Duke Energy
Carolinas

OFFICIAL COPY

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March 6, 2013

FILED
MAR 06 2013
Clerk's Office
N.C. Utilities Commission

Ms. Gail L. Mount
Deputy Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

RE: Docket No. E-7, Sub 1033
Duke Energy Carolinas' Fuel Charge Adjustment Proceeding

Dear Ms. Mount:

Enclosed for filing with the North Carolina Utilities Commission ("NCUC" or the "Commission") is an original and 30 copies of the Application of Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company") pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 relating to the fuel charge adjustments for electric utilities, together with the testimony and exhibits of Kim H. Smith, Sasha Weintraub, Joseph A. Miller, Jr., Robert J. Duncan, II and David C. Culp containing the information required in NCUC Rule R8-55.

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Information contained in Mr. Duncan's Exhibit 1 is confidential. Therefore, enclosed is the original plus 30 copies filed under seal pursuant to N.C. Gen. Stat. § 62-132.11, and one original plus one copy with the confidential information redacted. These confidential documents should only be shared with the Commission and Commission Staff. Parties to the docket may contact the Company regarding obtaining copies pursuant to an appropriate confidentiality agreement.

Please contact me if you have any questions.

Sincerely,

Brian L. Franklin

Brian L. Franklin (by dha)

Enclosures

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FILED
MAR 06 2013
Clerk's Office
N.C. Utilities Commission

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1033

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

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

1. The Applicant's general offices are located at 550 South Tryon Street, Charlotte, North Carolina, and its mailing address is:

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

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

Brian L. Franklin, Associate General Counsel
Duke Energy Carolinas, LLC
DEC45A/P.O. Box 1321
Charlotte, North Carolina 28201-1006
(980) 373-4465
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Copies of all pleadings, testimony, orders and correspondence in this proceeding should be served upon the attorneys listed above.

3. NCUC Rule R8-55 provides that the Commission shall schedule annual hearings pursuant to N.C. Gen. Stat. § 62-133.2 in order to review changes in the cost of fuel and fuel-related costs since the last general rate case for each utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service. Rule R8-55 schedules an annual cost of fuel and fuel-related costs adjustment hearing for DEC and requires that the Company use a calendar year test period (12 months ended December 31). Therefore, the test period used in this Application for these proceedings is the calendar year 2012.

4. In Docket No. E-7, Sub 1002, DEC's last fuel case, the Commission approved the following base fuel and fuel-related costs factors (excluding gross receipts tax and regulatory fee):

Residential -	2.2224¢ per kWh
Commercial -	2.2463¢ per kWh
Industrial -	2.2594¢ per kWh

Additionally, in Docket No. E-7, Sub 986 and pursuant to the merger between Duke Energy Corporation and Progress Energy, Inc. ("Merger"), the Commission approved the following decrement rider amounts to begin flowing merger fuel-related savings to customers during the period September 1, 2012 through August 31, 2013 (excluding gross receipts tax and regulatory fee).

Residential -	(0.0707)¢ per kWh
Commercial -	(0.0509)¢ per kWh
Industrial -	(0.0379)¢ per kWh

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

Residential -	2.2323¢ per kWh
Commercial -	2.3559¢ per kWh
Industrial -	2.3952¢ per kWh

The base fuel and fuel-related cost factors include merger fuel-related savings. In addition, they should be adjusted for the Experience Modification Factor ("EMF") by a decrement (excluding gross receipts tax and regulatory fee) of:

Residential -	(0.0382)¢ per kWh
Commercial -	(0.1099)¢ per kWh
Industrial -	(0.1216)¢ per kWh

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

Residential -	(0.0064)¢ per kWh
Commercial -	(0.0183)¢ per kWh
Industrial -	(0.0203)¢ per kWh

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

Residential -	2.1877¢ per kWh
Commercial -	2.2277¢ per kWh
Industrial -	2.2533¢ per kWh

The new fuel factors should become effective for service on or after September 1, 2013. The EMF factors include an adjustment that DEC proposes to make to the over-collection balance for calendar year 2012 in order to share certain merger fuel-related savings with Progress Energy Carolinas, Inc. that were achieved during the period prior to close of the Merger.

6. The information and data required to be filed by NCUC Rule R8-55 is contained in the testimony and exhibits of Alexander ("Sasha") J. Weintraub, Joseph Miller, Jr., Robert Duncan, II, David C. Culp, and Kim H. Smith, 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 capacity factor (89.79%) using adjusted test period sales and the methodology used for fuel costs in the Company's last general rate case. These base fuel and fuel-related costs factors are:

	NERC Average	Last General Rate Case
Residential -	2.2615¢ per kWh	2.1512¢ per kWh
Commercial -	2.2860¢ per kWh	2.1989¢ per kWh
Industrial -	2.2975¢ per kWh	2.2314¢ per kWh

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

Residential -	2.1877¢ per kWh
Commercial -	2.2277¢ per kWh
Industrial -	2.2533¢ per kWh

Respectfully submitted this 6th day of March, 2013.

By: Brian L. Franklin (by dha)

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ATTORNEYS FOR DUKE ENERGY CAROLINAS, LLC

STATE OF NORTH CAROLINA)
) VERIFICATION
COUNTY OF MECKLENBURG)

Kim H. Smith, bring first duly sworn, deposes and says:

That she is Rates Manager for Duke Energy Carolinas, 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.

Kim H. Smith

Sworn to and subscribed before
me this the 6th day of March, 2013.

Notary Public

My Commission expires: 5-26-2013

[SEAL]

BAMBI M. LOHR
NOTARY PUBLIC
MECKLENBURG COUNTY, N.C.
My Commission Expires May 26, 2013

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1033

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kim H. Smith. My business address is 526 South Church Street, Charlotte, North Carolina.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Marshall University with a Bachelor of Business Administration degree, and received a Master of Business Administration degree from the University of Charleston. I am a certified public accountant licensed in the state of North Carolina. I began my career with DEC in 2006 as an external reporting manager. Since I joined the Rate Department in 2008 as Rates Manager I have been responsible for providing regulatory support for retail and wholesale rates, providing guidance on DEC's and Progress Energy Carolinas' ("PEC") Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") compliance and cost recovery applications, and energy efficiency cost recovery process.

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

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

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

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC" or the "Commission") in DEC's 2010 and 2012 REPS compliance and cost recovery applications, Docket No. E-7, Subs 984 and 1008, respectively. In addition, I provided supplemental testimony in PEC's REPS cost recovery application in Docket No. E-2, Sub 1020.

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

A. Yes. Duke Energy Carolinas' 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 Smith Exhibits 1 through 6, along with supporting workpapers. The test period used in supplying this information and data is the twelve months ended December 31, 2012 ("test period"), and the billing period is September 1, 2013 through August 31, 2014 ("billing period").

Q. WHAT IS THE SOURCE OF THE ACTUAL INFORMATION AND DATA FOR THE CALENDAR YEAR 2012 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 appropriate regulatory agencies in the three jurisdictions 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 SMITH EXHIBITS 1 THROUGH 6 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

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

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

Exhibit 2:

Schedule 1: Fuel and Fuel-Related Costs Factors - reflecting a 92.84% proposed nuclear capacity factor and projected MWH sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 92.84% nuclear capacity factor and adjusted test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 89.79% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for pressurized water reactors and adjusted test period sales.

Exhibit 3:

Page 1: Calculation of the Proposed Composite EMF rate.

Page 2: Calculation of the EMF for residential customers.

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

Page 4: Calculation of the EMF for industrial customers.

Exhibit 4: Megawatt hour ("MWH") Sales, Fuel Revenue, and Fuel and Fuel-Related Expense, as well as System Peak for the test period.

Exhibit 5: Nuclear Capacity Ratings

Exhibit 6: December 2012 Monthly Fuel Reports.

1) December 2012 Monthly Fuel Report required by NCUC Rule R8-52.

2) December 2012 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

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

A. Smith Exhibit 1 presents a summary of fuel and fuel-related cost factors, including the current fuel and fuel-related cost factors, the fuel and fuel-related cost factors using the methodology approved in the Company's last general rate case in Docket No. E-7, Sub 989, the fuel and fuel-related cost factors using the NERC five-year average nuclear capacity factor, and the proposed fuel and fuel-related cost factors.

Q. WHAT FUEL FACTORS DOES THE COMPANY PROPOSE FOR INCLUSION IN RATES FOR THE BILLING PERIOD?

A. The Company proposes that fuel and fuel-related costs factors for residential, general service/lighting, and industrial customers of 2.1877¢, 2.2277¢, and 2.2533¢ per kWh, respectively, be reflected in rates during the billing period. The factors the Company proposes in this proceeding incorporate a 92.84% nuclear capacity factor as testified to by Company Witness Duncan, projected fossil fuel costs as testified to by Company Witness Weintraub, projected nuclear fuel costs as testified to by Company Witness Culp, and projected reagents costs as testified to by Company Witness Miller. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Smith Exhibit 1 are:

	Residential	General	Industrial
	cents/KWh	cents/KWh	cents/KWh
Total adjusted Fuel and Fuel Related Costs cents/kWh	2.2323	2.3559	2.3952
EMF Decrement cents/kWh	(0.0382)	(0.1099)	(0.1216)
EMF Interest Decrement cents/kWh	(0.0064)	(0.0183)	(0.0203)
Net Fuel and Fuel Related Costs Factors cents/kWh	2.1877	2.2277	2.2533

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 no impact on customers' bills. Line 1 below shows the proposed fuel and fuel-related cost factors in this proceeding, which includes the benefits of merger-related fuel savings. Line 2 shows the existing fuel and fuel-related cost factors including the merger fuel-related savings rider (without gross receipts tax and regulatory fee). When the existing factors expire on August 31, 2013, they will be replaced with the proposed net fuel and fuel-related costs factors of the same amounts.

	Residential	General	Industrial
	cents/KWh	cents/KWh	cents/KWh
1 **Proposed** Net Fuel and Fuel-Related Costs Factors cents/kWh	2.1877	2.2277	2.2533
2 **Existing** Net Fuel and Fuel-Related Costs Factors including MFS Rider cents/kWh	2.1877	2.2277	2.2533

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

A. A number of factors contribute to the proposed net fuel and fuel-related costs factors remaining unchanged for all customer classes, including reduced fuel costs due to greater availability of gas generation, the benefits of joint dispatch of the combined portfolio of DEC and PEC resources, and the incorporation of the return of $47 million of over-collected fuel costs for the calendar year 2012 into the proposed fuel factors, compared to $19 million of under-collected fuel costs that were included in existing fuel rates. This was offset by higher projected fuel prices and higher sales, which result in more frequent operation of DEC's higher cost generating units. For example, Company Witness Culp explains that the billing period price of 0.676 ¢ per kWh for nuclear fuel will be about 18% higher than experienced during the test period. Despite the higher projected nuclear fuel costs, however, those costs represent approximately 15% of system fuel costs while nuclear fuel generation represents approximately 48% of the expected system generation and purchased power mix.

As discussed by Company Witness Weintraub, the proposed fuel and fuel-related cost factors include an average delivered cost for coal for the billing period of $98.62 per ton, which is less than 1% lower than the average delivered cost of coal during the test period. In addition, Witness Weintraub notes an increase in natural gas prices as evidenced by the Henry Hub forward price of $4.03 per Million British Thermal Units used in the proposed fuel rates.

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

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

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

A. Exhibit 2 is divided into three schedules. Schedule 1 sets forth the determination of the prospective fuel and fuel-related costs. The calculation used the nuclear capacity factor of 92.84% as explained by Company Witness Duncan in his testimony, and forecasted MWH sales for the billing period along with the assumptions discussed above to determine the proposed fuel and fuel-related costs factors to be reflected in rates for service during the billing period.

Schedule 2 also uses the capacity factor of 92.84% along with adjusted test period KWH generation, as prescribed by NCUC Rule R8-55 (e)(3), which requires the use of the methodology adopted by the Commission in the Company's last general rate case.

The capacity factor shown on Schedule 3 is prescribed in NCUC Rule R8-55 (d)(1). The normalized five-year national weighted average NERC capacity factor is 89.79%. This capacity factor is based on NERC's 2007 through 2011 Generating Availability Report ("NERC Report") for pressurized water reactors. Typically, the Company obtains this figure from NERC's Generating Unit Statistical Brochure ("NERC Brochure"). The most recent NERC Brochure, however, has not yet been published, and as a result, the Company computed this number from the NERC Report. Adjusted test period KWH generation was also used for schedule 3 per NCUC Rule R8-55 (d)(1).

Page 2 of Exhibit 2, Schedules 1, 2, and 3, presents the calculation of the proposed fuel and fuel-related costs factors by customer class resulting from the allocation of renewable and cogeneration power capacity costs by customer class on the basis of production plant as described on page 89, paragraph 17 of the Order in the Company's general rate case in Docket No. E-7, Sub 909.

Page 3 of Exhibit 2, Schedules 1, 2, and 3, shows the calculation of the Company's proposed fuel and fuel-related cost factors for the residential, general service/lighting and industrial classes, exclusive of gross receipts tax and regulatory fee, using the uniform percentage average bill adjustment method.

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

A. The steps used to adjust test period generation, based on the Company's last general rate case methodology, are as follows:

(1) Total generation was calculated by applying a five-year average line loss/company use factor to the forecasted MWH sales for the billing period of September 2013 through August 2014.

(2) Estimated combustion turbine ("CT") generation reflects a three-year average.

(3) Estimated combined-cycle ("CC") generation for the billing period was included.

(4) For nuclear generation, the Company used the normalized five-year national industry average NERC capacity factor of 89.79%, as well as the capacity factor of 92.84% also used to calculate the prospective fuel and fuel-related costs.

(5) Conventional hydroelectric ("hydro") generation was based on the Company's historical 31-year median hydro generation for the period 1982 through 2012. Pumped storage hydro generation was based on the

five-year average pumped storage operation at Jocassee and Bad Creek pumped storage facilities.

(6) Expected renewable generation and renewable purchased power for the billing period was included.

(7) Residual generation is total generation as calculated in Step (1) above, less generation calculated above for natural gas, nuclear, hydro, and renewables, and further reduced by purchased and interchange power estimated at the test period level. The residual generation is obtained from the coal-fired generating units.

Q. SMITH EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD OVER/(UNDER) RECOVERY BALANCE AND THE EMF RATE. HOW DID FUEL EXPENSES COMPARE WITH FUEL REVENUE DURING CALENDAR YEAR 2012?

A. Smith Exhibit 3, Pages 1 through 4, demonstrates that for the test period, the Company experienced an over-recovery for residential, general service/lighting, and industrial customer classes of $8.1 million, $24.3 million, and $14.9 million respectively. The over-collected fuel amounts result in EMF decrements of 0.0382¢, 0.1099¢ and 0.1216¢ per kWh respectively, for residential, general service/lighting, and industrial customer classes, based on adjusted test period sales by customer class. The over-collection resulted in interest of $1.3 million, $4.0 million, and $2.5 million for EMF decrements of 0.0064¢, 0.0183¢ and 0.0203¢ per kWh respectively, for residential, general service/lighting, and industrial customer classes, based on adjusted test period sales by customer class.

The over/(under) collection amount was determined each month by comparing the amount of fuel revenue collected for each class, based on actual monthly sales, to incurred actual fuel costs allocated to customer classes based on fixed allocation percentages each month. The allocation percentages for each customer class were based on the customer class allocation of fuel costs in the Company's previous fuel proceeding based on the uniform percentage average bill adjustment method.

Exhibit 3 also includes an adjustment that the Company proposes to make to the over-collection balance for DEC for calendar year 2012 in order to share certain merger fuel-related savings with PEC customers. In his testimony, Company Witness Weintraub describes the circumstances under which certain merger fuel-related savings were accomplished during January through June 2012, prior to the closing date of the merger of Duke Energy Corporation and Progress Energy, Inc. ("Merger"). The Company has reported these savings to the Commission, totaling $10.7 million, on its monthly fuel filing "Schedule 11" report of merger fuel-related savings. The Company, however, has not reflected on its books the sharing of these costs with PEC. Upon approval by the Commission to adjust the over-collection for calendar year 2012 to reflect the sharing of merger fuel-related savings achieved during the period prior to Merger close, the Company will make the appropriate entries on its books to reflect the sharing of the savings. As shown on Smith Exhibit 3, Page 1 of 4, line 14, the North Carolina retail portion of the amount to be shared with PEC is $2.3 million.

Exhibit 3 also includes a correction related to the avoided cost associated with purchases of energy from renewable resources in accordance with N.C. Gen. Stat. § 62.133.2(a1)(6). The incremental cost of renewable purchased power (in excess of avoided cost) is recoverable through the Company's REPS rider in accordance with N.C. Gen. Stat. § 62-133.7(h). During the preparation of the Company's fuel and REPS filings, it was discovered that some renewable purchased power transactions that occurred in 2012 were not properly split between avoided cost and incremental cost. As a result, the amount of avoided cost included in the monthly fuel filings was overstated and the amount of incremental cost recoverable through REPS was understated.

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

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Smith Exhibit 4 sets forth test period actual MWH sales, the customer growth MWH adjustment, and the weather MWH adjustment. Test period MWH sales were normalized for weather using a 10-year period, as used in DEC's last general rate case (Docket No. E-7, Sub 989) and the last fuel proceeding (Docket No. E-7, Sub 1002). Customer growth was also determined using the methods adopted in the Company's last general rate case and used in the last fuel proceeding. Smith Exhibit 4 also sets forth actual test period fuel-related revenue and fuel expense on a total Company basis and for North Carolina Retail. Finally, Smith 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 SMITH EXHIBIT 5.

A. Smith Exhibit 5 sets forth the capacity ratings for each of DEC's nuclear units, in compliance with Rule R8-55 (e)(12). The ratings for McGuire Units 1 and 2 have changed from 1,100 MWs each in the Company's last general rate case to 1,129 MWs in this proceeding due to increases associated with low pressure turbine upgrades effective December 31, 2012.

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

A. Yes. As shown on Smith Exhibit 6, DEC's test year actual fuel and fuel-related costs were 2.2509¢ per kWh. Key factors in DEC's ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of DEC's and PEC's respective skills in procuring, transporting, managing and blending fuels, procuring reagents, and the increased and broader purchasing ability of the combined Company as well as the joint dispatch of DEC's and PEC's generation resources. Company Witness Duncan discusses the performance of DEC's nuclear generation fleet, and Company Witness Miller discusses the performance of the fossil and hydro fleet, as well as the market conditions of chemicals that DEC uses to reduce emissions. Company Witness Weintraub discusses the fossil fuel procurement strategies and key factors related to the Merger, and Company

Witness Culp discusses DEC's nuclear fuel costs and procurement strategies.

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

A. Yes, the costs for which statutory guidance is provided are allocated in compliance with N.C. Gen. Stat. § 62-133.2(a2). These costs are described in subdivisions (4), (5) and (6) of N.C. Gen. Stat. § 62-133.2(a1). Subdivision (4) includes purchased power non-capacity costs subject to economic curtailment or dispatch and is allocated based on MWH sales. Subdivision (5) includes renewable capacity costs and is based upon the production plant allocator from the cost of service study in the Company's most recent general rate case. Subdivision (6) includes cogeneration and independent power producer capacity costs. The allocation methods for subdivisions (4), (5) and (6) are found on page 89, paragraph 17 of the Company's general rate case Order in Docket E-7, Sub 909.

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

A. The costs for which statutory guidance is not provided are allocated using the uniform percentage average bill adjustment methodology in setting fuel rates in this fuel proceeding. The Company proposes to use the same uniform percentage average bill adjustment methodology to recover its proposed increase in fuel and fuel-related costs as it did in the Company's 2012 fuel and fuel-related cost recovery proceedings.

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

A. Smith Exhibit 2, Page 3 of Schedule 1 shows the Company's proposed fuel and fuel-related cost factors for the residential, general service/lighting and industrial classes, exclusive of gross receipts tax. The uniform bill percentage change of 0.00% was calculated by dividing the fuel and fuel-related cost increase of $151,634 for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $4,624,265,623. The cost increase of $151,634 was determined by comparing the total proposed fuel rate per kWh to the total fuel rate per kWh currently being collected from customers including the merger fuel-related savings decrement rider, and multiplying the resulting increase in fuel rate per kWh by projected North Carolina retail kWh sales for the billing period. The proposed fuel rate per kWh represents the rate necessary to recover projected period fuel costs for the billing period (as computed on Smith Exhibit 2, Schedule 1), minus the current over-collected fuel cost at the end of 2012 (as computed on Exhibit 3). The dollar amount of increase in fuel costs is insignificant, and as a result, the uniform percent change rounds to 0.00%. As such, the Company elected not to compute an associated increase in cents per kWh related to the dollar amount of the cost increase. Smith 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 SMITH EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

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

Q. HAS DEC'S ANNUAL INCREASE IN THE AGGREGATE AMOUNT OF THE COSTS IDENTIFIED IN SUBDIVISIONS (4), (5), AND (6) OF

N.C. GEN. STAT. § 62-133.2(a1) EXCEEDED 2% OF ITS NORTH CAROLINA RETAIL GROSS REVENUES FOR 2012?

A. No. When JDA-related costs are excluded from the purchased power calculation, the amount recoverable in the Company's proposed rates under the relevant sections of N.C. Gen. Stat. § 62-133.2(a1) does not increase by more than 2% of DEC's gross revenues for its North Carolina retail jurisdiction for calendar year 2012. North Carolina General Statutes § 62-133.2(a2) limits the amount of annual increase in certain purchased power costs identified in § 62-133.2(a1) that the Company can recover to 2% of its North Carolina retail gross revenues for the preceding calendar year. In determining whether purchased power costs included in the Company's proposed rates should be limited, DEC performed its evaluation excluding the costs directly related to JDA transactions between DEC and PEC, which are providing merger savings that the Company is passing through to its customers. As explained by Company Witness Weintraub, the JDA has allowed DEC's and PEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. The JDA was approved by the Commission in the Merger docket, and without it, these specific purchased expenses between DEC and PEC would not exist. As a result, the Company has included the full amount of its purchased power costs, including these transactions, in its cost recovery application.

Q. **THE COMPANY'S MERGER FUEL-RELATED SAVINGS RIDER BECAME EFFECTIVE ON SEPTEMBER 1, 2012 AND IS SET TO**

EXPIRE ON AUGUST 31, 2013. HOW ARE MERGER FUEL-RELATED SAVINGS HANDLED IN THE COMPANY'S PROPOSED FUEL RATES?

A. The expiration date of the merger fuel-related savings rider was set to align with the effective date of the Company's next fuel rate change, which is September 1, 2013. The rider was initially necessary to begin flowing merger fuel-related savings to customers promptly upon the close of the Merger. Since the Merger close, the fuel savings have been reflected on the Company's books in the form of lower fuel costs. The Company's true-up to actual fuel costs, including merger savings during the period January through December 2012, are reflected in the Company's over collection balance as shown on Exhibit 3. In addition, the projected fuel costs on which the Company's proposed fuel rates are based include expected merger fuel-related savings for the billing period. As a result, the Company has not proposed a separate merger fuel-related savings rider beyond August 2013.

Q. CAN YOU IDENTIFY WHERE IN THIS FILING THESE SAVINGS ARE INCLUDED?

A. As Company Witness Weintraub testified in Docket No. E-7, Sub 986, merger fuel-related savings automatically flow through to the DEC's retail customers through the fuel and fuel-related cost component of customer's rates. As described above, actual merger savings during the calendar year 2012 are included in the EMF portion of the proposed fuel and fuel-related cost factors. In addition, in the prospective component of the factors, the projected merger savings related to procuring coal and reagents, lower transportation costs, lower gas capacity costs and coal blending are reflected in the cost of fossil fuel. Projected joint dispatch savings, which are the result of using the combined systems' lowest available generation to meet total customer demand, are also reflected in the cost of fossil fuel as well as the projected cost purchases and sales that include the purchases and sales between DEC and PEC.

