-133.2 and NCUC Rule)
R8-55 Relating to Fuel and Fuel-Related)
Charge Adjustments for Electric Utilities)

DIRECT TESTIMONY OF DANA M. HARRINGTON FOR DUKE ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dana M. Harrington, and my business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am a Rates Manager supporting both Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Companies").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Psychology with Honors from the University of North Carolina at Chapel Hill and I am a certified public accountant licensed in the State of North Carolina. I began my accounting career in 2005 with Greer and Walker, LLC as a tax accountant and later a staff auditor. From 2007 until 2010 I was an Accounting Analyst with Duke Energy in the Finance organization. In 2010, I joined the Rates Department as a Lead Accounting Analyst where I have spent the past eight years. I was recently promoted to the position of Rates and Regulatory Strategy Manager.

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

A. No.

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

A. Yes. Duke Energy Progress' 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 Harrington Exhibits 1 through 6, along with supporting workpapers. The test period used in supplying this information is the period of April 1, 2018 through March 31, 2019 ("test period"), and the billing period is December 1, 2019 through November 30, 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 the Company's books and records. These books, records, and reports of the Company are subject to review by the regulatory agencies that regulate the Company'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 the Company's financial statements are accurate.

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

A. Yes, these exhibits were prepared by me or 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 94.62% proposed nuclear capacity factor and projected billing period megawatt hour ("MWh") sales.

- Exhibit 2, Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 94.62% proposed nuclear capacity factor and normalized test period MWh sales.
- Exhibit 2, Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting an 91.8% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for comparable units and projected billing period MWh sales.
- Exhibit 3, Page 1: Calculation of the Proposed Composite Experience Modification Factor ("EMF") rate.
- Exhibit 3, Page 2: Calculation of the EMF for residential customers.
- Exhibit 3, Page 3: Calculation of the EMF for small general service customers.
- Exhibit 3, Page 4: Calculation of the EMF for medium general service customers.
- Exhibit 3, Page 5: Calculation of the EMF for large general service customers.
- Exhibit 3, Page 6: Calculation of the EMF for lighting customers.
- Exhibit 4: Normalized Test Period MWh Sales, Fuel and Fuel-Related Revenue, Fuel and Fuel-Related Expense, and System Peak.
- Exhibit 5: Nuclear Capacity Ratings.
- Exhibit 6, Report 1: March 2019 Monthly Fuel Report, as required by NCUC Rule R8-52.
- Exhibit 6, Report 2: March 2019 Monthly Base Load Power Plant Performance Report, as required by NCUC Rule R8-53.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON HARRINGTON EXHIBIT 1.

A. Harrington Exhibit 1 presents a summary of fuel and fuel-related cost factors, which include: the currently approved fuel and fuel-related cost factors, the projected fuel and fuel-related cost factors using the NERC five-year national weighted average capacity factor with projected billing period sales, the projected fuel and fuel-related cost factors using the proposed capacity factor with normalized test period sales, and the proposed fuel and fuel-related cost factors using the proposed capacity factor with projected billing period sales.

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

A. The Company proposes that the fuel and fuel-related costs factors shown in the table below be reflected in rates during the billing period. The factors that DEP proposes in this proceeding utilize a 94.62% nuclear capacity factor as testified to by Company witness Henderson. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Harrington Exhibit 1 in cents per kWh ("cents/kWh"), are:

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Proposed Fuel and Fuel-Related Costs cents/kWh	2.355	2.469	2.432	2.099	2.121
EMF Increment/(Decrement) cents/kWh	0.252	0.120	0.170	0.557	0.435
Net Fuel and Fuel-Related Costs Factors cents/kWh	2.607	2.589	2.602	2.656	2.556

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

A. If the proposed fuel and fuel-related cost factors are approved, there will be a 2.4% decrease, on average, in customers' bills. The table below shows both the proposed and existing fuel and fuel-related cost factors (excluding regulatory fee).

	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
Proposed Factors cents/kWh	2.607	2.589	2.602	2.656	2.556
Current Factors cents/kWh	2.886	2.919	2.820	2.795	3.136

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

A. For this filing, DEP 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 DEP's and DEC's generation resources with the joint dispatch, which optimizes the generation fleets of DEP and DEC combined.

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

A. Exhibit 2 is divided into three schedules. Schedule 1 presents the prospective fuel and fuel-related costs. The calculation uses the nuclear capacity factor of 94.62%, as explained in Company witness Henderson's testimony, and provides the projected MWh sales for the billing period on which system generation and costs are based. Schedule 2 also uses the proposed capacity factor of 94.62% but against normalized test period kWh sales, as prescribed by NCUC Rule R8-55(e)(3), which requires the use of the methodology adopted by the Commission in the Company's last general rate case.

The Capacity factor shown on Schedule 3 is prescribed in NCUC Rule R8-55(d)(1). The NERC five-year national weighted average nuclear capacity factor used here is 91.8%. This capacity factor is based on the 2013 through 2017 data reported in the NERC's Generating Unit Statistical Brochure ("NERC Brochure") for units comparable to DEP's nuclear fleet. Schedule 3 also uses the projected billing period kWh sales as required by 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 cost factors by customer class resulting from the allocation of renewable and qualifying facility capacity costs by customer class on the basis of production plant as approved in the Company's 2017 and 2018 annual fuel proceedings (Docket Nos. E-2, Sub 1146 and E-2, Sub 1173).

Page 3 of Exhibit 2, Schedules 1, 2, and 3 shows the allocation of system fuel costs to the North Carolina retail jurisdiction, and the calculation of DEP's proposed fuel and fuel-related cost factors for the residential, small general service, medium general service, large general service, and lighting classes (excluding regulatory fee), using the uniform percentage average bill adjustment method.

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

A. As used in DEP's most recent general rate case, and for the purposes of this filing, Harrington Exhibit 2 Schedule 2 adjusts the coal generation produced by the dispatch model 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, DEP increased the level of coal generation produced by the dispatch model to account for the decrease in nuclear generation. The decrease in nuclear generation results from assuming an 91.8% NERC nuclear capacity factor compared to the proposed 94.62% nuclear capacity factor.

Q. HOW ARE PROJECTED FUEL AND FUEL-RELATED COSTS ALLOCATED?

A. System costs are allocated to the NC retail jurisdiction based on jurisdictional sales, with consideration given to any fuel and fuel-related costs or benefits that should be directly assigned. Costs are further allocated among customer classes using the uniform percentage average bill adjustment methodology to set fuel rates by customer class in this fuel proceeding as adopted in DEP's 2018 fuel and fuel-related cost recovery proceeding under Docket No. E-2, Sub 1173 with the exception of capacity-related purchased power costs described in subsections (5), (6) and (10) of N.C. Gen. Stat. § 62-133.2(a1), which are allocated based upon the production plant allocator from the most recent annual cost of service study.

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

A. Harrington Exhibit 2, Page 3 of Schedule 1 shows DEP's proposed fuel and fuel-related cost factors for the residential, small general service, medium general service, large general service, and lighting classes (excluding regulatory fee). The uniform bill percentage decrease of 2.4% was calculated by dividing the fuel and fuel-related cost decrease of $89 million for the North Carolina retail jurisdiction by the normalized annual North Carolina retail revenues at the existing rates of $3.7 billion. The cost decrease of $89 million was determined by comparing the total proposed fuel rate per kWh to the total fuel rate per kWh currently being collected from customers, and multiplying the resulting decrease in fuel rate per kWh by projected North Carolina retail kWh sales for the billing period. The proposed fuel rate per kWh equals the sum of the rate necessary to recover projected billing period fuel costs and the proposed composite EMF increment as computed on Harrington Exhibit 3, Page 1. Harrington 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 COST FACTORS FOR EACH CUSTOMER CLASS DERIVED FROM THE UNIFORM PERCENT ADJUSTMENT COMPUTED ON HARRINGTON EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. On each of Harrington Exhibit 2, Page 3 of Schedules 1, 2, and 3, the equal percent decrease for each customer class is applied to current annual revenues by customer class to determine a revenue decrease for each customer class. The revenue decrease is divided by the projected billing period sales for each class to derive a cents/kWh decrease. The current total fuel and fuel-related cost factors for each class are adjusted by the proposed cents/kWh decrease to get the proposed total fuel and fuel-related cost factors. The proposed total fuel factors are then separated into the prospective and EMF components by subtracting the EMF components for each customer class as computed on Harrington Exhibit 3, Pages 2, 3, 4, 5, and 6 to derive the prospective rate component for each customer class. Presentation of the projected fuel and fuel-related cost factors and the projected EMF increments are shown on Harrington Exhibit 2, Page 2 of Schedules 1, 2, and 3.

Q. DID YOU DETERMINE THAT DEP'S ANNUAL INCREASE IN THE AGGREGATE AMOUNT OF THE COSTS IDENTIFIED IN SUBSECTIONS (4), (5), (6), (10) AND (11) OF N.C. GEN. STAT. § 62-133.2(A1) DID NOT

EXCEED 2.5% OF ITS NC RETAIL GROSS REVENUES FOR 2018, AS REQUIRED BY N.C. GEN. STAT. § 62-133.2(A2)?

A. Yes. The Company's analysis shows that the annual increase in the costs recoverable under the relevant sections of the statute did not exceed 2.5% of DEP's gross revenues for the NC retail jurisdiction for the preceding calendar year; therefore, no adjustment has been made to exclude a portion of DEP's projected costs for the billing period as shown on Harrington Exhibit 2, Page 3 of Schedules 1, 2, or 3.

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

A. Harrington Exhibit 3, Page 1 demonstrates that, for the test period, the Company experienced a net under-recovery of approximately $146.8 million for the combined customer classes of the North Carolina retail jurisdiction. In its 2018 fuel proceeding, Docket E-2, Sub 1173, the Company reduced its forecasted purchased power costs by $57.4 million in order to comply with limitations in annual fuel increases as prescribed in G.S. 62-133.2(a2). As a result, the Company expected fuel revenues during the test period would be lower than fuel expenses, resulting in an under-collection.

The test period (over)/under collection was determined each month by comparing the actual fuel revenues collected from each class to actual fuel and fuel-related costs incurred by class based on the actual monthly sales of each class. DEP System fuel and fuel-related costs incurred were first allocated to the North Carolina 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 of purchased power capacity costs from renewables and qualifying facilities were allocated among customer classes based on production plant allocators from DEP's cost of service study. All other fuel and fuel-related costs were allocated among customer classes using the uniform percentage average bill adjustment method consistent with DEP's previous annual fuel proceeding.

Q. IS THE COMPANY PROPOSING ANY COST ADJUSTMENTS TO THE TEST PERIOD UNDER-COLLECTION OF FUEL AND FUEL-RELATED COSTS?

A. Yes. The Company is proposing to recover a component of net gain/loss on the sale of by-products included in test period costs on a cash basis rather than an accrual basis. The recommended adjustment relates to liquidated damages on the sale of by-products that are to be paid over 10 years under a settlement agreement with a third party to whom the Company sells gypsum. For accounting purposes, the full 10-year liability was accrued in December 2018. These system costs were reflected in the monthly fuel filings as they were recorded to the Company's books in FERC account 502, which is incorporated into the computation of net gain/loss on the sale of by-products. Currently, the NC retail share of these costs is reflected in the test period under-collection balance of $146.8 million. In this case, the Company believes that it is more equitable to customers for the Company to recover these costs as the amounts are paid, rather than when the liability was accrued. To achieve this result, an adjustment of ($44.1) million, to remove the North Carolina retail portion of the total amount recorded to the books during the test year, is presented on Harrington Exhibit 3, Page 1. Subsequently, a second adjustment of $6.6 million is presented on Harrington Exhibit 3, Page 1 to recognize only the North Carolina retail portion of the cash payments made during the test period. These adjustments are further identified by customer class on Harrington Exhibit 3, Pages 2 through 6.

In addition, the North Carolina retail portion of the cash payment to be made during the billing period, which totals approximately $5 million, is included in projected costs and would be included in projected costs annually until terms of the agreement are complete.

Q. WHY ARE THESE LIQUIDATED DAMAGES PROPERLY RECOVERED IN FUEL RATES?

A. N.C. Gen. Stat. § 62-133.2(a1)(9) specifies that "cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs." In this case, the liquidated damages are properly included in the calculation of net gain/loss on the sale of by-products because the liquidated damages provision was an essential commercial term of a larger transaction that was reasonably and prudently entered into by the Company for the benefit of customers. Due to changes in coal consumption over time, the Company was not able to meet its contractual gypsum supply obligations. Nevertheless, the Company's decision to enter into the arrangement was prudent and reasonable and the transaction as a whole still provided a benefit to customers.

Q. WERE ANY OTHER COST ADJUSTMENTS MADE TO THE TEST PERIOD UNDER-COLLECTION OF FUEL AND FUEL-RELATED COSTS?

A. Yes. Included in the test period under-recovered balance is the under-collection related to the coal inventory rider established in Ordering Paragraph 12 of the

Commission's February 23, 2018 *Order Accepting Stipulation, Deciding Contested Issue and Granting Partial Rate Increase* in Docket No. E-2, Sub 1142. DEP is not recovering any coal inventory rider costs other than interest beyond the month of October 2018 when the termination requirements were met, but the rates associated with the rider were not terminated from customer billings until service on and after December 1, 2018. Additional amounts collected through January 2019 reduced the October under-collected balance. Interest has been calculated on the under-collected balance through November 30, 2019. The inclusion of the coal inventory rider under-collection is shown on Harrington Exhibit 3, Page 1, and is further identified at the customer class level on Pages 2 through 6.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON HARRINGTON EXHIBIT 4.

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Harrington Exhibit 4 presents 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, consistent with the methodology utilized in DEP's most recent general rate case (Docket No. E-2, Sub 1142) and DEP's most recent fuel and fuel-related cost recovery proceeding (Docket No. E-2, Sub 1173). Customer growth was determined using regression analysis for residential, small general service, and lighting classes, and a customer-by-customer analysis for medium and large general service customers. Finally, Harrington Exhibit 4 shows the test period peak demand for the system and for North Carolina Retail customer classes.

Q. PLEASE IDENTIFY WHAT IS SHOWN ON HARRINGTON EXHIBIT 5.

A. Harrington Exhibit 5 presents the capacity ratings for each of DEP's nuclear units, in compliance with Rule R8-55(e)(12).

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

A. Yes. As shown on Harrington Exhibit 6, DEP's test year actual fuel and fuel-related costs were 2.658 cents/kWh. Key factors in DEP's ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio of nuclear, coal, natural gas, and hydro, the capacity factors of its nuclear fleet, and fuel procurement strategies, which mitigate volatility in supply costs. Other key factors include DEP's and DEC's respective expertise in transporting, managing and blending fuels, procuring reagents, and utilizing purchasing synergies of the combined Company, as well as the joint dispatch of DEP's and DEC's generation resources.

Company witness Henderson discusses the performance of DEP's nuclear generation fleet and Company witness Repko discusses the performance of the fossil/hydro/solar fleet, as well as the chemicals that DEP uses to reduce emissions. Company witness Phipps discusses fossil fuel costs and fossil fuel procurement strategies, and Company witness Church discusses nuclear fuel costs and nuclear fuel procurement strategies.

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

A. The largest component of the decrease in the proposed fuel and fuel-related cost factors is the request for collection of approximately $109.6 million of under-collected fuel costs via the proposed EMF increment, compared to the $224.3 million of under-collected fuel costs included in the existing EMF increment.

Q. HAS THE COMPANY FILED WORKPAPERS SUPPORTING THE CALCULATIONS, ADJUSTMENTS, AND NORMALIZATIONS AS REQUIRED BY NCUC RULE R8-55(E)(11)?

A. Yes. Working papers supporting the calculations, adjustments, and normalizations utilized to derive the proposed fuel factors are included with this filing.

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

A. Yes, it does.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Summary Comparison of Fuel and Fuel-Related Cost Factors
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Exhibit 1

Line No.	Description	Reference	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
	Current Fuel and Fuel-Related Cost Factors (Approved Fuel Rider Docket No. E-2, Sub 1173)						
1	Approved Fuel and Fuel-Related Costs Factors	Input	2.311	2.556	2.477	1.757	2.251
2	EMF Increment / (Decrement)	Input	0.575	0.363	0.343	1.038	0.885
3	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
4	Approved Net Fuel and Fuel-Related Costs Factors	Sum	2.886	2.919	2.820	2.795	3.136
	Other Fuel and Fuel-Related Cost Factors						
5	NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales	Exh 2 Sch 3 pg 3	2.650	2.639	2.635	2.678	2.645
6	Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales	Exh 2 Sch 2 pg 3	2.604	2.614	2.615	2.643	2.515
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 94.62% with Projected Billing Period MWh Sales						
7	Fuel and Fuel-Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	2.217	2.314	2.309	2.020	2.120
8	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.138	0.155	0.123	0.079	0.001
9	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Sum	2.355	2.469	2.432	2.099	2.121
10	EMF Increment/(Decrement) cents/kWh	Exh 2 Sch 1 pg 2	0.252	0.120	0.170	0.557	0.435
11	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
12	Net Proposed Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 1 pg 2	2.607	2.589	2.602	2.656	2.556

Note: The above rates do not include state regulatory fees.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% and Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 3-4	29,713,146	0.6170	$	183,324,690
2	Coal	Workpaper 3 - 4	11,131,286	3.1353		348,993,723
3	Gas - CT and CC	Workpaper 3 - 4	22,185,181	2.6683		591,960,856
4	Reagents & Byproducts	Workpaper 5	-			26,265,057
5	Total Fossil	Sum of Lines 2 - 4	33,316,467			967,219,636
6	Hydro	Workpaper 3	648,112			
7	Net Pumped Storage		-			
8	Total Hydro	Sum of Lines 6 - 7	648,112			
9	Utility Owned Solar Generation	Workpaper 3	279,675			
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	63,957,400			1,150,544,326
11	Purchases	Workpaper 3 - 4	7,560,370			464,368,032
12	JDA Savings Shared	Workpaper 5	-			(21,960,626)
13	Total Purchases	Sum of Lines 11 - 12	7,560,370			442,407,406
14	Total Generation and Purchases	Line 10 + Line 13	71,517,770			1,592,951,732
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(7,544,324)			(161,032,005)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,817,527)			
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16			$	1,431,919,727
18	Projected System MWh Sales for Fuel Factor	Workpaper 3	62,155,919			62,155,919
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 /Line 18 / 10				2.304

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% and Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Projected Billing Period MWh Sales	Workpaper 8	16,265,079	1,806,876	10,414,506	9,223,825	381,171	38,091,457
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 34,622,728
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,793,114
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 74,415,842
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Workpaper 13						61.00%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 45,394,250
7	Production Plant Allocation Factors	Workpaper 13	49.599%	6.156%	28.252%	15.986%	0.007%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,515,098	$ 2,794,328	$ 12,824,594	$ 7,256,923	$ 3,306	$ 45,394,250
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.138	0.155	0.123	0.079	0.001	0.119
	Summary of Total Rate by Class		cents/KWh	cents/KWh	cents/KWh	cents/KWh	cents/KWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.217	2.314	2.309	2.020	2.120	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.138	0.155	0.123	0.079	0.001	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.355	2.469	2.432	2.099	2.121	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.252	0.120	0.170	0.557	0.435	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	2.607	2.589	2.602	2.656	2.556	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.62% and Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	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) cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Workpaper 8	Workpaper 11	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential	16,265,079	$ 1,898,488,040	$ (45,419,195)	-2.4%	(0.279)	2.886	2.607
2	Small General Service	1,806,876	249,548,540	(5,970,169)	-2.4%	(0.330)	2.919	2.589
3	Medium General Service	10,414,506	950,513,824	(22,739,976)	-2.4%	(0.218)	2.820	2.602
4	Large General Service	9,223,825	534,744,328	(12,793,158)	-2.4%	(0.139)	2.795	2.656
5	Lighting	381,171	92,439,556	(2,211,513)	-2.4%	(0.580)	3.136	2.556
6	NC Retail	38,091,457	$ 3,725,734,287	$ (89,134,011)				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 8	$ 1,433,036,845
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	74,415,842
9	Adjusted System Other Fuel Costs	Line 7 - Line 8	$ 1,358,621,003
10	NC Retail Allocation % - sales at generation	Workpaper 10	61.68%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 837,997,435
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	45,394,250
13	NC Retail Total Fuel Costs before 2.5% Purchase Power Test	Line 11 + Line 12	$ 883,391,685
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 883,391,685
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 / 10	2.319
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.291
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19	2.610
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:		
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17	2.242
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18	0.602
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21-23	2.844
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.234)
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$ (89,134,010)

Notes:
Rounding differences may occur
Includes 100% ownership of all generating resources