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

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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Summary Comparison of Fuel and Fuel Related Cost Factors
Test Period Ended December 31, 2012
Billing Period September 2013 - August 2014
Docket E-7, Sub 1033

Smith Exhibit 1

Line #	Description	Reference	Residential cents/KWh	General cents/KWh	Industrial cents/KWh
	Current Fuel and Fuel Related Cost Factors (Approved Fuel Rider Docket No. E-7, Sub 1002)				
1	Approved Fuel and Fuel Related Costs Factors	Input	2.2224	2.2463	2.2594
2	Current Merger Savings decrement cents/kWh (Docket E-7, Sub 986)*	Workpaper 2	(0.0707)	(0.0509)	(0.0379)
3	EMF Increment	Input	0.0360	0.0323	0.0318
4	Approved Net Fuel and Fuel Related Costs Factors	Sum	2.1877	2.2277	2.2533
	Fuel and Fuel Related Cost Factors Required by Rule R8-55				
5	Proposed Nuclear Capacity Factor of 92.84% and Adjusted Test Period Sales	Exh 2 Sch 2 pg 2	2.1512	2.1989	2.2314
6	NERC 5 Year Average Nuclear Capacity Factor of 89.79% and Adjusted Test Period Sales	Exh 2 Sch 3 pg 2	2.2615	2.2860	2.2975
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 92.84%				
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	2.2070	2.3355	2.3752
8	Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.0253	0.0204	0.0200
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	2.2323	2.3559	2.3952
10	EMF Decrement cents/kWh	Exh 3 pg 2, 3, 4	(0.0382)	(0.1099)	(0.1216)
11	EMF Interest Decrement cents/kWh	Exh 3 pg 2, 3, 4	(0.0064)	(0.0183)	(0.0203)
12	Net Fuel and Fuel Related Costs Factors cents/kWh	Sum	2.1877	2.2277	2.2533

*excludes gross receipts tax and regulatory fee

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 92.84%
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Unit	Reference	MDC Rating (MW)	Hours In Year	Capacity Factor	Generation (MWH)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	B	D/(A*B)=C	D	E	D * E = F
1	Catawba 1	Workpaper 3	1,129	8,760	89.85%	8,885,994	0.6534	58,059,461
2	Catawba 2	Workpaper 3	1,129	8,760	92.01%	9,099,772	0.7078	64,408,351
3	McGuire 1	Workpaper 3	1,129	8,760	98.25%	9,717,272	0.6585	63,992,207
4	McGuire 2	Workpaper 3	1,129	8,760	93.26%	9,223,879	0.6627	61,127,783
5	Oconee 1	Workpaper 3	846	8,760	99.89%	7,402,727	0.6787	50,242,789
6	Oconee 2	Workpaper 3	846	8,760	84.02%	6,226,615	0.6964	43,360,558
7	Oconee 3	Workpaper 3	846	8,760	91.94%	6,813,773	0.6836	46,576,393
8	Total Nuclear	Workpaper 5 & 6	7,054		92.84%	57,370,032	0.6759	387,767,542
9	Coal	Workpaper 5 & 6				26,277,775	3.8023	999,170,804
10	Gas CT and CC	Workpaper 5 & 6				10,016,167	3.2554	326,064,809
11	Reagents	Workpaper 11				-		41,840,169
12	Total Fossil	Sum				36,293,942		1,367,075,782
13	Hydro	Workpaper 5				1,779,845		
14	Net Pumped Storage	Workpaper 5				(798,620)		
15	Total Hydro	Sum				981,225		
16	Total Generation	Line 8 + Line 12 + Line 15				94,645,199		1,754,843,324
17	Less Catawba Joint Owners	Workpaper 5				(13,929,209)		(94,148,372)
18	Net Generation	Sum				80,715,990		1,660,694,952
19	Purchases	Workpaper 5 & 6				9,448,043		336,257,185
20	JDA Savings Shared	Workpaper 7				-		8,791,208
21	Total Purchases					9,448,043		345,048,393
22	Total Generation and Purchases	Line 18 + Line 21				90,164,033		2,005,743,345
23	Adjustment to exclude cost of mitigation sales	Workpaper 5 & 7				(803,900)		(29,839,400)
24	Fuel expense recovered through intersystem sales	Workpaper 5 & 7				(1,683,858)		(66,967,909)
25	Line losses and Company use					(5,287,395)		-
26	System Fuel Expense for Fuel Factor	Lines 22 + 23 + 24						1,908,936,036
27	Projected System MWh Sales for Fuel Factor	Lines 22 + 23 + 24 + 25 and Workpaper 9				82,388,880		82,388,880
28	Fuel and Fuel Related Costs cents/kWh	Line 26/Line 27/10						2.3170

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 92.84%
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWH Sales	Workpaper 9	20,955,314	22,316,250	12,244,753	55,516,317
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class					Amount
2	Renewable Purchased Power - Capacity	Workpaper 6				$ 6,918,584
3	Cogeneration Purchased Power - Capacity	Workpaper 6				10,211,640
4	Total of Renewable and Cogeneration Purchased Power Capacity	Line 2 + Line 3				$ 17,130,224
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input				71.8170%
6	NC Renewable Purchased Power - Capacity	Line 4 * Line 5				$ 12,302,413
7	Production Plant Allocation Factors	Input	43.1736%	36.9466%	19.8798%	100.0000%
8	Renewable Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 5,311,395	$ 4,545,323	$ 2,445,695	$ 12,302,413
9	Renewable Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1	0.0253	0.0204	0.0200	0.0222
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Renewable Purchased Power and Cogeneration Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.2070	2.3355	2.3752	
11	Purchased Power - Capacity cents/kWh	Line 9	0.0253	0.0204	0.0200	
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.2323	2.3559	2.3952	
13	EMF Increment cents/kWh	Exh 3 pg 2, 3, 4	(0.0382)	(0.1099)	(0.1216)	
14	EMF Interest Increment cents/kWh	Exh 3 pg 2, 3, 4	(0.0064)	(0.0183)	(0.0203)	
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	2.1877	2.2277	2.2533	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 92.84%
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Rate Class	Projected Billing Period MWH Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Merger Savings decrement cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-7, Sub 1002	Proposed Total Fuel Rate (including renewables and EMF)
		A	B	C	D	E	F	G	H
		Workpaper 9	Workpaper 10	Line 28 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 7, Page 2 cents/kwh	Exhibit 1 Schedule 2c, page 2 cents/kwh	E + F + G = H
1	Residential	20,955,314	$ 2,128,247,266	$ 69,787	0.00%	-	(0.0707)	2 2584	2.1877
2	General Service/Lighting	22,316,250	1,756,843,269	57,609	0.00%	-	(0.0509)	2.2786	2.2277
3	Industrial	12,244,753	739,175,088	24,238	0.00%	-	(0.0379)	2.2912	2.2533
4	NC Retail	55,516,317	$ 4,624,265,623	$ 151,634					

Total Proposed Composite Fuel Rate:

Line #	Description	Source	Amount
5	System Total Fuel Costs	Exhibit 2 Sch 1, Page 1	$ 1,908,936,036
6	Cogen and Renewable Purchased Power - Capacity	Exhibit 2 Sch 1, Page 2	17,130,224
7	System Other Fuel Costs	Line 5 - Line 6	$ 1,891,805,812
8	Projected System MWh Sales for Fuel Factor	Workpaper 9	82,388,880
9	NC Retail Projected Billing Period MWH Sales	Line 4	55,516,317
10	Allocation %	Line 8 / Line 9	67.38%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,274,698,756
12	NC Cogen and Renewable Purchased Power - Capacity	Exhibit 2 Sch 1, Page 2	12,302,413
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,287,001,169
14	NC Retail Projected Billing Period MWH Sales	Line 4	55,516,317
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14	2.3182
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	(0.0852)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	(0.0142)
18	Total Proposed Composite Fuel Rate	Sum of Lines 17-19	2.2188

Total Current Composite Fuel Rate - Docket E-7 Sub 1001:

Line #	Description	Source	Amount
19	Current composite Fuel Rate cents/kWh	Supp Mc Manus Exh 6(c)	2.2404
22	Current composite Merger Savings decrement cents/kWh	Exhibit 7	(0.0555)
23	Current composite EMF Rate cents/kWh	Supp Mc Manus Exh 6(c)	0.0336
24	Current composite EMF Interest Rate cents/kWh	Supp Mc Manus Exh 6(c)	0.0000
25	Total Current Composite Fuel Rate	Sum	2.2185
26	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	0.0003
27	NC Retail Projected Billing Period MWH Sales	Line 4	55,516,317
28	Increase/(Decrease) in Fuel Costs	Line 26 * Line 27	$ 151,634

Note Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 92.84% and Adjusted Test Period Sales
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Unit	Reference	MDC Rating (MW)	Hours in Year	Capacity Factor	Generation (MWH)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	B	D/(A*B)=C	D	E	D * E = F
1	Catawba 1	Workpaper 3	1,129	8,760	89.85%	8,885,994	0.6534	58,059,461
2	Catawba 2	Workpaper 3	1,129	8,760	92.01%	9,099,772	0.7078	64,408,351
3	McGuire 1	Workpaper 3	1,129	8,760	98.25%	9,717,272	0.6585	63,992,207
4	McGuire 2	Workpaper 3	1,129	8,760	93.26%	9,223,879	0.6627	61,127,783
5	Oconee 1	Workpaper 3	846	8,760	99.89%	7,402,727	0.6787	50,242,789
6	Oconee 2	Workpaper 3	846	8,760	84.02%	6,226,615	0.6964	43,360,558
7	Oconee 3	Workpaper 3	846	8,760	91.94%	6,813,773	0.6836	46,576,393
8	Total Nuclear		7,054		92.84%	57,370,032	0.6759	387,767,542
9	Coal	Calculated				25,005,603	3.8023	950,798,492
1	Gas CT	Workpaper 17				755,750	3.4520	26,088,479
10	Gas CC	Workpaper 5				9,456,110	3.1557	298,403,910
11	Reagents	Workpaper 11				-		41,840,169
12	Total Fossil	Sum				35,217,463		1,317,131,050
13	Hydro	Workpaper 15				1,704,500		
14	Net Pumped Storage	Workpaper 16				(734,509)		
15	Total Hydro	Sum				969,991		
16	Total Generation	Line 8 + Line 12 + Line 15				93,557,486		1,704,898,592
17	Less Catawba Joint Owners					(13,929,209)		(94,148,372)
18	Net Generation	Sum				79,628,277		1,610,750,219
19	Purchases	Workpaper 5 & 6				9,448,043		336,257,185
20	JDA Savings Shared	Workpaper 7				-		8,791,208
21	Total Purchases	Sum				9,448,043		345,048,393
22	Total Generation and Purchases	Line 18 + Line 21				89,076,320		1,955,798,612
23	Adjustment to exclude cost of mitigation sales	Workpaper 5 & 7				(803,900)		(29,839,400)
24	Fuel expense recovered through intersystem sales	Workpaper 5 & 7				(1,683,858)		(66,967,909)
25	Line losses and Company use	Workpaper 14				(5,294,981)		-
26	System Fuel Expense for Fuel Factor							1,858,991,303
27	Projected System MWh Sales for Fuel Factor	Lines 22 + 23 + 24 + 25 and Exhibit 4				81,293,582		81,293,582
28	Fuel and Fuel Related Costs cents/kWh	Line 26/Line 27/10						2.2868

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 92.84% and Adjusted Test Period Sales
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWH Sales	Exhibit 4	21,143,695	22,112,646	12,278,269	55,534,611
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Renewable Purchased Power - Capacity	Workpaper 6				$ 6,918,584
3	Cogeneration Purchased Power - Capacity	Workpaper 6				10,211,640
4	Total of Renewable and Cogeneration Purchased Power Capacity	Line 2 + Line 3				$ 17,130,224
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Input				71.8170%
6	NC Renewable Purchased Power - Capacity	Line 4 * Line 5				$ 12,302,413
7	Production Plant Allocation Factors	Input	43.1736%	36.9466%	19.8798%	100.0000%
8	Renewable Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 5,311,395	$ 4,545,323	$ 2,445,695	$ 12,302,413
9	Renewable Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1	0.0251	0.0206	0.0199	0.0222
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Renewable Purchased Power and Cogeneration Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.1707	2.3065	2.3534	
11	Purchased Power - Renewable and Cogeneration Capacity cents/kWh	Line 9	0.0251	0.0206	0.0199	
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.1958	2.3271	2.3733	
13	EMF Increment cents/kWh	Exh 3 pg 2, 3, 4	(0.0382)	(0.1099)	(0.1216)	
14	EMF Interest Increment cents/kWh	Exh 3 pg 2, 3, 4	(0.0064)	(0.0183)	(0.0203)	
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	2.1512	2.1989	2.2314	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 92.84% and Adjusted Test Period Sales
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Rate Class	Adjusted Test Period MWH Sales		Annual Revenue at Current rates		Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/(Decrease) as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Merger Savings decrement cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-7, Sub 1002	Proposed Total Fuel Rate (including renewables and EMF)
		A		B		C	D	E	F	G	H
		Exhibit 4		Workpaper 10		Line 28 as a % of Column B	C / B	If D=0 then 0 If not then (C*100)/(A*1000)	Exhibit 7, Page 2 cents/kwh	Exhibit 1 Schedule 2c, page 2 cents/kwh	E + F + G = H
1	Residential	21,143,695	$	2,128,247,266	$	(7,725,670)	-0.36%	(0.0365)	(0.0707)	2.2584	2.1512
2	General Service/Lighting	22,112,646	$	1,756,843,269		(6,377,450)	-0.36%	(0.0288)	(0.0509)	2.2786	2.1989
3	Industrial	12,278,269	$	739,175,088		(2,683,252)	-0.36%	(0.0219)	(0.0379)	2.2912	2.2314
4	NC Retail	55,534,611	$	4,624,265,623	$	(16,786,372)					

Total Proposed Composite Fuel Rate:

Line #	Description	Source		Amount
5	System Total Fuel Costs	Exhibit 2 Sch 2, Page 1	$	1,858,991,303
6	Cogen and Renewable Purchased Power - Capacity	Exhibit 2 Sch 2, Page 2		17,130,224
7	System Other Fuel Costs	Line 5 - Line 6	$	1,841,861,079
8	Adjusted Test Period System MWh Sales for Fuel Factor	Exhibit 4		81,293,582
9	NC Retail Adjusted Test Period MWH Sales	Exhibit 4		55,534,611
10	Allocation %	Line 8 / Line 9		68.31%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$	1,258,175,303
12	NC Cogen and Renewable Purchased Power - Capacity	Exhibit 2 Sch 2, Page 2		12,302,413
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$	1,270,477,716
14	NC Retail Adjusted Test Period MWH Sales	Exhibit 4		55,534,611
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14		2.2877
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		(0.0852)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1		(0.0142)
18	Total Proposed Composite Fuel Rate	Sum		2.1883

Total Current Composite Fuel Rate - Docket E-7 Sub 1002:

Line #	Description	Source		Amount
19	Current composite Fuel Rate cents/kWh	Supp Mc Maneus Exh 6(c)		2.2404
22	Current composite Merger Savings decrement cents/kWh	Exhibit 7		(0.0555)
23	Current composite EMF Rate cents/kWh	Supp Mc Maneus Exh 6(c)		0.0336
24	Current composite EMF Interest Rate cents/kWh	Supp Mc Maneus Exh 6(c)		0.0000
25	Total Current Composite Fuel Rate	Sum		2 2185
26	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24		(0.0302)
27	NC Retail Adjusted Test Period MWH Sales	Exhibit 4		55,534,611
28	Increase/(Decrease) in Fuel Costs	Line 26 * Line 27	$	(16,786,372)

Note: Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor of 89.79% and Adjusted Test Period Sales
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Unit	Reference	MDC Rating (MW)	Hours in Year	Capacity Factor	Generation (MWH)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	B	D/(A*B)=C	D	E	D * E = F
1	Catawba 1	Workpaper 4	1,129	8,760	90.25%	8,925,761	0.6534	58,319,292
2	Catawba 2	Workpaper 4	1,129	8,760	90.25%	8,925,761	0.7078	63,176,699
3	McGuire 1	Workpaper 4	1,129	8,760	90.25%	8,925,761	0.6585	58,779,784
4	McGuire 2	Workpaper 4	1,129	8,760	90.25%	8,925,761	0.6627	59,152,119
5	Oconee 1	Workpaper 4	846	8,760	88.97%	6,593,531	0.6787	44,750,724
6	Oconee 2	Workpaper 4	846	8,760	88.97%	6,593,531	0.6964	45,915,668
7	Oconee 3	Workpaper 4	846	8,760	88.97%	6,593,531	0.6836	45,070,902
8	Total Nuclear		7,054		89.79%	55,483,638	0.6762	375,165,188
9	Coal					27,376,108	3.8023	1,040,933,166
1	Gas CT					755,750	3.4520	26,088,479
10	Gas CC					9,456,110	3.1557	298,403,910
11	Reagents					-		41,840,169
12	Total Fossil	Sum				37,587,968		1,407,265,724
13	Hydro					1,704,500		
14	Net Pumped Storage					(734,509)		
15	Total Hydro	Sum				969,991		
16	Total Generation	Line 8 + Line 12 + Line 15				94,041,596		1,782,430,912
17	Less Catawba Joint Owners					(14,413,319)		(97,458,972)
18	Net Generation	Sum				79,628,277		1,684,971,940
19	Purchases					9,448,043		336,257,185
20	JDA Savings Shared					-		8,791,208
21	Total Purchases					9,448,043		345,048,393
22	Total Generation and Purchases	Line 18 + Line 21				89,076,320		2,030,020,333
23	Adjustment to exclude cost of mitigation sales					(803,900)		(29,839,400)
24	Fuel expense recovered through intersystem sales					(1,683,858)		(66,967,909)
25	Line losses and Company use					(5,294,981)		-
26	System Fuel Expense for Fuel Factor							1,933,213,024
27	Projected System MWh Sales for Fuel Factor					81,293,582		81,293,582
28	Fuel and Fuel Related Costs cents/kWh							2.3781

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
NERC 5 Year Average Nuclear Capacity Factor of 89.79% and Adjusted Test Period Sales
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWH Sales	Exhibit 4	21,143,695	22,112,646	12,278,269	55,534,611
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Renewable Purchased Power - Capacity	Workpaper 6				$ 6,918,584
3	Cogeneration Purchased Power - Capacity	Workpaper 6				10,211,640
4	Total of Renewable and Cogeneration Purchased Power Capacity	Line 2 + Line 3				$ 17,130,224
5	NC Portion - Jursidicational % based on Production Plant Allocator	Input				71.8170%
6	NC Renewable Purchased Power - Capacity	Line 4 * Line 5				$ 12,302,413
7	Production Plant Allocation Factors	Input	43.1736%	36.9466%	19.8798%	100.0000%
8	Renewable Purchased Power - Capacity allocated on Production Plant %	Line 6 * Line 7	$ 5,311,395	$ 4,545,323	$ 2,445,695	$ 12,302,413
9	Renewable Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1	0.0251	0.0206	0.0199	0.0222
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Renewable Purchased Power and Cogeneration Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.2810	2.3936	2.4195	
11	Purchased Power - Renewable and Cogeneration Capacity cents/kWh	Line 9	0.0251	0.0206	0.0199	
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.3061	2.4142	2.4394	
13	EMF Increment cents/kWh	Exh 3 pg 2, 3, 4	(0.0382)	(0.1099)	(0.1216)	
14	EMF Interest Increment cents/kWh	Exh 3 pg 2, 3, 4	(0.0064)	(0.0183)	(0.0203)	
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	2.2615	2.2860	2.2975	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
NERC 5 Year Average Nuclear Capacity Factor of 89.79% and Adjusted Test Period Sales
Twelve Months September 2013 - August 2014
Docket E-7, Sub 1033

Line #	Rate Class	Adjusted Test Period MWH Sales		Annual Revenue at Current rates		Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Merger Savings decrement cents/kWh	Current Total Fuel Rate (including renewables and EMF) E-7, Sub 1002	Proposed Total Fuel Rate (including renewables and EMF)
		A		B		C	C / B = D	E	F	G	H
		Exhibit 4		Workpaper 10		Line 28 as a % of Column B	C / B	If D=0 then 0 If not then (C*100)/(A*1000)	Exhibit 7, Page 2 cents/kwh	Exhibit 1 Schedule 2c, page 2 cents/kwh	E + F + G = H
1	Residential	21,143,695	$	2,128,247,266	$	15,609,653	0.73%	0.0738	(0.0707)	2.2584	2.2615
2	General Service/Lighting	22,112,646	$	1,756,843,269	$	12,885,586	0.73%	0.0583	(0.0509)	2.2786	2.2860
3	Industrial	12,278,269	$	739,175,088	$	5,421,488	0.73%	0.0442	(0.0379)	2.2912	2.2975
4	NC Retail	55,534,611	$	4,624,265,623	$	33,916,727					

Total Proposed Composite Fuel Rate:

Line #	Description	Source		Amount
5	System Total Fuel Costs	Exhibit 2 Sch 3, Page 1	$	1,933,213,024
6	Cogen and Renewable Purchased Power - Capacity	Exhibit 2 Sch 3, Page 2		17,130,224
7	System Other Fuel Costs	Line 5 - Line 6	$	1,916,082,800
8	Adjusted Test Period System MWh Sales for Fuel Factor	Exhibit 4		81,293,582
9	NC Retail Adjusted Test Period MWH Sales	Exhibit 4		55,534,611
10	Allocation %	Line 8 / Line 9		68.31%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$	1,308,876,161
12	NC Cogen and Renewable Purchased Power - Capacity	Exhibit 2 Sch 3, Page 2		12,302,413
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$	1,321,178,574
14	NC Retail Adjusted Test Period MWH Sales	Exhibit 4		55,534,611
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14		2.3790
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		(0.0852)
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1		(0.0142)
18	Total Proposed Composite Fuel Rate	Sum		2.2796

Total Current Composite Fuel Rate - Docket E-7 Sub 1001:

Line #	Description	Source		Amount
19	Current composite Fuel Rate cents/kWh	Supp Mc Maneus Exh 6(c)		2.2404
22	Current composite Merger Savings decrement cents/kWh	Exhibit 7		(0.0555)
23	Current composite EMF Rate cents/kWh	Supp Mc Maneus Exh 6(c)		0.0336
24	Current composite EMF Interest Rate cents/kWh	Supp Mc Maneus Exh 6(c)		0.0000
25	Total Current Composite Fuel Rate	Sum		2.2185
26	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24		0.0611
27	NC Retail Adjusted Test Period MWH Sales	Exhibit 4		55,534,611
28	Increase/(Decrease) in Fuel Costs	Line 26 * Line 27	$	33,916,727

Note Rounding differences may occur

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Line No.	Month	Fuel Cost Incurred ¢/kwh (a)	Fuel Cost Billed ¢/kwh (b)	NC Retail MWH Sales (c)	Reported Over (Under) Recovery (d)	Correction Renewables (e)	Merger Savings to be Shared with PEC (f)	Adjusted Over(Under) Recovery (g)
1	January 2012			4,696,133	$ 19,638,596	$ 187,794	$ (423,273)	$ 19,403,116
2	February			4,471,304	$ 23,655,484	$ 134,844	$ (469,468)	$ 23,320,859
3	March			4,225,513	$ 24,585,301	$ 175,285	$ (358,714)	$ 24,401,871
4	April			4,010,671	$ 14,125,769	$ 175,371	$ (347,558)	$ 13,953,582
5	May[1]			4,082,258	$ (3,744,786)	$ 156,140	$ (311,282)	$ (3,899,928)
6	June			4,696,516	$ 285,688	$ 155,267	$ (372,323)	$ 68,632
7	July			5,356,807	$ (19,666,451)	$ 119,793	$ -	$ (19,546,658)
8	August			5,440,542	$ 4,397,805	$ 115,271	$ -	$ 4,513,076
9	September			4,959,528	$ 15,743,742	$ 141,367	$ -	$ 15,885,109
10	October			4,052,001	$ (2,870,169)	$ 183,651	$ -	$ (2,686,518)
11	November			4,169,014	$ (25,945,880)	$ 143,654	$ -	$ (25,802,226)
12	December			4,395,620	$ (2,399,967)	$ 95,536	$ -	$ (2,304,431)
				54,555,907	$ 47,805,133	$ 1,783,970	$ (2,282,619)	$ 47,306,484

13	Booked Over (Under) Recovery	January 2012 through December 2012	$ 47,306,484
14	Adjusted Test Period MWH Sales	Exhibit 4	55,534,611
15	Experience Modification Increment (Decrement) cents/KWh		(0.0852)
16	Annual Interest Rate		10%
17	Monthly Interest Rate		0.83333%
18	Number of Months (July 2012 - February 2014)		20
19	Interest		$ 7,884,411
20	EMF Interest Increment (Decrement)		(0.0142)

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

Totals may not foot due to rounding

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Line #	Month	Fuel Cost Incurred ¢/kwh (a)	Fuel Cost Billed ¢/kwh (b)	NC Retail MWH Sales (c)	Reported Over (Under) Recovery (d)	Correction Renewables (e)	Merger Savings to be Shared with PEC (f)	Adjusted Over(Under) Recovery (g)
1	January 2012	1.9757	2.3941	2,052,554	$ 8,587,317	$ 82,696	$ (185,001)	$ 8,485,012
2	February	1.8654	2.3941	1,785,443	$ 9,438,839	$ 55,007	$ (187,464)	$ 9,306,381
3	March	1.8137	2.3941	1,576,391	$ 9,149,599	$ 67,552	$ (133,824)	$ 9,083,328
4	April	2.0458	2.3941	1,252,705	$ 4,363,250	$ 58,610	$ (108,557)	$ 4,313,303
5	May(1)	2.4880	2.3941	1,320,093	$ (1,197,907)	$ 53,520	$ (100,660)	$ (1,245,048)
6	June	2.3891	2.3941	1,638,140	$ 81,288	$ 56,610	$ (129,866)	$ 8,032
7	July	2.7610	2.3941	2,159,210	$ (7,922,165)	$ 49,259	$ -	$ (7,872,906)
8	August	2.3132	2.3941	2,137,529	$ 1,730,239	$ 46,314	$ -	$ 1,776,553
9	September	2.0835	2.2944	1,773,808	$ 3,741,330	$ 52,198	$ -	$ 3,793,528
10	October	2.6980	2.1529	1,271,002	$ (6,927,371)	$ 61,013	$ -	$ (6,866,358)
11	November	3.0681	2.1517	1,428,843	$ (13,093,551)	$ 51,262	$ -	$ (13,042,289)
12	December	2.1338	2.1517	1,725,994	$ 309,292	$ 38,113	$ -	$ 347,404
13	Total Test Period			20,121,712	$ 8,260,159	$ 672,154	$ (845,373)	$ 8,086,940
14	Test Period Wtd Avg. ¢/kwh	2.2912	2.3321					