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 3-4	29,713,146	0.6170	$ 183,324,690
2	Coal	Workpaper 15	10,963,189	3.1353	343,723,461
3	Gas - CT and CC	Workpaper 3-4	22,185,181	2.6683	591,960,856
4	Reagents & Byproducts	Workpaper 4	-		26,265,057
5	Total Fossil	Sum of Lines 2 - 4	33,148,370		961,949,374
6	Hydro	Workpaper 3	648,112		
7	Net Pumped Storage		-		
8	Total Hydro	Sum of Lines 6 - 7	648,112		
9	Utility Owned Solar Generation	Workpaper 3	279,675		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	63,789,303		1,145,274,064
11	Purchases	Workpaper 3 - 4	7,560,370		464,368,032
12	JDA Savings Shared	Workpaper 5	-		(21,960,626)
13	Total Purchases	Sum of Lines 11 - 12	7,560,370		442,407,406
14	Total Generation and Purchases	Line 10 + Line 13	71,349,673		1,587,681,470
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(7,544,324)		(161,032,005)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,812,883)		
17	System Fuel Expense for Fuel Factor	Lines 14 + Line 15 + Line 16			$ 1,426,649,465
18	Normalized Test Period MWh Sales for Fuel Factor	Exhibit 4	61,992,467		61,992,467
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10			2.301

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Normalized Test Period MWh Sales	Workpaper 8a	16,022,241	1,943,714	11,007,307	8,368,542	353,965	37,695,769
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 34,622,728
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,793,114
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 74,415,842
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Input						61.00%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 45,394,250
7	Production Plant Allocation Factors	Workpaper 13	49.599%	6.156%	28.252%	15.986%	0.007%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,515,098	$ 2,794,328	$ 12,824,594	$ 7,256,923	$ 3,306	$ 45,394,250
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.141	0.144	0.117	0.087	0.001	0.120
	Summary of Total Rate by Class		**cents/KWh**	**cents/KWh**	**cents/KWh**	**cents/KWh**	**cents/KWh**	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.211	2.350	2.328	1.999	2.079	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.141	0.144	0.117	0.087	0.001	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.352	2.494	2.445	2.086	2.080	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.252	0.120	0.170	0.557	0.435	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	2.604	2.614	2.615	2.643	2.515	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	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) cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Workpaper 8a	Workpaper 11	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential	16,022,241	$ 1,898,488,040	$ (45,139,471)	-2.4%	(0.282)	2.886	2.604
2	Small General Service	1,943,714	249,548,540	(5,933,400)	-2.4%	(0.305)	2.919	2.614
3	Medium General Service	11,007,307	950,513,824	(22,599,927)	-2.4%	(0.205)	2.820	2.615
4	Large General Service	8,368,542	534,744,328	(12,714,368)	-2.4%	(0.152)	2.795	2.643
5	Lighting	353,965	92,439,556	(2,197,892)	-2.4%	(0.621)	3.136	2.515
6	NC Retail	37,695,769	$ 3,725,734,287	$ (88,585,058)				

Line No.	Description	Source		Amount
	Total Proposed Composite Fuel Rate:			
7	Adjusted System Total Fuel Costs	Workpaper 8a	$	1,427,766,584
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2		74,415,842
9	System Other Fuel Costs	Line 7 - Line 8	$	1,353,350,741
10	NC Retail Allocation % - sales at generation	Workpaper 10		61.21%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$	828,385,989
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2		45,394,250
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$	873,780,239
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16a		0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$	873,780,239
16	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A		37,695,769
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10		2.318
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		0.291
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1		0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19		2.609
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:			
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17		2.242
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18		0.602
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19		0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23		2.844
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24		(0.235)
26	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A		37,695,769
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$	(88,585,058)

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 2	28,826,864	0.6170	$ 177,856,495
2	Coal	Workpaper 15	12,017,568	3.1353	376,780,866
3	Gas - CT and CC	Workpaper 3 - 4	22,185,181	2.6683	591,960,856
4	Reagents & Byproducts	Workpaper 5	-		26,265,057
5	Total Fossil	Sum of Lines 2 - 4	34,202,749		995,006,779
6	Hydro	Workpaper 3	648,112		
7	Net Pumped Storage		-		
8	Total Hydro	Sum of Lines 6 - 7	648,112		
9	Utility Owned Solar Generation	Workpaper 3	279,675		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	63,957,400		1,172,863,274
11	Purchases	Workpaper 3 - 4	7,560,370		464,368,032
12	JDA Savings Shared	Workpaper 5	-		(21,960,626)
13	Total Purchases	Sum of Lines 11- 12	7,560,370		442,407,406
14	Total Generation and Purchases	Line 10 + Line 13	71,517,770		1,615,270,680
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(7,544,324)		(161,032,005)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,817,527)		
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16			$ 1,454,238,675
18	System MWh Sales for Fuel Factor	Workpaper 3	62,155,919		62,155,919
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10			2.340

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Projected Billing Period MWh Sales	Workpaper 8	16,265,079	1,806,876	10,414,506	9,223,825	381,171	38,091,457
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 34,622,728
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,793,114
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 74,415,842
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Input						61.00%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 45,394,250
7	Production Plant Allocation Factors	Workpaper 13	49.599%	6.156%	28.252%	15.986%	0.007%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,515,098	$ 2,794,328	$ 12,824,594	$ 7,256,923	$ 3,306	$ 45,394,250
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.138	0.155	0.123	0.079	0.001	0.119
	Summary of Total Rate by Class		cents/KWh	cents/KWh	cents/KWh	cents/KWh	cents/KWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.260	2.364	2.342	2.042	2.209	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.138	0.155	0.123	0.079	0.001	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.398	2.519	2.465	2.121	2.210	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.252	0.120	0.170	0.557	0.435	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	2.650	2.639	2.635	2.678	2.645	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	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) cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Workpaper 8	Workpaper 11	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = H
1	Residential	16,265,079	$ 1,898,488,040	$ (38,431,626)	-2.0%	(0.236)	2.886	2.650
2	Small General Service	1,806,876	249,548,540	(5,051,681)	-2.0%	(0.280)	2.919	2.639
3	Medium General Service	10,414,506	950,513,824	(19,241,518)	-2.0%	(0.185)	2.820	2.635
4	Large General Service	9,223,825	534,744,328	(10,824,980)	-2.0%	(0.117)	2.795	2.678
5	Lighting	381,171	92,439,556	(1,871,280)	-2.0%	(0.491)	3.136	2.645
6	NC Retail	38,091,457	$ 3,725,734,287	$ (75,421,085)				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 8b	$ 1,455,355,794
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	74,415,842
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,380,939,952
10	NC Retail Allocation % - sales at generation	Workpaper 10	61.68%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 851,763,762
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	45,394,250
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 897,158,012
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 897,158,012
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.355
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.291
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 15-17	2.646
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:		
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17	2.242
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18	0.602
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.844
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.198)
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457
27	Increase/(Decrease) in Fuel Costs	Line 25* Line 26 * 10	$ (75,421,085)

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	#REF!	#REF!	2,821,410	$ 6,616,553	-	$ 6,616,553
2	May	#REF!	#REF!	2,743,729	13,930,507	-	13,930,507
3	June	#REF!	#REF!	3,379,527	20,501,107	-	20,501,107
4	July	#REF!	#REF!	3,687,027	13,504,786	-	13,504,786
5	August	#REF!	#REF!	3,705,569	12,651,306	-	12,651,306
6	September	#REF!	#REF!	3,324,420	22,555,310	-	22,555,310
7	October	#REF!	#REF!	3,247,434	(4,537,212)	-	(4,537,212)
8	November	#REF!	#REF!	2,905,623	14,008,619	-	14,008,619
9	December (New Rates - Sub 1173)	#REF!	#REF!	2,853,152	56,124,620	-	56,124,620
10	January 2019	#REF!	#REF!	3,344,813	19,890,481	$ (33,252)	19,857,229
11	February	#REF!	#REF!	3,239,879	(41,422,510)	-	(41,422,510)
12	March	#REF!	#REF!	2,793,993	13,007,082	-	13,007,082
13	Total Test Period			38,046,575	$ 146,830,650	$ (33,252)	$ 146,797,398
14	Booked (Over) / Under Recovery						$ 146,797,398
15	Coal inventory Rider (Over) / Under Recovery						257,250
16	Adjustment to remove by-product net gain/loss accrued expense						(44,144,639)
17	Adjustment to include by-product net gain/loss cash payments						6,640,945
18	Total (Over) / Under Recovery						$ 109,550,954
19	Normalized Test Period MWh Sales	Exhibit 4					37,695,769
20	Experience Modification Increment / (Decrement) cents/KWh						0.291

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.501	2.179	1,138,012	$ 3,660,529		$ 3,660,529
2	May	3.023	2.179	1,016,135	8,577,706		8,577,706
3	June	2.787	2.179	1,404,775	8,539,907		8,539,907
4	July	2.467	2.179	1,586,631	4,574,733		4,574,733
5	August	2.510	2.179	1,553,969	5,138,198		5,138,198
6	September	2.811	2.179	1,404,365	8,874,465		8,874,465
7	October	2.193	2.179	1,264,650	179,201		179,201
8	November	2.995	2.179	1,072,132	8,748,809		8,748,809
9	December (New Rates - Sub 1173)	3.604	2.237	1,386,673	18,956,228		18,956,228
10	January 2019	2.682	2.311	1,552,025	5,751,516	$ (14,440)	5,737,076
11	February	0.899	2.311	1,553,478	(21,931,387)		(21,931,387)
12	March	2.733	2.311	1,214,159	5,128,001		5,128,001
13	Total Test Period			16,147,005	$ 56,197,905	$ (14,440)	$ 56,183,465
14	Booked (Over) / Under Recovery						$ 56,183,465
15	Coal inventory Rider (Over) / Under Recovery						109,177
16	Adjustment to remove by-product net gain/loss accrued expense						(18,735,029)
17	Adjustment to include by-product net gain/loss cash payments						2,818,424
18	Total (Over) / Under Recovery						$ 40,376,037
19	Normalized Test Period MWh Sales	Exhibit 4					16,022,241
20	Experience Modification Increment (Decrement) cents/KWh						0.252

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Small General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.289	2.121	140,607	$ 236,079		$ 236,079
2	May	2.535	2.121	136,871	567,097		567,097
3	June	2.480	2.121	178,846	642,201		642,201
4	July	2.281	2.121	194,597	310,810		310,810
5	August	2.231	2.121	198,191	217,119		217,119
6	September	2.489	2.121	179,772	662,100		662,100
7	October	1.789	2.121	174,119	(578,233)		(578,233)
8	November	2.312	2.121	156,234	298,658		298,658
9	December (New Rates - Sub 1173)	4.862	2.313	120,842	3,080,272		3,080,272
10	January 2019	2.969	2.556	174,110	718,822	$ (1,763)	717,059
11	February	1.095	2.556	159,655	(2,332,952)		(2,332,952)
12	March	2.847	2.556	144,886	421,865		421,865
13	Total Test Period			1,958,731	$ 4,243,838	$ (1,763)	$ 4,242,075
14	Booked (Over) / Under Recovery						$ 4,242,075
15	Coal inventory Rider (Over) / Under Recovery						13,244
16	Adjustment to remove by-product net gain/loss accrued expense						(2,272,674)
17	Adjustment to include by-product net gain/loss cash payments						341,892
18	Total (Over) / Under Recovery						$ 2,324,536
19	Normalized Test Period MWh Sales	Exhibit 4					1,943,714
20	Experience Modification Increment (Decrement) cents/KWh						0.120

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Medium General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.440	2.356	834,634	$ 700,759		$ 700,759
2	May	2.524	2.356	871,652	1,468,210		1,468,210
3	June	2.683	2.356	1,042,496	3,411,985		3,411,985
4	July	2.601	2.356	1,074,969	2,629,373		2,629,373
5	August	2.536	2.356	1,098,143	1,980,830		1,980,830
6	September	2.852	2.356	988,512	4,902,428		4,902,428
7	October	1.955	2.356	1,021,065	(4,091,099)		(4,091,099)
8	November	2.453	2.356	940,892	913,230		913,230
9	December (New Rates - Sub 1173)	5.035	2.409	706,334	18,544,231		18,544,231
10	January 2019	3.287	2.477	883,889	7,155,890	$ (9,828)	7,146,062
11	February	1.127	2.477	855,202	(11,548,986)		(11,548,986)
12	March	2.927	2.477	790,364	3,557,351		3,557,351
13	Total Test Period			11,108,152	$ 29,624,202	$ (9,828)	$ 29,614,374
14	Booked (Over) / Under Recovery						$ 29,614,374
15	Coal inventory Rider (Over) / Under Recovery						75,107
16	Adjustment to remove by-product net gain/loss accrued expense						(12,888,554)
17	Adjustment to include by-product net gain/loss cash payments						1,938,903
18	Total (Over) / Under Recovery						$ 18,739,830
19	Normalized Test Period MWh Sales	Exhibit 4					11,007,307
20	Experience Modification Increment (Decrement) cents/KWh						0.170

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Large General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.709	2.417	678,418	$ 1,978,810		$ 1,978,810
2	May	2.886	2.417	689,394	3,230,432		3,230,432
3	June	3.476	2.417	723,936	7,668,586		7,668,586
4	July	3.135	2.417	801,315	5,754,642		5,754,642
5	August	3.034	2.417	825,198	5,091,306		5,091,306
6	September	3.504	2.417	723,070	7,861,222		7,861,222
7	October	2.406	2.417	757,387	(84,221)		(84,221)
8	November	2.971	2.417	707,153	3,914,585		3,914,585
9	December (New Rates - Sub 1173)	4.582	2.125	610,753	15,002,143		15,002,143
10	January 2019	2.603	1.757	704,241	5,960,860	$ (7,072)	5,953,788
11	February	0.937	1.757	643,138	(5,275,468)		(5,275,468)
12	March	2.371	1.757	615,274	3,776,307		3,776,307
13	Total Test Period			8,479,278	$ 54,879,204	$ (7,072)	$ 54,872,132
14	Booked (Over) / Under Recovery						$ 54,872,132
15	Coal inventory Rider (Over) / Under Recovery						57,332
16	Adjustment to remove by-product net gain/loss accrued expense						(9,838,327)
17	Adjustment to include by-product net gain/loss cash payments						1,480,039
18	Total (Over) / Under Recovery						$ 46,571,176
19	Normalized Test Period MWh Sales	Exhibit 4					8,368,542
20	Experience Modification Increment (Decrement) cents/KWh						0.557

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Lighting
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	1.793	1.657	29,739	$ 40,376		$ 40,376
2	May	1.950	1.657	29,677	87,063		87,063
3	June	2.466	1.657	29,473	238,428		238,428
4	July	2.454	1.657	29,516	235,228		235,228
5	August	2.401	1.657	30,068	223,853		223,853
6	September	2.546	1.657	28,700	255,094		255,094
7	October	1.780	1.657	30,213	37,141		37,141
8	November	2.113	1.657	29,213	133,338		133,338
9	December (New Rates - Sub 1173)	3.817	1.919	28,549	541,747		541,747
10	January 2019	3.244	2.251	30,547	303,393	$ (149)	303,244
11	February	1.076	2.251	28,406	(333,718)		(333,718)
12	March	2.673	2.251	29,310	123,557		123,557
13	Total Test Period			353,410	$ 1,885,501	$ (149)	$ 1,885,352
14	Booked (Over) / Under Recovery						$ 1,885,352
15	Coal inventory Rider (Over) / Under Recovery						2,390
16	Adjustment to remove by-product net gain/loss accrued expense						(410,055)
17	Adjustment to include by-product net gain/loss cash payments						61,687
18	Total (Over) / Under Recovery						$ 1,539,374
19	Normalized Test Period MWh Sales	Exhibit 4					353,965
20	Experience Modification Increment (Decrement) cents/KWh						0.435

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Normalized Test Period MWh Sales, Fuel and Fuel-Related Revenue, Fuel and Fuel-Related Expense, and System Peak
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Exhibit 4

Line No.	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina Small General Service	North Carolina Medium General Service	North Carolina Large General Service	North Carolina Lighting
1	Test Period MWh Sales	Workpaper 8a	62,568,164	38,046,575	16,147,005	1,958,731	11,108,152	8,479,278	353,410
2	Customer Growth MWh Adjustment	Workpaper 8a	295,033	161,504	120,250	5,244	35,216	238	555
3	Weather MWh Adjustment	Workpaper 8a	(870,731)	(512,310)	(245,014)	(20,261)	(136,061)	(110,973)	-
4	Total Adjusted MWh Sales	Sum Lines 1-3	61,992,467	37,695,769	16,022,241	1,943,714	11,007,307	8,368,542	353,965
5	Test Period Fuel and Fuel-Related Revenue *		$ 1,420,894,881	$ 864,024,095					
6	Test Period Fuel and Fuel-Related Expense *		$ 1,670,130,626	$ 1,010,821,493					
7	Test Period Unadjusted (Over)/Under Recovery	Line 5 - Line 6	$ 249,235,745	$ 146,797,398					

Line No.	Description	2018 Winter Coincidental Peak (CP) KW
8	Total System Peak	15,022,364
9	NC Retail	8,952,091
10	NC Residential Peak	5,755,959
11	NC Small General Service	536,770
12	NC Medium General Service	1,812,628
13	NC Large General Service	846,735

Notes:

* Total Company Fuel and Fuel-Related Revenue and Fuel and Fuel-Related Expense are quantifed based on NC Retail's known share of revenues and expenses grossed up to also include the percentage of sales not belonging to NC Retail.

Rounding differences may occur.

Duke Energy Progress, LLC **Harrington Exhibit 5**
North Carolina Annual Fuel and Fuel-Related Expense
Nuclear Capacity Ratings - MWs
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Unit	Rate Case Docket E-2, Sub 1142	Fuel Docket E-2, Sub 1173	Proposed Capacity Rating MW
Brunswick 1	938	938	938
Brunswick 2	932	932	932
Harris 1	928	932	964
Robinson 2	741	741	741
Total Company	3,539	3,543	3,575

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Monthly Fuel and Baseload Report for March 2019
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Harrington Exhibit 6

March 2019
Monthly Fuel Filing and Baseload Report Cover Sheet

Schedule 1

Duke Energy Progress
Summary of Monthly Fuel Report

Docket No. E-2, Sub 1201

Line No.	Fuel Expenses:	March 2019	12 Months Ended March 2019
1	Total Fuel and Fuel-Related Costs	$ 123,073,670	$ 1,663,002,005
	MWH sales:		
2	Total System Sales	4,925,855	68,235,058
3	Less intersystem sales	372,873	5,666,892
4	Total sales less intersystem sales	4,552,982	62,568,166
5	Total fuel and fuel-related costs (¢/KWH) (Line 1/Line 4)	2.703	2.658
6	Current fuel & fuel-related cost component (¢/KWH) (per Schedule 4, Line 5a Total)	2.248	
	Generation Mix (MWH):		
	Fossil (By Primary Fuel Type):		
7	Coal	644,674	8,081,365
8	Oil	4,565	77,366
9	Natural Gas - Combustion Turbine	121,930	4,022,746
10	Natural Gas - Combined Cycle	1,611,916	19,134,953
11	Biogas	692	4,404
12	Total Fossil	2,383,777	31,320,834
13	Nuclear	1,979,009	27,748,149
14	Hydro - Conventional	82,564	848,406
15	Solar Distributed Generation	19,304	227,472
16	Total MWH generation	4,464,654	60,144,861

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

Schedule 2

Duke Energy Progress
Details of Fuel and Fuel-Related Costs

Docket No. E-2, Sub 1201

Description	March 2019	12 Months Ended March 2019
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0501110 coal consumed - steam	$ 24,936,974	$ 303,392,775
0501310 fuel oil consumed - steam	772,460	10,958,684
Total Steam Generation - Account 501	25,709,434	314,351,459
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	12,427,031	181,956,774
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	12,289,318	168,066,557
0547000 natural gas consumed - Combined Cycle	42,551,124	570,332,536
0547106 biogas consumed - Combined Cycle	43,261	247,299
0547200 fuel oil consumed	97,672	6,051,638
Total Other Generation - Account 547	54,981,375	744,698,030
Reagents		
Catalyst Depreciation	131,225	1,569,962
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	1,306,098	17,186,374
Total Reagents	1,437,323	18,756,335
By-products		
Net proceeds from sale of by-products	1,611,921	86,567,009
Total By-products	1,611,921	86,567,009
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	96,167,083	1,346,329,607
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (PURPA)	1,865,608	28,376,807
Capacity component of purchased power (renewables)	2,480,350	42,762,017
Fuel and fuel-related component of purchased power	32,070,833	485,950,079
Total Purchased Power and Net Interchange - Account 555	36,416,791	557,088,903
Less:		
Fuel and fuel-related costs recovered through intersystem sales	9,510,359	240,413,239
Solar Integration Charge	(154)	3,267
Total Fuel Credits - Accounts 447/456	9,510,205	240,416,505
Total Fuel and Fuel-Related Costs	$ 123,073,670	$ 1,663,002,005

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

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

MARCH 2019

Schedule 3, Purchases

Purchased Power	Total	Capacity	Non-capacity			
						Not Fuel $
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel-related $
Broad River Energy, LLC.	$ 2,802,106	$ 1,102,735	28,420	$ 1,238,034	$ 461,337	
City of Fayetteville	740,091	707,850	146	19,791	12,450	
DE Carolinas - Native Load Transfer	6,202,943	-	189,488	5,081,031	1,120,681	$ 1,231
DE Carolinas - Native Load Transfer Benefit	1,129,259	-	-	1,129,259	-	
DE Carolinas - Fees	501,604	-	-	-	501,604	
Haywood EMC	28,300	28,300	-	-	-	
NCEMC	3,471,917	2,777,986	16,181	693,931	-	
PJM Interconnection, LLC.	4,103	-	115	2,350	1,753	
Southern Company Services	4,236,908	802,620	107,883	2,828,970	605,318	
	$ 19,117,231	**$ 5,419,491**	**342,233**	**$ 10,993,366**	**$ 2,703,143**	**$ 1,231**
Renewable Energy						
REPS	$ 12,798,250	-	189,866	$ -	$ 12,798,250	-
DERP Qualifying Facilities	30,356	-	620	-	30,356	-
	$ 12,828,606	**$ -**	**190,486**	**$ -**	**$ 12,828,606**	**$ -**
HB589 PURPA Purchases						
Qualifying Facilities	$ 9,737,521	-	164,313		$ 9,737,521	-
	$ 9,737,521	**$ -**	**164,313**	**$ -**	**$ 9,737,521**	**$ -**
Non-dispatchable						
DE Carolinas - Reliability	$ 233,640	-	4,248	$ 142,520		$ 91,120
Energy Imbalance	12,053		372	10,929		1,124
Generation Imbalance	788		31	706		82
	$ 246,481	**$ -**	**4,651**	**$ 154,155**	**$ -**	**$ 92,326**
Total Purchased Power	**$ 41,929,839**	**$ 5,419,491**	**701,683**	**$ 11,147,521**	**$ 25,269,270**	**$ 93,557**

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

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

MARCH 2019

Schedule 3, Sales

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
SC Electric & Gas - Emergency	$ 4,224	-	107	$ 4,009	$ 215
Market Based:					
NCEMC Purchase Power Agreement	1,027,466	652,500	10,969	298,841	76,125
PJM Interconnection, LLC.	18,622	-	485	14,681	3,941
Other:					
DE Carolinas - Native Load Transfer Benefit	1,181,175	-	-	1,181,175	-
DE Carolinas - Native Load Transfer	8,263,589	-	361,305	8,011,653	251,936
Generation Imbalance	(3)	-	7	-	(3)
Total Intersystem Sales	**$ 10,495,073**	**$ 652,500**	**372,873**	**$ 9,510,359**	**$ 332,214**

* Sales for resale other than native load priority.

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

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

Twelve Months Ended MARCH 2019

Schedule 3, Purchases

Purchased Power	Total	Capacity	Non-capacity			
						Not Fuel $
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel-related $
Broad River Energy, LLC.	$ 127,085,389	$ 46,074,078	1,857,244	$ 68,440,822	$ 12,570,489	
City of Fayetteville	14,767,157	12,593,900	30,153	1,680,747	492,510	
DE Carolinas - Native Load Transfer	63,545,930	-	1,982,523	30,527,552	33,022,675	$ (4,297)
DE Carolinas - Native Load Transfer Benefit	5,755,905	-	-	5,755,905	-	
DE Carolinas - Fees	773,278	-	-	-	773,278	
Haywood EMC	346,350	346,350	-	-	-	
NCEMC	57,008,844	37,312,025	474,860	19,696,819	-	
PJM Interconnection, LLC.	3,551,137	-	117,614	2,113,417	1,437,720	
Southern Company Services	52,566,483	13,555,154	1,139,356	32,594,041	6,417,288	
	$ 325,400,473	**$ 109,881,507**	**5,601,750**	**$ 160,809,303**	**$ 54,713,960**	**$ (4,297)**
Renewable Energy						
REPS	$ 211,302,302	-	3,077,611	-	$ 211,302,302	-
DERP Net Metering Excess Generation	3,230	$ 557	75	-	-	$ 2,673
DERP Qualifying Facilities	568,966	-	11,630	-	568,966	-
	$ 211,874,498	**$ 557**	**3,089,316**	**$ -**	**$ 211,871,268**	**$ 2,673**
HB589 PURPA Purchases						
Qualifying Facilities	$ 126,885,293	$ -	2,036,984		$ 126,885,293	$ -
	$ 126,885,293	**$ -**	**2,036,984**	**$ -**	**$ 126,885,293**	**$ -**
Non-dispatchable						
DE Carolinas - Emergency	$ 15,390	-	333	$ 13,113		$ 2,277
DE Carolinas - Reliability	3,464,748	-	52,921	2,113,496		1,351,252
Haywood EMC	5,388	$ 5,388	-	-		-
Energy Imbalance	696,075	-	17,801	660,759		35,316
Generation Imbalance	35,222	-	1,462	21,711		13,511
	$ 4,216,823	**$ 5,388**	**72,517**	**$ 2,809,079**	**$ -**	**$ 1,402,356**
Total Purchased Power	**$ 668,377,087**	**$ 109,887,452**	**10,800,567**	**$ 163,618,382**	**$ 393,470,521**	**$ 1,400,732**

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

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

Twelve Months Ended
MARCH 2019

Schedule 3, Sales

	Total	Capacity	Non-capacity		
Sales	$	$	mWh	Fuel $	Non-fuel $
Utilities:					
SC Electric & Gas - Emergency	$ 16,314	-	312	$ 14,320	$ 1,994
SC Public Service Authority - Emergency	103	-	-	-	103
Market Based:					
NCEMC Purchase Power Agreement	11,778,585	$ 7,830,000	107,498	3,931,062	17,523
PJM Interconnection, LLC.	87,823	-	3,945	93,554	(5,731)
Other:					
DE Carolinas - Native Load Transfer Benefit	17,548,845	-	-	17,548,845	-
DE Carolinas - Native Load Transfer	177,756,508	-	5,554,827	168,972,668	8,783,840
DE Carolinas - Native Load Transfer (Prior Period Adjust.)	51,500,000	-	-	49,852,000	1,648,000
Generation Imbalance	2,394	-	310	790	1,604
Total Intersystem Sales	**$ 258,690,572**	**$ 7,830,000**	**5,666,892**	**$ 240,413,239**	**$ 10,447,333**

* Sales for resale other than native load priority.

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

Schedule 4

Duke Energy Progress
(Over) / Under Recovery of Fuel Costs
March 2019

Line No.			Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total
1	1a. System Retail kWh sales	Input						4,552,981,616
	1b. System kWh Sales at generation	Input						4,696,445,723
2	2a. DERP Net Metered kWh generation	Input						2,501,687
	2b. Line loss percentage from Cost of Service	Input Annually						3.460%
	2c. DERP Net Metered kWh at generation	L2a * (1 + 2b)						2,588,246
3	Adjusted System kWh sales	L1b + L2c						4,699,033,968
4	4a. N.C. Retail kWh sales	Input	1,214,159,107	144,886,112	790,364,355	615,274,288	29,309,559	2,793,993,421
	4b. Line loss percentage from Cost of Service	Input Annually	3.787%	3.786%	3.685%	3.080%	3.785%	
	4c. NC kWh Sales at generation	4a * (1+4b)	1,260,139,312	150,371,500	819,489,281	634,224,736	30,418,926	2,894,643,755
	4d. NC allocation % by customer class	Calculated	43.533%	5.195%	28.311%	21.910%	1.051%	
	4e. NC retail % of actual system total	L4c NC Total / L1b Total System						61.635%
	4f. NC retail % of adjusted system total	L4c NC Total / L3 Total System						61.601%
5	Approved fuel and fuel-related rates (¢/kWh)							
	5a Billed rates by class (¢/kWh)	Input Annually	2.311	2.556	2.477	1.757	2.251	2.248
	5b Billed fuel expense	L4a * L5a / 100	$28,059,217	$3,703,289	$19,577,325	$10,810,369	$659,758	$62,809,958
6	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)							
	Allocation changes:							
	6a New approved Docket E-2, Sub 1173 allocation factor	Input Annually	43.60%	5.40%	30.57%	19.36%	1.07%	100.00%
	6b System incurred expense	Input						$118,807,916
	6c NC incurred expense by class	L4f * L6a * L6b	$31,909,473	$3,952,091	$22,373,224	$14,168,977	$783,099	$73,186,865
	6d NC Incurred base fuel rates (¢/kWh)	L6c / L4a * 100	2.62811	2.72772	2.83075	2.30287	2.67182	2.61944
7	Incurred renewable purchased power capacity rates (¢/kWh)							
	7a NC retail production plant %	Input Annually						60.52%
	7b Production plant allocation factors	Input Annually	48.581%	6.580%	28.950%	15.881%	0.008%	100.00%
	7c System incurred expense	Input						$4,345,958
	7d NC incurred renewable capacity expense	L7a* L7b* L7c	$1,277,786	$173,066	$761,440	$417,697	$216	$2,630,204
	7e NC incurred rates by class	L7d / L4a * 100	0.10524	0.11945	0.09634	0.06789	0.00074	0.09414
8	Total incurred rates by class (¢/kWh)	L6h + 7e	2.7334	2.8472	2.9271	2.3708	2.6726	
9	Difference in ¢/kWh (incurred - billed)	L8 - L5a	0.42235	0.29117	0.45009	0.61376	0.42156	
10	(Over) / under recovery [See footnote]	L9 * L4a / 100	$5,128,001	$421,865	$3,557,351	$3,776,307	$123,557	$13,007,081
11	Prior period adjustments	Input						
12	Total (over) / under recovery [See footnote]	L10 + L11	$5,128,001	$421,865	$3,557,351	$3,776,307	$123,557	$13,007,081
13	Total System Incurred Expenses							$123,153,874
14	Less: Jurisdictional allocation adjustment	Input						80,204
15	Total Fuel and Fuel-related Costs per Schedule 2							$123,073,671

16 (Over) / under recovery for each month of the current test period [See footnote]

		(Over) / Under Recovery						
		Total To Date	Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total Company
	April 2018	$ 6,616,553	3,660,529	236,079	700,759	1,978,810	40,376	$ 6,616,553
	May	20,547,061	8,577,706	567,097	1,468,210	3,230,432	87,063	13,930,508
	June	41,048,168	8,539,907	642,201	3,411,985	7,668,586	238,428	20,501,107
	July	54,552,954	4,574,733	310,810	2,629,373	5,754,642	235,228	13,504,786
	August	67,204,260	5,138,198	217,119	1,980,830	5,091,306	223,853	12,651,306
	September	89,759,569	8,874,465	662,100	4,902,428	7,861,222	255,094	22,555,309
	October	85,222,358	179,201	(578,233)	(4,091,099)	(84,221)	37,141	(4,537,211)
	November	99,230,978	8,748,809	298,658	913,230	3,914,585	133,338	14,008,620
	December	155,355,599	18,956,228	3,080,272	18,544,231	15,002,143	541,747	56,124,621
_/1	January 2019	175,212,828	5,737,076	717,059	7,146,062	5,953,788	303,244	19,857,229
	February	133,790,317	(21,931,387)	(2,332,952)	(11,548,986)	(5,275,468)	(333,718)	(41,422,511)
	March	146,797,398	5,128,001	421,865	3,557,351	3,776,307	123,557	13,007,081
	Total		$ 56,183,466	$ 4,242,075	$ 29,614,374	$ 54,872,132	$ 1,885,351	$ 146,797,398

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.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2019

Description	Weatherspoon CT	Lee CC	Sutton CC/CT	Robinson Nuclear	Asheville Steam	Asheville CT	Roxboro Steam	Mayo Steam
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	$5,221,006	-	$20,932,462	$8,482,923
Oil	108,542	-	-	-	(99)	-	451,673	404,633
Gas - CC	-	20,510,566	13,595,268	-	-	-	-	-
Gas - CT	24	-	653,299	-	-	2,150,497	-	-
Biogas	-	-	-	-	-	-	-	-
Total	108,566	$20,510,566	$14,248,567	-	$5,220,907	$2,150,497	$21,384,135	$8,887,556
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	364.47	-	330.49	280.74
Oil	1,495.69	-	-	-	1,414.29	-	1,499.83	1,499.20
Gas - CC	-	405.30	470.88	-	-	-	-	-
Gas - CT	-	-	463.78	-	-	4,363.74	-	-
Biogas	-	-	-	-	-	-	-	-
Weighted Average	1,496.02	405.30	470.54	-	364.46	4,363.74	336.02	291.52
Cost of Fuel Burned ($)								
Coal	-	-	-	-	$5,236,744	-	$17,321,167	$2,379,063
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	23,727	-	-	-	96,120	22,056	520,592	155,747
Gas - CC	-	20,510,566	13,595,268	-	-	-	-	-
Gas - CT	24	-	653,299	-	-	2,150,497	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	3,301,699	-	-	-	-
Total	$23,751	$20,510,566	$14,248,567	$3,301,699	$5,332,864	$2,172,553	$17,841,759	$2,534,810
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	337.22	-	352.43	318.76
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	1,590.28	-	-	-	1,538.17	1,538.08	1,521.44	1,531.44
Gas - CC	-	405.30	470.88	-	-	-	-	-
Gas - CT	-	-	463.78	-	-	4,363.74	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	55.67	-	-	-	-
Weighted Average	1,591.89	405.30	470.54	55.67	342.03	4,283.85	360.52	335.06
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	4.12	-	3.83	3.65
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	-	-	-	-	18.82	25.35	16.38	17.53
Gas - CC	-	2.89	3.33	-	-	-	-	-
Gas - CT	-	-	4.70	-	-	68.59	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	0.56	-	-	-	-
Weighted Average	-	2.89	3.38	0.56	4.18	67.43	3.92	3.84
Burned MBTU's								
Coal	-	-	-	-	1,552,934	-	4,914,738	746,358
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	1,492	-	-	-	6,249	1,434	34,217	10,170
Gas - CC	-	5,060,592	2,887,234	-	-	-	-	-
Gas - CT	-	-	140,865	-	-	49,281	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	5,930,593	-	-	-	-
Total	1,492	5,060,592	3,028,099	5,930,593	1,559,183	50,715	4,948,955	756,528
Net Generation (mWh)								
Coal	-	-	-	-	127,212	-	452,280	65,182
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	(28)	-	-	-	511	87	3,179	888
Gas - CC	-	710,152	408,268	-	-	-	-	-
Gas - CT	-	-	13,900	-	-	3,135	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	587,358	-	-	-	-
Hydro (Total System)								
Solar (Total System)								
Total	(28)	710,152	422,168	587,358	127,723	3,222	455,459	66,070
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	-	-	$75,257	$9,558
Limestone	-	-	-	-	164,560	-	574,657	99,999
Re-emission Chemical	-	-	-	-	-	-	-	-
Sorbents	-	-	-	-	5,765	-	216,421	32,145
Urea	-	-	-	-	114,710	-	-	-
Total	-	-	-	-	$285,035	-	$866,336	$141,702

Notes:

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

Schedule excludes in-transit, terminal and tolling agreement activity.

Cents/MBTU and cents/kWh are not computed when costs and/or net generation is negative.

Lee and Wayne oil burn is associated with inventory consumption shown on Schedule 6 for Wayne.

Re-emission chemical reagent expense is not recoverable in NC.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2019

Description	Brunswick Nuclear	Blewett CT	Wayne County CT	Darlington CT	Smith Energy Complex CC/CT	Harris Nuclear	Current Month	Total 12 ME March 2019
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	-	-	$34,636,391	$306,305,926
Oil	2,331	-	-	-	-	-	967,080	18,118,231
Gas - CC	-	-	-	-	8,445,290	-	42,551,124	570,332,536
Gas - CT	-	-	243,212	54,046	9,188,240	-	12,289,318	168,066,557
Biogas	-	-	-	-	128,337	-	128,337	920,702
Total	2,331	-	$243,212	$54,046	$17,633,530	-	$90,572,250	$1,063,743,952
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	-	-	321.07	336.61
Oil	-	-	-	-	-	-	1,502.73	1,508.31
Gas - CC	-	-	-	-	389.64	-	420.66	416.97
Gas - CT	-	-	399.99	408.17	375.47	-	453.26	368.85
Biogas	-	-	-	-	2,919.40	-	2,919.40	2,933.85
Weighted Average	-	-	399.99	408.17	384.54	-	382.43	387.41
Cost of Fuel Burned ($)								
Coal	-	-	-	-	-	-	$24,936,974	$303,392,775
Oil - CC	-	-	-	-	149	-	149	2,216
Oil - Steam/CT	-	19,661	-	14,049	18,031	-	869,983	17,008,105
Gas - CC	-	-	-	-	8,445,290	-	42,551,124	570,332,536
Gas - CT	-	-	243,212	54,046	9,188,240	-	12,289,318	168,066,557
Biogas	-	-	-	-	128,337	-	128,337	920,702
Nuclear	4,276,463	-	-	-	-	4,848,869	12,427,031	181,956,773
Total	$4,276,463	19,661	$243,212	$68,095	17,780,047.00	$4,848,869	$93,202,916	$1,241,679,664
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	-	-	345.67	331.03
Oil - CC	-	-	-	-	1,655.56	-	1,655.56	1,653.73
Oil - Steam/CT	-	1,683.33	-	1,730.17	1,663.38	-	1,536.37	1,583.93
Gas - CC	-	-	-	-	389.64	-	420.66	416.97
Gas - CT	-	-	399.99	408.17	375.47	-	453.26	368.85
Biogas	-	-	-	-	2,919.40	-	2,919.40	2,933.85
Nuclear	61.77	-	-	-	-	64.95	61.16	62.63
Weighted Average	61.77	1,683.33	399.99	484.56	384.84	64.95	230.58	219.53
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	-	-	3.87	3.75
Oil - CC	-	-	-	-	14.90	-	14.90	18.47
Oil - Steam/CT	-	-	-	-	18.30	-	19.06	21.99
Gas - CC	-	-	-	-	1.71	-	2.64	2.98
Gas - CT	-	-	5.72	10.10	9.18	-	10.08	4.18
Biogas	-	-	-	-	18.53	-	18.53	20.91
Nuclear	0.65	-	-	-	-	0.66	0.63	0.66
Weighted Average	0.65	-	5.72	17.83	2.99	0.66	2.09	2.06
Burned MBTU's								
Coal	-	-	-	-	-	-	7,214,030	91,650,544
Oil - CC	-	-	-	-	9	-	9	134
Oil - Steam/CT	-	1,168	-	812	1,084	-	56,626	1,073,793
Gas - CC	-	-	-	-	2,167,471	-	10,115,297	136,780,403
Gas - CT	-	-	60,805	13,241	2,447,150	-	2,711,342	45,564,794
Biogas	-	-	-	-	4,396	-	4,396	31,382
Nuclear	6,923,119	-	-	-	-	7,465,910	20,319,622	290,513,318
Total	6,923,119	1,168	60,805	14,053	4,620,110	7,465,910	40,421,322	565,614,368
Net Generation (mWh)								
Coal	-	-	-	-	-	-	644,674	8,081,365
Oil - CC	-	-	-	-	1	-	1	12
Oil - Steam/CT	-	(18)	-	(153)	99	-	4,564	77,354
Gas - CC	-	-	-	-	493,496	-	1,611,916	19,134,953
Gas - CT	-	-	4,250	535	100,109	-	121,930	4,022,746
Biogas	-	-	-	-	692	-	692	4,404
Nuclear	653,858	-	-	-	-	737,793	1,979,009	27,748,149
Hydro (Total System)							82,564	848,406
Solar (Total System)							19,304	227,472
Total	653,858	(18)	4,250	382	594,397	737,793	4,464,654	60,144,861
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	$13,025	-	$97,840	$1,636,851
Limestone	-	-	-	-	-	-	839,216	11,266,783
Re-emission Chemical	-	-	-	-	-	-	-	84,162
Sorbents	-	-	-	-	-	-	254,331	3,094,114
Urea	-	-	-	-	-	-	114,710	1,188,625
Total	-	-	-	-	$13,025	-	$1,306,098	$17,270,536

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2019

Schedule 6

Description	Weatherspoon	Lee	Sutton	Robinson	Asheville
Coal Data:					
Beginning balance	-	-	-	-	76,420
Tons received during period	-	-	-	-	57,452
Inventory adjustments	-	-	-	-	-
Tons burned during period	-	-	-	-	62,187
Ending balance	-	-	-	-	71,685
MBTUs per ton burned	-	-	-	-	24.97
Cost of ending inventory ($/ton)	-	-	-	-	84.21
Oil Data:					
Beginning balance	642,863	-	2,623,651	78,040	2,980,615
Gallons received during period	52,588	-	-	-	(50)
Miscellaneous use and adjustments	-	-	-	-	(5,202)
Gallons burned during period	10,657	-	-	-	55,895
Ending balance	684,794	-	2,623,651	78,040	2,919,468
Cost of ending inventory ($/gal)	2.23	-	2.80	2.42	2.11
Natural Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	4,891,110	2,950,888	-	48,124
MCF burned during period	-	4,891,110	2,950,888	-	48,124
Ending balance	-	-	-	-	-
Biogas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	-	-	-	-
MCF burned during period	-	-	-	-	-
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	-	-	-	-	15,946
Tons received during period	-	-	-	-	3,770
Inventory adjustments	-	-	-	-	-
Tons consumed during period	-	-	-	-	3,046
Ending balance	-	-	-	-	16,670
Cost of ending inventory ($/ton)	-	-	-	-	51.83

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit, terminal and tolling agreement activity.
Gas is burned as received; therefore, inventory balances are not maintained.
The oil inventory data for Wayne reflects the common usage of the oil tank used for both Wayne and Lee units.