15	Booked Over (Under) Recovery January 2012 to December 2012		$ 8,086,940
16	Adjusted Test Period MWH Sales	Exhibit 4	21,143,695
17	Experience Modification Increment (Decrement) cents/KWh		(0.0382)
16	Annual Interest Rate		10%
17	Monthly Interest Rate		0.83333%
18	Number of Months (July 2012 - February 2014)		20
19	Interest		$ 1,347,823
20	EMF Interest Increment (Decrement)		(0.0064)

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

Totals may not foot due to rounding

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - GS/Lighting
Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Line #	Month	Fuel Cost Incurred ¢/kwh (a)	Fuel Cost Billed ¢/kwh (b)	NC Retail MWH Sales (c)	Reported Over (Under) Recovery (d)	Correction Renewables (e)	Merger Savings to be Shared with PEC (f)	Adjusted Over(Under) Recovery (g)
1	January 2012	1.9752	2.3931	1,772,833	$ 7,408,542	$ 70,835	$ (159,790)	$ 7,319,588
2	February	1.8643	2.3931	1,698,008	$ 8,979,856	$ 51,123	$ (178,284)	$ 8,852,696
3	March	1.8110	2.3931	1,673,313	$ 9,739,578	$ 68,901	$ (142,052)	$ 9,666,427
4	April	2.0398	2.3931	1,736,780	$ 6,136,815	$ 74,447	$ (150,506)	$ 6,060,756
5	May(1)	2.4841	2.3931	1,734,967	$ (1,586,902)	$ 65,261	$ (132,295)	$ (1,653,936)
6	June	2.3866	2.3931	1,957,034	$ 127,816	$ 63,790	$ (155,147)	$ 36,459
7	July	2.7603	2.3931	2,108,480	$ (7,742,783)	$ 46,840	$ -	$ (7,695,942)
8	August	2.3123	2.3931	2,162,678	$ 1,747,384	$ 45,484	$ -	$ 1,792,868
9	September	1.8993	2.3118	2,080,164	$ 8,581,691	$ 58,447	$ -	$ 8,640,139
10	October	2.0850	2.1964	1,757,762	$ 1,957,749	$ 78,146	$ -	$ 2,035,896
11	November	2.7306	2.1954	1,716,585	$ (9,186,739)	$ 58,448	$ -	$ (9,128,290)
12	December	2.2927	2.1954	1,717,661	$ (1,671,731)	$ 37,181	$ -	$ (1,634,551)
13	Total Test Period			22,116,267	$ 24,491,277	$ 718,904	$ (918,074)	$ 24,292,108
14	Test Period Wtd Avg. ¢/kwh	2.2283	2.3391					
15	Booked Over (Under) Recovery January 2012 to December 2012							$ 24,292,108
16	Adjusted Test Period MWH Sales			Exhibit 4				22,112,646
17	Experience Modification Increment (Decrement) cents/KWh							(0.1099)
16	Annual Interest Rate							10%
17	Monthly Interest Rate							0.83333%
18	Number of Months (July 2012 - February 2014)							20
19	Interest							$ 4,048,683
20	EMF Interest Increment (Decrement)							(0.0183)

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Industrial
Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Line #	Month	Fuel Cost Incurred ¢/kwh (a)	Fuel Cost Billed ¢/kwh (b)	NC Retail MWH Sales (c)		Reported Over (Under) Recovery (d)		Correction Renewables (e)		Merger Savings to be Shared with PEC (f)		Adjusted Over(Under) Recovery (g)
1	January 2012	1.9743	2.3926	870,747	$	3,642,737	$	34,263	$	(78,482)	$	3,598,517
2	February	1.8625	2.3926	987,853	$	5,236,789	$	28,714	$	(103,720)	$	5,161,782
3	March	1.8089	2.3926	975,808	$	5,696,124	$	38,831	$	(82,839)	$	5,652,116
4	April	2.0376	2.3926	1,021,186	$	3,625,704	$	42,313	$	(88,494)	$	3,579,523
5	May(1)	2.4827	2.3926	1,027,197	$	(959,977)	$	37,359	$	(78,326)	$	(1,000,944)
6	June	2.3856	2.3926	1,101,342	$	76,585	$	34,867	$	(87,311)	$	24,142
7	July	2.7600	2.3926	1,089,116	$	(4,001,503)	$	23,693	$	-	$	(3,977,810)
8	August	2.3119	2.3926	1,140,335	$	920,182	$	23,472	$	-	$	943,654
9	September	2.0128	2.3223	1,105,555	$	3,420,721	$	30,722	$	-	$	3,451,443
10	October	2.0172	2.2224	1,023,236	$	2,099,453	$	44,491	$	-	$	2,143,944
11	November	2.5796	2.2215	1,023,586	$	(3,665,590)	$	33,944	$	-	$	(3,631,646)
12	December	2.3305	2.2215	951,965	$	(1,037,527)	$	20,243	$	-	$	(1,017,284)
13	Total Test Period			12,317,928	$	15,053,696	$	392,912	$	(519,173)	$	14,927,436
14	Test Period Wtd Avg. ¢/kwh	2.2222	2.3447									

15	Booked Over (Under) Recovery January 2012 to December 2012		$	14,927,436
16	Adjusted Test Period MWH Sales	Exhibit 4		12,278,269
17	Experience Modification Increment (Decrement) cents/KWh			(0.1216)
16	Annual Interest Rate			10%
17	Monthly Interest Rate			0.83333%
18	Number of Months (July 2012 - February 2014)			20
19	Interest		$	2,487,905
20	EMF Interest Increment (Decrement)			(0.0203)

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Sales, Fuel Revenue, Fuel Expense and System Peak
Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Smith Exhibit 4

Line #	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina General Service/Lighting	North Carolina Industrial
1	Test Period MWH Sales (excluding inter system sales)	Workpaper 19	79,868,568	54,555,907	20,121,712	22,116,267	12,317,928
2	Customer Growth MWH Adjustment	Workpaper 21	(30,932)	(47,556)	46,063	(76,154)	(17,466)
3	Weather MWH Adjustment	Workpaper 20	1,455,945	1,026,260	975,920	72,533	(22,193)
4	Total Adjusted MWH Sales	Sum	81,293,582	55,534,611	21,143,695	22,112,646	12,278,269
5	Test Period Fuel and Fuel Related Revenue *		$ 1,872,319,831	$ 1,275,399,739			
6	Test Period Fuel and Fuel Related Expense *		$ 1,757,881,194	$ 1,227,594,608			
7	Test Period Unadjusted Over/(Under) Recovery		$ 114,438,637	$ 47,805,131			

Line #	Description	Summer Coincidental Peak (CP) KW
8	Total System Peak	17,051,270
9	NC Retail	11,985,789
10	NC Residential Peak	5,588,503
11	NC General Service/Lighting Peak	4,371,590
12	NC Industrial Peak	2,025,696

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

DUKE ENERGY CAROLINAS **Smith Exhibit 5**

North Carolina Annual Fuel and Fuel Related Expense

Nuclear Capacity Ratings

Test Period Ended December 31, 2012

Docket E-7, Sub 1033

Unit	Rate Case Docket E-7, Sub 989	Fuel Docket E-7, Sub 1002	Proposed Capacity Rating MW
Oconee Unit 1	846	846	846
Oconee Unit 2	846	846	846
Oconee Unit 3	846	846	846
McGuire Unit 1 [1]	1,100	1,100	1,129
McGuire Unit 2 [1]	1,100	1,100	1,129
Catawba Unit 1	1,129	1,129	1,129
Catawba Unit 2	1,129	1,129	1,129
Total Company	6,996	6,996	7,054

[1] As of 12/31/2012 – includes capacity increases associated to low pressure turbine upgrades.

Schedule 1

DUKE ENERGY CAROLINAS
SUMMARY OF MONTHLY FUEL REPORT
NCUC R8-52

Docket No. E-7, Sub 1003

Line No.	Fuel Expenses:	December 2012	12 Months Ended December 2012
1	Fuel and fuel-related costs	$ 154,308,247	$ 1,836,815,457
2	Less fuel expenses (in line 1) recovered through intersystem sales (a)	10,131,389	39,092,889
3	Total fuel and fuel-related costs (line 1 minus line 2)	$ 144,176,858	$ 1,797,722,568
	MWH sales:		
4	Total system sales	6,738,544	81,010,541
5	Less intersystem sales	295,729	1,141,973
6	Total sales less intersystem sales	6,442,815	79,868,568
7	Total fuel and fuel-related costs (¢/KWH) (line 3/line 6)	2.2378	2.2509
8	Current fuel and fuel-related cost component (¢/KWH) (per Schedule 4, Line 2c Total)	2.1839	
	Generation Mix (MWH):		
	Fossil (by primary fuel type):		
9	Coal	2,576,425	27,969,376
10	Biomass	126	1,365
11	Fuel Oil	(12)	6,865
12	Natural Gas - Combustion Turbine	6,646	916,328
13	Natural Gas - Combined Cycle	569,988	4,418,878
14	Total fossil	3,153,173	33,312,812
15	Nuclear 100%	4,491,871	56,444,931
16	Hydro - Conventional	83,306	1,400,604
17	Hydro - Pumped storage	(61,666)	(641,599)
18	Total hydro	21,640	759,005
19	Solar Distributed Generation	643	10,479
20	Total MWH generation	7,667,327	90,527,227
21	Less joint owners' portion	742,049	14,441,479
22	Adjusted total MWH generation	6,925,278	76,085,748
	(a) Line 2 includes:		
	Fuel from intersystem sales (Schedule 3)	$ 10,120,906	$ 38,950,061
	Fuel-related costs recovered in off-system sales	-	11,579
	Fuel in loss compensation	10,483	131,249
	Total fuel recovered from intersystem sales	$ 10,131,389	$ 39,092,889

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

Schedule 2
Page 1 of 2

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS
NCUC R8-52

Docket No. E-7, Sub 1003

Fuel and fuel-related costs:	December 2012	12 Months Ended December 2012
Steam Generation - FERC Account 501		
0501016 coal blending merger savings	$ 1,260,522	$ 6,009,815
0501016 coal procurement merger savings	(217,188)	(774,414)
0501016 transportation merger savings	6,683	16,030
0501110 coal consumed - steam	89,547,048	1,054,162,590
0501222-0501223 biomass/test fuel consumed	6,885	74,783
0501310 fuel oil consumed - steam	1,728,401	21,523,259
0501330 fuel oil light-off - steam	1,252,714	21,726,282
Total Steam Generation - Account 501	93,585,065	1,102,738,145
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	3,340,371	24,947,678
0502160 reagent procurement merger savings	(32,242)	(110,273)
Net proceeds from sale of by-products	465,649	4,165,977
Nuclear Generation - FERC Account 518		
0518100 burnup of owned fuel	22,319,965	270,643,815
0518600 nuclear fuel disposal cost	4,224,676	53,141,510
Total Nuclear Generation - 100%	26,544,641	323,785,325
Less joint owners' portion	4,427,286	80,745,553
Total Nuclear Generation - Account 518	22,117,355	243,039,772
Other Generation - FERC Account 547		
0547100 natural gas consumed - Combustion Turbine	394,641	29,840,791
0547101 natural gas consumed - Combined Cycle	17,388,713	112,152,561
0547123 gas capacity merger savings	826,518	1,946,781
0547200 fuel oil consumed - Combustion Turbine	2,673	1,625,100
Total Other Generation - Account 547	18,612,545	145,565,233
Total fossil and nuclear fuel expenses included in base fuel component	138,088,743	1,520,366,532
Fuel component of purchased and interchange power	9,126,282	179,883,461
Fuel related component of purchased power (economic)	4,495,772	93,984,368
Fuel related component of purchased power (renewables)	2,597,450	42,581,098
Total fuel and fuel-related costs	$ 154,308,247	$ 1,836,815,457

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

Schedule 2
Page 2 of 2

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS
NCUC R8-52

Docket No. E-7, Sub 1003

Other fuel expenses not included in fuel and fuel-related costs:	December 2012	12 Months Ended December 2012
0501223 biomass excess above avoided cost	$ 1,124	$ 19,429
0501224 North Carolina incremental renewable fuel	(3,380)	(18,267)
0509000, 0557451 emissions allowance expense	2,557	51,729
0509213 RECs consumption expense	-	955,996
0518610 spent fuel canisters-accrual	-	2,348,911
0518620 canister design expense	67,234	590,812
0518700 fuel cycle study costs	-	235,885
0547127 gas desk merger savings	13,802	88,185
0411822, 0411832, 0411875 emission allowance gains	(986,432)	(11,105,504)
Purchased and interchanged power not included in fuel and fuel-related costs	2,710,622	49,254,175
Total other fuel expenses not included in fuel and fuel-related costs:	$ 1,805,527	$ 42,421,331
Total FERC Account 501 - Total Steam Generation	93,582,809	1,102,739,307
Total FERC Account 518 - Total Nuclear Generation	22,184,589	246,215,360
Total FERC Account 547 - Other Generation	18,612,545	145,565,233
Total RECs consumption expense	-	955,996
Total Reagents Expense	3,308,129	24,837,405
Total Gain/Loss from Sale of By-Products	465,649	4,185,977
Total Emission Allowance Expense	2,557	51,729
Total Gain/Loss from Sale of Emission Allowances	(986,432)	(11,105,504)
Total Purchased and Interchanged Power Expenses	18,930,126	365,703,100
Total Merger Savings Excluded from Fuel Recovery	13,802	88,185
Total Fuel, Fuel Related and Purchased Power Expenses	$ 156,113,774	$ 1,879,236,788

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

DUKE ENERGY CAROLINAS
PURCHASED POWER AND INTERCHANGE
NCUC-R8-52

DECEMBER 2012

Purchased Power — Economic	Total $	Capacity MW	Capacity $	Non-capacity MWH	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Alcoa Power Generating Inc.	$ 38,960	-	-	1,380	$ 24,376	$ 15,584	
Blue Ridge Electric Membership Corp - Economic	524,817	19	$ 184,350	11,012	207,686	132,782	
Cherokee County Cogeneration Partners	4,047,044	-	1,110,788	66,262	2,004,517	931,739	
City of Kings Mtn	8,979	3	8,979	-	-	-	
Constellation	10,502	-	-	525	6,406	4,096	
DE Progress - Native Load Transfer	5,764,001	-	-	204,090	4,161,618	1 607 008	$ (4 625)
DE Progress - Native Load Transfer Savings	420,611	-	-	-	420,611	-	
EDF Trading North America, LLC	1,372	-	-	49	837	535	
Haywood Electric - Economic	95,782	9	52,220	1,391	26,673	16,889	
Lockhart Power Co.	19,272	7	19,272	-	-	-	
NCEMC - Economic	-	-	-	-	(12)	12	
NCMPA - Economic	125,925	-	-	6,370	72,302	53,623	
NCMPA Load Following - Economic	1,347,046	-	-	44,663	775,842	571,504	
Piedmont Electric Membership Corp - Economic	333,651	12	115,430	7,076	133,115	85,106	
PJM Interconnection LLC	2,479,230	-	-	98,321	1,612,330	866,900	
Rutherford Electric Membership Corp. - Economic	460,199	-	-	15,659	408,837	51,362	
Southern	(6,776)	-	-	343	(4,133)	(2,643)	
Town of Dallas	584	-	584	-	-	-	
Town of Forest City	19,866	7	19,866	-	-	-	
TVA	166,860	-	-	5,560	85,685	81,175	
	$ 18,846,918	54	$ 1,511,476	438,868	$ 9,846,250	$ 4,498,772	$ (4,626)

Purchased Power — Renewables	Total $	Capacity MW	Capacity $	Non-capacity MWH	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Cargill Power Marketing	$ 1,513,395			25,870		$ 1,513,395	
City of Charlotte	1,893			24		1,893	
Concord Energy, LLC	211,637			2,981		211,637	
Davidson Gas Producers, LLC	79,866			1,149		79,866	
Dixon Dairy Road, LLC	38,953			612		38,953	
Durham Landfill Electricity, LLC	102,051			1,760		102,051	
Gas Recovery Systems, LLC	123,271			1,805		123,271	
Gaston County	122,850			1,966		122,850	
Greenville Gas Producer, LLC	80,213			1,643		80,213	
Lockhart - Lower Pacolet Hydro	15,020			221		15,020	
Lockhart Power Company	67,140			1,046		67,140	
Lynwood Solar, LLC	823			13		823	
Nypro, Inc.	1,058			21		1,058	
Ronnie B. Powers	1,134			22		1,134	
Sun Edison, LLC	128,189			1,861		128,189	
Tencarva Machinery Company	851			18		851	
WM Renewable Energy, LLC	111,506			1,650		111,506	
	$ 2,597,455	-	$ -	42,669	$ -	$ 2,597,440	$ -

Purchased Power — Other	Total $	Capacity MW	Capacity $	Non-capacity MWH	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Blue Ridge Electric Membership Corp	$ 1,432,308	46	$ 686,277	29,996	$ 448,979		$ 297 052
City of Concord	2,227	-	233	44	-		1,994
Haywood Electric	376,406	12	148,435	7,433	138,482		89 519
Piedmont Electric Membership Corp	700,165	20	326,101	14,880	228,179		145,885
DE Progress - Fees	63,533	-	-	-	-		63,533
Generation Imbalance	254,222	-	-	8,040	150,683		103 539
Energy Imbalance - Purchases	170,737	-	-	(3,304)	104,150		66 587
Energy Imbalance - Sales	(235,692)	-	-	-	(182,377)		(53 315)
Other Qualifying Facilities	668,802	-	-	13,509			668,802
	$ 3,431,796	78	$ 1,171,846	70,966	$ 888,966	$ -	$ 1,372,886
TOTAL PURCHASED POWER	$ 21,876,163	134	$ 2,682,626	563,093	$ 10,734,380	$ 7,083,222	$ 1,368,081
INTERCHANGES IN							
Other Catawba Joint Owners	4,144,278	-	-	387,513	2,113,026		2,031,253
Total Interchanges In	4,144,278	-	-	387,513	2,113,026		2,031,253
INTERCHANGES OUT							
Other Catawba Joint Owners	(6 861 588)	(866)	(134 208)	(638,867)	(3,530,914)		(3,196 465)
Catawba- Net Negative Generation	(230,727)	-	-	(8,770)	(190,184)		(40,543)
Total Interchanges Out	(7,092,316)	(866)	(134,208)	(647,637)	(3,721,098)		(3,237,008)
Net Purchases and Interchange Power	$ 18,930,128	(732)	$ 2,548,316	292,579	$ 9,126,282	$ 7,083,222	$ 162,306

NOTE Detail amounts may not add to totals shown due to rounding
As of December 2012, non-fuel costs related to mitigation losses and sharing of mitigation loss margins are no longer presented on this report.

DUKE ENERGY CAROLINAS
INTERSYSTEM SALES*
NCUC-R8-52

DECEMBER 2012

Schedule 3, NC, Sales, Month
Page 2 of 4

	Total	Capacity		Non-capacity		
SALES	$	MW	$	MWH	Fuel $	Non-fuel $
Market Based:						
Constellation Power Sources	$ 2,100	-	-	50	$ 1,862	$ 238
NCMPA	133,891	50	$ 87,500	1,030	31,953	14,438
PJM Interconnection LLC	40,171	-	-	829	30,482	9,689
Southern	-	-	-	-	(223)	223
The Energy Authority	70,760	-	-	995	41,942	28,818
Other:						
Cargill-Alliant, LLC - Mitigation sales	1,998,312	-	(695,000)	103,400	3,380,218	(686,906)
DE Progress - Native Load Transfer Savings	406,814	-	-	-	406,814	-
DE Progress - Native Load Transfer	6,444,056	-	-	182,222	6,045,532	398,524
DE Progress - Off System Sales/PJM Share	1,728	-	-	11	424	1,304
DE Progress - Purchases	137,642	-	-	5,722	137,642	-
Generation Imbalance	64,353	-	-	1,470	44,060	20,293
BPM Transmission	(13,778)	-	-			(13,778)
Total Intersystem Sales	$ 9,286,049	50	$ (607,500)	295,729	$ 10,120,906	$ (227,167)

* Sales for resale other than native load priority.

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

DUKE ENERGY CAROLINAS
PURCHASED POWER AND INTERCHANGE
NCUC-R8-52

Twelve Months Ended
DECEMBER 2012

Schedule 3, NC. Purchases 1212
Page 3 of 4

Purchased Power	Total	Capacity		Non-capacity			
Economic	$	MW	$	MWH	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Alcoa Power Generating Inc	$ 8,279,584	-	-	224,354	$ 3,830,548	$ 2,449,038	
American Electric Power Serv Corp	18,800	-	-	300	11,829	7,371	
Associated Electric Cooperative Inc	693,180	-	-	25,940	422,840	270,340	
Blue Ridge Electric Membership Corp - Economic	5,482,252	19	$ 2,212,200	120,958	1,862,532	1,267,520	
Calpine Power Services Marketing	1,176,376	-	-	45,486	717,588	458,788	
Cargill Power Marketers LLC	3,258,311	-	-	118,089	1,987,969	1,270,742	
Cherokee County Cogeneration Partners	47,759,839	-	11,213,608	985,888	15,876,745	20,668,486	
Citigroup Energy	21,200	-	-	800	12,932	8,268	
City of Kings Mtn	107,748	3	107,748	-	-	-	
Constellation	28,704,413	-	-	1,080,322	17,509,691	11,194,722	
DE Progress - Native Load Transfer	77,876,947	-	-	2,188,084	60,087,187	12,860,498	$ 4,629,281
DE Progress - Native Load Transfer- prior period correcti	-	-	-	-	-	3,156,588	(3,156,588)
DE Progress - Native Load Transfer Savings	3,558,602	-	-	-	3,558,602	-	
Eagle Energy Partners	287,184	-	-	8,888	182,982	104,202	
EDF Trading North America LLC	3,191,081	-	-	118,976	1,946,551	1,244,520	
Haywood Electric - Economic	1,208,831	8	604,863	21,089	368,864	235,704	
J Aron & Company	2,718,403	-	-	100,383	1,657,008	1,060,387	
Lockhart Power Co	231,284	7	231,284	-	-	-	
MISO	299	-	-	-	183	116	
Morgan Stanley Capital Group	3,127,809	-	-	118,620	1,907,863	1,219,946	
NCEMC	867,136	-	-	33,380	487,094	380,042	
NCMPA	7,947,204	-	-	308,810	4,366,382	3,580,822	
NCMPA Load Following	19,192,762	-	-	545,098	10,633,958	8,558,803	
Oglethorpe Power	44,350	-	-	2,610	27,053	17,297	
Piedmont Electric Membership Corp. - Economic	3,459,974	12	1,386,180	77,245	1,265,026	808,768	
PJM Interconnection LLC	46,734,951	-	-	1,686,482	28,508,320	18,226,631	
Rutherford Electric Membership Corp - Economic	3,289,653	-	-	123,700	2,761,219	518,434	
Southern	3,526,607	-	-	122,619	2,151,231	1,375,376	
The Energy Authority	3,247,822	-	-	123,468	1,981,171	1,266,651	
Town of Dallas	7,008	-	7,008	-	-	-	
Town of Forest City	238,272	7	238,272	-	-	-	
TVA	4,485,410	-	-	216,739	2,736,099	1,749,311	
Wester Energy Inc.	48,299	-	-	2,186	29,243	19,056	
	$ 378,213,875	58	$ 15,999,985	[illegible]	$ [illegible]	$ [illegible]	$ 1,473,643

Purchased Power	Total	Capacity		Non-capacity			
Renewables	$	MW	$	MWH	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Actaro Concepts, LLC	$ 8,722			109		$ 8,722	
Cargill Power Marketing	29,457,443			503,548		29,457,443	
City of Charlotte	28,213			408		28,213	
Concord Energy, LLC	1,613,738			25,540		1,613,738	
Davidson Gas Producers, LLC	934,629			13,287		934,629	
Dixon Dairy Road, LLC	861,515			7,088		861,515	
Durham Landfill Electricity, LLC	1,214,902			20,848		1,214,902	
Gas Recovery Systems, LLC	1,837,495			28,428		1,837,495	
Gaston County	1,367,325			21,718		1,367,325	
Greenville Gas Producer, LLC	1,129,520			20,085		1,129,520	
Lockhart - Lower Pacolet Hydro	27,984			412		27,984	
Lockhart Power Company	655,803			10,214		655,803	
Lynwood Solar, LLC	4,539			69		4,539	
Hypro, Inc	18,980			303		18,980	
Rennie B. Powers	45,380			742		45,380	
Sun Edison, LLC	2,082,418			30,418		2,082,418	
Tenaxys Machinery Company	15,183			233		15,183	
WM Renewable Energy LLC	1,319,361			18,551		1,319,361	
	$ 42,481,068	-	$ -	703,881	$ -	$ 42,481,068	$ -