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2019

Schedule 6

Description	Roxboro	Mayo	Brunswick	Blewett	Wayne County
Coal Data:					
Beginning balance	918,904	233,107	-	-	-
Tons received during period	252,785	115,986	-	-	-
Inventory adjustments	-	-	-	-	-
Tons burned during period	193,871	29,161	-	-	-
Ending balance	977,818	319,932	-	-	-
MBTUs per ton burned	25.35	25.59	-	-	-
Cost of ending inventory ($/ton)	89.33	81.58	-	-	-
Oil Data:					
Beginning balance	226,564	185,849	170,137	798,782	12,012,380
Gallons received during period	218,223	195,583	-	-	-
Miscellaneous use and adjustments	(7,509)	(2,879)	-	-	-
Gallons burned during period	248,114	73,853	5,958	8,311	-
Ending balance	189,164	304,700	164,179	790,471	12,012,380
Cost of ending inventory ($/gal)	2.10	2.11	2.42	2.37	2.40
Natural Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	-	-	-	58,639
MCF burned during period	-	-	-	-	58,639
Ending balance	-	-	-	-	-
Biogas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	-	-	-	-
MCF burned during period	-	-	-	-	-
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	57,492	18,726	-	-	-
Tons received during period	6,784	46	-	-	-
Inventory adjustments	-	-	-	-	-
Tons consumed during period	13,316	1,826	-	-	-
Ending balance	50,960	16,946	-	-	-
Cost of ending inventory ($/ton)	41.10	51.77	-	-	-

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2019

Schedule 6

Description	Darlington	Smith Energy Complex	Harris	Current Month	Total 12 ME March 2019
Coal Data:					
Beginning balance	-	-	-	1,228,431	1,446,194
Tons received during period	-	-	-	426,223	3,611,686
Inventory adjustments	-	-	-	-	(53,917)
Tons burned during period	-	-	-	285,219	3,634,528
Ending balance	-	-	-	1,369,435	1,369,435
MBTUs per ton burned	-	-	-	25.29	25.22
Cost of ending inventory ($/ton)	-	-	-	87.25	87.25
Oil Data:					
Beginning balance	10,427,173	8,183,597	272,031	38,601,682	38,156,552
Gallons received during period	-	-	-	466,344	8,704,526
Miscellaneous use and adjustments	-	-	-	(15,590)	(190,076)
Gallons burned during period	5,871	7,810	-	416,469	8,035,035
Ending balance	10,421,302	8,175,787	272,031	38,635,967	38,635,967
Cost of ending inventory ($/gal)	2.39	2.33	2.42	2.38	2.38
Natural Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	13,020	4,496,490	-	12,458,271	177,403,519
MCF burned during period	13,020	4,496,490	-	12,458,271	177,403,519
Ending balance	-	-	-	-	-
Biogas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	4,280	-	4,280	30,605
MCF burned during period	-	4,280	-	4,280	30,605
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	-	-	-	92,164	127,587
Tons received during period	-	-	-	10,600	202,258
Inventory adjustments	-	-	-	-	(3,989)
Tons consumed during period	-	-	-	18,188	241,280
Ending balance	-	-	-	84,576	84,576
Cost of ending inventory ($/ton)	-	-	-	45.35	45.35

Schedule 7

DUKE ENERGY PROGRESS

ANALYSIS OF COAL PURCHASED

MARCH 2019

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ASHEVILLE	SPOT	11,285	$ 1,081,014	$ 95.79
	CONTRACT	46,167	3,335,178	72.24
	FIXED TRANSPORTATION/ADJUSTMENTS	-	804,814	-
	TOTAL	57,452	5,221,006	90.88
MAYO	SPOT	-	-	-
	CONTRACT	115,986	7,676,160	66.18
	FIXED TRANSPORTATION/ADJUSTMENTS	-	806,763	-
	TOTAL	115,986	8,482,923	73.14
ROXBORO	SPOT	12,785	923,729	72.25
	CONTRACT	240,000	16,160,146	67.33
	FIXED TRANSPORTATION/ADJUSTMENTS	-	3,848,587	-
	TOTAL	252,785	20,932,462	82.81
ALL PLANTS	SPOT	24,070	2,004,743	83.29
	CONTRACT	402,153	27,171,484	67.57
	FIXED TRANSPORTATION/ADJUSTMENTS	-	5,460,164	-
	TOTAL	426,223	$ 34,636,391	$ 81.26

Schedule 8

DUKE ENERGY PROGRESS
ANALYSIS OF COAL QUALITY RECEIVED
MARCH 2019

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
ASHEVILLE	6.98	10.30	12,467	1.64
MAYO	5.90	7.81	13,026	2.68
ROXBORO	6.34	9.94	12,528	1.80

DUKE ENERGY PROGRESS
ANALYSIS OF OIL PURCHASED
MARCH 2019

	ASHEVILLE	MAYO	ROXBORO	WEATHERSPOON
VENDOR	Indigo	Greensboro Tank Farm	Greensboro Tank Farm	Indigo
SPOT/CONTRACT	Contract	Contract	Contract	Contract
SULFUR CONTENT %	0	0	0	0
GALLONS RECEIVED	(50)	195,583	218,223	52,588
TOTAL DELIVERED COST	$ (99)	$ 404,633	$ 451,673	$ 108,542
DELIVERED COST/GALLON	$ 1.98	$ 2.07	$ 2.07	$ 2.06
BTU/GALLON	138,000	138,000	138,000	138,000

Notes:

A price adjustment of $2,331 for the Brunswick station is excluded.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 - March, 2019
Nuclear Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Brunswick 1	7,819,962	938	95.17	96.00
Brunswick 2	6,876,141	932	84.22	87.43
Harris 1	7,787,575	940	94.59	90.44
Robinson 2	5,264,471	741	81.10	78.71

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 through March, 2019
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Lee Energy Complex	1A	1,423,723	225	72.23	80.19
Lee Energy Complex	1B	1,430,643	227	71.95	79.56
Lee Energy Complex	1C	1,449,864	228	72.59	79.30
Lee Energy Complex	ST1	2,839,979	379	85.54	91.89
Lee Energy Complex	Block Total	7,144,209	1,059	77.01	84.05
Richmond County CC	7	1,242,500	190	74.56	82.37
Richmond County CC	8	1,232,784	190	73.98	82.31
Richmond County CC	ST4	1,387,299	177	89.61	91.20
Richmond County CC	9	1,414,983	216	74.78	80.18
Richmond County CC	10	1,427,236	216	75.43	80.50
Richmond County CC	ST5	1,840,903	248	84.74	90.61
Richmond County CC	Block Total	8,545,705	1,237	78.85	84.54
Sutton Energy Complex	1A	1,129,922	224	57.58	71.58
Sutton Energy Complex	1B	1,102,837	224	56.20	67.19
Sutton Energy Complex	ST1	1,216,696	271	51.25	64.56
Sutton Energy Complex	Block Total	3,449,455	719	54.77	67.56

Notes:

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

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 through March, 2019

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Mayo 1	1,350,056	746	20.66	66.37
Roxboro 2	1,555,700	673	26.39	79.51
Roxboro 3	1,374,062	698	22.47	57.68
Roxboro 4	1,960,487	711	31.48	64.47

Notes:

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

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 through March, 2019
Other Cycling Steam Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Asheville	1	682,433	192	40.57	93.57
Asheville	2	564,038	192	33.54	93.81
Roxboro	1	648,835	380	19.49	88.95

Notes:

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

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 through March, 2019
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Asheville CT	442,747	370	75.11
Blewett CT	-185	68	98.31
Darlington CT	152,757	825	85.44
Richmond County CT	2,892,244	934	86.50
Sutton Fast Start CT	179,798	98	87.91
Wayne County CT	378,117	963	95.72
Weatherspoon CT	374	164	93.83

Notes:

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

Duke Energy Progress
Power Plant Performance Data

Twelve Month Summary
April, 2018 through March, 2019
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Blewett	58,217	27.0	45.80
Marshall	-365	4.0	0.00
Tillery	294,593	84.0	92.24
Walters	495,961	113.0	81.43

Notes:

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

Duke Energy Progress
Base Load Power Plant Performance Review Plan

Period: March, 2019

Station	Unit	Date of Outage	Duration of Outage	Scheduled / Unscheduled	Cause of Outage	Reason Outage Occurred	Remedial Action Taken
Brunswick	1	03/28/2019 - 04/01/2019	79.95	Unscheduled	Forced outage due to drywell leak	Failed instrument coupling.	Replace failed coupling and complete an extent of condition review.
	2	03/02/2019 - 04/01/2019	719.00	Scheduled	End-of-cycle 24 refueling outage	Planned refueling outage.	None, planned outage.
Harris	1	None					
Robinson	2	None					

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Lee Energy Complex

No Outages at Baseload Units During the Month.

Richmond County Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
7	2/23/2019 3:00:00 AM To 3/8/2019 9:25:00 PM	Sch	5272	Gas Turbine - Boroscope Inspection	Borescope and BOP outage.	
8	2/23/2019 3:00:00 AM To 3/8/2019 11:23:00 PM	Sch	5272	Gas Turbine - Boroscope Inspection	Borescope and BOP outage.	
ST4	2/23/2019 2:58:00 AM To 3/9/2019 12:38:00 AM	Sch	5272	Gas Turbine - Boroscope Inspection	Borescope inspections on U7, U8 and BOP outage.	
9	3/16/2019 4:03:00 AM To 4/1/2019 12:00:00 AM	Sch	5260	Major Gas Turbine Overhaul	CTmajor, BOP and ST major.	
10	3/16/2019 4:03:00 AM To 4/1/2019 12:00:00 AM	Sch	5260	Major Gas Turbine Overhaul	CTmajor, BOP and ST major.	
ST5	3/16/2019 3:54:00 AM To 4/1/2019 12:00:00 AM	Sch	4400	Major Turbine Overhaul (720 Hours Or Longer)	CTmajor, BOP and ST major.	

Sutton Energy Complex

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
ST1	3/14/2019 6:53:00 PM To 3/14/2019 7:10:00 PM	Unsch	4099	Other High Pressure Turbine Problems	Cold Reheat Temp tripped STG	

Notes:

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

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2019
Brunswick Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	938		932	
(B) Period Hours	743		743	
(C) Net Gen (mWh) and Capacity Factor (%)	640,194	91.86	13,664	1.97
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00	670,108	96.77
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00	8,534	1.23
(F) Net mWh Not Gen due to Full Forced Outages	74,993	10.76	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-18,253	-2.62	170	0.03
* (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	696,934	100.00%	692,476	100.00%
(K) Equivalent Availability (%)		89.08		2.72
(L) Output Factor (%)		102.93		61.09
(M) Heat Rate (BTU/NkWh)		10,485		14,754

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2019
Harris Nuclear Station

	Unit 1	
(A) MDC (mW)	964	
(B) Period Hours	743	
(C) Net Gen (mWh) and Capacity Factor (%)	737,793	103.01
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-21,541	-3.01
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	716,252	100.00%
(K) Equivalent Availability (%)		100.00
(L) Output Factor (%)		103.01
(M) Heat Rate (BTU/NkWh)		10,119

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2019
Robinson Nuclear Station

	Unit 2	
(A) MDC (mW)	741	
(B) Period Hours	743	
(C) Net Gen (mWh) and Capacity Factor (%)	587,358	106.68
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-36,795	-6.68
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	550,563	100.00%
(K) Equivalent Availability (%)		100.00
(L) Output Factor (%)		106.68
(M) Heat Rate (BTU/NkWh)		10,097

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Lee Energy Complex

	Unit 1A	Unit 1B	Unit 1C	Unit ST1	Block Total
(A) MDC (mW)	225	227	228	379	1,059
(B) Period Hrs	743	743	743	743	743
(C) Net Generation (mWh)	144,726	143,181	145,742	276,503	710,152
(D) Capacity Factor (%)	86.57	84.89	86.03	98.19	90.25
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	20,433	21,175	21,547	371	63,526
(H) Scheduled Derates: percent of Period Hrs	12.22	12.56	12.72	0.13	8.07
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	2,017	4,305	2,115	4,723	13,159
(N) Economic Dispatch: percent of Period Hrs	1.21	2.55	1.25	1.68	1.67
(O) Net mWh Possible in Period	167,175	168,661	169,404	281,597	786,837
(P) Equivalent Availability (%)	87.78	87.44	87.28	99.87	91.93
(Q) Output Factor (%)	86.57	84.89	86.03	98.19	90.25
(R) Heat Rate (BTU/NkWh)	8,727	8,767	8,728	4,600	7,128

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Richmond County Station

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	194	194	182	570
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	89,949	89,752	98,060	277,761
(D) Capacity Factor (%)	62.40	62.27	72.52	65.59
(E) Net mWh Not Generated due to Full Scheduled Outages	36,747	37,128	35,059	108,934
(F) Scheduled Outages: percent of Period Hrs	25.49	25.76	25.93	25.72
(G) Net mWh Not Generated due to Partial Scheduled Outages	11,072	11,308	3,577	25,957
(H) Scheduled Derates: percent of Period Hrs	7.68	7.85	2.65	6.13
(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	6,375	5,953	0	12,328
(N) Economic Dispatch: percent of Period Hrs	4.42	4.13	0.00	2.91
(O) Net mWh Possible in Period	144,142	144,142	135,226	423,510
(P) Equivalent Availability (%)	66.83	66.40	71.43	68.15
(Q) Output Factor (%)	83.76	83.87	97.90	88.30
(R) Heat Rate (BTU/NkWh)	11,095	11,074	0	7,171

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Richmond County Station

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	216	216	248	680
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	66,681	67,016	82,731	216,428
(D) Capacity Factor (%)	41.55	41.76	44.90	42.84
(E) Net mWh Not Generated due to Full Scheduled Outages	82,069	82,069	94,265	258,403
(F) Scheduled Outages: percent of Period Hrs	51.14	51.14	51.16	51.14
(G) Net mWh Not Generated due to Partial Scheduled Outages	7,624	7,443	0	15,067
(H) Scheduled Derates: percent of Period Hrs	4.75	4.64	0.00	2.98
(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	4,114	3,960	7,268	15,342
(N) Economic Dispatch: percent of Period Hrs	2.56	2.47	3.94	3.04
(O) Net mWh Possible in Period	160,488	160,488	184,264	505,240
(P) Equivalent Availability (%)	44.11	44.23	48.84	45.87
(Q) Output Factor (%)	85.03	85.46	91.92	87.68
(R) Heat Rate (BTU/NkWh)	11,417	11,320	0	7,023

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Sutton Energy Complex

	Unit 1A	Unit 1B	Unit ST1	Block Total
(A) MDC (mW)	224	224	271	719
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	131,326	131,593	145,349	408,268
(D) Capacity Factor (%)	78.91	79.07	72.19	76.42
(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	20,061	19,689	1,857	41,607
(H) Scheduled Derates: percent of Period Hrs	12.05	11.83	0.92	7.79
(I) Net mWh Not Generated due to Full Forced Outages	0	0	77	77
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.04	0.01
(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	15,045	15,150	54,070	84,265
(N) Economic Dispatch: percent of Period Hrs	9.04	9.10	26.85	15.77
(O) Net mWh Possible in Period	166,432	166,432	201,353	534,217
(P) Equivalent Availability (%)	87.95	88.17	99.04	92.20
(Q) Output Factor (%)	80.79	80.88	74.49	78.46
(R) Heat Rate (BTU/NkWh)	10,994	10,972	0	7,073

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

Duke Energy Progress
Intermediate Power Plant Performance
Review Plan
March 2019

	Mayo Station
	Unit 1
(A) MDC (mW)	746
(B) Period Hrs	743
(C) Net Generation (mWh)	66,070
(D) Net mWh Possible in Period	554,278
(E) Equivalent Availability (%)	88.61
(F) Output Factor (%)	48.64
(G) Capacity Factor (%)	11.92

Notes:

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

Duke Energy Progress
Intermediate Power Plant Performance
Review Plan
March 2019

Roxboro Station

		Unit 2	Unit 3	Unit 4
(A)	MDC (mW)	673	698	711
(B)	Period Hrs	743	743	743
(C)	Net Generation (mWh)	-5,253	104,530	357,456
(D)	Net mWh Possible in Period	500,039	518,614	528,273
(E)	Equivalent Availability (%)	100.00	36.00	96.26
(F)	Output Factor (%)	0.00	60.59	70.24
(G)	Capacity Factor (%)	0.00	20.16	67.67

Notes:

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

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2018 - March 2019
Brunswick Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	938		932	
(B) Period Hours	8760		8760	
(C) Net Gen (mWh) and Capacity Factor (%)	7,819,962	95.17	6,876,141	84.22
(D) Net mWh Not Gen due to Full Schedule Outages	81,262	0.99	670,108	8.21
* (E) Net mWh Not Gen due to Partial Scheduled Outages	44,629	0.54	82,363	1.01
(F) Net mWh Not Gen due to Full Forced Outages	331,693	4.04	252,868	3.10
* (G) Net mWh Not Gen due to Partial Forced Outages	-60,666	-0.74	282,840	3.46
* (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	8,216,880	100.00%	8,164,320	100.00%
(K) Equivalent Availability (%)		96.00		87.43
(L) Output Factor (%)		100.21		94.96
(M) Heat Rate (BTU/NkWh)		10,416		10,798

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2018 - March 2019
Harris Nuclear Station

	Unit 1	
(A) MDC (mW)	964	
(B) Period Hours	8760	
(C) Net Gen (mWh) and Capacity Factor (%)	7,787,575	94.59
(D) Net mWh Not Gen due to Full Schedule Outages	756,318	9.19
* (E) Net mWh Not Gen due to Partial Scheduled Outages	20,006	0.24
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-330,491	-4.02
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	8,233,408	100.00%
(K) Equivalent Availability (%)		90.44
(L) Output Factor (%)		104.23
(M) Heat Rate (BTU/NkWh)		10,226

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2018 - March 2019
Robinson Nuclear Station

	Unit 2	
(A) MDC (mW)	741	
(B) Period Hours	8760	
(C) Net Gen (mWh) and Capacity Factor (%)	5,264,471	81.10
(D) Net mWh Not Gen due to Full Schedule Outages	1,297,442	19.99
* (E) Net mWh Not Gen due to Partial Scheduled Outages	99,165	1.53
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-169,918	-2.62
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	6,491,160	100.00%
(K) Equivalent Availability (%)		78.71
(L) Output Factor (%)		101.36
(M) Heat Rate (BTU/NkWh)		10,476

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2018 through March, 2019

Lee Energy Complex

	Unit 1A	Unit 1B	Unit 1C	Unit ST1	Block Total
(A) MDC (mW)	225	227	228	379	1,059
(B) Period Hrs	8,760	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,423,723	1,430,643	1,449,864	2,839,979	7,144,209
(D) Capacity Factor (%)	72.23	71.95	72.59	85.54	77.01
(E) Net mWh Not Generated due to Full Scheduled Outages	73,316	85,738	88,863	132,069	379,986
(F) Scheduled Outages: percent of Period Hrs	3.72	4.31	4.45	3.98	4.10
(G) Net mWh Not Generated due to Partial Scheduled Outages	271,178	283,193	288,469	49,253	892,092
(H) Scheduled Derates: percent of Period Hrs	13.76	14.24	14.44	1.48	9.62
(I) Net mWh Not Generated due to Full Forced Outages	45,975	37,561	36,096	78,529	198,161
(J) Forced Outages: percent of Period Hrs	2.33	1.89	1.81	2.37	2.14
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	9,254	9,254
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.28	0.10
(M) Net mWh Not Generated due to Economic Dispatch	156,808	151,385	133,988	210,957	653,138
(N) Economic Dispatch: percent of Period Hrs	7.96	7.61	6.71	6.35	7.04
(O) Net mWh Possible in Period	1,971,000	1,988,520	1,997,280	3,320,040	9,276,840
(P) Equivalent Availability (%)	80.19	79.56	79.30	91.89	84.05
(Q) Output Factor (%)	78.54	77.06	77.80	91.79	82.81
(R) Heat Rate (BTU/NkWh)	9,013	9,096	9,010	4,572	7,263

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2018 through March, 2019

Richmond County Station

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	190	190	177	557
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,242,500	1,232,784	1,387,299	3,862,583
(D) Capacity Factor (%)	74.56	73.98	89.61	79.14
(E) Net mWh Not Generated due to Full Scheduled Outages	103,816	93,362	60,727	257,904
(F) Scheduled Outages: percent of Period Hrs	6.23	5.60	3.92	5.28
(G) Net mWh Not Generated due to Partial Scheduled Outages	175,091	179,560	59,403	414,053
(H) Scheduled Derates: percent of Period Hrs	10.51	10.78	3.84	8.48
(I) Net mWh Not Generated due to Full Forced Outages	15,578	22,448	5,014	43,040
(J) Forced Outages: percent of Period Hrs	0.93	1.35	0.32	0.88
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	12,850	12,850
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.83	0.26
(M) Net mWh Not Generated due to Economic Dispatch	129,451	138,281	22,819	290,552
(N) Economic Dispatch: percent of Period Hrs	7.77	8.30	1.47	5.95
(O) Net mWh Possible in Period	1,666,435	1,666,435	1,548,113	4,880,983
(P) Equivalent Availability (%)	82.37	82.31	91.20	85.09
(Q) Output Factor (%)	80.63	80.52	94.01	84.93
(R) Heat Rate (BTU/NkWh)	11,328	11,164	0	7,207