Purchased Power	Total	Capacity		Non-capacity			
Other	$	MW	$	MWH	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
SC Public Service Authority - Emergency	$ 5,181	-	-	100	$ 3,161		$ 2,020
Blue Ridge Electric Membership Corp	17,000,744	46	$ 7,722,531	353,619	5,658,711		3,618,502
City of Concord	67,748	-	19,468	1,080	-		48,280
Haywood Electric	4,349,332	12	1,772,247	66,494	1,572,021		1,005,064
NCEMC Load Following	-	-	-	-	(442)		442
Piedmont Electric Membership Corp	8,330,008	20	3,683,876	176,468	2,834,141		1,811,991
DE Progress - Fees	158,830	-	-	-	-		158,830
Generation Imbalance	3,118,938	-	-	98,633	1,828,711		1,291,227
Energy Imbalance - Purchases	2,210,031	-	-	28,091	1,348,120		861,911
Energy Imbalance - Sales	(1,124,888)	-	-	-	(648,846)		(476,042)
Other Qualifying Facilities	8,458,514			171,841			8,458,514
	$ 43,873,139	78	$ 13,198,120	897,382	$ 12,595,577	$ -	$ 17,778,439
TOTAL PURCHASED POWER	$ 364,567,906	134	$ 29,197,943	9,704,831	$ 179,682,396	$ 136,895,484	$ 19,263,103
INTERCHANGES IN							
Other Catawba Joint Owners	70,602,047	-	-	7,287,229	31,066,565		39,535,482
Total Interchanges In	70,602,047	-	-	7,287,229	31,066,565	-	39,535,482
INTERCHANGES OUT							
Other Catawba Joint Owners	(68,891,830)	(898)	(1,584,534)	(7,037,166)	(30,274,591)		(37,032,605)
Catawba- Net Negative Generation	(576,162)	-	-	(28,498)	(460,948)		(114,213)
Total Interchanges Out	(69,468,992)	(898)	(1,584,534)	(7,065,664)	(30,735,500)	-	(37,146,818)
Net Purchases and Interchange Power	$ 365,700,160	(762)	$ 27,613,409	9,927,896	$ 179,983,461	$ 136,895,484	$ 21,640,768

NOTES Detail amounts may not add to totals shown due to rounding.
Capacity MW amounts varied across the range of time indicated
The amounts shown represent the capacity effective as of the period end date
As of December 2012, non-fuel costs related to mitigation losses and sharing of mitigation loss margins are no longer presented on this report

DUKE ENERGY CAROLINAS
INTERSYSTEM SALES*
NCUC-R8-52

Twelve Months Ended
DECEMBER 2012

Schedule 3, NC, Sales, 12ME
Page 4 of 4

	Total	Capacity		Non-capacity		
SALES	$	MW	$	MWH	Fuel $	Non-fuel $
Utilities:						
Progress Energy Carolinas - Emergency	$ 11,711	-	-	320	$ 10,871	$ 740
SC Public Service Authority - Emergency	130,644	-	-	2,758	102,834	27,810
SC Electric & Gas - Emergency	25,183	-	-	417	15,424	9,759
Market Based:						
American Electric Power Services Corp.	5,625	-	-	75	2,989	2,636
Cargill-Alliant, LLC	30,506	-	-	542	24,079	6,427
Cobb Electric Membership Corp	-	-	-	-	(9 268)	9,268
Constellation Power Sources	(289,039)	-	-	(7,914)	6,009	(295,048)
EDF Trading North America, LLC	27,465	-	-	454	25,181	2,284
MISO	77,032	-	-	1,200	121,897	(44,865)
Morgan Stanley	29,211	-	-	544	22 999	6,212
NCEMC (Generator/Instantaneous)	11,250	-	-	150	5,241	6,009
NCMPA #1	1,510,541	50	$ 1,038,380	9,868	388,702	83,459
Oglethorpe	11,666	-	-	222	8 325	3,341
PJM Interconnection LLC	10,613,635	-	-	176,779	6,987,112	3 626,523
SC Electric & Gas Market based	1,173 615	-	-	14,536	613 203	560,412
Southern	92,780	-	-	1,455	71,347	21,433
The Energy Authority	937,435	-	-	15,180	643,302	294,133
TVA	257,180	-	-	4,381	191,211	65,969
Other:						
Cargill-Alliant, LLC - Mitigation sales	10,193,130	-	(16 935)	421,592	13,915,967	(3,705,902)
DE Progress - Native Load Transfer Savings	546,583	-	-	-	546 583	-
DE Progress - Native Load Transfer	10,177,437	-	-	282,350	9,588,985	588,452
DE Progress - Off System Sales/PJM Share	2,089,921	-	-	125	6,148	2,083,773
DE Progress - Purchases	5,334,092	-	-	207,457	5 334 092	-
Generation Imbalance	430,731	-	-	9,502	326,728	104,003
BPM Transmission	(1,489,018)	-	-		-	(1,489,018)
Total Intersystem Sales	$ 41,939,316	50	$ 1,021,445	1,141,873	$ 38,950,061	$ 1,967,810

* Sales for resale other than native load priority

NOTES: Detail amounts may not add to totals shown due to rounding.
Capacity MW amounts varied across the range of time indicated.
The amounts shown represent the capacity effective December 31, 2012.

Duke Energy Carolinas
Over / (Under) Recovery of Fuel Costs
December 2012
NCUC R8-52

Schedule 4

Line No			Residential	Commercial	Industrial	Total
1	N.C. Retail kWh sales	Input	1,725 993,659	1,717,681,336	951,965,307	4 395,620,302
2	Approved fuel and fuel related rates (¢/kWh)					
	2a Billed rates by class (¢/kWh)	Input	2.2224	2.2463	2.2594	
	2b Merger fuel savings decrement	Input	(0.0707)	(0.0509)	(0.0379)	
	2c Net billed rates by class (¢/kWh)	L2a + L2b	2.1517	2.1954	2.2215	2 1839
	2d Billed fuel expense	L1 * L2c / 100	$37,138,206	$37,709,537	$21,147,909	$95,995,652
3	Total system kWh sales	Input				6 442,815,299
4	NC kWh sales %	L1 T / L3				68.23%
5	Incurred base fuel and fuel related (¢/kWh) (less renewable purchased power capacity)					
	5a Docket E-7, Sub 1002 allocation factor	Input	37.41%	40.03%	22.56%	100.00%
	5b System incurred expense	Input				$143,795,965
	5c Incurred base fuel rates (¢/kWh)	(L4 * L5b) * L5a / L1 * 100	2.1265	2.2863	2.3248	2.2319
	5d NC incurred expense by class	L5c* L1 / 100	$36 703,134	$39,270,666	$22,131,211	$98 105,011
6	Incurred renewable purchased power capacity rates (¢/kWh)					
	6a NC retail production plant %	Input				76.30%
	6b Production plant allocation factors	Input	43.26%	38.08%	18.66%	100.00%
	6c System incurred expense	Input				$380,893
	6d Incurred renewable capacity rates (¢/kWh)	(L6a * L6c) * L6b / L1 * 100	0.0073	0.0064	0.0057	0.0066
	6e NC incurred renewable capacity expense	L6d * L1 / 100	$125,780	$110,602	$54,226	$290,608
7	Total incurred rates by class (¢/kWh)	L5c + 6d	2.1338	2.2927	2.3306	2.2385
8	Difference in ¢/kWh (billed - incurred)	L2c - L7	0.0179	(0.0973)	(0.1090)	(0.0546)
9	Over / (under) recovery	L8 * L1 / 100	$309,292	($1,671,731)	($1,037,528)	($2,399,967)
10	Prior period adjustments	Input				
11	Total over / (under) recovery	L9 + L10	$309,292	($1,671,731)	($1,037,528)	($2,399,967)
12	Total system incurred expense	L5b + L6c				$144,176,858
13	Over / (under) recovery for each month of the current calendar year					

	Year 2012	Total To Date	Over / (Under) Recovery Residential	Commercial	Industrial	Total Company
	January	$19,636,597	$8,587,318	$7,406,542	$3,642,737	$19,636,597
	February	43,294,079	9,438,638	8,979,856	5,236,788	23,655,482
	March	67,879 379	9 149,699	9,739,577	5,696,124	24,585 300
	April	82,005 147	4 363,250	6,136,814	3,625,704	14,125 768
_/1	May	78,260,361	(1,197,907)	(1,586,902)	(959,977)	(3,744,786)
	June	78 546,051	81,289	127,818	76,585	285 690
	July	58 679 600	(7,922,165)	(7,742,783)	(4,001,503)	(19 666 451)
	August	63,277,405	1,730,239	1,747,384	920,182	4 397,805
_/2	September	79,021,147	3 741,329	8,581,691	3,420,722	15,743,742
_/2	October	76 150 978	(6,927,371)	1,957,749	2,099,453	(2 870 169)
	November	50 205 097	(13 093,551)	(9,166,739)	(3,665,591)	(25,945,881)
	December	$47,805 130	$309,292	($1,671,731)	($1,037,528)	($2 399 967)

Notes:

Detail amounts may not recalculate due to percentages presented as rounded

_/1 Includes prior period adjustments.

_/2 Reflects a prorated rate for periods in which the approved rates change.

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
December 2012

Description	Allen Steam	Belews Creek Steam	(G) Buck Steam/CT	Buck Gas/CC	Catawba Nuclear	(H) Cliffside Steam	(G), (I) Dan River Gas/CC	Lee Steam/CT	Lincoln CT	Marshall Steam	McGuire Nuclear	Mill Creek CT	Oconee Nuclear	(G) Riverbend Steam/CT	Rockingham CT	Current Month	Total 12 ME December 2012
Cost of Fuel Received																	
Coal (A)	[illegible]	$30,220,4[illegible]	-			$7,767,230	$ (360,673)	$0		$33,199,7[illegible]				$0		$97,973,919	$1,129,213,919
Biomass	-	-	-			-		-		-				-		-	4,309
Fuel Oil	330,479	491,701	146,176.81			2,537,623		306,455	-	944,043		-		95,970	-	4,330,036	90,140,029
Gas - CT			(380)					33,786	$15,113			999,927		-	$270,343	394,041	29,540,701
Gas - CC				$13,028,548			$4,380,187									17,388,713	172,162,681
Total	[illegible]	$30,872,159	$146,[illegible]	$13,028,548		$10,304,857	$3,981,294	$[illegible]	$15,113	$32,743,466		$999,927		$[illegible]	$270,343	$[illegible]	$1,[illegible]
Received (¢/MBTU) Avg																	
Coal (A)	480.30	389.19				401.11				404.48						411.83	409.87
Biomass	-	-	-			-		-	-	-		-		-	-	-	914.32
Fuel Oil	2,319.80	2,339.31	2,290.85			2,273.41		2,491.97	-	2,407.58		-		2,395.11	-	2,314.85	2,290.57
Gas - CT			-					669.18	617.89			537.30		-	380.73	394.47	383.13
Gas - CC				418.14			380.89									418.14	350.48
Weighted Average	500.71	402.[illegible]	2,308.[illegible]	418.14		573.46	348.27	2,100.84	617.89	418.18		537.30		2,395.11	380.73	424.89	418.97
Cost of Fuel Burned (B) (C)																	
Coal (D)	$7,389,373	$48,838,779	$612,891			$4,916,836	($360,673)	$0		$32,229,[illegible]				$867,205		$[illegible],847,048	$1,034,192,880
Biomass (E)	-	-	8,009			-		-		-				-		8,009	84,212
Fuel Oil (F)	223,869	307,219	72,979			2,080,889		2,009	8894	169,771		-		64,[illegible]	-	2,583,786	44,574,041
Gas - CT			380					33,786	15,113			969,027		-	$270,343	394,641	29,640,701
Gas - CC				$13,028,548			$4,380,187									17,388,713	172,152,881
Nuclear					$8,482,438						$8,073,204		$11,888,922			28,644,841	333,700,226
Total	$7,614,272	$49,317,398	$694,025	$13,028,548	$8,482,438	$6,971,524	$3,981,294	$35,777	$15,777	$32,394,387	$8,073,204	$969,027	$11,888,922	$1,031,770	$270,343	$138,[illegible],840	$1,584,910,117
Burned (¢/MBTU) Avg																	
Coal	431.87	400.33	438.72			323.87		-		343.73				418.31		372.77	387.31
Biomass	-	-	510.81			-		-		-				-		510.81	648.67
Fuel Oil	2,288.42	2,339.40	2,140.84			2,281.89		2,080.08	1,070.35	2,347.80		-		2,202.88	-	2,238.50	2,183.43
Gas - CT			-					669.10	617.89			532.30		-	380.73	394.47	383.13
Gas - CC				418.14			380.89									418.14	350.48
Nuclear					63.78						58.09		61.47			68.89	58.78
Weighted Average	483.27	403.03	487.25	418.14	63.78	433.87	348.27	[illegible]	638.07	346.35	58.09	532.30	61.47	437.53	380.73	188.28	177.84
Generated (¢/KWh) Avg																	
Coal	4.86	3.66	4.74			2.97	NF	(B)		3.38				4.32		3.48	3.77
Biomass	-	-	6.37			-	-	-		-				-		6.37	6.60
Fuel Oil	-	-	-			-	-	33.49	(B)	-		-		-	-	(B)	480.97
Gas - CT			-					13.35	(B)			9.32		-	4.35	5.84	3.29
Gas - CC				2.97			3.31									3.08	2.84
Nuclear					0.90						0.58		0.62			0.59	0.57
Weighted Average	4.59	3.83	5.32	2.97	0.90	4.32	3.31	(B)	(B)	3.38	0.56	9.32	0.62	5.14	4.35	1.78	1.73
Burned MBTU's																	
Coal	864,825	12,197,679	143,672			1,517,886		-		9,379,838				232,[illegible]		34,022,308	388,322,410
Biomass	-	-	1,582			-		-		-				-		1,582	17,237
Fuel Oil	9,764	17,881	3,380			90,089		96	82	7,103		-		2,882	-	130,383	2,045,067
Gas - CT			-					3,886	2,446			13,316		-	72,883	92,130	10,030,671
Gas - CC				3,125,888			1,149,778									4,275,774	31,988,571
Nuclear					9,330,798						16,488,991		19,505,888			45,394,446	571,843,319
Total	884,358	12,214,761	148,[illegible]	3,125,888	9,330,798	1,607,785	1,149,778	3,881	2,528	9,387,[illegible]	16,488,991	13,316	19,505,888	235,317	72,883	73,[illegible]	[illegible]
Net Generation (mWh)																	
Coal	52,384	1,337,839	12,916			169,312		(791)		888,882				20,083		2,578,426	27,888,378
Biomass	-	-	128			-		-		-				-		128	1,388
Fuel Oil	-	-	-			-	-	6	(18)	-		-		-	-	(12)	6,863
Gas - CT			-					253	(706)			741		-	6,356	6,640	916,320
Gas - CC				437,746			132,240									569,986	4,418,878
Nuclear 100%					918,981						1,632,779		1,940,280			4,491,971	58,444,891
Hydro (Total System)																21,840	780,806
Solar (Total System)																643	66,479
Total	52,384	1,337,839	13,042	437,746	918,981	169,312	132,240	(532)	(724)	888,882	1,632,779	741	1,940,280	20,083	6,356	7,867,327	98,527,227
Cost of Reagents Consumed ($)																	
Ammonia	-	$1,283,380	-	$13,548		$0				-				-		$1,308,917	$8,748,142
Limestone (C)	$108,016	713,456	-	-		161,455				$390,440				-		1,637,386	14,232,831
Urea	82,377	-	-	-		-				313,376				-		395,853	3,714,744
Organic Acid	-	-	-	-		-				-				-		-	-
Sorbents	78,634	-	-	-		-				-				-		78,634	299,171
Total	$348,829	$2,000,734	-	$13,548		$161,455				$803,716				-		$3,348,371	$34,947,878

(A) Coal receipts exclude 6,412 tons and $387,728 associated with sorbents for the current month
(A) Cost of coal received includes a transfer of inventory from Dan River to Belews Creek valued at $360,673 in the current month and $6,795,495 for the twelve months ended.
(A) Cost of the coal inventory transfer between Dan River to Belews Creek nets to zero in the current month with the exception of the $51,809 cost of freight reported in cost of coal received at Belews Creek.
(B) Cents/kWh not computed when costs and/or net generation is negative
(C) Cost of fuel burned excludes $2,557 associated with emission allowance expense for the month and $51,723 for the twelve months ended.
(D) The current month and twelve months ended data include an annual coal survey adjustment recorded in Dec 2012
(D) Cost of coal burned includes a $360,673 reduction in consumption expense at Dan River Station following a true-up to physical inventory
(E) Cost of biomass burned is reported at book cost prior to the reallocation of fuel expense applicable to NC renewable energy which is -$3,380 for the month and -$16,287 for the twelve months ended
(F) Cost of fuel oil burned excludes $0,000 in diesel fuel costs for on-site standby generators for the month and $34,385 for the twelve months ended
(G) The following CT units were retired October 1, 2012: Buck units 7, 8, & 9; Dan River units 4, 5, & 6, Riverbend units 8, 9, 10, & 11, and Buzzard Roost units 6, 7, 8, 9, 10, 11, 12, 13, 14, & 15.
(H) Cliffside unit 6 was placed in service December 30, 2012
(I) Dan River coal units 1, 2, & 3 were retired April 1, 2012. Dan River combined cycle plant was placed in service December 10, 2012

Notes:
Detail amounts may not add to totals shown due to rounding
Fuel cost information on this report does not reflect intercompany sharing of fuel-related merger savings between Duke Energy Carolinas and Progress Energy Carolinas.
Fuel costs based on recoverability unless otherwise noted. Data reflected at 100% ownership

Schedule 6

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED CONSUMPTION AND INVENTORY REPORT
December 2012

Description	Allen Steam	Belews Creek Steam	(G) Buck Steam/CT	Buck Gas/CC	(H) Cliffside Steam	(G), (I) Dan River Gas/CC	Lee Steam/CT	Lincoln CT	Marshall Steam	Mill Creek CT	(G) Riverbend Steam/CT	Rockingham CT	Current Month	Total 12 ME December 2012
Coal Data:														
Beginning balance	780,008	1,845,337	63,262		501,147	-	130,167		1,281,389		165,560		4,767,889	4,138,358
Tons received during period	80,838	305,278	-		79,178	-	-		325,533		-		880,828	11,336,466
Inventory adjustments (A)	120	885	204		1,160	-	-		(3,348)		-		(872)	(30,216)
Tons burned during period (B)	23,723	480,948	6,082		48,838	-	-		322,478		8,487		902,371	10,700,138
Ending balance (C)	837,230	1,760,882	57,384		531,840	-	130,167		1,281,100		157,083		4,745,471	4,745,471
MBTUs per ton burned	23.37	24.85	23.57		30.58	-	-		28.07		24.52		28.62	24.80
Cost of ending inventory ($/ton) (C)	100.75	98.63	100.21		102.41	-	88.80		100.21		101.85		100.38	100.38
Biomass/Test Fuel Data:														
Beginning balance			283				-						283	2,222
Tons received during period			-				-						-	95
Inventory adjustments			-				-						-	2
Tons burned during period			195				-						195	2,251
Ending balance			68				-						68	68
Cost of ending inventory ($/ton)			41.07				-						41.07	41.07
Fuel Oil Data:														
Beginning balance	96,182	229,500	280,942		34,370	82,507	486,035	9,818,408	205,745	3,984,180	128,412	2,988,580	18,324,854	15,333,803
Gallons received during period	74,888	140,848	45,838		803,872	-	88,815	-	164,580	-	30,587	-	1,250,148	18,718,488
Miscellaneous usage, transfers and adjustments	(5,808)	(8,546)	(1,017)		(3,830)	(1)	(2,589)	-	(28,585)	-	(222)	-	(51,067)	(518,084)
Gallons burned during period (D)	71,278	124,258	24,658		650,873	-	704	444	51,881	-	21,315	-	945,854	14,853,318
Ending balance	93,802	237,344	301,103		183,339	82,506	572,857	9,817,981	290,069	3,984,180	137,462	2,988,580	18,678,089	18,678,089
Cost of ending inventory ($/gal)	3.14	3.20	2.98		3.14	3.06	2.85	1.49	3.23	2.89	3.03	2.47	2.13	2.13
Gas Data: (E)														
Beginning balance														
MCF received during period (F)			-	3,075,740		1,130,836	3,817	2,407		13,033	-	71,381	4,297,300	41,956,759
MCF burned during period (F)			-	3,075,740		1,130,836	3,817	2,407		13,033	-	71,381	4,297,300	41,956,759
Ending balance														
Cost of ending inventory ($/mcf)														
Limestone Data:														
Beginning balance	25,579	47,943			25,304				52,957				151,783	215,643
Tons received during period	-	6,851			-				13,136				19,986	338,745
Tons consumed during period (B)	4,673	22,989			5,185				19,552				52,399	434,919
Ending balance	20,906	31,805			20,119				46,540				119,370	119,370
Cost of ending inventory ($/ton)	35.77	31.02			30.85				30.61				31.50	31.50

(A) Coal inventory adjustments include a transfer from Dan River to Belews Creek of 3,808 tons in the current month and 85,803 tons for the twelve months ended. The tons transferred between the stations net to zero.
(A) Coal inventory adjustments include a 3,808 ton increase at Dan River Station following a true-up to physical inventory
(B) The current month and twelve months ended data include an annual aerial survey adjustment recorded in Dec 2012
(C) Coal Inventory Ending Balance excludes 6,412 tons and $367,728 associated with terminals for the current month
(D) Total gallons of fuel oil burned includes 842 gallons of diesel fuel oil for on-site standby generators for the month and 5,887 for the twelve months ended. Monthly consumption is reported on a month lag due to timing of data availability. Offsetting activity for the on-site standby generator consumption is reported as miscellaneous usage, transfers and adjustments
(E) Gas is burned as received; therefore, inventory balances are not maintained.
(F) Twelve months ended Gas MCF received and burned includes 31,563,485 attributable to combined cycle plant activity.
(G) The following CT units were retired October 1, 2012: Buck units 7, 8, & 9; Dan River units 4, 5, & 6; Riverbend units 8, 9, 10, & 11; and Buzzard Roost units 6, 7, 8, 9, 10, 11, 12, 13, 14, & 15
(H) Cliffside unit 6 was placed in service December 30, 2012.
(I) Dan River coal units 1, 2, & 3 were retired April 1, 2012. Dan River combined cycle plant was placed in service December 10, 2012.

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

Schedule 6

Schedule 7

DUKE ENERGY CAROLINAS
ANALYSIS OF COAL PURCHASES
December 2012

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ALLEN	SPOT	-	-	-
	CONTRACT	80,839	$ 8,000,372.60	$ 98.97
	ADJUSTMENTS	-	716,012.16	-
	TOTAL	80,839	8,716,384.76	107.82
BELEWS CREEK	SPOT	-	-	-
	CONTRACT	395,278	36,360,329.11	91.99
	ADJUSTMENTS (A)	3,909	2,860,078.67	731.74
	TOTAL	399,186	39,220,407.78	98.25
CLIFFSIDE	SPOT	-	-	-
	CONTRACT	79,176	7,226,032.40	91.27
	ADJUSTMENTS	-	561,199.28	-
	TOTAL	79,176	7,787,231.68	98.35
DAN RIVER	SPOT	-	-	-
	CONTRACT	-	-	-
	ADJUSTMENTS (A)	(3,909)	(398,872.65)	102.05
	TOTAL	(3,909)	(398,872.65)	102.05
MARSHALL	SPOT	-	-	-
	CONTRACT	325,533	31,191,548.61	95.82
	ADJUSTMENTS	-	1,007,215.95	-
	TOTAL	325,533	32,198,764.56	98.91
ALL PLANTS	SPOT	-	-	-
	CONTRACT	880,826	82,778,282.72	93.98
	ADJUSTMENTS	-	4,745,633.41	-
	TOTAL	880,826	$ 87,523,916.13	$ 99.37

(A) 3,908.60 coal tons were transferred from Dan River station to Belews Creek station.
The book cost of coal tons transferred was $398,872.65 plus the $51,000.00 cost of freight.

Schedule 8

Duke Energy Carolinas
Analysis of Quality of Coal Received
December 2012

Station	Percent Moisture	Percent Ash	Heat Value	Percent Sulfur
Allen	16.01	7.10	10,998	3.47
Belews Creek	6.86	10.31	12,428	1.35
Cliffside	7.72	19.76	10,665	1.34
Marshall	6.61	11.74	12,227	1.41

Duke Energy Carolinas
Analysis of Cost of Oil Purchases
December 2012

Station	Allen	Belews Creek	Buck	Cliffside	Lee	Marshall	Riverbend
Vendor		HighTowers	HighTowers	HighTowers	HighTowers	High Towers	High Towers
Spot / Contract	Contract	Contract	Contract	Contract	Contract	Contract	Contract
Sulfur Content %	0	0	0	0	0	0	0
Gallons Received	74,898	140,648	45,836	803,672	89,915	164,590	30,587
Total Delivered Cost	$ 238,478.54	$ 451,701.49	$ 145,176.81	$ 2,537,625.23	$ 305,454.77	$ 544,643.39	$ 96,976.08
Delivered Cost/Gal	$ 3.18	$ 3.21	$ 3.17	$ 3.16	$ 3.40	$ 3.31	$ 3.17
BTU/Gallon	137,264	137,467	137,723	138,890	136,374	137,446	137,538

Note A: Total delivered cost for receipts from HighTowers Petroleum.

DUKE ENERGY CAROLINAS
POWER PLANT PERFORMANCE DATA
TWELVE MONTHS SUMMARY
January, 2012 - December, 2012

Plant Name	Generation MWH	Capacity Rating MW	Capacity Factor %	Net Equivalent Availability %
Oconee	20,647,480	2,538	92.62	91.26
McGuire	17,968,152	2,200	92.98	89.04
Catawba	17,829,299	2,258	89.89	87.89

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January 2012 through December 2012
Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Belews Creek 1	7,685,065	1,110	78.82	90.70
Belews Creek 2	6,305,060	1,110	64.67	85.20

Duke Energy Carolinas
Power Plant Performance Data
Twelve Month Summary
January 2012 through December 2012

Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Cliffside 5	1,144,368	555	23.49	89.57
Marshall 1	1,078,626	380	32.31	84.84
Marshall 2	1,370,510	380	41.06	87.87
Marshall 3	3,263,260	658	56.46	88.39
Marshall 4	3,902,223	660	67.31	87.65

Note: This report is limited to capturing data beginning the first full month a unit is in commercial operation.

Cliffside unit 6 began pre-commercial operation in June 2012 and commercial operation on December 30, 2012. Cliffside unit 6 net generation (mWh) within the twelve month period was as follows:

June 2012:	1,496 mWh; pre-commercial
July 2012:	77,787 mWh; pre-commercial
August 2012:	212,376 mWh; pre-commercial
September 2012:	139,874 mWh; pre-commercial
October 2012:	(1,302) mWh; pre-commercial (auxiliaries only)
November 2012:	170,464 mWh; pre-commercial
December 2012:	168,280 mWh; pre-commercial & commercial combined

Duke Energy Carolinas
Power Plant Performance Data

Twelve Month Summary
January 2012 through December 2012
Other Cycling Coal Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Allen 1	100,069	162	7.03	88.77
Allen 2	78,152	162	5.49	89.76
Allen 3	606,229	261	26.44	92.76
Allen 4	777,282	276	32.06	95.97
Allen 5	386,992	266	16.56	86.90
Buck 5	146,714	128	13.05	98.94
Buck 6	73,215	128	6.51	99.53
Dan River 1	-1,373	67	0.00	100.00
Dan River 2	-166	67	0.00	100.00
Dan River 3	-396	142	0.00	100.00
Lee 1	19,113	100	2.18	99.86
Lee 2	29,392	100	3.35	97.96
Lee 3	80,920	170	5.42	99.24
Riverbend 4	26,139	94	3.17	99.31
Riverbend 5	23,562	94	2.85	99.57
Riverbend 6	45,321	133	3.88	98.84
Riverbend 7	61,489	133	5.26	99.15

Note:

Dan River units 1, 2, & 3 were retired April 1, 2012.

Duke Energy Carolinas
Power Plant Performance Data

Twelve Month Summary

January,2012 through December,2012

Combustion Turbines

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Buck CT	-180	47	66.67
Buzzard Roost CT	-868	132	89.99
Dan River CT	-153	36	87.48
Lee CT	55,780	82	98.88
Lincoln CT	28,506	1,264	94.26
Mill Creek CT	125,402	592	91.10
Riverbend CT	-725	48	100.00
Rockingham CT	715,431	825	56.55

Note:

The following units were retired October 1, 2012:

Buck CT units 7, 8, & 9
Buzzard Roost CT units 6, 7, 8, 9, 10, 11, 12, 13, 14, & 15.
Dan River CT units 4, 5, & 6
Riverbend CT units 8, 9, 10, & 11.

Duke Energy Carolinas
Power Plant Performance
12 Months Ended December 2012

Name of Plant	Generation (MWH)	Capacity Rating (MW)	Operating Availability (%)
Conventional Hydro Plants:			
Bridgewater	41,458	31.500	91.45
Cedar Creek	93,606	45.000	98.80
Cowans Ford	100,905	325 200	95.61
Dearborn	104,232	42.000	78.44
Fishing Creek	91,594	49.000	99.77
Gaston Shoals	16,221	2 000	42.52
Great Falls	7,948	12 000	98.36
Keowee	41,997	152.000	99.35
Lookout Shoals	67,912	27.900	81.28
Mountain Island	71,839	62 000	98.51
Ninety Nine Island	49,577	6.400	98.54
Oxford	77,315	40 000	79.75
Rhodhiss	48,476	30.000	91.65
Rocky Creek	(191)	-	-
Tuxedo	19,953	6 400	72.67
Wateree	125,831	85 000	92.02
Wylie	85,679	72.000	92.34
Nantahala	208,704	50 000	97.25
Queens Creek	2,616	1.440	94.60
Thorpe	69,509	19.700	83.02
Tuckasegee	5,988	2.500	84.40
Tennessee Creek	26,421	9.800	92.95
Bear Creek	24,861	9.450	99.96
Cedar Cliff	17,699	6 400	93.54
Mission	1,557	0.600	88.46
Franklin	1,489	0.600	74.58
Bryson	1,208	0.480	99.86
Total Conventional	1,400,604		
Pumped Storage Plants:			
Jocassee	928,617	780 000	91.64
Bad Creek	1,752,364	1,380.000	95.79
Subtotal	2,680,981		
Energy for Pumping:			
Jocassee	(1,103,984)		
Bad Creek	(2,218,596)		
Subtotal	(3,322,580)		
Generation less Energy for Pumping			
Jocassee	(175,367)		
Bad Creek	(466,232)		
Total Pumped Storage	(641,599)		

NOTE(S):
Capacity MW amounts varied across the range of time indicated.
The amounts shown represent the capacity effective as of the period end date.

Duke Energy Carolinas
Power Plant Performance Data

Twelve Month Summary

January 2012 through December 2012

Combined Cycle Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Buck CC 10	4,167,226	620	76.52	89.93

Note: This report is limited to capturing data beginning the first full month a station is in commercial operation.

Dan River CC began pre-commercial operation in July 2012 and commercial operation on December 10, 2012. Dan River CC net generation (mWh) within the twelve month period was as follows:

July 2012:	935 mWh; pre-commercial
August 2012:	3,526 mWh; pre-commercial
September 2012:	2,209 mWh; pre-commercial
October 2012:	8,488 mWh; pre-commercial
November 2012:	104,254 mWh; pre-commercial
December 2012:	1,986 mWh; pre-commercial
December 2012:	135,081 mWh; commercial

Schedule 11

Duke Energy Carolinas
Month Ending: December 2012
Dollars reported in ($)

		Gross Savings			Allocated Savings		DE Carolinas
		DE Carolinas	DE Progress	Combined	DE Carolinas	DE Progress	NC Retail portion
1	Joint Dispatch	$ 1,301,356	$ 800,756	$ 2,102,112	$ 1,287,559	$ 814,553	$ 878,439
2	Coal Blending	3,283,962	-	3,283,962	2,023,440	1,260,522	1,380,495
3	Coal Procurement	113,682	428,992	542,674	330,870	211,804	225,737
4	Coal Transportation	608,727	370,382	979,109	602,044	377,065	410,745
5	Reagent Procurement & Transportation	49,572	83,138	132,710	81,814	50,896	55,818
6	Natural Gas Capacity	2,159,479	-	2,159,479	1,332,961	826,518	909,414
7	Natural Gas Trading	35,954	-	35,954	22,152	13,802	15,113
		$ 7,552,732	$ [illegible]	$ 9,236,000	$ [illegible]	$ [illegible]	$ [illegible]

	DE Carolinas	DE Progress	Combined			
Resource ratio %	61.25%	38.73%	100.00%			
Billed Sales (MWH)				6,442,815		4,395,620
Sales allocation %						68.23%

Twelve Months Ending: December 2012

		Gross Savings			Allocated Savings		DE Carolinas
		DE Carolinas	DE Progress	Combined	DE Carolinas	DE Progress	NC Retail portion
1	Joint Dispatch	$ 11,328,001	$ 2,820,298	$ 14,148,300	$ 8,316,083	$ 5,832,217	$ 5,683,604
2	Coal Blending (a)	23,524,131	-	23,524,131	17,514,516	6,009,615	11,944,691
3	Coal Procurement (a)	1,624,630	2,475,010	4,099,640	2,399,044	1,700,596	1,638,917
4	Coal Transportation (a)	2,181,451	1,805,939	3,987,390	2,165,421	1,821,969	1,475,238
5	Reagent Procurement & Transportation	450,300	689,849	1,140,149	560,574	579,575	382,795
6	Natural Gas Capacity	4,754,353	-	4,754,353	2,807,572	1,946,781	1,907,678
7	Natural Gas Trading	215,724	-	215,724	127,540	88,185	87,260
		$ 44,078,991	$ 7,792,038	$ 51,869,687	$ 33,890,749	$ 17,978,938	$ 23,120,183

Total-to-date: December 2012

		Target	Gross Savings			Allocated Savings		DE Carolinas
			DE Carolinas	DE Progress	Combined	DE Carolinas	DE Progress	NC Retail portion
1	Joint Dispatch	$ 318,955,000	$ 11,328,001	$ 2,820,298	$ 14,148,300	$ 8,316,083	$ 5,832,217	$ 5,683,604
2	Coal Blending (a)	259,800,000	23,524,131	-	23,524,131	17,514,516	6,009,615	11,944,691
3	Coal Procurement (a)	45,950,000	1,624,630	2,475,010	4,099,640	2,399,044	1,700,596	1,638,917
4	Coal Transportation (a)	30,335,000	2,181,451	1,805,939	3,987,390	2,165,421	1,821,969	1,475,238
5	Reagent Procurement & Transportation	12,800,000	450,300	689,849	1,140,149	560,574	579,575	382,795
6	Natural Gas Capacity	16,900,000	4,754,353	-	4,754,353	2,807,572	1,946,781	1,907,678
7	Natural Gas Trading	2,000,000	215,724	-	215,724	127,540	88,185	87,260
		$ [illegible]	$ 44,078,981	$ 7,791,086	$ 51,869,687	$ 33,890,749	$ 17,978,938	$ 23,130,183

(a) Includes January – June 2012 savings associated with fuel-related savings guarantees, retained by the originating company

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

DUKE ENERGY CAROLINAS
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN
NCUC RULE R8-53 (b)

PERIOD: December, 2012

PLANT	UNIT	DATE OF OUTAGE	DURATION OF OUTAGE	SCHEDULED / UNSCHEDULED	CAUSE OF OUTAGE	REASON OUTAGE OCCURRED	REMEDIAL ACTION TAKEN
Oconee	1	None					
	2	None					
	3	None					
McGuire	1	None					
	2	12/01/2012 - 12/02/2012	23.65	UNSCHEDULED	TURBINE TRIP DUE TO INCORRECT TURBINE INLET PRESSURE SETPOINT	ENGINEERING MODIFICATION SETPOINT ERROR	DEVELOPED NEW SETPOINTS
Catawba	1	11/24/2012 - 12/20/2012	460.42	SCHEDULED	END-OF-CYCLE 20 REFUELING OUTAGE	REFUEL AND MAINTENANCE	REFUEL AND MAINTENANCE
	1	12/20/2012 - 12/20/2012	8.00	UNSCHEDULED	OUTAGE DELAYED 0.33 DAYS DUE TO REFUELING EQUIPMENT PERFORMANCE DEFICIENCIES	REFUELING EQUIPMENT FAILURES	REPAIRED REFUELING EQUIPMENT

DUKE ENERGY CAROLINAS

BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN

NCUC RULE R8-53 (b)

PERIOD: December, 2012

PLANT	UNIT	DATE OF OUTAGE	DURATION OF OUTAGE	SCHEDULED / UNSCHEDULED	CAUSE OF OUTAGE	REASON OUTAGE OCCURRED	REMEDIAL ACTION TAKEN
	1	12/20/2012 - 12/24/2012	93.00	UNSCHEDULED	OUTAGE DELAYED 3.88 DAYS DUE TO REACTOR COOLANT PUMP SEAL INJECTION CHECK VALVE FAILURE	REACTOR COOLANT PUMP SEAL CHECK VALVE FAILURE	REPAIR REACTOR COOLANT PUMP SEAL CHECK VALVE
	1	12/24/2012 - 12/28/2012	94.62	UNSCHEDULED	OUTAGE DELAYED 3.94 DAYS DUE TO AUXILIARY FEEDWATER PUMP TURBINE FAILURE DURING TESTING	AUXILIARY FEEDWATER PUMP TURBINE FAILURE	REPAIR AUXILIARY FEEDWATER PUMP
	1	12/28/2012 - 12/28/2012	3.70	SCHEDULED	MAIN TURBINE OVERSPEED TRIP TEST	SCHEDULED OVERSPEED TEST	COMPLETED SCHEDULED OVERSPEED TEST
	2	None					

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

NCUC Rule R8-53 (B)

December 2012

Belews Creek Steam Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
02	12/2/2012 10:02:00 PM To 12/3/2012 11:05:00 PM	Unsch	1050	Second Superheater Leaks	BOILER TUBE LEAK,SSH.	

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
01	12/14/2012 1:58:00 PM To 12/17/2012 7:03:00 AM	Unsch	1050	Second Superheater Leaks	BOILER TUBE LEAK,SSH.	

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN
NCUC RULE R8-53 (c) (2) (3)
December 2012
Oconee Nuclear Station

	Unit 1		Unit 2		Unit 3	
(A) MDC (MW)	846		846		846	
(B) Period Hours	744		744		744	
(C1) Net Gen (MWH) and Capacity Factor	640302	101.73	647687	102.90	652211	103.62
(D1) Net MWH Not Gen Due To Full Schedule Outages	0	0.00	0	0.00	0	0.00
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	1826	0.29	0	0.00	213	0.03
(E1) Net MWH Not Gen Due To Full Forced Outages	0	0.00	0	0.00	0	0.00
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-12704	-2.02	-18263	-2.90	-23000	-3.65
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00	0	0.00
(H) Net MWH Possible In Period	629424	100.00%	629424	100.00%	629424	100.00%
(I) Equivalent Availability		99.71		100.00		99.97
(J) Output Factor		101.73		102.90		103.62
(K) Heat Rate		10,132		10,052		9,976

* Estimate
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN
NCUC RULE R8-53 (c) (2) (3)
December 2012
McGuire Nuclear Station

	Unit 1		Unit 2	
(A) MDC (MW)	1100		1100	
(B) Period Hours	744		744	
(C1) Net Gen (MWH) and Capacity Factor	861255	105.24	771515	94.27
(D1) Net MWH Not Gen Due To Full Schedule Outages	0	0.00	0	0.00
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	0	0.00	53512	6.54
(E1) Net MWH Not Gen Due To Full Forced Outages	0	0.00	26015	3.18
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-42855	-5.24	-32642	-3.99
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00
(H) Net MWH Possible in Period	818400	100.00%	818400	100.00%
(I) Equivalent Availability		100.00		89.60
(J) Output Factor		105.24		97.37
(K) Heat Rate		10,040		10,138

* Estimate
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN
NCUC RULE R8-53 (c) (2) (3)
December 2012
Catawba Nuclear Station

	Unit 1		Unit 2	
(A) MDC (MW)	1129		1129	
(B) Period Hours	744		744	
(C1) Net Gen (MWH) and Capacity Factor	54805	6.52	864096	102.87
(D1) Net MWH Not Gen Due To Full Schedule Outages	523991	62.38	0	0.00
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	34934	4.16	0	0.00
(E1) Net MWH Not Gen Due To Full Forced Outages	220855	26.29	0	0.00
* (E2) Net MWH Not Gen Due To Partial Forced Outages	5391	0.65	-24120	-2.87
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00
(H) Net MWH Possible In Period	839976	100.00%	839976	100.00%
(I) Equivalent Availability		7.78		100.00
(J) Output Factor		57.60		102.87
(K) Heat Rate		13,140		9,965

* Estimate
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

NCUC Rule R8-53 (C) (2) (3)

December 2012

Belews Creek Steam Station

	Unit 1	Unit 2
(A) MDC (mw)	1,110	1,110
(B) Period Hrs	744	744
(C1) Net Generation (mWh)	686,947	650,712
(C1) Capacity Factor	83.18	78.79
(D1) Net mWh Not Generated due to Full Scheduled Outages	0	0
(D1) Scheduled Outages: percent of Period Hrs	0.00	0.00
(D2) Net mWh Not Generated due to Partial Scheduled Outages	0	0
(D2) Scheduled Derates: percent of Period Hrs	0.00	0.00
(E1) Net mWh Not Generated due to Full Forced Outages	72,243	27,805
(E1) Forced Outages: percent of Period Hrs	8.75	3.37
(E2) Net mWh Not Generated due to Partial Forced Outages	0	11
(E2) Forced Derates: percent of Period Hrs	0.00	0.00
(F) Net mWh Not Generated due to Economic Dispatch	66,650	147,311
(F) Economic Dispatch: percent of Period Hrs	8.07	17.84
(G) Net mWh Possible in Period	825,840	825,840
(H) Equivalent Availability	91.25	96.63
(I) Output Factor (%)	91.16	85.25
(J) Heat Rate (BTU/NkWh)	9,056	9,211

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

NCUC Rule R8-53 (C) (2)

December 2012

Marshall Steam Station

	Marshall 1	Marshall 2	Marshall 3	Marshall 4
(A) MDC (mWh)	380	380	658	660
(B) Period Hrs	744	744	744	744
(C1) Net Generation (mWh)	76,799	159,950	365,452	386,661
(D) Net mWh Possible in Period	282,720	282,720	489,552	491,040
(E) Equivalent Availability	90.31	98.75	94.71	99.56
(F) Output Factor (%)	58.54	61.57	78.70	78.74
(G) Capacity Factor	27.16	56.58	74.65	78.74

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

NCUC Rule R8-53 (C) (2)

December 2012

Cliffside Steam Station

		Cliffside 5
(A)	MDC (mWh)	556
(B)	Period Hrs	744
(C1)	Net Generation (mWh)	-2,968
(D)	Net mWh Possible in Period	413,664
(E)	Equivalent Availability	57.46
(F)	Output Factor (%)	0.00
(G)	Capacity Factor	0.00

Note:

This report is limited to capturing units in full months of commercial operation. Cliffside unit 6 was placed into service on December 30, 2012. During the month of December 2012, Cliffside unit 6 produced 168,280 mWh of pre-commercial and commercial generation combined.

DUKE ENERGY CAROLINAS
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN
NCUC RULE R8-53 (c) (2) (3)
January 2012 - December 2012
Oconee Nuclear Station

	UNIT 1		UNIT 2		UNIT 3	
(A) MDC (MW)	846		846		846	
(B) Period Hours	8784		8784		8784	
(C1) Net Gen (MWH) and Capacity Factor	6701974	90.19	7537005	101.42	6408501	86.24
(D1) Net MWH Not Gen Due To Full Scheduled Outages	589282	7.93	0	0.00	1111221	14.95
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	19514	0.26	1082	0.01	52836	0.71
(E1) Net MWH Not Gen Due To Full Forced Outages	155672	2.09	22994	0.31	0	0.00
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-35178	-0.47	-129817	-1.74	-141294	-1.90
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00	0	0.00
* (G) Core Conservation	0	0.00	0	0.00	0	0.00
(H) Net MWH Possible In Period	7431264	100.00%	7431264	100.00%	7431264	100.00%
(I) Equivalent Availability		89.31		99.57		84.90
(J) Output Factor		100.23		101.74		101.40
(K) Heat Rate		10,256		10,158		10,025

*Estimate
FOOTNOTE: D1 and E1 Include Ramping Losses

DUKE ENERGY CAROLINAS
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN
NCUC RULE R8-53 (c) (2) (3)
January 2012 - December 2012
McGuire Nuclear Station

	UNIT 1		UNIT 2	
(A) MDC (MW)	1100		1100	
(B) Period Hours	8784		8784	
(C1) Net Gen (MWH) and Capacity Factor	10114042	104.67	7854110	81.29
(D1) Net MWH Not Gen Due To Full Scheduled Outages	0	0.00	1003200	10.38
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	1143	0.01	67742	0.70
(E1) Net MWH Not Gen Due To Full Forced Outages	0	0.00	1042690	10.79
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-452785	-4.68	-305342	-3.16
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00
* (G) Core Conversion	0	0.00	0	0.00
(H) Net MWH Possible In Period	9662400	100.00%	9662400	100.00%
(I) Equivalent Availability		99.99		78.08
(J) Output Factor		104.67		103.12
(K) Heat Rate		10,097		10,126

*Estimate
FOOTNOTE: D1 and E1 Include Ramping Losses

DUKE ENERGY CAROLINAS
BASE LOAD POWER PLANT PERFORMANCE REVIEW PLAN
NCUC RULE R8-53 (c) (2) (3)
January 2012 - December 2012
Catawba Nuclear Station

	UNIT 1		UNIT 2	
(A) MDC (MW)	1129		1129	
(B) Period Hours	8784		8784	
(C1) Net Gen (MWH) and Capacity Factor	8767327	88.41	9061972	91.38
(D1) Net MWH Not Gen Due To Full Scheduled Outages	708673	7.15	734449	7.41
* (D2) Net MWH Not Gen Due To Partial Scheduled Outages	27712	0.28	30272	0.31
(E1) Net MWH Not Gen Due To Full Forced Outages	556247	5.61	314347	3.17
* (E2) Net MWH Not Gen Due To Partial Forced Outages	-142823	-1.45	-223904	-2.27
* (F) Net MWH Not Gen Due To Economic Dispatch	0	0.00	0	0.00
* (G) Core Conversion	0	0.00	0	0.00
(H) Net MWH Possible In Period	9917136	100.00%	9917136	100.00%
(I) Equivalent Availability		86.68		89.10
(J) Output Factor		101.33		102.18
(K) Heat Rate		10,094		10,022

*Estimate
FOOTNOTE: D1 and E1 Include Ramping Losses

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

NCUC Rule R8-53 (C) (2) (3)

January 2012 through December 2012

Belews Creek Steam Station

	Unit 1	Unit 2
(A) MDC (mw)	1,110	1,110
(B) Period Hrs	8,784	8,784
(C1) Net Generation (mWh)	7,685,065	6,305,060
(C1) Capacity Factor	78.82	64.67
(D1) Net mWh Not Generated due to Full Scheduled Outages	567,081	1,243,570
(D1) Scheduled Outages: percent of Period Hrs	5.82	12.75
(D2) Net mWh Not Generated due to Partial Scheduled Outages	40,005	56,080
(D2) Scheduled Derates: percent of Period Hrs	0.29	0.57
(E1) Net mWh Not Generated due to Full Forced Outages	275,243	36,741
(E1) Forced Outages: percent of Period Hrs	2.82	0.38
(E2) Net mWh Not Generated due to Partial Forced Outages	24,326	106,993
(E2) Forced Derates: percent of Period Hrs	0.25	1.10
(F) Net mWh Not Generated due to Economic Dispatch	1,158,520	2,001,796
(F) Economic Dispatch: percent of Period Hrs	11.88	20.53
(G) Net mWh Possible in Period	9,750,240	9,750,240
(H) Equivalent Availability	90.70	85.20
(I) Output Factor (%)	89.40	84.30
(J) Heat Rate (BTU/NkWh)	9,102	9,279

*Estimated

Footnote: (J) Includes Light Off BTU's

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

NCUC Rule R8-53 (C) (2)

January 2012 through December 2012

Marshall Steam Station

	Marshall 1	Marshall 2	Marshall 3	Marshall 4
(A) MDC (mWh)	380	380	658	660
(B) Period Hrs	8,784	8,784	8,784	8,784
(C1) Net Generation (mWh)	1,078,626	1,370,510	3,263,260	3,902,223
(D) Net mWh Possible in Period	3,337,920	3,337,920	5,779,872	5,797,440
(E) Equivalent Availability	84.84	87.87	88.39	87.65
(F) Output Factor (%)	68.21	67.78	74.44	76.70
(G) Capacity Factor	32.31	41.06	56.46	67.31

Duke Energy Carolinas
Base Load Power Plant
Performance Review Plan

NCUC Rule R8-53 (C) (2)

January 2012 through December 2012

Cliffside Steam Station

		Cliffside 5
(A)	MDC (mWh)	554
(B)	Period Hrs	8,784
(C1)	Net Generation (mWh)	1,144,388
(D)	Net mWh Possible in Period	4,872,192
(E)	Equivalent Availability	89.57
(F)	Output Factor (%)	70.96
(G)	Capacity Factor	23.49

Note: This report is limited to capturing data beginning the first full month a unit is in commercial operation.