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2018 through March, 2019

Richmond County Station

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	216	216	248	680
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,414,983	1,427,236	1,840,903	4,683,122
(D) Capacity Factor (%)	74.78	75.43	84.74	78.62
(E) Net mWh Not Generated due to Full Scheduled Outages	172,670	174,442	202,083	549,195
(F) Scheduled Outages: percent of Period Hrs	9.13	9.22	9.30	9.22
(G) Net mWh Not Generated due to Partial Scheduled Outages	198,417	194,176	0	392,593
(H) Scheduled Derates: percent of Period Hrs	10.49	10.26	0.00	6.59
(I) Net mWh Not Generated due to Full Forced Outages	3,920	277	0	4,198
(J) Forced Outages: percent of Period Hrs	0.21	0.01	0.00	0.07
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	1,848	1,848
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.09	0.03
(M) Net mWh Not Generated due to Economic Dispatch	102,169	96,030	127,646	325,845
(N) Economic Dispatch: percent of Period Hrs	5.40	5.08	5.88	5.47
(O) Net mWh Possible in Period	1,892,160	1,892,160	2,172,480	5,956,800
(P) Equivalent Availability (%)	80.18	80.50	90.61	84.09
(Q) Output Factor (%)	82.97	83.12	93.43	86.84
(R) Heat Rate (BTU/NkWh)	11,311	11,252	0	6,847

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

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2018 through March, 2019

Sutton Energy Complex

	Unit 1A	Unit 1B	Unit ST1	Block Total
(A) MDC (mW)	224	224	271	719
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,129,922	1,102,837	1,216,696	3,449,455
(D) Capacity Factor (%)	57.58	56.20	51.25	54.77
(E) Net mWh Not Generated due to Full Scheduled Outages	204,202	273,175	242,491	719,868
(F) Scheduled Outages: percent of Period Hrs	10.41	13.92	10.21	11.43
(G) Net mWh Not Generated due to Partial Scheduled Outages	220,747	203,720	16,716	441,183
(H) Scheduled Derates: percent of Period Hrs	11.25	10.38	0.70	7.00
(I) Net mWh Not Generated due to Full Forced Outages	132,765	166,996	569,552	869,312
(J) Forced Outages: percent of Period Hrs	6.77	8.51	23.99	13.80
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	12,685	12,685
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.53	0.20
(M) Net mWh Not Generated due to Economic Dispatch	274,604	215,512	315,820	805,936
(N) Economic Dispatch: percent of Period Hrs	13.99	10.98	13.30	12.80
(O) Net mWh Possible in Period	1,962,240	1,962,240	2,373,960	6,298,440
(P) Equivalent Availability (%)	71.58	67.19	64.56	67.56
(Q) Output Factor (%)	77.34	77.94	78.28	77.86
(R) Heat Rate (BTU/NkWh)	11,366	11,373	0	7,359

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

Duke Energy Progress
Intermediate Power Plant
Performance Review Plan
April, 2018 through March, 2019

Mayo Station

Units	Unit 1
(A) MDC (mW)	746
(B) Period Hrs	8,760
(C) Net Generation (mWh)	1,350,056
(D) Net mWh Possible in Period	6,534,960
(E) Equivalent Availability (%)	66.37
(F) Output Factor (%)	37.55
(G) Capacity Factor (%)	20.66

Notes:

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

Duke Energy Progress
Intermediate Power Plant
Performance Review Plan
April, 2018 through March, 2019

Roxboro Station

Units	Unit 2	Unit 3	Unit 4
(A) MDC (mW)	673	698	711
(B) Period Hrs	8,760	8,760	8,760
(C) Net Generation (mWh)	1,555,700	1,374,062	1,960,487
(D) Net mWh Possible in Period	5,895,480	6,114,480	6,228,360
(E) Equivalent Availability (%)	79.51	57.68	64.47
(F) Output Factor (%)	49.91	49.96	56.50
(G) Capacity Factor (%)	26.39	22.47	31.48

Notes:

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

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 1**
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs	7,500,998	8,022,954	8,298,420	5,890,772	29,713,145
Cost	$ 45,226,821	$ 47,347,803	$ 56,256,531	$ 34,493,536	$ 183,324,690
$/MWhs	$ 6.0294	$ 5.9015	$ 6.7792	$ 5.8555	
Avg. $/MWhs					**$ 6.1698**
Cents per kWh					**0.6170**

	Unit		Dec'19-Nov'20
MDC			
	Brunswick 1	MW	938
	Brunswick 2	MW	932
	Harris 1	MW	964
	Robinson 1	MW	741
			3,575
Hours in Year			8,784
Generation in GWhs			
	Brunswick 1	GWh	7,501
	Brunswick 2	GWh	8,023
	Harris 1	GWh	8,298
	Robinson 1	GWh	5,891
			29,713
	Proposed Nuclear Capacity Factor		**94.62%**

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 2**
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs with NERC applied	7,777,986	7,728,233	7,743,781	5,576,863	28,826,864
Hours in Year	8,784	8,784	8,784	8,784	8,784
MDC	938	932	964	741	3,575
Capacity Factor-NERC 5yr Avg	0.9440	0.944	0.9145	0.8568	
Cost ($)	$ 47,988,756	$ 47,681,792	$ 47,777,718	$ 34,408,229	$ 177,856,495
Avg. $/MWHs					**$ 6.1698**
Cents per kWh					**0.6170**

	Capacity Rating	NCF Rating	Weighted Average
Brunswick 1	938	94.40%	24.77%
Brunswick 2	932	94.40%	24.61%
Harris 1	964	91.45%	24.66%
Robinson 1	741	85.68%	17.76%
	3,575		**91.80%**

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 3**

North Carolina Annual Fuel and Fuel Related Expense

North Carolina Generation in MWhs

Billing Period December 1, 2019 - November 30, 2020

Docket No. E-2, Sub 1204

Resource Type		**MWh Dec'19-Nov'20**
Nuclear		29,600,524
Adjust for Higher Nuclear Capacity Factor		112,622
Adjusted Nuclear Total		29,713,146
Coal		11,243,908
Adjust for Higher Nuclear Capacity Factor		(112,622)
Adjusted Coal Total		11,131,286
Gas CT and CC Total		22,185,181
Total Hydro		648,112
Utility Owned Solar Generation		279,675
Total Net Generation		63,957,400
Purchases	287,950	
Purchases for REPS Compliance	2,984,954	
Purchases from Qualifying Facilities	3,766,456	
Allocated Economic Purchases	168,026	
Joint Dispatch purchases	352,984	7,560,370
Total Net Generation and Purchases		71,517,770
Sales Totals (intersystem sales, JDA sales)		(7,544,324)
Line Losses and Company Use		(1,817,527)
Total NC System Sales		**62,155,919**

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Fuel Costs ($)
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 4

Resource Type		**Costs $ Dec'19-Nov'20**
Nuclear		$ 182,708,089
Adjust for Higher Nuclear Capacity Factor		616,601
Adjusted Nuclear		183,324,690
Coal		352,524,698
Adjust for Higher Nuclear Capacity Factor		(3,530,975)
Adjusted Coal Total		348,993,723
Reagent and By-Product Costs		26,265,057
Gas CT and CC Total		591,960,856
Total Hydro		-
Utility Owned Solar Generation		-
Total Generation Costs		1,150,544,326
Purchases	$ 14,160,859	
Purchases for REPS Compliance	168,625,939	
Purchases for REPS Compliance Capacity	34,622,728	
Purchases from Qualifying Facilities Energy	193,990,299	
Purchases from Qualifying Facilities Capacity	39,793,114	
Allocated Economic Purchases	5,318,328	
Joint Dispatch Purchases	7,856,766	
Joint Dispatch Savings	(21,960,626)	$ 442,407,406
Total Net Generation and Purchases		1,592,951,732
Sales Totals (intersystem sales)	$ (9,482,483)	
Fuel Transfer Sales	(151,549,522)	(161,032,005)
Total System Fuel and Related Expenses		$ 1,431,919,727

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Reagents ($)
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Month	Year	Ammonia/ Urea	Limestone	Limestone Off-System Sales	Catalyst Depreciation	Magnesium Hydroxide	Calcium Carbonate	Total NC System Reagent Cost	Gypsum (Gain)/Loss	Ash (Gain)/Loss	Total NC System Reagent Cost and ByProduct (Gain)/Loss
December	2019	$ 501,258	$ 856,904	$ (13,875)	$ 131,225	$ 263,707	$ 566,911	$ 2,306,129	$ (159,935)	$ (16,514)	$ 2,129,680
January	2020	592,683	1,032,605	(60,191)	131,225	308,141	664,267	2,668,730	(183,141)	(26,970)	2,458,618
February	2020	564,062	1,015,062	(46,890)	131,225	295,418	627,340	2,586,217	8,224,137	(25,083)	10,785,271
March	2020	220,821	420,575	(13,341)	131,225	116,287	268,209	1,143,776	(38,896)	(7,993)	1,096,887
April	2020	125,700	248,850	(13,623)	130,758	68,966	158,824	719,475	(22,476)	(4,721)	692,278
May	2020	135,515	268,249	(8,647)	130,761	74,608	170,523	771,009	(22,587)	(4,998)	743,425
June	2020	307,837	590,654	(9,998)	129,062	166,913	370,721	1,555,190	(91,698)	(13,733)	1,449,759
July	2020	469,410	904,197	(2,067)	130,557	256,238	544,005	2,302,340	(156,469)	(21,595)	2,124,276
August	2020	444,150	866,174	(5,165)	130,802	243,033	516,617	2,195,611	(152,236)	(20,531)	2,022,844
September	2020	263,756	515,430	(2,417)	130,797	142,429	315,333	1,365,329	(102,025)	(12,865)	1,250,439
October	2020	165,988	324,185	(5,426)	131,100	90,205	198,672	904,724	(69,861)	(8,450)	826,413
November	2020	140,011	266,433	(4,077)	131,225	77,471	155,661	766,725	(73,558)	(8,000)	685,167
12ME Nov	2020	$ 3,931,192	$ 7,309,319	$ (185,717)	$ 1,569,962	$ 2,103,416	$ 4,557,084	$ 19,285,255	$ 7,151,255	$ (171,453)	$ 26,265,057

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Fuel Impacts
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 6

		Positive numbers represent expense, Negative numbers represent revenues							
		Allocated Economic Purchase Cost		Economic Sales Cost		Fuel Transfer Payment		JDA Savings Payment	
Month	**Year**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**
December	2019	$ 370,332	$ 526,346	$ (473,650)	$ (80,551)	$ (20,734,306)	$ 20,734,306	$ (2,620,619)	$ 2,620,619
January	2020	$ 805,729	$ 1,120,696	$ (1,322,174)	$ (2,956,749)	$ (2,199,575)	$ 2,199,575	$ (499,078)	$ 499,078
February	2020	$ 468,910	$ 658,964	$ (1,700,288)	$ (1,944,948)	$ (2,966,788)	$ 2,966,788	$ (389,767)	$ 389,767
March	2020	$ 440,334	$ 645,266	$ (317,900)	$ (366,295)	$ (7,807,638)	$ 7,807,638	$ (1,677,115)	$ 1,677,115
April	2020	$ 565,883	$ 861,314	$ (307,322)	$ (42,935)	$ (17,492,082)	$ 17,492,082	$ (3,023,951)	$ 3,023,951
May	2020	$ 318,273	$ 484,205	$ (420,769)	$ (53,391)	$ (15,669,339)	$ 15,669,339	$ (2,463,276)	$ 2,463,276
June	2020	$ 265,020	$ 391,037	$ (266,975)	$ (133,411)	$ (13,367,229)	$ 13,367,229	$ (1,420,206)	$ 1,420,206
July	2020	$ 402,156	$ 570,790	$ (355,561)	$ (554,537)	$ (12,885,849)	$ 12,885,849	$ (1,852,753)	$ 1,852,753
August	2020	$ 503,884	$ 715,819	$ (349,678)	$ (170,188)	$ (12,569,311)	$ 12,569,311	$ (1,395,342)	$ 1,395,342
September	2020	$ 386,514	$ 552,358	$ (206,144)	$ (60,045)	$ (11,359,236)	$ 11,359,236	$ (1,715,765)	$ 1,715,765
October	2020	$ 319,946	$ 470,917	$ (42,092)	$ (45,603)	$ (14,464,750)	$ 14,464,750	$ (3,003,174)	$ 3,003,174
November	2020	$ 471,347	$ 699,707	$ (238,409)	$ (114,001)	$ (12,176,653)	$ 12,176,653	$ (1,899,580)	$ 1,899,580
Total		$ 5,318,328		$ (6,000,962)		$ (143,692,756)		$ (21,960,626)	

Note: Totals may not sum due to rounding

		Fuel Transfer Payments	
		Purchases	**Sales**
December	2019	$ 174,910	$ 20,909,216
January	2020	$ 3,426,589	$ 5,626,164
February	2020	$ 2,934,054	$ 5,900,842
March	2020	$ 173,089	$ 7,980,727
April	2020	$ 651	$ 17,492,733
May	2020	$ 140,440	$ 15,809,779
June	2020	$ 41,137	$ 13,408,366
July	2020	$ 327,326	$ 13,213,176
August	2020	$ 154,737	$ 12,724,048
September	2020	$ 50,830	$ 11,410,066
October	2020	$ 263,167	$ 14,727,916
November	2020	$ 169,837	$ 12,346,489
		$ 7,856,766	$ 151,549,522
			$ (143,692,756)

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Payments
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 7

		MWh Transfer Projection		MWh Purchase Allocation Delta		Adjusted MWh Transfer		Fossil Gen Cost $/MWh		Pre-Net Payments $		Actual Payments $	
Month	**Year**	**DEP to DEC**	**DEC to DEP**	**DEP**	**DEC**	**DEP to DEC**	**DEC to DEP**	**DEP**	**DEC**	**DEP to DEC**	**DEC to DEP**	**DEP to DEC**	**DEC to DEP**
December	2019	880,616	7,953	4,764	(4,764)	885,380	7,953	$ 23.62	$ 21.99	$ 174,910	$ 20,909,216	$ -	$ 20,734,306
January	2020	280,440	127,954	(8,459)	8,459	280,440	136,413	$ 20.06	$ 25.12	$ 3,426,589	$ 5,626,164	$ -	$ 2,199,575
February	2020	246,473	109,549	(10,607)	10,607	246,473	120,156	$ 23.94	$ 24.42	$ 2,934,054	$ 5,900,842	$ -	$ 2,966,788
March	2020	485,080	9,971	4,607	(4,607)	489,687	9,971	$ 16.30	$ 17.36	$ 173,089	$ 7,980,727	$ -	$ 7,807,638
April	2020	839,369	44	10,681	(10,681)	850,049	44	$ 20.58	$ 14.88	$ 651	$ 17,492,733	$ -	$ 17,492,082
May	2020	756,005	7,983	8,211	(8,211)	764,216	7,983	$ 20.69	$ 17.59	$ 140,440	$ 15,809,779	$ -	$ 15,669,339
June	2020	621,236	3,230	3,731	(3,731)	624,967	3,230	$ 21.45	$ 12.74	$ 41,137	$ 13,408,366	$ -	$ 13,367,229
July	2020	591,188	22,850	2,247	(2,247)	593,436	22,850	$ 22.27	$ 14.32	$ 327,326	$ 13,213,176	$ -	$ 12,885,849
August	2020	559,731	11,450	14,246	(14,246)	573,978	11,450	$ 22.17	$ 13.51	$ 154,737	$ 12,724,048	$ -	$ 12,569,311
September	2020	560,773	3,782	9,132	(9,132)	569,905	3,782	$ 20.02	$ 13.44	$ 50,830	$ 11,410,066	$ -	$ 11,359,236
October	2020	699,609	16,686	8,585	(8,585)	708,194	16,686	$ 20.80	$ 15.77	$ 263,167	$ 14,727,916	$ -	$ 14,464,750
November	2020	580,820	12,468	8,209	(8,209)	589,029	12,468	$ 20.96	$ 13.62	$ 169,837	$ 12,346,489	$ -	$ 12,176,653
Total		7,101,341	333,918	55,346	(55,346)	7,175,753	352,984			$ 7,856,766	$ 151,549,522	$ -	$ 143,692,756

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 8

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC			
Residential	16,265,079		16,265,079
Small General Service	1,806,876		1,806,876
Medium General Service	10,414,506		10,414,506
Large General Service	9,223,825		9,223,825
Lighting	381,171		381,171
NC Retail	38,091,457		38,091,457
SC Retail	6,739,878	34,790	6,774,668
Total Wholesale	17,324,584		17,324,584
Total Adjusted NC System Sales	62,155,919	34,790	62,190,710
NC as a percentage of total	61.28%	0.00%	61.25%
SC as a percentage of total	10.84%	100.00%	10.89%
Wholesale as a percentage of total	27.87%	0.00%	27.86%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs		34,790	
Marginal Fuel rate per MWh for SC NEM	$	32.11	
Fuel Benefit to be directly assigned to SC	$	1,117,119	
System Fuel Expense	$	1,431,919,727	Exh 2 Sch 1 Pg 1
Fuel benefit to be directly assigned to SC Retail		1,117,119	
Total Adjusted System Fuel Expense	$	1,433,036,845	Exh 2 Sch 1 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Normalized Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 8a

		Test Period Sales MWhs	Weather Normalization	Customer Growth	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC						
	Residential	16,147,005	(245,014)	120,250		16,022,241
	Small General Service	1,958,731	(20,261)	5,244		1,943,714
	Medium General Service	11,108,152	(136,061)	35,216		11,007,307
	Large General Service	8,479,278	(110,973)	238		8,368,542
	Lighting	353,410	0	555		353,965
Total		38,046,575	(512,310)	161,504		37,695,769
SC Retail		6,414,956	(85,144)	7,439	34,790	6,372,042
Total Wholesale		18,106,633	(273,277)	126,090		17,959,446
Total Adjusted NC System Sales		62,568,164	(870,731)	295,033	34,790	62,027,257
NC as a percentage of total		60.81%				60.77%
SC as a percentage of total		10.25%				10.27%
Wholesale as a percentage of total		28.94%				28.95%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs		34,790	
Marginal Fuel rate per MWh for SC NEM	$	32.11	
Fuel Benefit to be directly assigned to SC	$	1,117,119	
System Fuel Expense	$	1,426,649,465	Exh 2 Sch 2 Pg 1
Fuel benefit to be directly assigned to SC Retail		1,117,119	
Total Adjusted System Fuel Expense	$	1,427,766,584	Exh 2 Sch 2 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales - NERC 5 year Average
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 8b

		Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC				
	Residential	16,265,079		16,265,079
	Small General Service	1,806,876		1,806,876
	Medium General Service	10,414,506		10,414,506
	Large General Service	9,223,825		9,223,825
	Lighting	381,171		381,171
Total		38,091,457		38,091,457
SC Retail		6,739,878	34,790	6,774,668
Total Wholesale		17,324,584		17,324,584
Total Adjusted NC System Sales		62,155,919	34,790	62,190,710
NC as a percentage of total		61.28%	0.00%	61.25%
SC as a percentage of total		10.84%	100.00%	10.89%
Wholesale as a percentage of total		27.87%	0.00%	27.86%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs		34,790	
Marginal Fuel rate per MWh for SC NEM	$	32.11	
Fuel Benefit to be directly assigned to SC	$	1,117,119	
System Fuel Expense	$	1,454,238,675	Exh 2 Sch 3 Pg 1
Fuel benefit to be directly assigned to SC Retail		1,117,119	
Total Adjusted System Fuel Expense	$	1,455,355,794	Exh 2 Sch 3 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adustment - MWh
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Harrington Workpaper 9

Rate Schedule	Reference	NC Proposed MWH [1] Adjustment	SC Proposed MWH Adjustment	Wholesale Proposed MWH Adjustment
Residential	RES	120,250	7,814	
General:				
General Service Small	SGS	5,244	(2,492)	
General Service Medium	MGS	35,216	2,162	
Total General		40,460	(330)	
Lighting:				
Street Lighting	SLS/SLR	417	11	
Sports Field Lighting	SFLS	95	(6)	
Traffic Signal Service	TSS/TFS	42	(50)	
Total Street Lighting		555	(44)	
Industrial:				
I - Textile	LGS	-	-	
I - Nontextile	LGS	238	-	
Total Industrial		238	-	
Total		**161,504**	**7,439**	**126,090**

[1] Using the regression method (Residential, Lighting, SGS classes) and a customer by customer method for MGS and Industrial.