Cliffside unit 6 began pre-commercial operation in June 2012 and commercial operation on December 30, 2012. Cliffside unit 6 net generation (mWh) within the twelve month period was as follows:

June 2012:	1,496 mWh; pre-commercial
July 2012:	77,787 mWh; pre-commercial
August 2012:	212,376 mWh; pre-commercial
September 2012:	139,874 mWh; pre-commercial
October 2012:	(1,302) mWh; pre-commercial (auxiliaries only)
November 2012:	170,464 mWh; pre-commercial
December 2012:	168,280 mWh; pre-commercial & commercial combined

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Smith Workpaper 1

Exhibit No. 3
Page 2 of 2

DUKE ENERGY CAROLINAS
DOCKET NO. E-7, SUB 986
CALCULATION OF MERGER-RELATED FUEL COST SAVINGS

Line No.				
1	Total DEC and PEC Savings Projected For Year 1	$72,000,000		Merger Application Exhibits 4 and 5
2	Portion of Year One in Initial DEC Rate Period	83.33%		September 2012 through June 2013
3	Amount to Include in Initial DEC Rate Reduction		$60,000,000	Line 1 x Line 2
4	Total DEC and PEC Savings Projected For Year 2	$100,000,000		Merger Application Exhibits 4 and 5
5	Portion of Year Two in Initial DEC Rate Period	16.67%		July 2013 through August 2013
6	Amount to Include in Initial DEC Rate Reduction		$16,666,667	Line 4 x Line 5
7	Total Amount to Include in Initial DEC Rate Reduction		$76,666,667	Line 3 + Line 6
8	Projected Allocation to DEC based on 2012 Fuel Filings		58.75%	Forecasts in E-7, Sub 1002 and E-2, Sub 1018
9	Amount Allocated to DEC		$45,041,667	Line 7 x Line 8
10	Projected Allocation to NC Retail based on E-7, Sub		67.78%	Line 9 of Supplemental McManeus Exhibit 1, Schedule 2(c), Page 2 (E-7,Sub 1002)
11	Amount Allocated to DEC NC Retail		$30,527,839	Line 9 x Line 10
12	Projected Billing MWh Sales		55,014,183	Supplemental McManeus Exhibit 1, Schedule 2c, page 2 (E-7, Sub 1002)
13	Current composite Merger Savings decrement cents/kWh		(0.0555)	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Smith Workpaper 2

DUKE ENERGY CAROLINAS
E-7, SUB 986
FUEL RATE CHANGE ASSOCIATED WITH MERGER SAVINGS
DERIVATION OF EQUAL PERCENTAGE DECREASE FOR ALL RATE CLASSES

Line No.	Rate Class	Projected Billing Period MWH Sales (a) Supplemental McManeus Exhibit 1, Schedule 2c, page 2 (E-7, Sub 1002)		Annual Revenue at Current Rates (b) Supplemental McManeus Exhibit 6(c) (E-7, Sub 1002)		Allocate Merger Related Fuel Cost Savings To Customer Class (c) (b) /(b) line 4 * (c) line 4	Increase / (Decrease) as % of Annual Revenue at Current Rates (d) (c) / (b)	Rider XXX Increase/(Decrease) (e) (c) / (a) *100 ¢ / kwh	Rider XXXX Billing Factor[2] ¢ / kwh
1	Residential	20,759,438	$	2,166,605	$	(14,686)	-0.7%	(0.0707)	(0.0731)
2	General Service/Lighting	21,958,810	$	1,649,633	$	(11,181)	-0.7%	(0.0509)	(0.0527)
3	Industrial	12,295,938	$	687,624	$	(4,661)	-0.7%	(0.0379)	(0.0392)
4	NC Retail	55,014,183	$	4,503,863	$	(30,528)			
5	NC Retail Decrease in Fuel Revenue[1]				$	(30,528)			

(2) Decremental Rates including NC gross receipts taxes and regulatory fee.

DUKE ENERGY CAROLINAS **Smith Workpaper 3**

North Carolina Annual Fuel and Fuel Related Expense

Billing Period Sept 2013 through Aug 2014
Docket E-7, Sub 1033

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWHs	8886	9100	9717	9224	7403	6227	6814	57,370.03
Hours	8760	8760	8760	8760	8760	8760	8760	8760
MDC	1129	1129	1129	1129	846	846	846	7054
Capacity factor	89.85%	92.01%	98.25%	93.26%	99.89%	84.02%	91.94%	92.84%
Cost	58,506.30	64,893.26	64,136.26	61,268.04	50,747.55	43,802.62	47,039.02	390,393.04
$/MWH	6.58	7.13	6.60	6.64	6.86	7.03	6.90	
Avg $/MWHr		6.80483						
Remove dry storage cask cost (DSC)	99.24%	99.25%	99.78%	99.77%	99.01%	98.99%	99.02%	
Costs W/O DSC	58,059.46	64,408.35	63,992.21	61,127.78	50,242.79	43,360.56	46,576.39	387,767.54
$/MWH W/O DSC	6.53	7.08	6.59	6.63	6.79	6.96	6.84	
Avg $/MWHr		6.759061						
Cents per KWh		0.675906						

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DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Billing Period Sept 2013 through Aug 2014
Docket E-7, Sub 1033

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWHs with approved CF	8926	8926	8926	8926	6594	6594	6594	55,483.64
Hours	8760	8760	8760	8760	8760	8760	8760	8760
MDC	1129	1129	1129	1129	846	846	846	7,054.00
Capacity factor	90.25%	90.25%	90.25%	90.25%	88.97%	88.97%	88.97%	89.79%
Cost	60,738.24	60,738.24	60,738.24	60,738.24	44,867.83	44,867.83	44,867.83	377,556.45
Avg $/MWHr		**6.80483**						
Costs W/O DSC	60,329.76	60,329.76	60,329.76	60,329.76	44,566.08	44,566.08	44,566.08	375,017.29
$/MWH W/O DSC								
Avg $/MWHr		**6.759061**						
Cents per KWh		**0.675906**						

DUKE ENERGY CAROLINAS **Smith Workpaper 5**

North Carolina Annual Fuel and Fuel Related Expense

Billing Period Sept 2013 through Aug 2014

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RESOURCE_TYP DATA_TYPE	UNIT Sept 13- Aug 14	
NUC Total	57,370.032	
COAL Total	26,716.153	
Adjustment	(438.378)	
Adusted Coal Total	26,277.775	
Gas CT and CC total	10,016.167	CC and CT
Run of River Total	1,779.848	
Pumped storage total	3,194.477	
conversion factor	80%	
Energy used to generate	3,993.096	
	798.62	
Catawba Joint Owners	(13,929.209)	
PURC Total	9,448.043	
Adjustment to exclude cost of mitigation sales	(803.900)	
SALE Total	(1,683.858)	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

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RESOURCE_TYPE	Sept 13 - Aug 14	
NUC Total	390,393.04	
Adjustment for DSC	(2,625.50)	
Total Nuclear	387,767.54	
COAL Total	1,006,203.35	
Adjustment	(16,668.63)	
Portion of savings pymt to PEC	9,636.08	Workpaper 7
Adjusted Coal Total	999,170.80	
Gas CT and CC total	302,936.92	
Gas Transportation cost	19,900.00	
Portion of savings pymt to PEC	3,177.89	Workpaper 7
	326,014.80	
PURC Total	9,070.28	
Co gen Capacity	10,211.64	
Renewables	34,567.18	
Renewables Capacity	6,918.58	
Other Purchase info not in model	6,923.83	
Allocated Economic Purchase cost	103,191.82	Workpaper 7
Payment to Progress	165,373.85	Workpaper 7
	336,257.19	

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Billing Period Sept 2013 through Aug 2014
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Oct 12 to Sept 13

	Positive numbers represent costs, Negative numbers represent savings/cost reduction													
	Allocated Economic Purchase Cost		Mitigation Sale Cost		Economic Sales Cost		Fuel Transfer Payment		JDA Savings Payment		Gas Savings Payment		Coal Savings Payment	
	PEC	DEC	PEC	DEC	PEC	DEC	PEC	DEC	PEC	DEC	PEC	DEC	PEC	DEC
9/1/2013	$ 6,780,998	$ 9,589,247	$ -	$ -	$ -	$ (459,770)	$ (10,479,526)	$ 10,479,526	$ (428,536)	$ 428,536	$ (67,271)	$ 67,271	$ (1,308,113)	$ 1,308,113
10/1/2013	$ 5,124,944	$ 7,157,863	$ -	$ -	$ -	$ (696,100)	$ (11,061,496)	$ 11,061,496	$ (799,989)	$ 799,989	$ (69,367)	$ 69,367	$ (1,324,626)	$ 1,324,626
11/1/2013	$ 7,549,439	$ 10,786,446	$ -	$ -	$ (289,700)	$ (1,264,000)	$ (14,735,637)	$ 14,735,637	$ (726,903)	$ 726,903	$ (858,972)	$ 858,972	$ (1,374,776)	$ 1,374,776
12/1/2013	$ 2,941,157	$ 3,945,203	$ -	$ (3,411,800)	$ (1,314,600)	$ (2,092,300)	$ (3,669,466)	$ 3,669,466	$ (97,817)	$ 97,817	$ (920,024)	$ 920,024	$ (1,455,264)	$ 1,455,264
1/1/2014	$ 2,924,984	$ 4,113,413	$ -	$ (3,657,900)	$ (3,567,900)	$ (7,363,800)	$ (4,391,413)	$ 4,391,413	$ (140,707)	$ 140,707	$ (377,316)	$ 377,316	$ (83,098)	$ 83,098
2/1/2014	$ 3,099,233	$ 4,524,973	$ -	$ (3,249,300)	$ (2,975,000)	$ (2,781,800)	$ (5,880,090)	$ 5,880,090	$ (469,082)	$ 469,082	$ (369,075)	$ 369,075	$ (52,808)	$ 52,808
3/1/2014	$ 5,020,350	$ 7,293,577	$ -	$ -	$ -	$ (823,100)	$ (7,489,707)	$ 7,489,707	$ (731,892)	$ 731,892	$ (370,163)	$ 370,163	$ (472,671)	$ 472,671
4/1/2014	$ 7,142,443	$ 10,338,543	$ -	$ -	$ (196,716)	$ (43,166)	$ (7,687,536)	$ 7,687,536	$ (1,117,127)	$ 1,117,127	$ (28,630)	$ 28,630	$ (500,195)	$ 500,195
5/1/2014	$ 6,848,487	$ 9,986,384	$ -	$ -	$ (933,800)	$ (1,565,200)	$ (25,680,262)	$ 25,680,262	$ (1,975,799)	$ 1,975,799	$ (28,506)	$ 28,506	$ (492,511)	$ 492,511
6/1/2014	$ 8,191,616	$ 11,389,974	$ (10,963,200)	$ (6,193,400)	$ (3,309,100)	$ (3,005,800)	$ (14,051,278)	$ 14,051,278	$ (1,132,866)	$ 1,132,866	$ (29,323)	$ 29,323	$ (542,839)	$ 542,839
7/1/2014	$ 8,546,598	$ 11,715,463	$ (12,736,000)	$ (6,127,800)	$ (1,358,600)	$ (5,094,400)	$ (11,237,850)	$ 11,237,850	$ (500,234)	$ 500,234	$ (29,557)	$ 29,557	$ (1,009,672)	$ 1,009,672
8/1/2014	$ 9,074,791	$ 12,346,738	$ (11,695,800)	$ (7,199,200)	$ (984,300)	$ (2,896,600)	$ (10,127,715)	$ 10,127,715	$ (670,256)	$ 670,256	$ (29,685)	$ 29,685	$ (1,019,513)	$ 1,019,513
Sept 13 - Aug 14		$ 103,191,824		$ (29,839,400)		$ (28,086,036)		$ 126,491,974		$ 8,791,207		$ 3,177,889		$ 9,636,084

$ 165,373,847 Workpaper 8
$ 38,881,873 Workpaper 8
$ 126,491,974

$ (38,881,873)
$ (28,086,036)
$ (66,967,909)

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Billing Period Sept 2013 through Aug 2014
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	Transfer Projection		Purchase Allocation Delta		Adjusted Transfer		Fossil Gen Cost		Pre-Net Payments		Actual Payments	
	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC	PECtoDEC	DECtoPEC
9/1/2013	211,342	49,902	137,687	(137,687)	349,029	49,902	$ 35.15	$ 35.82	$ 1,787,629	$ 12,267,155	$ -	$ 10,479,526
10/1/2013	219,225	6,464	105,379	(105,379)	324,604	6,464	$ 34.77	$ 34.95	$ 225,929	$ 11,287,424	$ -	$ 11,061,496
11/1/2013	313,598	69,920	181,505	(181,505)	495,103	69,920	$ 34.65	$ 34.57	$ 2,417,473	$ 17,153,110	$ -	$ 14,735,637
12/1/2013	241,167	151,218	11,555	(11,555)	252,721	151,218	$ 36.30	$ 36.40	$ 5,504,254	$ 9,173,720	$ -	$ 3,669,466
1/1/2014	284,237	179,120	7,741	(7,741)	291,977	179,120	$ 38.21	$ 37.76	$ 6,764,168	$ 11,155,581	$ -	$ 4,391,413
2/1/2014	290,285	153,988	13,527	(13,527)	303,813	153,988	$ 38.41	$ 37.60	$ 5,789,681	$ 11,669,771	$ -	$ 5,880,090
3/1/2014	257,980	101,227	51,399	(51,399)	309,378	101,227	$ 36.39	$ 37.21	$ 3,767,083	$ 11,256,790	$ -	$ 7,489,707
4/1/2014	303,867	122,212	27,920	(27,920)	331,787	122,212	$ 36.73	$ 36.80	$ 4,497,867	$ 12,185,402	$ -	$ 7,687,536
5/1/2014	513,221	16,830	222,430	(222,430)	735,651	16,830	$ 35.74	$ 36.57	$ 615,447	$ 26,295,708	$ -	$ 25,680,262
6/1/2014	319,160	36,971	105,402	(105,402)	424,562	36,971	$ 36.43	$ 38.30	$ 1,415,877	$ 15,467,155	$ -	$ 14,051,278
7/1/2014	253,516	74,399	126,996	(126,996)	380,512	74,399	$ 37.17	$ 39.08	$ 2,907,318	$ 14,145,168	$ -	$ 11,237,850
8/1/2014	267,901	83,041	96,694	(96,694)	364,595	83,041	$ 36.53	$ 38.40	$ 3,189,148	$ 13,316,863	$ -	$ 10,127,715
	3,475,498	1,045,292			4,563,732	1,045,292			38,881,873	165,373,847	-	126,491,974

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Smith Workpaper 9

Billing Period Sept 2013 through Aug 2014
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	Sept - Aug	Retail Sales
NC Retail Sales	55,516,317	55,516,317
SC Residential MWh sales	6,516,476	6,516,476
SC Commercial MWh sales, incl. outdoor light	5,872,824	5,872,824
SC Public Light	41,371	41,371
SC Industrial MWh sales	8,545,462	8,545,462
NPL Resale	90,124	76,492,451
10A NC	1,191,810	
10A SC	317,356	
Rutherford @meter above FFR 2009-2010	816,960	
Piedmont @meter	390,737	
Blue Ridge @meter	1,150,383	
NC EMC fixed load shape	379,552	
Haywood @meter	115,735	
New River @meter	250,924	
Greenwood @meter	296,972	
Central @meter	895,875	
Regular Sales	82,388,880	
Company Use	218,987	
Line Losses	5,164,802	
Change in Unbilled	(96,395)	
Line Losses & Change in Unbilled & Company Use	5,287,395	
SC total	20,976,133	

North Carolina:

Residential	20,955,314
General	22,081,756
Industrial	9,637,232
Textile	2,607,521
Other	234,494
NC RETAIL	55,516,317

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Test Period Ended December 31, 2012
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	February 1, 2012 - June 30, 2012 KWh sales	Rate difference	Dollar difference	July 1 2012 - August 31, 2012 KWh sales	Rate difference	Dollar difference	September 1 2012 - December 31, 2012 KWh sales	Rate difference	Dollar difference
	A	B	A * B = C	D	E	D * E = F	G	H	G * H = I
Residential	7,571,772,850	(0.2720)	$ (20,597,942)	4,298,739,615	(0.3079)	$ (13,229,661)	6,199,646,483	(0.0862)	$ (5,344,095)
General	8,800,102,937	(0.1461)	$ (12,856,950)	4,271,157,541	(0.1820)	$ (7,773,507)	7,272,173,112	(0.0171)	$ (1,243,542)
General subject to EE	7,715,930,255	0.0771	$ 5,948,982	3,744,950,932	0.0771	$ 2,887,357	6,376,241,385	0.0771	$ 4,916,082
Total General			$ (6,907,968)			$ (4,886,150)			$ 3,672,541
Industrial	5,113,386,660	(0.1038)	$ (5,363,365)	2,229,431,266	(0.1447)	$ (3,226,018)	4,104,343,143	(0.0171)	$ (701,842)
Industrial EE	3,185,128,551	0.0771	$ 2,455,734	1,388,725,194	0.0771	$ 1,070,707	2,956,995,344	0.0771	$ 1,971,133
Total General			$ (3,107,631)			$ (2,155,309)			$ 1,269,292

	Total adjustment	Revenue per RAC report	Adjusted Revenue	KWh Sales - Feb to Dec	Sales - Jan 13	total KWH Sales - Feb 12 thru Jan 13	Avg ¢/kwh at Current rates	Normalized Test Period Sales	Annualized Revenues
	C + F + I = J	K	J + K = L	A + D + G = M	N RAC Report	M + N = O	L / M = R	O Smith EX 4	N * O = P
Residential	$ (39,171,698)	$ 2,069,452,787	$ 2,030,281,089	18,069,158,748	2,101,262 608	20,170,421,356	10.06364	21,143,695	$ 2,128,247,266
General	$ (21,873,999)	$ 1,769,249,428	$ 1,747,375,430	20,343,433,590					
General subject to EE	$ 13,752,422		$ 13,752,422	-					
Total General	$ (8,121,577)	$ 1,769,249,428	$ 1,761,127,851	20,343,433,590	1,823,141,641	22,166,575,231	7.94497	22,112,647	$ 1,756,843,289
Industrial	$ (9,491,225)	$ 747,829,763	$ 738,328,540	11,447,161,069					
Industrial EE	$ 5,497,576		$ 5,497,578						
Total General	$ (3,993,647)	$ 747,829,763	$ 743,826,118	11,447,161,069	808,345,095	12,255,526,164	6.02019	12,278,189	$ 739,175,088
		4,586 521,978	4,535 235,058	49,859,773,407	4,832,749,344	54,692,522,751	8.29224	55,534,811	$ 4,624,265,623

General	Opt out %	KWHs opted out	KWHs opt in
8,800,102,937	12.32%	1,084 172 682	7,715 930 255
4,271,157,541	12.32%	526 206,609	3,744,950 932
7,272,173,112	12.32%	895,931,727	6 376,241,385
20,343,433,590	12.32%	2,506,311,018	17,837,122,572

Industrial	Opt out %	KWHs opted out	KWHs opt in
5,113,386,660	37.71%	1,928,258 109	3 185,128,551
2,229,431,266	37.71%	840,726,072	1,388,725,194
4,104,343,143	37.71%	1 547,747 799	2,556 995 344
11,447,161,069	37.71%	4,316,731,981	7,130,449,088

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Smith Workpaper 11

Billing Period Sept 2013 through Aug 2014
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Reagents Forecast
Summary of All Stations

	2013 SEP	2013 OCT	2013 NOV	2013 DEC	2014 JAN	2014 FEB	2014 MAR	2014 APR	2014 MAY	2014 JUN	2014 JUL	2014 AUG	12ME 2014 AUG
Tons													
Limestone	48,651	38,354	39,200	57,835	80,418	64,575	61,128	39,636	44,517	75,244	81,022	83,005	713,585
Lime	513	404	544	568	968	856	898	700	401	819	866	900	8,437
Ammonia	772	260	249	908	1,193	890	749	653	591	1,026	1,122	1,190	9,604
Urea	1,321	1,532	1,440	1,550	1,846	1,563	1,466	591	1,137	1,711	1,790	1,747	17,685
Aqueous Ammonia	502	501	473	616	509	454	264	489	508	489	483	531	5,719
DBA	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Reagents	51,759	41,051	41,907	61,377	84,934	68,329	64,506	42,069	47,154	79,288	85,283	87,373	755,030
Average Cost/Ton													
Limestone	30.50	30.09	29.65	30.47	30.78	30.78	30.60	30.44	31.44	30.87	30.93	31.02	
Lime	125.20	125.65	125.65	125.65	127.28	127.28	127.26	127.74	127.74	127.74	128.20	128.20	
Ammonia	772.32	782.01	789.05	744.50	753.11	753.20	757.34	758.00	769.01	772.15	758.16	724.24	
Urea	384.69	376.98	363.95	363.67	369.78	386.04	401.11	414.03	427.12	400.55	400.21	384.94	
Aqueous Ammonia	212.54	211.40	212.23	207.67	207.64	207.63	223.61	208.65	211.28	211.27	208.48	202.71	
DBA	-	-	-	-	-	-	-	-	-	-	-	-	
Cost													
Limestone	1,483,692	1,154,025	1,162,247	1,762,034	2,475,256	1,986,384	1,870,562	1,206,658	1,399,734	2,322,748	2,506,022	2,574,903	21,904,445
Lime	64,286	50,766	68,331	71,321	123,199	108,953	114,268	89,402	51,276	104,562	111,055	115,364	1,072,784
Ammonia	595,958	203,283	196,605	676,184	898,593	670,542	567,524	494,624	454,616	792,485	850,668	861,928	7,263,011
Urea	508,226	577,595	524,192	563,828	682,595	602,746	588,181	244,866	485,512	685,136	716,435	672,534	6,851,848
Aqueous Ammonia	106,667	105,904	100,450	107,183	105,591	94,312	59,030	102,073	107,304	103,274	100,767	107,669	1,200,225
DBA	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Reagents	$ 2,759,034	$ 2,091,572	$ 2,051,825	$ 3,180,550	$ 4,285,234	$ 3,462,916	$ 3,199,565	$ 2,137,623	$ 2,498,442	$ 4,008,205	$ 4,284,947	$ 4,332,398	$ 38,292,312
Summary Costs by Station													
Allen	-	-	-	-	16,528	-	-	-	-	29,550	102,158	64,220	212,456
Belews Creek	999,411	241,618	163,909	1,133,079	1,438,204	1,069,685	861,184	798,216	815,767	1,277,517	1,360,251	1,480,645	11,659,688
Buck	1,507	-	-	-	-	-	-	-	-	4,472	12,746	2,939	21,664
Buck CC	51,262	54,600	49,243	49,278	48,632	43,470	1,417	46,771	49,645	47,798	46,671	47,543	536,330
Dan River CC	55,405	51,304	51,208	57,906	56,959	50,841	57,613	55,302	57,659	55,476	54,096	60,125	663,895
Cliffside	487,260	383,813	517,600	581,392	1,063,616	637,683	835,290	644,913	370,647	936,257	1,027,750	989,969	8,676,090
Marshall	1,159,533	1,360,237	1,269,866	1,352,669	1,655,422	1,456,224	1,444,061	590,077	1,204,724	1,626,916	1,629,604	1,666,518	16,415,851
Riverbend	4,656	-	-	6,228	5,973	4,813	-	2,344	-	30,218	31,670	20,438	106,338
Total by Station	$ 2,759,034	$ 2,091,572	$ 2,051,825	$ 3,180,550	$ 4,285,234	$ 3,462,916	$ 3,199,565	$ 2,137,623	$ 2,498,442	$ 4,008,205	$ 4,284,947	$ 4,332,398	$ 38,292,312

Total by Product 12ME 2014 AUG		Allen	BC	Buck	Buck CC	Cliffside	Dan River CC	Marshal	Riverbend	Total	less Riverbend	Add New	Total
	Limestone	132,406	6,165,534	-	-	5,634,449	-	9,772,065	-	21,904,445			
	Lime	-	-	-	-	1,072,784	-	-	-	1,072,784			
	Ammonia	-	5,494,153	-	-	1,768,857	-	-	-	7,263,011			
	Urea	80,049	-	21,664	-	-	-	6,643,798	106,338	6,851,848	(106,338)		
	Aqueous Ammonia	-	-	-	536,330	-	663,895	-	-	1,200,225			
	DBA	-	-	-	-	-	-	-	-	-			
	Total	212,456	11,659,688	21,664	536,330	8,676,090	663,895	16,415,851	106,338	38,292,312	(106,338)	3,654,195	41,840,169

DUKE ENERGY CAROLINAS
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Projected DEC fuel flex chemicals

	Mag Hydroxide Cost ($1000)				Calcium Carbinate ($1000)				Hydrated Lime ($1000)				
Month	Allen	Belews Creek	Cliffside 5	Marshall	Allen	Belews Creek	Cliffside 5	Marshall	Allen	Belews Creek	Cliffside 5	Marshall	
September-13	$ -	$ 51.34	$ -	$ 70.64	$ -	$ 32.57	$ -	$ 67.23	$ -	$ 29.81	$ -	$ -	
October-13	$ -	$ 53.14	$ -	$ 58.29	$ -	$ 33.71	$ -	$ 55.47	$ -	$ 30.86	$ -	$ -	
November-13	$ -	$ 48.34	$ -	$ 61.08	$ -	$ 30.67	$ -	$ 58.13	$ -	$ 32.75	$ -	$ -	
December-13	$ -	$ 55.62	$ -	$ 73.47	$ -	$ 35.28	$ -	$ 69.91	$ -	$ 44.85	$ -	$ -	
January-14	$ 3.19	$ 83.09	$ -	$ 91.70	$ 2.02	$ 52.71	$ -	$ 87.26	$ -	$ 61.65	$ -	$ -	
February-14	$ 2.14	$ 61.68	$ -	$ 77.30	$ 1.35	$ 39.13	$ -	$ 73.56	$ -	$ 45.76	$ -	$ -	
March-14	$ -	$ 59.80	$ -	$ 80.43	$ -	$ 37.93	$ -	$ 76.54	$ -	$ 44.36	$ -	$ -	
April-14	$ -	$ 57.21	$ -	$ 35.79	$ -	$ 36.29	$ -	$ 34.05	$ -	$ 42.44	$ -	$ -	
May-14	$ -	$ 52.01	$ -	$ 64.19	$ -	$ 32.99	$ -	$ 61.09	$ -	$ 38.59	$ 7.90	$ -	
June-14	$ 3.44	$ 84.74	$ -	$ 76.81	$ 2.18	$ 53.76	$ -	$ 73.10	$ -	$ 62.87	$ 26.87	$ -	
July-14	$ 13.53	$ 95.99	$ -	$ 75.97	$ 8.58	$ 60.90	$ -	$ 72.29	$ -	$ 55.74	$ 31.96	$ -	
August-14	$ 5.69	$ 103.44	$ -	$ 80.56	$ 3.61	$ 65.62	$ -	$ 76.67	$ -	$ 60.06	$ 22.49	$ -	
12 ME 8/31/2014	$ 28	$ 806	$ -	$ 846	$ 18	$ 512	$ -	$ 805	$ -	$ 550	$ 89	$ -	$ 3,654

Data provided by: Ashley Coleman/Dan Donochod

3/6/2013

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
2% calculation test
Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Line No.	Description	Forecast $	(over)/under Collection $	Total $
1	Amount in current docket	117,326,716	43,824,250	161,150,967
2	Amount in Sub 1002, prior year docket	127,612,570	68,615,504	196,228,074
3	Increase/(Decrease)	(10,285,854)	(24,791,254)	(35,077,108)
4	2% of 2012 NC revenue of 4,557,487,757			91,149,755
	Excess of purchased power growth over 2% of Revenue			0

WP 6	PURC Total	9,070.28	68.31%	6,195,648
WP 6	Cogen Capacity	10,211.64	71.82%	7,333,693
WP 6	Renewables	34,567.18	68.31%	23,611,842
WP 6	Renewables Capacity	6,918.58	71.82%	4,968,719
WP 6	Other Purchase info not in model	6,923.83	68.31%	4,729,466
WP 6	Allocated Economic Purchase cost	103,191.82	68.31%	70,487,347
		170,883.34		117,326,716

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
2% calculation test
Test Period Ended December 31, 2012
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Smith Workpaper 13a

2012

	Jan12	Feb12	Mar12	Apr12	May12	Jun12
System KWH Sales - Sch 4	6,895,689,814	6,519,270,541	6,137,030,129	5,909,384,411	6,037,637,846	6,919,336,378
NC Retail KWH Sales - Sch 4	4,696,133,138	4,471,304,228	4,225,512,682	4,010,671,402	4,082,257,686	4,698,516,271
NC Retail % of Sales (Calc)	68.10%	68.59%	68.85%	67.87%	67.61%	67.88%
Link to Sch 4	68.10%	68.59%	68.85%	67.87%	67.61%	67.88%
	ok	ok	ok	ok	ok	ok
Fuel related component of purchased power (economic)						
System Actual $ - Sch 3 Fuel$	$ 8,255,726	$ 10,719,383	$ 9,191,069	$ 14,679,715	$ 10,695,899	$ 6,502,953
System Actual $ - Sch 3 Fuel-related$; Sch 2 pg 1	7,718,288	7,934,045	6,771,006	10,021,398	8,976,304	8,597,443
Total System Economic $	15,974,014	18,653,428	15,962,075	24,701,113	19,672,203	15,100,396
Less Native Load Transfers & Native Load Transfer Savings						
Total System Economic $ w/o Native Load Transfers	$ 15,974,014	$ 18,653,428	$ 15,962,075	$ 24,701,113	$ 19,672,203	$ 15,100,396
NC Actual $ (Calc)	$ 10,878,694	$ 12,793,631	$ 10,990,324	$ 16,764,529	$ 13,301,083	$ 10,249,430
Billed rate ($/kWh)	0.1589	0.1589	0.1589	0.1589	0.1589	0.1589
Billed $:	$ 7,462,156	$ 7,104,902	$ 6,714,340	$ 6,372,957	$ 6,486,707	$ 7,482,764
Over (Under) $:	$ (3,416,538)	$ (5,688,730)	$ (4,275,984)	$ (10,391,572)	$ (6,814,356)	$ (2,766,666)
Fuel related component of purchased power (renewables)						
System Actual $ - Sch 2 pg 1	$ 4,133,406	$ 3,175,281	$ 3,840,448	$ 3,865,382	$ 3,712,275	$ 3,750,184
Less: REPS correction	187,794	134,844	178,285	175,371	156,140	155,267
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	3,945,675	3,040,437	3,665,161	3,690,011	3,556,135	3,594,917
NC Actual $ (Calc)	$ 2,687,101	$ 2,085,313	$ 2,523,563	$ 2,504,393	$ 2,404,427	$ 2,440,059
Billed rate ($/kWh)	0.0223	0.0223	0.0223	0.0223	0.0223	0.0223
Billed $	$ 1,047,238	$ 997,101	$ 942,289	$ 894,380	$ 910,343	$ 1,047,323
Over (Under) $:	$ (1,639,863)	$ (1,088,212)	$ (1,581,274)	$ (1,610,013)	$ (1,494,084)	$ (1,392,735)

	Jul12	Aug12	Sep12	Oct12	Nov12	Dec12	12 ME
System KWH Sales - Sch 4	7,834,763,631	7,870,766,350	7,192,112,868	5,947,169,618	6,162,546,397	6,442,815,299	79,868,687,279
NC Retail KWH Sales - Sch 4	5,356,606,570	5,440,541,652	4,959,527,586	4,052,000,506	4,169,014,344	4,395,620,302	54,558,966,648
NC Retail % of Sales (Calc)	68.37%	69.12%	68.96%	68.13%	67.65%	68.23%	68.31%
Link to Sch 4	68.37%	69.12%	68.96%	68.13%	67.65%	68.23%	
	ok	ok	ok	ok	ok	ok	
Fuel related component of purchased power (economic)							
System Actual $ - Sch 3 Fuel$	$ 17,512,487	$ 17,204,401	$ 16,824,787	$ 22,712,589	$ 20,811,541	$ 9,846,289	$ 166,956,819
System Actual $ - Sch 3 Fuel-related$; Sch 2 pg 1	6,537,885	7,628,918	8,097,361	9,953,029	9,252,897	4,495,772	$ 93,984,366
Total System Economic $	24,050,372	24,833,319	24,922,148	32,665,618	30,064,438	14,342,061	$ 260,941,185
Less Native Load Transfers & Native Load Transfer Savings	11,339,314	10,419,741	10,174,248	23,773,408	17,766,638	6,189,237	$ 79,662,766
Total System Economic $ w/o Native Load Transfers	$ 12,711,058	$ 14,413,578	$ 14,747,900	$ 8,892,210	$ 12,297,800	$ 8,152,824	$ 181,278,399
NC Actual $ (Calc)	$ 8,690,818	$ 9,963,154	$ 10,169,837	$ 6,058,532	$ 8,319,427	$ 5,562,276	$ 123,741,717
Billed rate ($/kWh)	0.1589	0.1589	0.1984	0.1984	0.1984	0.1984	
Billed $:	$ 8,511,966	$ 8,645,021	$ 9,839,703	$ 8,039,169	$ 8,271,324	$ 8,720,911	$ 93,631,920
Over (Under) $:	$ (178,852)	$ (1,318,133)	$ (330,134)	$ 1,980,637	$ (48,102)	$ 3,158,634	$ (30,109,797)
Fuel related component of purchased power (renewables)							
System Actual $ - Sch 2 pg 1	$ 3,164,099	$ 3,084,572	$ 3,571,248	$ 4,199,338	$ 3,487,354	$ 2,597,450	$ 42,581,098
Less: REPS correction	119,793	115,271	141,367	183,651	143,654	95,536	$ 1,783,973
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	3,044,306	2,969,301	3,429,881	4,015,687	3,343,700	2,501,914	$ 40,797,125
NC Actual $ (Calc)	$ 2,081,456	$ 2,052,481	$ 2,365,173	$ 2,736,009	$ 2,262,040	$ 1,706,935	$ 27,848,950
Billed rate ($/kWh)	0.0223	0.0223	0.0335	0.0335	0.0335	0.0335	
Billed $	$ 1,194,568	$ 1,213,241	$ 1,661,442	$ 1,357,420	$ 1,396,620	$ 1,472,533	$ 14,134,497
Over (Under) $:	$ (886,888)	$ (839,241)	$ (703,731)	$ (1,378,589)	$ (865,421)	$ (234,402)	$ (13,714,453)

TOTAL Over (Under) $: $ (43,824,250)

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
2% calculation test
Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Smith Workpaper 13b

2011

	Jan11	Feb11	Mar11	Apr11	11-May	11-Jun	11-Jul	11-Aug	11-Sep	11-Oct	11-Nov	11-Dec	12 ME
System KWH Sales - Sch 4	8,049,323,157	6,812,081,664	6,070,596,768	6,060,396,448	6,022,058,699	7,381,119,256	7,788,342,170	8,351,124,039	7,481,207,082	6,046,921,470	5,867,549,474	6,271,930,562	82,292,829,776
NC Retail KWH Sales - Sch 4	5,541,322,301	4,680,662,611	4,114,424,497	4,134,590,176	4,010,233,612	5,000,619,491	5,270,645,977	5,702,669,021	5,136,873,658	4,086,696,907	3,975,774,127	4,301,666,750	56,666,071,628
NC Retail % of Sales (Calc)	68.84%	68.66%	67.78%	68.22%	66.59%	67.75%	67.67%	68.29%	68.66%	67.58%	67.76%	68.59%	68.08%
Link to Sch 4	68.84%	68.66%	67.78%	68.22%	66.59%	67.75%	67.67%	68.29%	68.66%	67.58%	67.76%	68.59%	
	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	
Fuel related component of purchased power (economic)													
System Actual $ - Sch 3 Fuel$	$ 16 739 943	$ 5,949,773	$ 7,369,546	$ 6,729,595	$ 9,532,161	$ 13,202,825	$ 12,295,664	$ 16,327,183	$ 9,144,776	$ 10,794,118	$ 12,343,970	$ 10,035,702	$ 130,465,256
System Actual $ - Sch 3 Fuel-related$, Sch 2 pg 1	8,018 456	2,338,937	5.144,277	5,080,615	6,533,594	8,608,615	6,971,864	9,939,855	6,122,295	7,238,996	8,928,907	6,225,082	$ 80,151,493
Total System Economic $	24 758,399	8 288,710	12.513,823	11,810,210	15,065,765	21,811,440	19,267,528	26,267,038	15,267,070	18,033,114	21,272,877	16,260,784	$ 210,616,748
NC Actual $ (Calc)	$ 17,044,199	$ 5,707,444	$ 8,481,403	$ 8,057,292	$ 10,032,648	$ 14,776,988	$ 13,039,016	$ 17,936,774	$ 10,482,935	$ 12,187,045	$ 14,414,221	$ 11,152,623	$ 143,312,583
Billed rate (¢/kWh)	0.1390	0.1390	0.1390	0.1390	0.1390	0.1390	0.1390	0.1390	0.1589	0.1589	0.1589	0.1589	
Billed $:	$ 7,702,438	$ 6,520,007	$ 5,719,050	$ 5,747,080	$ 5,574,225	$ 6,950,861	$ 7,326,198	$ 7,926,710	$ 8,162,492	$ 6,493,606	$ 6,317,505	$ 6,835,348	$ 81,275,521
Over (Under) $:	$ (9,341,761)	$ 812,563	$ (2,762 353)	$ (2,310 212)	$ (4,458,423)	$ (7,826,127)	$ (5,712,818)	$ (10,010,084)	$ (2,320,443)	$ (5,693,439)	$ (8,096,716)	$ (4,317,274)	$ (62,037,088)
Fuel related component of purchased power (renewables)													
System Actual $ - Sch 2 pg 1	$ 517.096	$ 554 583	$ 540.414	$ 625 460	$ 725,886	$ 3 237,830	$ 2,736,721	$ 2,214 935	$ 2,371.920	$ 3,831,696	$ 3,764,341	$ 3 120,942	$ 24 241,823
NC Actual $ (Calc)	$ 355,980	$ 381,875	$ 366,272	$ 426,708	$ 483,383	$ 2,193,591	$ 1,852,036	$ 1,512,496	$ 1,628,648	$ 2,589,516	$ 2,550,668	$ 2,140,530	$ 16 481.704
Billed rate (¢/kWh)	0 0156	0.0156	0.0156	0.0156	0.0156	0.0156	0.0156	0.0156	0.0223	0.0223	0.0223	0.0223	
Billed $	$ 864,446	$ 731,742	$ 641,850	$ 644,996	$ 625.596	$ 780,097	$ 822,221	$ 889,616	$ 1,145,523	$ 911,312	$ 886,598	$ 959,272	$ 9,903 268
Over (Under) $:	$ 508 467	$ 349,867	$ 275,578	$ 218,288	$ 142 212	$ (1,413 494)	$ (1,029,815)	$ (622,880)	$ (483 125)	$ (1,678,206)	$ (1,664 070)	$ (1,181,258)	$ (6,578,436)
TOTAL Over (Under) $:													$ (68,618,504)

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Test Period Ended December 31, 2012
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Line No.	Year	Reference	MWH Net Output	MWH Line Loss/ Company Use	Average Line Loss/ Co. Use %
1	2008	Prior fuel filing	90,943,002	5,234,947	
2	2009	Prior fuel filing	84,321,352	5,181,728	
3	2010	Prior fuel filing	90,359,224	5,683,489	
4	2011	Prior fuel filing	87,535,397	4,792,382	
5	2012	Exhibit 6	86,224,791	5,214,250	
6	5 Years	Sum L1:L5	439,383,766	26,106,795	5.94%
7	Line Loss/Co. Use Factor		((1/(1-L6))		1.0632

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Smith Workpaper 15

Test Period Ended December 31, 2012
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Subject: Median Hydro Generation 1982 - 2012

The table below summarizes the updated 31 year median hydro generation for the historical calendar year period 1982 - 2012.

Duke Energy

MEDIAN CONVENTIONAL HYDRO GENERATION (MWH)
(Pumped Storage Hydro plants are not included)
31 YEARS 1982 - 2012

	Median Year	System Total	R-O-R	Storage	Nantahala
January	1994	222,000	10,500	173,400	38,100
February	2004	170,700	10,800	122,000	37,900
March	1982	220,000	10,600	163,800	45,600
April	1996	154,600	13,000	114,900	26,700
May	2005	128,200	8,400	84,400	35,400
June	1987	124,700	4,900	81,700	38,000
July	1998	96,900	6,000	69,000	22,000
August	1993	109,200	5,000	77,300	26,900
September	1983	106,800	4,700	64,500	37,700
October	1984	98,700	4,800	66,900	27,000
November	1984	103,000	5,100	68,100	29,800
December	1995	169,700	9,600	104,200	55,800
TOTALS		1,704,500	93,400	1,190,200	420,900

Note: The Run-of-River (R-O-R), Storage, and Nantahala Medians do not necessarily correspond to the year of the System Median.

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Test Period Ended December 31, 2012
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Line No.	Year	Reference to NC Fuel Filing	Jocassee Pumped Storage Output	Jocassee Pumping Input	Bad Creek Pumped Storage Output	Bad Creek Pumping Input	System Total Net
1	2008	Sch 10, p. 6 of 6	1,083,815	1,387,130	2,554,294	3,210,183	(959,204)
2	2009	Sch 10, p. 6 of 6	926,568	1,148,967	1,917,824	2,417,800	(722,375)
3	2010	Sch 10, p. 6 of 6	925,837	1,077,790	2,041,348	2,578,364	(688,969)
4	2011	Sch 10, p. 6 of 7	917,215	1,042,175	1,997,078	2,532,517	(660,399)
5	2012	Sch 10, p. 6 of 7	928,617	1,103,984	1,752,364	2,218,596	(641,599)
6	Average		956,410	1,152,009	2,052,582	2,591,492	(734,509)

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Test Period Ended December 31, 2012
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Line No.	Year	Reference	Actual Generation from CTs Oil MWH	Gas CT MWH	Total MWH
1	2010	Schedule 5	(9,500)	612,241	602,741
2	2011	Schedule 5	40,811	700,504	741,315
3	2012	Schedule 5	6,865	916,328	923,193
4	Total	Sum L1:L3	38,176	2,229,073	2,267,249
5	Average	Calc	**12,725**	**743,024**	**755,750**

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Test Period Ended December 31, 2012
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	January	February	March	April	May	June	Total
	1	2	3	4	5	6	
Fuel Savings - Gross for current month							
DEC Fuel Savings - Gross							
. Coal Blending	$ 1,383,822	$ 1,531,341	$ 1,223,878	$ 1,445,766	$ 1,362,588	$ 1,910,429	8,857,824
. Coal Commodity	159,879	171,243	127,638	86,616	85,702	20,858	651,936
. Coal Transportation	-	-	-	-	-	-	-
. Natural Gas / Oil	-	-	-	-	-	-	-
. Reagents	14,213	7,899	12,582	4,023	36,103	66,374	141,194
. Avoided Gas Desk O&M Cost	-	-	-	-	-	-	-
subtotal - DEC fuel savings	1,557,914	1,710,483	1,364,098	1,536,405	1,484,393	1,997,661	9,650,954
PEC Fuel Savings - Gross for current month							
. Coal Blending	-	-	-	-	-	-	-
. Coal Commodity	-	-	-	70,567	112,326	296,607	479,500
. Coal Transportation	-	-	-	75,137	106,683	124,184	306,004
. Natural Gas / Oil	-	-	-	-	-	-	-
. Reagents	35,182	35,046	70,300	60,565	38,762	46,962	286,817
. Avoided Gas Desk O&M Cost	-	-	-	-	-	-	-
subtotal - PEC fuel savings	35,182	35,046	70,300	206,269	257,771	467,753	1,072,321
Total - Fuel Saving -Gross	1,593,096	1,745,529	1,434,398	1,742,674	1,742,164	2,465,414	10,723,275
DEC sharing ratio July - Dec	0.58777968	0.58777968	0.58777968	0.58777968	0.58777968	0.58777968	
PEC sharing ratio July - Dec	0.41222032	0.41222032	0.41222032	0.41222032	0.41222032	0.41222032	
Total DEC share	936,389	1,025,986	843,110	1,024,308	1,024,009	1,449,120	6,302,923
Total PEC share	656,707	719,543	591,288	718,366	718,155	1,016,294	4,420,352
DEC gross	1,557,914	1,710,483	1,364,098	1,536,405	1,484,393	1,997,661	9,650,954
DEC net share	936,389	1,025,986	843,110	1,024,308	1,024,009	1,449,120	6,302,923
Amount to be shared with PEC	(621,525)	(684,497)	(520,988)	(512,097)	(460,384)	(548,541)	(3,348,031)
	68.10%	68.59%	68.85%	67.87%	67.61%	67.88%	
	(423,273)	(469,468)	(358,714)	(347,558)	(311,282)	(372,323)	(2,282,619)
PEC gross	35,182	35,046	70,300	206,269	257,771	467,753	1,072,321
PEC net share	656,707	719,543	591,288	718,366	718,155	1,016,294	4,420,352
Amount to be received from DEC	621,525	684,497	520,988	512,097	460,384	548,541	3,348,031

	Adjusted test period sales MWhs	Adjusted test period sales as a % of total MWh sales	Amount to be shared with PEC allocated as a % of total MWh sales
Residential	21,143,695	38.07%	(868,993)
General	22,112,646	39.82%	(908,939)
Industrial	12,278,269	22.11%	(504,687)
	55,534,611	100.00%	(2,282,619)

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Test Period Ended December 31, 2012
Docket E-7, Sub 1033
MWhs

Line #	Description	Reference	NORTH CAROLINA	SOUTH CAROLINA	Retail TOTAL COMPANY	% NC	% SC
1	RESIDENTIAL	RAC001	20,121,712	6,157,414	26,279,126	76.57	23.43
2	Total General Service	RAC001	22,116,267	5,649,488	27,765,755		
3	less Lighting and Traffic Signals		739,161	227,740	966,901		
4	General Service subject to weather		21,377,106	5,421,748	26,798,854	79.77	20.23
	INDUSTRIAL						
5	Textile	RAC001	2,794,192	1,125,375	3,919,567	71.29	28.71
6	Other Industrial	RAC001	9,523,736	7,534,250	17,057,986	55.83	44.17
7	Total Industrial		12,317,928	8,659,625	20,977,553	58.72	41.28
8	Total Retail Sales	1+2+7	54,555,907	20,466,527	75,022,434		
9	Total Retail Sales subject to weather	1+4+7	53,816,746	20,238,787	74,055,533	72.67	27.33

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Test Period Ended December 31, 2012
Weather Normalization Adjustment
Docket E-7, Sub 1033

Line #	Description	REFERENCE MWH	REFERENCE %	Total Company MWH	NC RETAIL % To Total	NC RETAIL MWH	SC RETAIL % To Total	SC RETAIL MWH
	Residential							
1	Total Residential			1,274,546	76.57	975,920	23.43	298,626
	General Service							
2	Total General Service			90,927	79.77	72,533	20.23	18,395
	Industrial							
3	Textile			(10,161)	71.29	(7,243)	28.71	(2,917)
4	Other			(26,777)	55.83	(14,950)	44.17	(11,827)
5	Total Industrial			(36,937)	58.72	(22,193)	41.28	(14,744)
6	Total Retail	L1:L2 + L5		1,328,536		1,026,260		302,277
7	Wholesale			127,409				
8	Total Company	L6 + L7		1,455,945		1,026,260		302,277

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Test Period Ended December 31, 2012
Weather Normalization Adjustment
Docket E-7, Sub 1033

2012	TOTAL MWH ADJUSTMENT
JAN	228,976
FEB	299,365
MAR	263,635
APR	297,306
MAY	(49,081)
JUN	65,830
JUL	(160,338)
AUG	(22,169)
SEP	186,835
OCT	101,001
NOV	(63,599)
DEC	126,785
ANN. SUM	1,274,546

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Test Period Ended December 31, 2012
Weather Normalization Adjustment- General
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2012	Non-TOD Non-Electric Heat	Non-TOD Electric Heat	TOD Non-Electric Hat	TOD Electric Heat	TOTAL MWH ADJUSTMENT
JAN	14,370	3,802	(7,783)	2,631	13,020
FEB	18,782	4,981	(10,278)	3,607	17,092
MAR	14,573	2,862	(13,413)	2,909	6,931
APR	15,423	2,354	(17,622)	3,124	3,279
MAY	(7,478)	(4,562)	(9,543)	(1,303)	(22,886)
JUN	6,392	3,026	3,558	1,151	14,127
JUL	(19,581)	(10,737)	(18,778)	(3,454)	(52,550)
AUG	(2,699)	(1,496)	(2,575)	(478)	(7,247)
SEP	22,897	12,648	22,001	4,109	61,655
OCT	13,962	8,171	15,710	2,421	40,265
NOV	(1,130)	1,326	9,193	(318)	9,071
DEC	8,064	2,249	(3,677)	1,536	8,171
ANN. SUM	83,575	24,625	(33,209)	15,936	90,927

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Test Period Ended December 31, 2012
Weather Normalization Adjustment- Industrial
Docket E-7, Sub 1033

2012	TEXTILES	OTHER INDUSTRIAL	TOTAL MWH ADJUSTMENT
JAN	(1,568)	(4,183)	**(5,751)**
FEB	(3,132)	(8,360)	**(11,492)**
MAR	(5,402)	(14,755)	**(20,157)**
APR	(4,067)	(11.073)	**(15,140)**
MAY	(3.529)	(9,952)	**(13,481)**
JUN	4,542	12.862	**17,403**
JUL	(10,500)	(29,717)	**(40,217)**
AUG	3,315	9.381	**12,696**
SEP	5.750	16.285	**22,035**
OCT	5,126	14,385	**19,511**
NOV	2,483	6.834	**9,317**
DEC	(3,179)	(8,484)	**(11,664)**
ANN. SUM	(10,161)	(26,777)	**(36,937)**

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense
Test Period Ended December 31, 2012
Weather Normalization Adjustment- Wholesale
Docket E-7, Sub 1033

2012	TOTAL MWH ADJUSTMENT
JAN	31,280
FEB	23,892
MAR	43,059
APR	12,244
MAY	(6,383)
JUN	2,534
JUL	(16,366)
AUG	9,029
SEP	16,022
OCT	2,590
NOV	(19,217)
DEC	28,725
ANN. SUM	127,409

Note: The Resale customers include:

1 Concord
2 Dallas
3 Forest City
4 Kings Mountain
5 Due West
6 Prosperity
7 Lockhart
8 Western Carolina University
9 City of Highlands
10 Haywood
11 Piedmont
12 Rutherford
13 Blue Ridge
14 Greenwood

DUKE ENERGY CAROLINAS
Customer Growth Adjustment to KWH Sales
Twelve Months Ended December 31, 2012

Smith Workpaper 21
Page 1

Rate Schedule	Reference	NC Proposed KWH [1] Adjustment	SC Proposed KWH Adjustment	Wholesale Proposed KWH Adjustment
NC Residential	ND-310/1	46,063,236	15,983,294	
NC General:				
General Service Small and Large	ND-330	(78,013,556)	(13,358,995)	
T2 Flood Lighting/Outdoor Lighting	ND-310/2	(1,406,241)	1,740,247	
Miscellaneous	ND-310/3	318,397	243,176	
Total General		(79,101,400)	(11,375,572)	
NC Public Street Lighting:				
T	ND-310/4	3,070,775	161,167	
TS	ND-310/5	(122,998)	59,808	
Total Street Lighting		2,947,777	220,975	
NC Industrial:				
I - Textile	ND-330	(946,436)	(1,007,571)	
I - Nontextile	ND-330	(16,519,327)	(1,668,123)	
Total Industrial		(17,465,764)	(2,675,694)	
Total		(47,556,150)	2,153,003	14,471,452