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
NC Retail Allocation %
Energy Allocation Factors - 12 Months Ending December 31, 2018
Docket No. E-2, Sub 1204

	kWh @ Meter	E-2 Allocation	kWh @ Prod Out.	E-1 Allocation	Losses
NC RES	16,158,859,096	0.253513	16,886,868,234	0.256060	728,009,138
NC RES-TOU	507,187,493	0.007957	530,037,939	0.008037	22,850,446
NC SGS	1,950,982,004	0.030609	2,038,860,205	0.030916	87,878,201
NC SGS-CLR	31,614,397	0.000496	33,038,728	0.000501	1,424,331
NC MGS-TOU	8,371,865,197	0.131344	8,732,655,226	0.132416	360,790,029
NC MGS	2,807,099,681	0.044040	2,930,697,735	0.044439	123,598,054
NC SI	43,075,313	0.000676	44,807,202	0.000679	1,731,889
NC LGS	1,141,204,433	0.017904	1,182,461,085	0.017930	41,256,652
NC LGS-TOU	1,598,681,135	0.025081	1,654,866,445	0.025093	56,185,310
NC LGS-RTP	5,717,905,454	0.089707	5,891,608,297	0.089336	173,702,843
NC TSS	4,754,792	0.000075	4,969,011	0.000075	214,219
NC ALS	267,795,639	0.004201	279,860,703	0.004244	12,065,064
NC SLS	85,107,971	0.001335	88,942,362	0.001349	3,834,391
NC SFLS	1,134,908	0.000018	1,175,511	0.000018	40,603
Total NCR	38,687,267,513	0.606957	40,300,848,683	0.611093	1,613,581,170
NCEMPA	7,640,609,496	0.119872	7,781,142,553	0.117988	140,533,057
NCEMC	7,861,748,196	0.123341	8,006,348,638	0.121403	144,600,442
Fayetteville	2,134,092,683	0.033481	2,173,344,861	0.032955	39,252,179
FBEMC	548,372,445	0.008603	558,458,611	0.008468	10,086,166
Piedmont EMC	76,153,133	0.001195	77,553,811	0.001176	1,400,678
Haywood EMC	83,779,955	0.001314	85,320,912	0.001294	1,540,957
Total NCWHS	10,704,146,412	0.167935	10,901,026,834	0.165295	196,880,422
Total NC	57,032,023,421	0.894764	58,983,018,069	0.894376	1,950,994,648
SC RES	2,148,532,519	0.033708	2,245,330,894	0.034047	96,798,375
SC RET	41,479,049	0.000651	43,347,815	0.000657	1,868,766
SC SGS	278,936,083	0.004376	291,483,609	0.004420	12,547,526
SC SGS-CLR	4,439,514	0.000070	4,639,529	0.000070	200,015
SC MGS-TOU	1,115,225,685	0.017497	1,163,034,915	0.017635	47,809,230
SC MGS	537,836,914	0.008438	561,105,498	0.008508	23,268,584
SC SI	18,492,882	0.000290	19,221,900	0.000291	729,018
SC LGS	698,027,189	0.010951	723,387,192	0.010969	25,360,003
SC LGS-TOU	309,355,839	0.004853	318,750,549	0.004833	9,394,710
SC LGS-CRTL-TOU	702,376,100	0.011019	720,122,869	0.010919	17,746,769
SC LGS-RTP	571,293,865	0.008963	586,269,865	0.008890	14,976,000
SC TSS	855,613	0.000013	894,161	0.000014	38,548
SC ALS	63,427,856	0.000995	66,285,487	0.001005	2,857,631
SC SLS	16,316,405	0.000256	17,051,512	0.000259	735,107
SC SFLS	149,692	0.000002	155,048	0.000002	5,356
Total SCR	6,506,745,205	0.102083	6,761,080,842	0.102520	254,335,637
SCWHS (Camden)	200,980,232	0.003153	204,676,844	0.003104	3,696,612
Total SC	6,707,725,437	0.105236	6,965,757,686	0.105624	258,032,249
Total System	63,739,748,858	1.000000	65,948,775,755	1.000000	2,209,026,897

Cost of Service Data Summarized

	kWh @ Meter	kWh @ Prod Out.	Losses (kWh)	Loss Percent
Residential	16,666,046,589	17,416,906,173	750,859,584	4.51%
SGS	1,987,351,193	2,076,867,944	89,516,751	4.50%
MGS	11,222,040,191	11,708,160,163	486,119,972	4.33%
LGS	8,457,791,022	8,728,935,826	271,144,804	3.21%
Lighting	354,038,518	369,978,576	15,940,058	4.50%
Total NC Retail	38,687,267,513	40,300,848,683	1,613,581,170	4.17%
Total NC Retail	38,687,267,513	40,300,848,683	1,613,581,170	4.17%
SC Retail	6,506,745,205	6,761,080,842	254,335,637	3.91%
NEM Generation	18,558,183	19,313,093	754,910	
Total SC Retail	6,525,303,388	6,780,393,935	255,090,547	3.91%
All other jurisdictions	18,527,177,957	18,867,533,137	340,355,180	1.84%
Total System	63,739,748,858	65,948,775,755	2,209,026,897	3.47%

Line Loss Calculations for Projected Fuel Costs	MWh @ Meter	MWh @ Prod Out.	Losses (MWh)	Loss Percent
Total NC Retail	38,091,457	39,749,335	1,657,878	4.35%
Total SC Retail	6,774,668	7,050,281	275,613	4.07%
All other jurisdictions	17,324,584	17,648,803	324,219	1.87%
Total System	62,190,710	64,448,420	2,257,710	3.63%
Allocation percent - NC retail	61.25%	61.68%		

Line Loss Calculations for Normalized Test Period Sales	MWh @ Meter	MWh @ Prod Out.	Losses (MWh)	Loss Percent
Total NC Retail	37,695,769	39,336,426	1,640,656	4.35%
Total SC Retail	6,372,042	6,631,275	259,233	4.07%
All other jurisdictions	17,959,446	18,295,546	336,100	1.87%
Total System	62,027,257	64,263,247	2,235,990	3.60%
Allocation percent - NC retail	60.77%	61.21%		

DUKE ENERGY PROGRESS, LLC
nnual Fuel and Fuel Related Expense
Derivation of Equal Percent Increases for all Rate Classes
Annualized Revenues at Current Rates
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Harrington Workpaper 11

									Remove Partial Year Impacts						Add Impact of Approved Rate Changes During Test Year					
Revenue Class (1)	Annual Sales (2) per RMC2B	Annual EE Opt-Out Sales (3) per RMCRY14E	Annual DSM Opt-Out Sales (4) per RMCRY14E	Annual Customer Count (5) per RMC2B	Annual Rider JAA kWh Units (6) per RMC2B	Annual Rider JAA Demand Units (7) per PMCM7M	Annual Customer Count (Adjusted for Premise Billing) (8) = (5) adjusted by RMCRY10	Annual Revenues (9) per RMC2B	Test Year Rate Changes** (10) - See Annualization Adjustment Worksheet	Opt-Out Credit Due to Jan 2019 EE Rate (11) per RMCRY14	Opt-Out Credit Due to Jan. 2019 DSM Rate (12) per RMCRY15	NC Rate Case - Mar. 16, 2018 (13) per Report PMCM7M Worksheet	REPS Revenue Due to December 2018 Rate Change (14) per RMCRY10	Annual Revenues Excluding All Rate Adjustments (15)=(9)-[10-11-12]-(13)-(14)	Annual Impact of Rate Changes*** (16) See Annualization Adjustment worksheet	Annual Opt-Out Impact of 1/19 EE Rate (17) = (3) * Rate Change	Annual Opt-Out Impact of 1/19 EE Rate (18) = (4) * Rate Change	NC Rate Case - Mar. 16, 2018 (19) per Report PMCM7M Worksheet	Annual Impact of Dec. 2018 REPS Rate (20) = (8) * Rate Change	Annual Revenue At Current Rates (21)=(15)+[16-17-18]+(19)+(20)
Residential	16,212,932,955	0	0	14,734,929	16,212,932,955	0	14,620,840	$1,847,496,050	$48,836,176	$0	$0	$96,029,193	$3,614,551	$1,699,016,130	$107,022,665	$0	$0	$101,952,080	$12,720,131	$1,920,711,005
Residential	16,146,992,624	0	0	14,619,905	16,146,992,624	0	14,538,187	$1,825,812,669	$48,753,421	$0	$0	$96,632,058	$3,594,532	$1,676,832,658	$106,416,618	$0	$0	$102,590,341	$12,648,223	$1,898,487,840
SGS	-2,556	0	0	9	-2,556	0	0	-$225	$1	$0	$0	($11)	$0	-$216	($8)	$0	$0	($11)	$0	-$235
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	($18)	$18	$0	$0	$0	$0	$0	$18
LGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lighting	65,942,887	0	0	115,015	65,942,887	0	82,653	$21,683,606	$82,753	$0	$0	($602,855)	$20,037	$22,183,670	$606,054	$0	$0	($638,251)	$71,908	$22,223,382
Commercial	12,342,849,169	3,972,313,132	4,057,417,628	2,463,499	2,201,284,432	30,452,498	2,353,302	$1,109,669,837	$58,675,286	$1,452,371	$24,887	$33,409,890	$1,035,922	$1,018,025,997	$120,802,685	$9,426,103	$161,817	$35,295,813	$3,624,085	$1,168,160,660
Residential	1,202	0	0	16	1,202	0	0	$202	$7	$0	$0	$10	$8	$178	$11	$0	$0	$10	$0	$200
SGS	1,935,230,064	16,684,073	17,157,566	2,010,433	1,935,230,064	0	1,808,958	$231,791,855	$10,228,666	$7,389	$127	$10,824,534	$795,854	$209,950,318	$22,780,740	$39,708	$686	$11,391,522	$2,785,796	$246,867,982
MGS	9,061,499,382	2,825,998,190	2,930,307,406	438,224	51,943,437	28,184,415	393,029	$744,673,521	$47,095,727	$1,061,231	$18,470	$21,685,730	$173,334	$676,798,431	$91,701,933	$6,725,876	$117,212	$22,990,156	$605,264	$785,252,696
LGS	1,132,008,792	1,118,154,703	1,097,955,335	1,115	0	2,268,083	877	$84,286,732	$1,089,115	$383,866	$6,290	$2,593,161	$377	$80,994,235	$4,352,574	$2,661,208	$43,918	$2,707,167	$1,350	$85,350,199
Lighting	214,109,729	11,476,166	11,997,321	13,711	214,109,729	0	150,438	$48,917,527	$261,771	($115)	$0	($1,693,545)	$66,349	$50,282,836	$1,967,427	($689)	$0	($1,793,043)	$231,675	$50,689,583
Industrial	8,008,590,935	8,086,451,889	8,119,913,879	41,674	35,054,487	18,564,478	22,101	$521,580,186	$16,566,304	$3,043,278	$51,354	$16,963,357	$92,439	$491,052,719	$43,890,438	$19,225,430	$324,449	$17,795,532	$319,580	$533,508,391
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	19,175,904	8,859,945	8,940,858	12,301	19,175,904	0	3,422	$2,081,181	$103,329	$3,742	$64	$97,088	$14,757	$1,869,814	$226,642	$21,087	$358	$102,163	$49,486	$2,226,660
MGS	2,045,869,405	1,541,179,827	1,546,029,304	26,872	854,853	5,918,516	7,751	$157,739,942	$10,497,086	$584,511	$9,872	$4,517,932	$32,518	$143,286,788	$20,795,139	$3,668,008	$61,841	$4,796,947	$112,084	$165,261,110
LGS	5,928,521,896	6,528,082,168	6,556,260,926	2,306	0	12,645,962	9,617	$359,106,306	$5,948,253	$2,455,108	$41,419	$12,447,485	$39,297	$343,167,796	$22,730,681	$15,536,836	$262,250	$13,001,392	$139,055	$363,239,838
Lighting	15,023,730	8,329,949	8,682,791	195	15,023,730	0	1,311	$2,652,757	$17,636	($82)	$0	($99,148)	$5,867	$2,728,321	$137,976	($500)	$0	($104,970)	$18,955	$2,780,782
Public Streets & Highwa	62,685,816	0	0	11,027	62,685,816	0	10,198	$16,694,211	$94,074	$0	$0	($2,321)	$4,275	$16,598,184	$588,281	$0	$0	($2,458)	$15,705	$17,199,713
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	4,353,685	0	0	5,445	4,353,685	0	5,362	$415,967	$22,436	$0	$0	$39,311	$2,172	$352,047	$52,209	$0	$0	$41,619	$8,258	$454,133
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lighting	58,332,131	0	0	5,582	58,332,131	0	4,836	$16,278,244	$71,637	$0	$0	($41,632)	$2,103	$16,246,137	$536,072	$0	$0	($44,077)	$7,447	$16,745,580
Military	1,418,748,802	1,524,087,345	1,524,087,345	48	1,920	3,396,213	39	$84,990,339	$1,211,971	$501,074	$8,421	$3,146,323	$176	$81,141,365	$5,414,921	$3,627,328	$60,963	$3,285,960	$564	$86,154,519
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LGS	1,418,746,882	1,524,087,345	1,524,087,345	48	0	3,396,213	39	$84,990,125	$1,211,969	$501,074	$8,421	$3,146,331	$176	$81,141,146	$5,414,904	$3,627,328	$60,963	$3,285,968	$564	$86,154,290
Lighting	1,920	0	0	0	1,920	0	0	$214	$2	$0	$0	($8)	$0	$220	$18	$0	$0	($9)	$0	$229
NC Retail	38,045,807,677	13,582,852,366	13,701,418,852	17,251,177	18,511,959,610	52,413,189	17,006,480	$3,580,430,623	$125,383,810	$4,996,724	$84,663	$149,546,441	$4,747,363	$3,305,834,396	$277,718,991	$32,278,862	$547,230	$158,326,926	$16,680,065	$3,725,734,287
Rate Schedules (excludes REPS)																				
RES (includes RES-RECD)	15,665,019,184	0	0	14,343,037	15,665,019,184	0	0	$1,778,815,316	$37,385,804	$0	$0	$94,196,369	$3,594,533	$1,643,638,610	$81,778,225	$0	$0	$0	$0	$1,725,416,835
SGS	1,918,181,640	25,544,018	26,098,424	1,940,238	1,918,181,640	0	0	$229,393,523	$10,153,219	$11,131	$191	$21,662,202	$774,405	$196,815,019	$22,620,236	$60,795	$1,044	$0	$0	$219,373,416
MGS	2,723,394,968	330,330,189	334,265,992	197,036	0	12,841,955	0	$272,654,804	$13,932,137	$125,686	$2,122	$34,666,873	$105,809	$224,077,793	$26,626,025	$786,186	$13,371	$0	$0	$249,904,261
SGS-TOU	8,307,422,849	4,030,048,704	4,135,188,329	256,698	0	21,198,905	0	$621,397,177	$43,287,020	$1,518,596	$26,194	$17,232,356	$128,967	$562,293,625	$85,163,821	$9,591,516	$165,408	$0	$0	$637,700,522
LGS	1,127,991,905	1,142,257,424	1,165,983,605	1,075	0	2,311,774	0	$88,746,559	$1,106,011	$424,692	$7,294	$20,824,087	$2,552	$67,245,895	$4,347,647	$2,718,573	$46,639	$0	$0	$68,828,331
LGS-TOU	1,592,061,416	1,679,924,598	1,664,177,807	1,432	0	3,017,370	0	$114,895,733	$1,671,213	$638,652	$10,572	$3,529,455	$2,121	$110,342,168	$6,155,548	$3,998,221	$66,567	$0	$0	$112,432,928
LGS-RTP	10,614,788	10,614,788	10,614,788	13	0	40,387	0	$899,542	$80,290	$4,570	$77	$31,821	$0	$792,079	$254,760	$25,263	$425	$0	$0	$1,021,151
LGS-RTP-TOU	5,748,609,461	6,336,490,606	6,336,490,606	949	0	12,940,727	0	$323,841,329	$5,391,824	$2,272,134	$38,187	$11,988,593	$2,772	$308,768,461	$21,740,204	$15,080,848	$253,460	$0	$0	$315,174,358
LGS Class	8,479,277,570	9,169,287,416	9,177,266,806	3,469	0	18,310,258	0	$528,383,163	$8,249,337	$3,340,048	$56,130	$36,373,956	$7,445	$487,148,604	$32,498,159	$21,822,904	$367,091	$0	$0	$497,456,768
Rate Class																				
Residential	16,146,993,826	0	0	14,619,921	16,146,993,826	0	14,538,187	$1,825,812,871	$48,753,428	$0	$0	$96,632,067	$3,594,539	$1,676,832,836	$106,416,630	$0	$0	$102,590,352	$12,648,223	$1,898,488,040
SGS	1,958,757,097	25,544,018	26,098,424	2,028,188	1,958,757,097	0	1,817,743	$234,288,778	$10,354,432	$11,131	$191	$10,960,922	$812,783	$212,171,962	$23,059,584	$60,795	$1,044	$11,535,293	$2,843,539	$249,548,540
MGS	11,107,368,787	4,367,178,017	4,476,336,710	465,096	52,798,290	34,102,931	400,780	$902,413,463	$57,592,813	$1,645,742	$28,341	$26,203,662	$205,834	$820,085,237	$112,497,072	$10,393,884	$179,053	$27,787,103	$717,348	$950,513,824
LGS	8,479,277,570	9,170,324,216	9,178,303,606	3,469	0	18,310,258	10,532	$528,383,163	$8,249,337	$3,340,048	$56,130	$18,186,978	$39,850	$505,303,177	$32,498,159	$21,825,372	$367,132	$18,994,527	$140,969	$534,744,328
Lighting	353,410,397	19,806,115	20,680,112	134,503	353,410,397	0	239,238	$89,532,348	$433,799	($197)	$0	($2,437,188)	$94,356	$91,441,183	$3,247,547	($1,188)	$0	($2,580,349)	$329,986	$92,439,556
	38,045,807,677	13,582,852,366	13,701,418,852	17,251,177	18,511,959,610	52,413,189	17,006,480	$3,580,430,623	$125,383,810	$4,996,724	$84,663	$149,546,441	$4,747,363	$3,305,834,396	$277,718,991	$32,278,862	$547,230	$158,326,926	$16,680,065	$3,725,734,287

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 12**
North Carolina Annual Fuel and Fuel Related Expense
Actual MWH Sales by Jurisdiction - Subject to Weather
Twelve Months Ended March 31, 2018
Docket No. E-2, Sub 1204

Line No.	Description	Reference	North Carolina	South Carolina	Retail Total Company	% NC	% SC
1	Residential	Company Records	16,212,941	2,124,879	18,337,820	88.41	11.59
2	Commercial	Company Records	12,343,207	1,695,832	14,039,039	87.92	12.08
3	Industrial	Company Records	8,008,994	2,530,292	10,539,285	75.99	24.01
4	Other Public Authority	Company Records	1,418,749	49,526	1,468,275	96.63	3.37
5	Total Retail Sales subject to weather	Sum 1 through 4	37,983,890	6,400,529	44,384,420		
6	Lighting	Company Records	62,686	14,427	77,113		
7	Total Retail Sales	Line 5 + Line 6	38,046,576	6,414,956	44,461,533		

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Production Plant Allocation Factors
Cost of Service Study ending December 31, 2018
Docket No. E-2, Sub 1204

Harrington Workpaper 13

Total Production Plant	System	NC Retail	Residential	Small GS	Med GS	Lrg GS	Ltg
Rate Base	16,654,620,260.27	10,159,449,637.14	5,038,986,361.77	625,383,836.37	2,870,205,385.50	1,624,134,063.08	739,990.43
NC Retail % to Total System		61.00%	30.26%	3.76%	17.23%	9.75%	0.00%
Allocation of Classes to Total NC Retail		100.00%	49.60%	6.16%	28.25%	15.99%	0.01%

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Adjustment - MWh
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Description	Reference	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Residential		(277,134)	88.41	(245,014)	11.59	(32,120)
	Commercial						
2	Small and Medium General Service		(177,800)	87.92	(156,322)	12.08	(21,478)
	Industrial						
3	Large General Service		(129,569)	75.99	(98,460)	24.01	(31,110)
	OPA						
4	Other Public Authority (Large General Service)		(12,950)	96.63	(12,514)	3.37	(436)
5	Total Retail	L1+ L2+ L3 + L4	(597,454)		(512,310)		(85,144)
6	Wholesale		(273,277)				
7	Total Company	L5 + L6	(870,731)		(512,310)		(85,144)

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Adjustment - MWh
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

		Residential MWH Adjustment	Commercial MWH Adjustment	Industrial MWH Adjustment	Other Public Authority MWH Adjustment	Total Retail MWH Adjustment	Wholesale MWH Adjustment
April	2018	(103,408)	-	(35,282)	-	(138,690)	(1,563)
May	2018	(28,053)	(8,585)	(17,810)	-	(54,447)	(33,684)
June	2018	(185,737)	(86,887)	(21,885)	(5,782)	(300,291)	(198,952)
July	2018	(92,102)	(33,697)	(106,078)	(3,424)	(235,301)	(79,798)
August	2018	24,133	10,823	5,669	1,191	41,816	20,525
September	2018	(127,205)	31,171	101,925	(8,189)	(2,297)	(79,728)
October	2018	(221,055)	(123,169)	(110,300)	(860)	(455,384)	(122,663)
November	2018	(8,362)	(130,560)	(58,350)	(6,178)	(203,451)	(10,818)
December	2018	(101,677)	130,283	96,047	-	124,653	(62,059)
January	2019	224,778	29,898	16,496	842	272,014	164,657
February	2019	77,988	2,922	-	1,051	81,962	90,461
March	2019	263,564	-	-	8,399	271,963	40,344
12ME March	**2019**	**(277,134)**	**(177,800)**	**(129,569)**	**(12,950)**	**(597,454)**	**(273,277)**

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Scenario Differences
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 15

Exhibit 2 Schedule 1: Line Loss

Line Losses	Exh 2 Sch 1 Pg 1 Ln 16	(1,817,527)
Generation	Exh 2 Sch 1 Pg 1 Ln 10	63,957,400
	%	-2.842%
	Multiplier	1.028418

Schedule 2: Proposed Nuclear Capacity Factor & Normalized Sales

Normalized Sales	Exh 4, Total Co., Ln 4	61,992,467
Sales Forecast	Exh 2 Sch 1 Pg 1 Ln 18	62,155,919
Difference		(163,452)
Gross up for losses		(168,097)
MWh changes in Coal		(168,097)
MWH changes in Losses		4,645

		Before Adj	Adj	Total
Total Coal MWh	WP 3	11,131,286	(168,097)	10,963,189
Total Losses MWh		(1,817,527)	4,645	(1,812,882)

		Before Adj	After Adj	Adjustment
Total Coal $	WP 4	348,993,723	343,723,461	(5,270,262)

Schedule 3: NERC 5 year average Capacity Factor & Projected Sales

		Nuclear-MWHs	Nuclear Costs
Nuclear	WP 1-Nuclear	29,713,145	$ 183,324,690
Nuclear - NERC Average	WP 2-Nuclear NERC	28,826,864	$ 177,856,495
	Adjustment	(886,281)	$ (5,468,195)

		Coal	Coal Costs	
Coal MWh	WP 3	11,131,286	$ 348,993,723	
Adjustment from Above	above	886,281	$ 27,787,143	(Priced at the avg Coal $/MWH)
		12,017,568	$ 376,780,866	

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 16**
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 280,994,289	$ 82,823,475	$ 363,817,764
2	Amount in 2018 Filing: Docket E-2 Sub 1173	310,910,776	78,097,747	389,008,523
3	Reduction in prior year docket in excess of 2.5%	(57,234,383)		(57,234,383)
4	Increase/(Decrease)	$ 27,317,896	$ 4,725,727	$ 32,043,624
5	2.5% of 2018 NC revenue of $3,587,884,326			89,697,108
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases	$ 14,160,859	61.66%	$ 8,731,585
WP 4	Purchases for REPS Compliance	168,625,939	61.66%	103,974,754
WP 4	Purchases for REPS Compliance Capacity	34,622,728	61.00%	21,120,137
WP 4	Purchases from Qualifying Facilities Energy	193,990,299	61.66%	119,614,418
WP 4	Purchases from Qualifying Facilities Capacity	39,793,114	61.00%	24,274,113
WP 4	Allocated Economic Purchases	5,318,328	61.66%	3,279,281
	Total	$ 456,511,266		$ 280,994,289

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Purchases	$ 71,395,237	60.59%	$ 43,258,374
Prior Year	Purchases for REPS Compliance	187,595,597	60.59%	113,664,172
Prior Year	Purchases for REPS Compliance Capacity	38,515,117	60.52%	23,309,349
Prior Year	Purchases from Qualifying Facilities Energy	162,649,793	60.59%	98,549,509
Prior Year	Purchases from Qualifying Facilities Capacity	33,362,793	60.52%	20,191,162
Prior Year	Allocated Economic Purchases	19,703,265	60.59%	11,938,208
	Total	$ 513,221,803		$ 310,910,776

DUKE ENERGY PROGRESS, LLC **Harrington Workpaper 16a**

North Carolina Annual Fuel and Fuel Related Expense

2.5% Calculation Test - Normalized

Billing Period December 1, 2019 - November 30, 2020

Docket No. E-2, Sub 1204

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 277,604,760	$ 82,823,475	$ 360,428,234
2	Amount in 2018 Filing: Docket E-2 Sub 1173	309,190,377	78,097,747	387,288,125
3	Reduction in prior year docket in excess of 2.5%	(54,730,355)		(54,730,355)
4	Increase/(Decrease)	$ 23,144,738	$ 4,725,727	$ 27,870,465
5	2.5% of 2018 NC revenue of $3,587,884,326			89,697,108
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases	$ 14,160,859	60.77%	$ 8,605,966
WP 4	Purchases for REPS Compliance	168,625,939	60.77%	102,478,890
WP 4	Purchases for REPS Compliance Capacity	34,622,728	61.00%	21,120,137
WP 4	Purchases from Qualifying Facilities Energy	193,990,299	60.77%	117,893,550
WP 4	Purchases from Qualifying Facilities Capacity	39,793,114	61.00%	24,274,113
WP 4	Allocated Economic Purchases	5,318,328	60.77%	3,232,103
	Total	$ 456,511,266		$ 277,604,760

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Purchases	$ 71,395,237	60.20%	$ 42,980,069
Prior Year	Purchases for REPS Compliance	187,595,597	60.20%	112,932,908
Prior Year	Purchases for REPS Compliance Capacity	38,515,117	60.52%	23,309,349
Prior Year	Purchases from Qualifying Facilities Energy	162,649,793	60.20%	97,915,486
Prior Year	Purchases from Qualifying Facilities Capacity	33,362,793	60.52%	20,191,162
Prior Year	Allocated Economic Purchases	19,703,265	60.20%	11,861,403
	Total	$ 513,221,803		$ 309,190,377

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test-Detail Calculation
Test Period April 2018 - March 2019
Docket No. E-2, Sub 1204

Harrington Workpaper 16b

Line No.		Reference	Apr'18	May'18	Jun'18	July'18	Aug'18	Sept'18	Oct'18	Nov'18	Dec'18	Jan'19	Feb'19	Mar'19	12ME
1	System kWh Sales, at generation		4,636,856,473	4,790,246,098	5,856,645,043	6,359,201,366	6,396,519,871	5,600,434,066	5,314,903,250	4,874,260,445	4,981,394,129	5,794,466,810	5,252,024,407	4,699,033,969	64,555,985,928
2	NC Retail kWh Sales, at generation		2,922,606,924	2,841,868,501	3,501,325,638	3,819,890,072	3,838,942,450	3,444,193,130	3,364,015,670	3,009,697,941	2,956,160,111	3,465,598,155	3,357,151,243	2,894,643,756	39,416,093,589
3	NC Retail % of Sales	Line 2 / Line 1	63.03%	59.33%	59.78%	60.07%	60.02%	61.50%	63.29%	61.75%	59.34%	59.81%	63.92%	61.60%	61.06%
	Total Purchase Power, Excl. JDA														
4	System Purchase Power, Excl. JDA		$ 30,903,462	$ 37,042,584	$ 36,347,253	$ 48,228,217	$ 43,182,460	$ 51,035,291	$ 32,621,404	$ 34,293,760	$ 17,654,479	$ 21,940,974	$ 25,169,675	$ 23,859,381	$ 402,278,939
5	NC Purchase Power	Line 4 * Line 3	$ 19,478,452	$ 21,975,883	$ 21,729,842	$ 28,970,207	$ 25,916,385	$ 31,386,194	$ 20,647,392	$ 21,175,368	$ 10,476,874	$ 13,122,677	$ 16,088,708	$ 14,697,618	$ 245,665,599
6	NC Retail kWh Sales		2,821,409,876	2,743,728,563	3,379,526,908	3,687,026,670	3,705,569,376	3,324,420,103	3,247,433,903	2,905,623,408	2,853,151,529	3,344,812,989	3,239,878,500	2,793,993,421	38,046,575,246
7	Incurred Rate	Line 5 / Line 6 * 100	0.690	0.801	0.643	0.786	0.699	0.944	0.636	0.729	0.367	0.392	0.497	0.526	0.646
	Total Capacity														
8	System Capacity		$ 5,782,707	$ 5,674,828	$ 9,101,624	$ 9,523,762	$ 9,397,062	$ 9,555,756	$ 2,508,522	$ 3,801,068	$ 2,050,191	$ 4,238,370	$ 5,182,042	$ 4,345,958	$ 71,161,889
9	NC Capacity	Capacity*.6052	$ 3,499,694	$ 3,434,406	$ 5,508,303	$ 5,763,781	$ 5,687,102	$ 5,783,144	$ 1,518,157	$ 2,300,406	$ 1,240,775	$ 2,565,062	$ 3,136,172	$ 2,630,174	$ 43,067,175
10	NC Retail kWh Sales	Line 6	2,821,409,876	2,743,728,563	3,379,526,908	3,687,026,670	3,705,569,376	3,324,420,103	3,247,433,903	2,905,623,408	2,853,151,529	3,344,812,989	3,239,878,500	2,793,993,421	38,046,575,246
11	Incurred Rate	Line 9/Line 10*100	0.124	0.125	0.163	0.156	0.153	0.174	0.047	0.079	0.043	0.077	0.097	0.094	0.113
12	Total Incurred Rate	Line 7 + Line 11	0.814	0.926	0.806	0.942	0.853	1.118	0.683	0.808	0.411	0.469	0.593	0.620	0.759
13	Billed Rate	Billed Rates Below	0.461	0.461	0.461	0.461	0.461	0.461	0.461	0.461	0.588	0.747	0.747	0.747	
14	(Over)/Under cents per kwh	Line 13 - Line 12	0.353	0.465	0.345	0.481	0.392	0.657	0.221	0.347	(0.177)	(0.278)	(0.154)	(0.127)	
15	(Over)/Under $	Line 14 * Line10 /100	9,966,974	12,757,351	11,653,168	17,730,950	14,514,938	21,838,490	7,189,730	10,076,244	(5,048,825)	(9,311,212)	(4,989,889)	(3,554,444)	82,823,475

	Billed Rate from Docket E-2, Sub 1146 - Apr'18-Nov'18			**Billed Rate from Docket E-2, Sub 1173 - Dec'18-Mar'19**		
16	Purchases (Other Purchases + Economic Purchases)	60,888,103	2017 Ward WP 4	Purchases (Other Purchases + Economic Purchases)	91,098,502	2018 Ward WP 4
17	MWH Sales	68,022,851	2017 Ward WP 3	MWH Sales	68,667,857	2018 Ward WP 3
18	Billed Rate for Purchases	**0.090**		Billed Rate for Purchases	**0.133**	
19	Renewables	154,215,192	2017 Ward WP 4	Renewables	187,595,597	2018 Ward WP 4
20	MWH Sales	68,022,851	2017 Ward WP 3	MWH Sales	68,667,857	2018 Ward WP 3
21	Billed Rate for Renewables	**0.227**		Billed Rate for Renewables	**0.273**	
22	QF Purchases	55,113,822	2017 Ward WP 4	QF Purchases (energy)	162,649,793	2018 Ward WP 4
23	MWH Sales	68,022,851	2017 Ward WP 3	MWH Sales	68,667,857	2018 Ward WP 3
24	Billed Rate for Renewables	**0.081**		Billed Rate for Renewables	**0.237**	
25	Capacity (REPS and QF)	43,476,066	2017 Ward WP 4	Capacity (REPS and QF)	71,877,910	2018 Ward WP 4
26	MWH Sales	68,022,851	2017 Ward WP 3	MWH Sales	68,667,857	2018 Ward WP 3
27	Billed Rate for Capacity	**0.064**		Billed Rate for Capacity	**0.105**	
28	Total Billed Rate	**0.461**		Total Billed Rate	**0.747**	

*** December billed Rate is based on prorated billing factors**

	Prior Bill Rate (Sub 1146)	New Bill Rate (Sub 1173)	December Blended Rate
Approved Rates	0.461	0.747	
Ratios of Days to rate	55.81%	44.19%	
Prorated Rate	**0.257**	**0.330**	**0.588**

**** January billed Rate is based on prorated billing factors**

	Prior Bill Rate (Sub 1146)	New Bill Rate (Sub 1173)	January Blended Rate
Approved Rates	0.461	0.747	
Ratios of Days to rate	0.001%	99.999%	
Prorated Rate	**0.000**	**0.747**	**0.747**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of Application of Duke Energy Progress, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	**DIRECT TESTIMONY OF BRETT PHIPPS FOR DUKE ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am employed as Managing Director, Fuel Procurement, for Duke Energy Corporation ("Duke Energy"). In that capacity, I directly manage the organization responsible for the purchase and delivery of coal and natural gas to Duke Energy's regulated generation fleet, including Duke Energy Progress, LLC ("Duke Energy Progress," "DEP," or the "Company") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Utilities," or the "Companies"). In addition to fuels, I also supervise the procurement of all reagents.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Chemistry from Marshall University. I began in the mining industry in 1993 where I held various roles associated with surface mining operations. I joined Progress Energy in 1999, holding roles in terminal operations and sales and marketing for the unregulated business. I transitioned to the regulated utility in 2005 where I worked in various fuels procurement functions and leadership roles. I joined Duke Energy in July 2012 and am currently Managing Director, Fuels Procurement. I am on the Board of Directors of the American Coal Council, and am a member of the The Coal Institute, the Lexington Coal Exchange, Southern Gas Association, and the American Gas Association.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR

PROCEEDING?

A. Yes. I testified in support of DEP's 2016 fuel and fuel-related cost recovery application in Docket No. E-2, Sub 1146 and in May of 2017, I adopted the testimony filed by Swati V. Daji in support of DEC's 2016 fuel and fuel-related cost recovery application in Docket No. E-7, Sub 1129.

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

A. The purpose of my testimony is to describe DEP's fossil fuel purchasing practices, provide actual fossil fuel costs for the period April 1, 2018 through March 31, 2019 ("test period") versus the period April 1, 2017 through March 31, 2018 ("prior test period"), and describe changes projected for the billing period of December 1, 2019 through November 30, 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 Phipps Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Phipps 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 Phipps Exhibit 3, which summarizes the 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, of which DEP receives an allocated portion based on its pro rata share of the overall gas plant burns for the respective month.

Q. HOW DOES DEP OPERATE ITS PORTFOLIO OF GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS?

A. Both DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically committed and dispatched to serve their respective customers. To that end, both companies consider numerous factors such as 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 $84.81 per ton, compared to $80.82 per ton in the prior test period, representing an increase of approximately 5%. This includes an average transportation cost of $32.72 per ton in the test period, compared to $29.42 per ton in the prior test period, representing an increase of approximately 11%. The Company's average price of gas purchased for the test period was $4.05 per Million British Thermal Units ("MMBtu"), compared to $4.68 per MMBtu in the prior test period, representing a decrease of approximately 13%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEP's coal burn for the test period was 3.6 million tons, compared to a coal burn of 3.9 million tons in the prior test period, representing a decrease of approximately 7%. The Company's natural gas burn for the test period was 182.4million MMBtu, compared to a gas burn of 169.4 million MMBtu in the prior test period, representing an increase of approximately 8%. The primary contributing factors were changes in (1) weather driven demand, and (2) 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) continued changes in 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. DEP's current coal burn projection for the billing period is 4.4 million tons, compared to 3.6 million tons consumed during the test period. DEP'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, DEP projects average delivered coal costs of approximately $66.12 per ton for the billing period compared to $84.81 per ton in the test period. The lower projected cost is due, in part, to newly negotiated rail transportation contracts that went into effect March 1, 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 DEP is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEP'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.

DEP's current natural gas burn projection for the billing period is approximately 158.5 million MMBtu, which is a decrease from the 182.4 million MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.76 per MMBtu, compared to $3.12 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 DEP 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, DEP 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 Process, 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 PROGRESS
Summary of Coal Purchases
Twelve Months Ended March 31, 2019 & 2018
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
1	April 2018	250,213	0	250,213
2	May	229,852	0	229,852
3	June	170,145	0	170,145
4	July	281,312	25,688	307,000
5	August	316,012	24,850	340,861
6	September	280,066	74,767	354,833
7	October	230,501	83,019	313,519
8	November	166,987	74,177	241,164
9	December	60,781	259,086	319,867
10	January 2019	148,090	170,562	318,652
11	February	314,005	25,352	339,357
12	March	402,153	24,070	426,223
13	**Total** (Sum L1:L12)	**2,850,117**	**761,571**	**3,611,686**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
14	April 2017	223,875	0	223,875
15	May	224,952	0	224,952
16	June	238,854	12,264	251,118
17	July	320,213	0	320,213
18	August	430,436	0	430,436
19	September	346,651	0	346,651
20	October	325,000	0	325,000
21	November	324,889	0	324,889
22	December	229,150	0	229,150
23	January 2018	212,233	0	212,233
24	February	235,368	0	235,368
25	March	260,527	326	260,853
26	**Total** (Sum L14:L25)	**3,372,148**	**12,590**	**3,384,738**

DUKE ENERGY PROGRESS
Summary of Gas Purchases
Twelve Months Ended March 31, 2019 & 2018
MBTUs

Line No.	Month	MBTUs
1	April 2018	11,053,613
2	May	12,806,726
3	June	15,479,769
4	July	20,299,371
5	August	19,387,566
6	September	17,128,278
7	October	16,867,758
8	November	14,807,040
9	December	14,345,919
10	January 2019	13,375,182
11	February	13,994,322
12	March	12,831,035
13	**Total** (Sum L1:L12)	**182,376,579**

Line No.	Month	MBTUs
14	April 2017	11,260,572
15	May	11,466,510
16	June	13,517,327
17	July	15,763,956
18	August	15,138,794
19	September	13,928,655
20	October	12,729,705
21	November	14,540,861
22	December	16,817,106
23	January 2018	14,446,004
24	February	13,775,980
25	March	15,986,353
26	**Total** (Sum L14:L25)	**169,371,823**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of	)
Application of Duke Energy Progress, LLC	)
Pursuant to G.S. 62-133.2 and NCUC Rule	)
R8-55 Relating to Fuel and Fuel-Related	)
Charge Adjustments for Electric Utilities	)

BRETT PHIPPS CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

JUNE 11, 2019

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of	)	
Application of Duke Energy Progress, 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 PROGRESS, 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 Progress, LLC ("DEP" 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. 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 DEP'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 DEP's Fossil/Hydro/Solar facilities during the test period of April 1, 2018 through March 31, 2019 (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 DEP'S FOSSIL/HYDRO/SOLAR GENERATION PORTFOLIO.

A. The Company's Fossil/Hydro/Solar generation portfolio consists of 9,204 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	3,544 MWs
Combustion Turbines -	2,816 MWs
Combined Cycle Turbines -	2,568 MWs
Hydro -	227 MWs
Solar -	49 MWs[1]

[1] This value represents the relative dependable capacity contribution to meeting summer peak demand, based on the Company's integrated resource planning metrics. The nameplate capacity of the Company's solar facilities is 141 MWs.

The 3,544 MWs of coal-fired generation represent the three generating stations of Roxboro, Mayo, and Asheville, which total seven units. These units are equipped with emission control equipment, including selective catalytic reduction ("SCR") equipment for removing nitrogen oxides ("NO_x"), flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"), and low NO_x burners. This inventory of coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content – providing flexibility for DEP to procure the most cost-effective options for fuel supply.

The Company has a total of 32 simple cycle combustion turbine ("CT") units, the larger 14 of which provide 2,183 MWs, or 78% of CT capacity. These 14 units are located at Asheville, Darlington, Richmond County, and Wayne County facilities, and are equipped with water injection systems that reduce NO_x and/or have low NO_x burner equipment in use. The 2,568 MWs shown as "Combined Cycle Turbines" ("CC") represent four power blocks. The H.F. Lee Energy Complex CC power block ("Lee CC") has a configuration of three CTs and one steam turbine. The two Richmond County power blocks located at the Smith Energy Complex consist of two CTs and one steam turbine each. The Sutton Combined Cycle at Sutton Energy Complex ("Sutton CC") consists of two CTs and one steam turbine. The four CC power blocks are equipped with SCR equipment, and all nine CTs have low NOx burners. The steam turbines do not combust fuel and, therefore, do not require NOx controls. The Company's hydro fleet consists of 15 units providing 227 MWs of capacity. The Company's solar fleet consists of four sites providing 49 MWs of dependable capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEP'S 2018 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. Darlington CT Unit 5 retired in May 2018, which reduced capacity by 51 MWs.

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

A. The primary objective of DEP's Fossil/Hydro/Solar generation department is to provide safe, reliable and cost-effective electricity to DEP'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 DEP'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 DEP'S COAL UNITS DURING THE TEST PERIOD?

A. Over the test period, the Company's seven coal units produced 25% of the Fossil/Hydro/Solar generation, with the average heat rate for the coal-fired units being 11,352 Btu/kWh. The most active station during this period was Roxboro, providing 68% of the coal production for the fleet with a heat rate of 10,624 Btu/kWh. During the test period, the Company's four combined cycle power blocks produced 59% of the Fossil/Hydro/Solar generation, with an average heat rate of 7,167 Btu/kWh.

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

A. For the test period, DEP's total system generation was 60,144,861 megawatt-hours ("MWHs"), of which 32,396,712 MWHs, or approximately 54%, was provided by the Fossil/Hydro/Solar fleet. The breakdown includes a 39% contribution from gas facilities, 14% contribution from coal-fired stations, 1.4% contribution from hydro facilities, and 0.4% from solar facilities.

The Company's portfolio includes a diverse mix of units that, along with its nuclear capacity, allows DEP to meet the dynamics of customer load requirements in a logical and cost-effective manner. Additionally, DEP has utilized the Joint Dispatch Agreement with Duke Energy Carolinas, LLC

("DEC"), which allows generating resources for DEP and DEC to be dispatched as a single system to enhance dispatching at the lowest possible cost. 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 DEP 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 lower pricing of natural gas. Further, the addition of new CC units within DEP's portfolio in recent years has provided DEP 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. Gas fired facilities provided 59% of the DEP Fossil/Hydro/Solar generation during the test period.

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

A. The Company's generating units operated efficiently and reliably during the test period. Several 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 maintenance (*i.e.*, forced) outage time); (2) net capacity factor ("NCF"), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF *is* affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate ("EFOR"), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and, (4) starting reliability ("SR"), which represents the percentage of successful starts.

The following chart provides operational results categorized by generator type, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") representing the period 2013 through 2017. The NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating.

Generator Type	Measure	Review Period DEP Operational Results	2013-2017 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	71.4%	81.6%	418
	NCF	25.9%	57.8%	
	EFOR	6.1%	8.1%	
Coal-Fired Summer Peak	EAF	93.1%	n/a	n/a
Total CC Average	EAF	80.3%	85.0%	338
	NCF	72.5%	52.7%	
	EFOR	4.77%	5.3%	
Total CT Average	EAF	80.2%	87.8%	776
	SR	98.7%	98.1%	
Hydro	EAF	79.7%	80.4%	1,113

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

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

Roxboro Unit 4 had a planned outage in Spring 2018. The primary purpose of the outage was to perform major boiler maintenance and precipitator maintenance. Mayo Unit 1 had a planned outage in Fall 2018 to replace the generator breaker and perform minor boiler maintenance. Roxboro Unit 2 had a planned outage in Fall 2018. The primary purpose of the outage was to replace burners, perform MATS inspection, and tie-in the dry bottom ash system.

The CC fleet performed planned outages at Richmond County CC PB5 and Sutton CC in Spring 2018. The primary purposes of the Richmond CC PB5 outage was to perform borescope inspections on the combustion turbines and steam turbine, perform a Heat Recovery Steam Generator ("HRSG") inspection, and balance of plant equipment maintenance. The primary purpose of the Sutton CC outage was to perform a hot gas path inspection of the combustion turbines.

The CT fleet performed planned outages in Spring and Fall 2018. In Spring 2018, Smith CT Unit 1 and Unit 2 had planned outages. The primary purpose of the Smith CT Unit 1 outage was to replace the existing exhaust stack. The primary purpose of the Smith CT Unit 2 outage was to rewind the generator rotor, perform a hot gas path inspection, and replace the existing exhaust stack. In Fall 2018, Asheville CT Unit 3 and Unit 4 had a planned outage to perform transmission work in the switchyard for the new Asheville CC plant and to perform balance of plant maintenance.

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

A. The Company has installed pollution control equipment on coal-fired units, as well as new generation resources, in order to meet various current federal, state, and local reduction requirements for NOx and SO2 emissions. The SCR technology that DEP currently operates on the coal-fired units uses ammonia or urea for NOx removal and the scrubber technology employed uses crushed limestone or lime for SO2 removal. SCR equipment is also an integral part of the design of the newer CC facilities in which aqueous ammonia (19% solution of NH_3) is introduced for NOx 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 and utilization of non-traditional coals. Overall, the goal is to effectively comply with emissions regulations and provide the optimal total-cost solution for operation of the unit. The Company will continue to leverage new technologies and chemicals to meet both present and future state and federal emissions requirements including the Mercury and Air Toxics Standards ("MATS") rule. Company witness Harrington provides the cost information for DEP'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-2, SUB 1204

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**KENNETH D. CHURCH FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS,**
Charge Adjustments for Electric Utilities	)	**LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kenneth D. Church 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 General Manager of Nuclear Fuel Engineering for Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEP?

A. I am responsible for nuclear fuel procurement and spent fuel management, as well as the fuel mechanical design, reactor core design, probabilistic risk assessment, and safety analysis for the nuclear units owned and operated by DEP and DEC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from North Carolina State University with a Bachelor of Science degree in mechanical engineering. I began my career with DEC in 1991 as an engineer and worked in various roles, including nuclear fuel assembly and control component design, fuel performance, and fuel reload engineering. I assumed the commercial responsibility for purchasing uranium, conversion services, enrichment services, and fuel fabrication services at DEC in 2001. Beginning in 2011, I incrementally assumed responsibility at DEC for spent nuclear fuel management along with the nuclear fuel mechanical design and reload licensing analysis functions. Subsequently, I assumed the same responsibilities for DEP following the merger between Duke Energy Corporation and Progress Energy, Inc. before entering my current position in January of 2019.

I have served as Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use, and have also served as Chairman of the World Nuclear Fuel Market's Board of Governors, an organization that promotes efficiencies in the nuclear fuel markets. I am currently a registered professional engineer in the state of North Carolina.

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

A. The purpose of my testimony is to: (1) provide information regarding DEP's nuclear fuel purchasing practices (2) provide costs for the April 1, 2018 through March 31, 2019 test period ("test period"), and (3) describe changes forthcoming for the December 1, 2019 through November 30, 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 Church Exhibit 1, which is a Graphical Representation of the Nuclear Fuel Cycle, and Church 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 Church 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 DEP'S NUCLEAR FUEL PROCUREMENT PRACTICES.

A. As set forth in Church Exhibit 2, DEP'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. DEP 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, DEP'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 mitigating DEP's exposure to price volatility. Diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Q. PLEASE DESCRIBE DEP'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 DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets. DEP 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, DEP entered into several long-term contracts during the test period.

DEP's portfolio of diversified contract pricing yielded an average unit cost of $41.38 per pound for uranium concentrates during the test period, representing an increase of 42% per pound from the prior test period. This increase was primarily due to the purchase of low cost uranium available in the spot market during the prior test period.

A majority of DEP's enrichment purchases during the test period were delivered under long-term contracts negotiated prior to the test period. The average unit cost of DEP's purchases of enrichment services during the test period decreased 8% to $93.22 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 – 22% and 5%, respectively, for the fuel batches recently loaded into DEP's reactors – of DEP's total direct fuel cost relative to uranium concentrates or enrichment, which each represent 43% and 30%, respectively, of the total.

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

A. Prices in the uranium concentrate markets remain relatively low due to reduced demand following the March 2011 event at Fukushima. Industry consultants believe that recent production cutbacks have been warranted due to the previously existing oversupply conditions and that market prices need to increase in the longer term to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements.

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

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

Q. WHAT CHANGES DO YOU SEE IN DEP'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), DEP'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 contribute 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 0.656 cents per kWh incurred in the test period, to approximately 0.617 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 DEP TAKING TO PROVIDE STABILITY IN ITS NUCLEAR FUEL COSTS AND TO MITIGATE PRICE INCREASES IN THE VARIOUS COMPONENTS OF NUCLEAR FUEL?

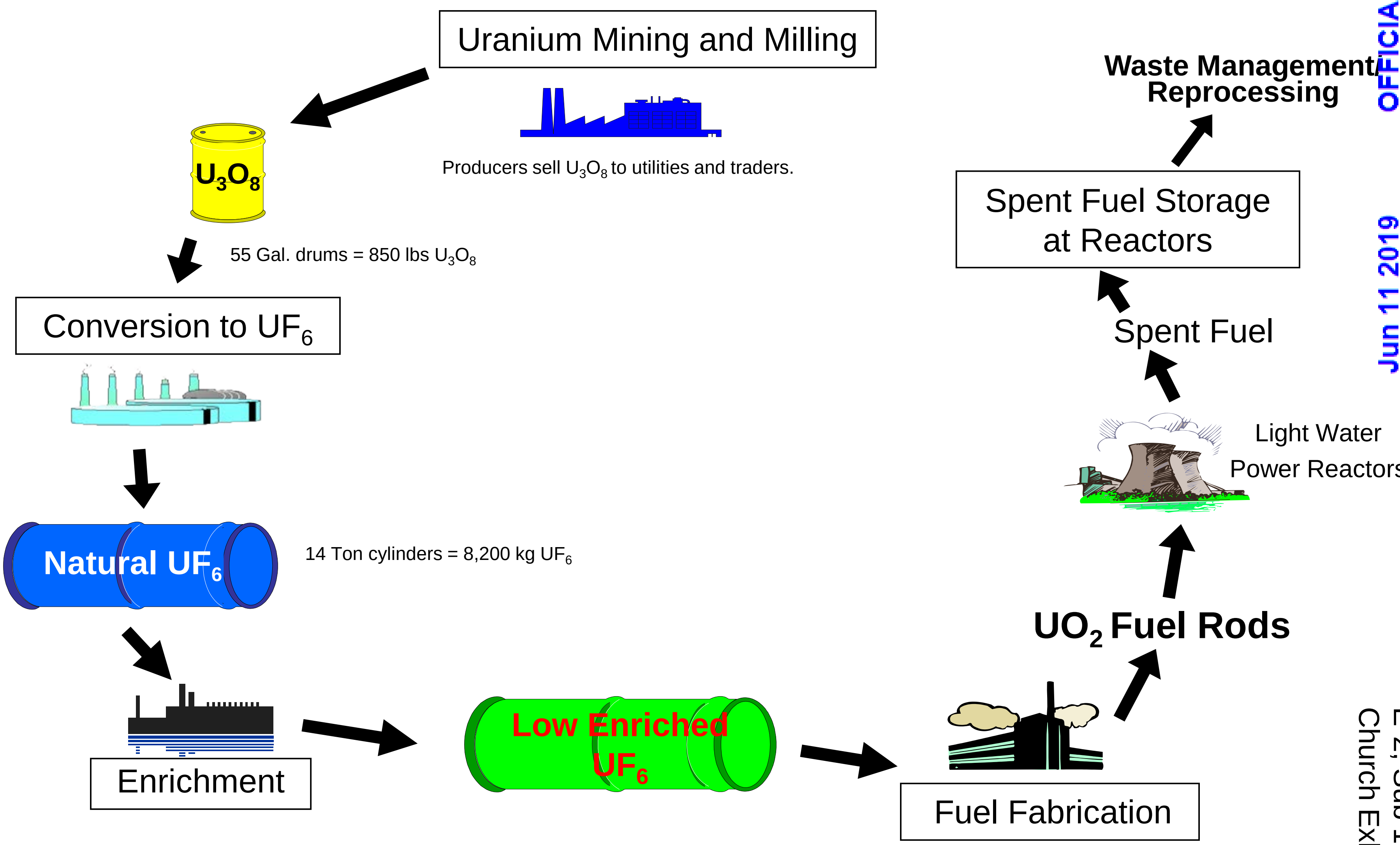
A. As I discussed earlier and as described in Church Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEP relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating a range of pricing mechanisms, DEP'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 mitigating DEP'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 DEP's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

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

A. Yes, it does.

The Nuclear Fuel Cycle



E-2, Sub 1204
Church Exhibit 1

Duke Energy Progress, LLC Nuclear Fuel Procurement Practices

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

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**KELVIN HENDERSON FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY PROGRESS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelvin Henderson 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 North Carolina nuclear stations, including Duke Energy Progress, LLC's ("DEP" or the "Company") Brunswick Nuclear Station ("Brunswick") in Brunswick County, North Carolina, the Harris Nuclear Station ("Harris") in Wake County, North Carolina, and Duke Energy Carolinas, LLC's ("DEC") McGuire Nuclear Station, located in Mecklenburg County, North Carolina.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor's degree in Mechanical Engineering from Bradley University and over 27 years of nuclear energy experience with increasing responsibilities. My nuclear career began at Commonwealth Edison's Zion Nuclear Station in Illinois where I received a senior reactor operator license from the Nuclear Regulatory Commission ("NRC") and served as a control room unit supervisor. In 1998, I joined Progress Energy in the operations department at the Harris Nuclear Station. After serving in various leadership roles in Operations, Work Management, and Maintenance, I was named plant manager at Harris. In 2011, I was named general manager of nuclear fleet operations for Progress Energy. Following the Duke Progress merger in 2012, I became site vice president of DEC's Catawba Nuclear Station in York County, South Carolina. In 2016, I was named senior vice president of corporate nuclear, and I assumed my current role as Senior Vice President of Nuclear Operations in December 2017.

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

A. Yes, I provided testimony in DEP's 2018 fuel case proceeding in Docket No. E-2, Sub 1173.

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 Brunswick, Harris, and Robinson for the period of April 1, 2018 through March 31, 2019 (the "test period"). I will provide information about refueling outages for the test period and also discuss the nuclear capacity factor being proposed by DEP for use in this proceeding in determining the fuel factor to be reflected in rates during the billing period of December 1, 2019 through November 30, 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 DEP's nuclear units through the billing period. This exhibit represents DEP's current plan, which is subject to adjustment due to changes in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEP'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 3,575[1] megawatts ("MWs") of generating capacity, made up as follows:

Brunswick -	1,870 MWs
Harris -	964 MWs
Robinson -	741 MWs

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF DEP'S NUCLEAR GENERATION ASSETS.

A. The Company's nuclear fleet consists of three generating stations and a total of four units. Brunswick is a boiling water reactor facility with two units and was the first nuclear plant built in North Carolina. Unit 2 began commercial operation in 1975, followed by Unit 1 in 1977. The operating licenses for Brunswick were renewed in 2006 by the NRC, extending operations up to 2036 and 2034 for Units 1 and 2, respectively. Harris is a single unit pressurized water reactor that began commercial operation in 1987. The NRC issued a renewed license for Harris in 2008, extending operation up to 2046. Robinson is also a single unit pressurized water reactor that

[1] As of January 1, 2019.

began commercial operation in 1971. The license renewal for Robinson Unit 2 was issued by the NRC in 2004, extending operation up to 2030.

Q. WERE THERE ANY CAPACITY CHANGES WITHIN DEP'S NUCLEAR PORTFOLIO DURING THE TEST PERIOD?

A. Yes. Efficiency gains from the replacement of the Harris low pressure turbine in the spring of 2018 increased the capacity of the unit. After seasonal observations and validation testing, the Harris maximum dependable capacity ("MDC") was increased by 32 MWs to 964 MWs effective January 1, 2019. The winter capability rating was also increased, adding 29 MWs to the unit's winter capability.

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

A. The primary objective of DEP's nuclear generation department is to safely provide reliable and cost-effective electricity to DEP'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 DEP'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 46% of the total power generated by DEP. The four nuclear units operated at an actual system average capacity factor of 89.21% during the test period, which included three refueling outages.[2] Output from three of the four DEP nuclear units was significantly impacted during the test period by Hurricane Florence. Consistent with site procedures, both Brunswick units were taken offline prior to the expected landfall of Hurricane Florence. Brunswick Unit 1 was offline for 8.8 days and Unit 2 was offline for 6.3 days. After the Federal Emergency Management Agency ensured normal emergency recovery capabilities had been restored in the area, both Brunswick units returned to service. Additionally, the availability of Robinson was impacted by Hurricane Florence. As described later in my testimony, the Robinson refueling outage, which began one week after the hurricane's landfall, was impacted by resource constraints directly attributable to the hurricane and its aftermath.

The performance results discussed in my testimony demonstrate DEP's continued commitment to achieving high performance without compromising safety and reliability.

Q. HOW DOES THE PERFORMANCE OF DEP'S NUCLEAR FLEET COMPARE TO INDUSTRY AVERAGES?

[2] Brunswick Unit 2 entered a refueling outage on March 2, 2019 and remained offline at the end of the test period.

A. The Company's nuclear fleet has a history of exceptional 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 industry average capacity factor of 91.8% for comparable units for the five-year period 2013 through 2017. During the five-year period ending March 31, 2019, DEP's nuclear fleet achieved an average capacity factor of 93.29% compared to the industry average of 91.8%. DEP's two-year average[3] of 92.44% also exceeded the NERC comparable average of 91.8%. The Company's test period capacity factor of 89.21%, impacted by Hurricane Florence, fell just below the industry five-year average.

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

A. In general, refueling requirements, maintenance requirements, prudent maintenance practices, and NRC operating requirements impact the availability of DEP's nuclear system. Prior to a planned outage, DEP develops a detailed schedule for the outage including major tasks to be performed along with sub-schedules for particular activities.

The Company's scheduling philosophy is to plan for a best possible outcome for each outage activity within the outage plan. For example, if the "best ever" time a particular outage task was performed is 10 days, then 10 days or less becomes the goal for that task in each subsequent outage. Those individual goals are

[3] This represents the simple average for the current test period and prior test period of 12 months ended March 2018 for the DEP nuclear fleet.

incorporated into an overall outage schedule. The Company aggressively works to meet, and measures itself against, that schedule. Further, to minimize potential impacts to outage schedules, "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. Those discovery activities also have pre-planned contingency actions to ensure that, when incorporated into the schedule, the activities required for appropriate repair can be performed as efficiently as possible.

As noted, the Company uses the schedule for measuring outage planning and execution, and driving continuous improvement efforts. However, in order to provide reasonable, rather than best ever, total outage time for planning purposes, particularly with the dispatch and system operating center functions, DEP also develops an allocation of outage time which 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 DEP HANDLE OUTAGE EXTENSIONS AND FORCED OUTAGES?

A. When an outage extension becomes necessary, DEP seeks to ensure that work completed in the extension results in longer continuous run times and fewer forced outages, thereby reducing fuel costs in the long run. Therefore, if an unanticipated issue that has the potential to become an on-line reliability issue 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 usually extended to perform necessary maintenance or repairs prior to returning the unit to service. 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 DEP PERFORM POST-OUTAGE CRITIQUES AND CAUSE ANALYSES FOR INTERNAL IMPROVEMENT EFFORTS?

A. Yes. DEP 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 in order to identify areas in which it can utilize a self-critical analysis to drive further 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 REFUELING OUTAGES WERE COMPLETED AT DEP'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. There were two refueling outages completed during the test period: Harris and Robinson.

The Harris spring refueling outage began on April 7, 2018. In addition to refueling activities, safety, regulatory projects and reliability enhancements were completed. Safety and regulatory work included reactor vessel head inspections and repair, and reactor vessel in-service inspections. Replacement of the station's low-pressure turbine addressed the aging of the existing turbine and mitigated the free-standing blade root cracking concerns. The new turbine also improved thermal efficiency and added 32 MWs to the station's capacity. After testing and validation during 2018, the station's maximum dependable capacity was increased by 32 MWs to 964 MWs effective January 1, 2019. The station also completed installation of a new turbine control system. The new system addresses equipment obsolescence and single-point vulnerabilities, enhancing the reliability of the station. Other reliability work included refurbishment of the "B" reactor coolant pump motor and seals, "A" heater drain pump and motor, and overhaul of the auxiliary feed water turbine. All outage goals were met, and outage dose was the lowest ever recorded for a Harris refueling outage. After refueling, projects, maintenance, and inspection activity completed, the unit returned to service on May 10, 2018; a duration of 33.8 days compared to a schedule allocation of 37 days.

The Robinson refueling outage was originally scheduled to begin on September 15, 2018, just one day after Hurricane Florence made landfall along North Carolina's southeast coast. The outage start was delayed by one week, and on September 22, 2018, Robinson entered the fall refueling outage. In addition to refueling activities, significant safety, regulatory, and reliability enhancements were completed. Regulatory and safety enhancements included the transmission upgrade project ("TUP") and modifications required to transition to the NFPA 805. Significant activities associated with the TUP included replacement of the 115KV startup transformer, addition of a second 230KV startup transformer, and upgrades to the 4KV bus and transmission lines. The TUP provides the station with a second off-site power path, aligning the station with the current industry standard for U.S. nuclear plants. NFPA 805 modifications included replacement of refueling water storage tank discharge values, residual heat removal loop isolation valves, and loops "B" and "C" hotleg shutoff valves. Numerous new motor control centers and distribution panels were also installed as part of the NFPA 805 modifications. A main power open phase detection modification was also completed. This system improves safety margins related to offsite power by providing a fully redundant open phase protection system.

Reliability enhancements included the replacement of both low-pressure turbines, which addressed blade design issues that have impacted generation since 2012. The Siemens low-pressure turbines were replaced under warranty. Other reliability enhancements included replacement of the "B" reactor coolant pump motor and seal replacements on "A', "B", and "C" pumps. The "B" heater drain pump was also replaced.

After refueling, maintenance, projects and inspection activities were completed, the unit returned to service on November 26, 2018. The 65-day outage extended beyond the schedule allocation of 37 days, with the overrun primarily attributable to direct impacts on resource availability related to Hurricane Florence and challenges with the complex transmission upgrade project.

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

A. The Company proposes to use a 94.62% capacity factor, which is a reasonable value for use in this proceeding based upon the operational history of DEP'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 Harrington and exceeds the five-year industry weighted average capacity factor of 91.8% 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-2, SUB 1204

In the Matter of	)
Application of Duke Energy Progress, LLC	)
Pursuant to G.S. 62-133.2 and NCUC Rule	)
R8-55 Relating to Fuel and Fuel-Related	)
Charge Adjustments for Electric Utilities	)

KELVIN HENDERSON CONFIDENTIAL EXHIBIT 1

FILED UNDER SEAL

JUNE 11, 2019

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's Fuel Charge Adjustment Proceeding, in Docket No. E-2, Sub 1204, 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 11th day of June, 2019.

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