[1] Using the regression method (Residential, Lighting, Misc classes) and a customer by customer method for General Service and Industrial

DUKE ENERGY CAROLINAS
Calculation of Customer Growth Adjustment to KWH Sales - Wholesale
Twelve Months Ended December 31, 2012

Line No.		Reference	
1	Total System Resale (kWh Sales)	RAC001	6,130,366,441
2	Less Intersystem Sales	Schedule 1	1,141,573
3	KWH Sales Excluding Intersystem Sales	L1 - L2	6,129,224,868
4	Total Residential Growth Factor	Line 8	0.2361
5	Adjustment to KWH's - Wholesale	L3 * L4 / 100	14,471,452
6	Total System Retail Residential kWh Sales	RAC001	26,279,126,866
7	2012 Proposed Adjustment KWH - Residential (NC+SC)	ND310	62,046,530
8	Percent Adjustment	L7 / L6 * 100	0.2361

"RAC001": CarolinasOperating Revenue Report

DUKE ENERGY CAROLINAS
Customer Growth Adjustment to KWH Sales
Twelve Months Ended December 31, 2012
Customer by Customer Approach

NC	Rate Schedule	No. of Bills New Accounts	Test Yr Consumption New Accounts	(a) Unrealized Sales from New Accounts (kWh)	No. of Bills Closed Accounts	(b) Lost Sales from Closed Accounts	Net Adjustment to Growth (a minus b)
NC							
NC	GENL NTEX	32,375	64,207,556	68,652,550	77,333	146,666,106	(78,013,556)
NC	INDL NTEX	163	8,947,590	8,847,597	830	25,366,924	(16,519,327)
NC	INDL TEX	21	393,154	188,410	68	1,134,846	(946,436)
NC	Total	32,559	73,548,300	77,688,557	78,231	173,167,876	(95,479,319)

SC	Rate Schedule	No. of Bills New Accounts	Test Yr Consumption New Accounts	(a) Unrealized Sales from New Accounts (kWh)	No. of Bills Closed Accounts	(b) Lost Sales from Closed Accounts	Net Adjustment to Growth (a minus b)
SC							
SC	GENL NTEX	9,531	19,863,363	20,275,925	21,277	33,634,920	(13,358,995)
SC	INDL NTEX	66	4,486,152	3,323,226	245	4,991,349	(1,668,123)
SC	INDL TEX				19	1,007,571	(1,007,571)
SC	Total	9,597	24,349,515	23,599,151	21,541	39,633,840	(16,034,689)

(a): Estimated from individual accounts and bills
(b): Calculated from individual accounts and bills

The method uses the estimated lost sales from closed accounts, offset by the unrealized sales from newly established accounts with less than the full complement of bills (normally 12) issued during the year.The method was first approved for use in Docket E-7 Sub 909; see Bailey Direct Testimony pages 5,6 for a more detailed explanation and rationale

DUKE ENERGY CAROLINAS

Smith Workpaper 21
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Calculation of Customer Growth Adjustment to kWh
Twelve Months Ended Dec 31 2012
North Carolina Retail

Month	Number of Customers: Actual # of Customers [1]	Projected [3]	Increase (Decrease)	KWH Consumption [2]	Average Per Customer	Increase (Decrease) in KWh
January	1,592,490	1,600,367	7,877	2,052,553,641	1,289	10,153,453
February	1,592,911	1,600,367	7,456	1,785,443,480	1,121	8,358,176
March	1,594,367	1,600,367	6,000	1,576,390,855	989	5,934,000
April	1,594,956	1,600,367	5,411	1,252,704,582	785	4,247,635
May	1,595,500	1,600,367	4,867	1,320,093,240	827	4,025,009
June	1,596,272	1,600,367	4,095	1,638,140,493	1,026	4,201,470
July	1,597,773	1,600,367	2,594	2,159,210,131	1,351	3,504,494
August	1,598,508	1,600,367	1,859	2,137,529,484	1,337	2,485,483
September	1,598,686	1,600,367	1,681	1,773,807,828	1,110	1,865,910
October	1,598,501	1,600,367	1,866	1,271,002,314	795	1,483,470
November	1,600,025	1,600,367	342	1,428,842,682	893	305,406
December	1,600,832	1,600,367	(465)	1,725,993,659	1,078	(501,270)
Total	19,160,821		43,583	20,121,712,389		46,063,236

[1] Carolinas ORR Jan-Dec 2012
[2] Carolinas ORR Jan-Dec 2012
[3] Using Polynomial Cubic 24 Month Regression

DUKE ENERGY CAROLINAS

Calculation of Customer Growth Adjustment to kWh
Twelve Months Ended Dec 31 2012
North Carolina Retail

Smith Workpaper 21
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GENERAL T2 (Outdoor Lighting)
Schedules 25,34,35,36,26,37,38,39,94,95,96
(includes NPL yard and flood lighting)

	Number of Customers					
Month	Actual # of Customers [1]	Projected [2]	Increase (Decrease)	KWH Consumption [1]	Average Per Customer	Increase (Decrease) in KWh
January	277,900	275,362	(2,538)	41,309,482	149	(378,162)
February	275,512	275,362	(150)	40,881,612	148	(22,200)
March	277,314	275,362	(1,952)	40,992,971	148	(288,898)
April	275,085	275,362	277	40,783,584	148	40,996
May	276,142	275,362	(780)	40,967,603	148	(115,440)
June	273,080	275,362	2,282	40,557,043	149	340,018
July	278,769	275,362	(3,407)	41,419,562	149	(507,643)
August	273,210	275,362	2,152	40,638,593	149	320,648
September	279,011	275,362	(3,649)	41,123,566	147	(536,403)
October	278,480	275,362	(3,118)	41,095,891	148	(461,464)
November	275,623	275,362	(261)	40,859,325	148	(38,628)
December	273,745	275,362	1,617	40,705,161	149	240,933
Total	3,313,871		(9,527)	491,314,393		(1,406,241)

[1] Per Book by Rate Schedule Page 8 attached
[2] Using polynomial quartic 48 month regression
Note: NPL unmetered signs included with Public Lighting

DUKE ENERGY CAROLINAS

Calculation of Customer Growth Adjustment to kWh
Twelve Months Ended December 31 2012
North Carolina Retail

Smith Workpaper 21
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GENERAL-MISC.
Schedules 49 (BC)

Month	Number of Customers: Actual # of Customers [1]	Projected [2]	Increase (Decrease)	KWH Consumption [1]	Average Per Customer	Increase (Decrease) in KWh
January	4,260	4,686	426	948,459	223	94,998
February	4,172	4,686	514	973,584	233	119,762
March	4,388	4,686	298	797,557	182	54,236
April	4,453	4,686	233	616,592	138	32,154
May	4,560	4,686	126	571,850	125	15,750
June	4,596	4,686	90	662,903	144	12,960
July	4,643	4,686	43	751,216	162	6,966
August	4,646	4,686	40	727,609	157	6,280
September	4,744	4,686	(58)	651,894	137	(7,946)
October	4,811	4,686	(125)	523,308	109	(13,625)
November	4,701	4,686	(15)	779,946	166	(2,490)
December	4,690	4,686	(4)	758,274	162	(648)
Total	54,664		1,568	8,763,192		318,397

[1] Per Book by Rate Schedule Page 4 attached
[2] Using polynomial cubic 12 month regression

DUKE ENERGY CAROLINAS

Calculation of Customer Growth Adjustment to kWh

Twelve Months Ended December 31 2012

North Carolina Retail

Smith Workpaper 21

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GENERAL T (Public and Govt Lighting)

Schedule 72,73,74,75

	Number of Customers					
Month	Actual # of Customers [1]	Projected [2]	Increase (Decrease)	KWH Consumption [1]	Average Per Customer	Increase (Decrease) in KWh
January	5,279	5,376	97	19,626,814	3,718	360,646
February	5,244	5,376	132	19,651,634	3,747	494,604
March	5,240	5,376	136	19,637,349	3,748	509,728
April	5,209	5,376	167	19,624,399	3,767	629,089
May	5,359	5,376	17	19,705,973	3,677	62,509
June	5,249	5,376	127	19,701,720	3,753	476,631
July	5,435	5,376	(59)	19,735,428	3,631	(214,229)
August	5,268	5,376	108	19,716,875	3,743	404,244
September	5,371	5,376	5	19,744,417	3,676	18,380
October	5,371	5,376	5	19,766,935	3,680	18,400
November	5,333	5,376	43	19,768,573	3,707	159,401
December	5,335	5,376	41	19,695,607	3,692	151,372
Total	63,693		819	236,375,724		3,070,775

[1] Per Book by Rate Schedule Page 1. New Schedule GL (73,74,75) included beginning 2010

[2] Using polynomial Cubic 48 month regression

DUKE ENERGY CAROLINAS **Smith Workpaper 21**

Calculation of Customer Growth Adjustment to kWh **Page 8**

Twelve Months Ended December 31 2012

North Carolina Retail

GENERAL TS

Schedule 83

Month	Number of Customers: Actual # of Customers [1]	Projected [2]	Increase (Decrease)	KWH Consumption [1]	Average Per Customer	Increase (Decrease) in KWh
January	5,734	5,616	(118)	1,052,360	184	(21,712)
February	5,709	5,616	(93)	944,416	165	(15,345)
March	5,723	5,616	(107)	955,003	167	(17,869)
April	5,706	5,616	(90)	961,785	169	(15,210)
May	5,730	5,616	(114)	901,657	157	(17,898)
June	5,640	5,616	(24)	961,118	170	(4,080)
July	5,713	5,616	(97)	939,207	164	(15,908)
August	5,640	5,616	(24)	940,936	167	(4,008)
September	5,622	5,616	(6)	954,809	170	(1,020)
October	5,704	5,616	(88)	925,723	162	(14,256)
November	5,630	5,616	(14)	954,425	170	(2,380)
December	5,578	5,616	38	979,742	176	6,688
Total	68,129		(737)	11,471,181		(122,998)

1 Per Book by Rate Schedule Page 2

2 Using linear 12 month regression

DUKE ENERGY CAROLINAS

Calculation of Customer Growth Adjustment to KWHs

Twelve Months Ended December 31, 2012

South Carolina Retail

RESIDENTIAL

	Number of Customers					
Month	Actual # of Customers[1]	Projected[3]	Increase (Decrease)	KWH Consumption[2]	Average Per Customer	Increase (Decrease) in KWh
January	454,717	457,241	2,524	620,513,075	1,365	3,445,260
February	455,053	457,241	2,188	536,456,051	1,179	2,579,652
March	455,546	457,241	1,695	459,027,591	1,008	1,708,560
April	455,401	457,241	1,840	385,882,606	847	1,558,480
May	455,894	457,241	1,347	411,595,345	903	1,216,341
June	455,935	457,241	1,306	522,268,634	1,145	1,495,370
July	456,614	457,241	627	683,840,454	1,498	939,246
August	456,332	457,241	909	667,940,089	1,464	1,330,776
September	456,282	457,241	959	550,767,430	1,207	1,157,513
October	456,339	457,241	902	387,130,969	848	764,896
November	457,165	457,241	76	419,192,832	917	69,692
December	457,493	457,241	(252)	512,799,401	1,121	(282,492)
Total	5,472,771		14,121	6,157,414,477		15,983,294

[1] Carolinas Operating Revenue Report Summary

[2] Carolinas Operating Revenue Report Summary

[3] Using Polynomial Quartic 36 Month Regression

DUKE ENERGY CAROLINAS

Calculation of Customer Growth Adjustment to KWHs

Twelve Months Ended December 31, 2012

South Carolina Retail

Smith Workpaper 21

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GENERAL T2 (Outdoor Lighting)

Schedules 25,32,34,35,36,26,37,38,39,95,96

(includes Greenwood SL)

Month	Number of Customers: Actual # of Customers [1]	Projected [4]	Increase (Decrease)	KWH Consumption [1]	Average Per Customer	Increase (Decrease) in KWh	kWh for T2	kwh for SL *
January	116,812	118,125	1,313	15,109,623	129	169,377	15,080,081	29,542
February	116,938	118,125	1,187	15,569,705	133	157,871	15,540,361	29,344
March	116,899	118,125	1,226	15,483,642	132	161,832	15,454,220	29,422
April	116,998	118,125	1,127	15,524,512	133	149,891	15,495,091	29,421
May	116,415	118,125	1,710	15,445,783	133	227,430	15,416,161	29,602
June	117,329	118,125	796	15,592,593	133	105,868	15,563,095	29,498
July	116,935	118,125	1,190	15,585,239	133	158,270	15,555,939	29,300
August	116,924	118,125	1,201	15,520,010	133	159,733	15,490,550	29,460
September	116,924	118,125	1,201	15,363,152	131	157,331	15,333,808	29,344
October	116,777	118,125	1,348	15,455,773	132	177,936	15,426,465	29,308
November	117,178	118,125	947	15,524,575	132	125,004	15,495,412	29,163
December	118,203	118,125	(78)	15,575,221	132	(10,296)	15,546,131	29,090
Total	1,404,332		13,168	185,749,808		1,740,247	185,397,314	352,494

[1] Per Book by Rate Schedule Pages 14 (Misc T2-Greenwood) and Page 18 attached

[4] Using Polynomial Quartic 12 month regression

DUKE ENERGY CAROLINAS

Calculation of Customer Growth Adjustment to KWHs
Twelve Months Ended December 31, 2012
South Carolina Retail

Smith Workpaper 21
Page 11

GENERAL-MISC.
Schedules 33, 49 (BC and EH)

	Number of Customers					
Month	Actual # of Customers [1]	Projected [2]	Increase (Decrease)	KWH Consumption [1]	Average Per Customer	Increase (Decrease) in KWh
January	1,274	1,603	329	296,634	233	76,657
February	1,299	1,603	304	231,714	178	54,112
March	1,354	1,603	249	287,103	212	52,788
April	1,379	1,603	224	49,503	36	8,064
May	1,446	1,603	157	141,602	98	15,386
June	1,478	1,603	125	161,419	109	13,625
July	1,533	1,603	70	222,592	145	10,150
August	1,554	1,603	49	230,274	148	7,252
September	1,583	1,603	20	198,121	125	2,500
October	1,584	1,603	19	164,311	104	1,976
November	1,596	1,603	7	187,125	117	819
December	1,604	1,603	(1)	246,086	153	(153)
Total	17,684		1,552	2,416,484		243,176

[1] Per Book by Rate Schedule Page 12
[2] Using polynomial quartic12 month regression

DUKE ENERGY CAROLINAS

Calculation of Customer Growth Adjustment to KWHs
Twelve Months Ended December 31, 2012
South Carolina Retail

Smith Workpaper 21
Page 12

GENERAL T
Schedule 72,73,74,75
(Government, Public Lighting)

Month	Number of Customers: Actual # of Customers [1]	Projected [4]	Increase (Decrease)	KWH Consumption [1]	Average Per Customer	Increase (Decrease) in KWh
January	1,902	1,934	32	3,192,398	1,678	53,696
February	1,899	1,934	35	3,302,937	1,739	60,865
March	1,913	1,934	21	3,300,055	1,725	36,225
April	1,916	1,934	18	3,304,942	1,725	31,050
May	1,913	1,934	21	3,307,589	1,729	36,309
June	1,938	1,934	(4)	3,316,560	1,711	(6,844)
July	1,928	1,934	6	3,337,956	1,731	10,386
August	1,937	1,934	(3)	3,334,991	1,722	(5,166)
September	1,968	1,934	(34)	3,307,362	1,681	(57,154)
October	1,923	1,934	11	3,288,857	1,710	18,810
November	1,929	1,934	5	3,328,017	1,725	8,625
December	1,949	1,934	(15)	3,331,323	1,709	(25,635)
Total	23,115		93	39,652,985		161,167

[1] Per Book by Rate Schedule Page 9
[4] Using polynomial Quartic 24 month regression

DUKE ENERGY CAROLINAS

Calculation of Customer Growth Adjustment to KWHs

Twelve Months Ended December 31, 2012

South Carolina Retail

Smith Workpaper 21

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GENERAL TS

Schedule 83

Month	Number of Customers Actual # of Customers [1]	Projected [2]	Increase (Decrease)	KWH Consumption [1]	Average Per Customer	Increase (Decrease) in KWh
January	1,419	1,467	48	208,290	147	7,056
February	1,423	1,467	44	183,106	129	5,676
March	1,424	1,467	43	187,414	132	5,676
April	1,421	1,467	46	193,663	136	6,256
May	1,417	1,467	50	183,141	129	6,450
June	1,423	1,467	44	197,006	138	6,072
July	1,427	1,467	40	195,487	137	5,480
August	1,441	1,467	26	194,881	135	3,510
September	1,430	1,467	37	196,669	138	5,106
October	1,428	1,467	39	190,810	134	5,226
November	1,439	1,467	28	198,663	138	3,864
December	1,471	1,467	(4)	207,613	141	(564)
Total	17,163		441	2,336,743		59,808

1 Per Book by Rate Schedule Page 10

2 Using Polynomial Quartic 12 month regression

DUKE ENERGY CAROLINAS
North Carolina Annual Fuel and Fuel Related Expense

Smith Workpaper 22

Test Period Ended December 31, 2012
Docket E-7, Sub 1033

Year 2012	AC- Energy	AC- Capacity	North Carolina AC- Energy	North Carolina AC- Capacity	NC Retail MWH Sales	Total sales from fuel report less intersystem	% of NC to total sales from fuel report	Plant allocator NC	Plant allocator Resid	General	Industrial
January	$ (236,971)	$ (38,781)	(161,383)	(26,411)	4,696,133	6,895,691	68.10%	0.00%	46.04%	37.53%	16.43%
February	$ (168,871)	$ (27,734)	(115,822)	(19,022)	4,471,304	6,519,271	68.59%	0.00%	46.04%	37.53%	16.43%
March	$ (218,661)	$ (35,918)	(150,554)	(24,731)	4,225,513	6,137,030	68.85%	0.00%	46.04%	37.53%	16.43%
April	$ (220,235)	$ (38,158)	(149,473)	(25,898)	4,010,671	5,909,384	67.87%	0.00%	46.04%	37.53%	16.43%
May(1)	$ (198,242)	$ (32,688)	(134,038)	(22,101)	4,082,258	6,037,638	67.61%	0.00%	46.04%	37.53%	16.43%
June	$ (196,371)	$ (32,383)	(133,287)	(21,980)	4,696,516	6,919,337	67.88%	0.00%	46.04%	37.53%	16.43%
July	$ (150,373)	$ (24,834)	(102,813)	(16,980)	5,356,807	7,834,783	68.37%	0.00%	46.04%	37.53%	16.43%
August	$ (144,778)	$ (21,982)	(100,076)	(15,195)	5,440,542	7,870,768	69.12%	0.00%	46.04%	37.53%	16.43%
September	$ (173,415)	$ (28,550)	(119,583)	(21,784)	4,959,528	7,192,113	68.96%	0.00%	46.04%	37.53%	16.43%
October	$ (227,572)	$ (37,482)	(155,052)	(28,599)	4,052,001	5,947,190	68.13%	76.30%	43.28%	38.06%	18.66%
November	$ (179,071)	$ (29,504)	(121,143)	(22,511)	4,169,014	6,162,548	67.65%	76.30%	43.28%	38.06%	18.66%
December	$ (118,150)	$ (19,565)	(80,608)	(14,928)	4,395,620	6,442,815	68.23%	76.30%	43.28%	38.06%	18.66%
Total	$ (2,232,710)	$ (367,579)	(1,523,832)	(260,138)	54,555,907	79,868,568	68.31%				

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1033

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alexander ("Sasha") J. Weintraub. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am Vice President, Fuels & Systems Optimization for Duke Energy Corporation ("Duke Energy"). In that capacity I am responsible for the procurement of fossil fuels and environmental reagents for the Duke Energy Carolinas, LLC ("DEC" or the "Company") and Progress Energy Carolinas, Inc. ("PEC") (collectively, the "Companies") generation fleet, as well as for the generation fleets of the other Duke Energy regulated utilities. I am also responsible for portfolio management and short term power trading for Duke Energy, and am responsible for the fossil fuel price forecasts used for fuel filings and resource planning purposes for all of Duke Energy's regulated utility subsidiaries, including DEC.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Engineering from Rensselaer Polytechnic Institute, a Master's in Mechanical Engineering from Columbia University, and a Ph.D. in Industrial Engineering from North Carolina State University. From February 2003 until June 2005, I was Director of Coal Marketing and Trading for Progress Fuel Corporation, a former subsidiary of Progress Energy, Inc. ("Progress Energy"). Subsequently, I was Director of Coal for PEC and Progress Energy Florida, Inc. ("PEF"), and before assuming my current position, I was Vice President - Fuels and Power Optimization for PEC and PEF.

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

A. The purpose of my testimony is to describe DEC's fossil fuel purchasing practices, provide fossil fuel costs for the period January 1, 2012 through December 31, 2012 ("test period"), and describe changes forthcoming in the billing period of September 1, 2013 through August, 31 2014 ("billing period"). I also provide an update from a procurement and operations perspective on the Joint Dispatch Agreement ("JDA") that – pursuant to the merger agreement between Duke Energy and Progress Energy ("Merger") – Duke Energy is using to deliver savings to its North and South Carolina customers, as well as fuel savings that DEC has realized to date on behalf of its customers as a result of the Merger.

Q. PLEASE PROVIDE A DESCRIPTION OF THE EXHIBITS TO YOUR TESTIMONY.

A. Weintraub Exhibit 1 summarizes the Company's Fossil Fuel Procurement Practices, and Weintraub Exhibit 2 summarizes monthly contract and spot coal purchases during 2011 and 2012.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes, they were prepared at my direction.

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

A. A summary of the Company's fossil fuel procurement practices is set out in Weintraub Exhibit 1. The practices of both Duke Energy and Progress Energy, are under review and will be modified to adopt the best practices for the combined company going forward.

Q. PLEASE DESCRIBE THE COMPANY'S DELIVERED COST OF COAL DURING 2012.

A. The Company's average delivered coal cost per ton increased 5.3% from $94.52 per ton in 2011 to $99.52 per ton in 2012. The average transportation costs increased approximately 8.6%, from $27.00 per ton in 2011 to $29.32 per ton in 2012.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN COAL MARKET CONDITIONS.

A. Coal markets continue to be in a state of flux due to a number of factors, including (1) recent U.S. Environmental Protection Agency ("EPA") regulations for power plants that result in utilities retiring or modifying plants, which lower total domestic steam coal demand, and can result in some plants shifting coal sources to different basins; (2) continuing growth in global demand for both steam and metallurgical coal, which makes coal exports increasingly attractive to U.S. coal producers; (3) continued low gas prices combined with installation of new combined cycle generation by utilities, especially in the Southeast, which also lowers overall coal demand; and (4) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity

Q. HOW DO YOU EXPECT THESE TRENDS TO AFFECT DEC'S COAL

BURN AND INVENTORY LEVELS?

A. Due to increasingly lower power prices and reduced demand for coal generation, coal burn projections for 2013 and forward are forecasted to be lower than historical volumes. As an example of the impact, the actual coal burn for DEC's stations in 2012 was just over 10,700,000 tons, approximately 30% less than the average coal burn over the prior five-year period of over 15,900,000 tons. Based on the low coal burns in 2012, as well as the downward projection for coal burns in 2013 as compared to the amount of coal under contract for delivery in 2013, the Company expects coal inventories to be above target levels during 2013. If the Company experiences mild weather and continued low purchased power prices, there likely will be further upward pressure on coal inventories.

Q. WHAT IS THE PROJECTED AVERAGE DELIVERED COAL COST FOR THE BILLING PERIOD?

A. Combining coal and transportation costs, the Company projects average delivered coal costs of approximately $98.62 per ton for the billing period. This represents a less than 1% decrease compared to the 2012 actual cost. This cost, however, is subject to change based on (1) changes in oil prices, which impact transportation rates; (2) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts; (3) performance of contract deliveries by suppliers and railroads which may not occur despite the Company's strong contract compliance monitoring process; (4) cost of potential contract volume deferrals in light of declining coal burn projections and high coal inventories; and (5) the amount of non-Central Appalachian coal the Company is able to consume.

Q. DOES THE COMPANY'S PRIMARY SOURCE OF COAL CONTINUE TO BE CENTRAL APPALACHIA?

A. No, the Company's primary source of coal supply is no longer the Central Appalachian region. Historically, fuel switching to a different coal basin has been difficult for DEC because coal quality characteristics vary greatly between coal producing basins, and the design of DEC's plants was meant to optimize the use of Central Appalachian coals. The Company's test burn program provides data for determining operational and environmental impacts, as well as the costs—both capital and O&M—to mitigate those impacts. Where the impacts require mitigation, the Company has undertaken engineering and economic studies to determine whether the cost is justified by the savings obtained through burning the non-Central Appalachian coal.

Additionally, as a result of the Merger, the Company can achieve fuel savings by sharing best practices between DEC and PEC for coal blending at their respective coal-fired plants. Specifically, and as mentioned in my testimony submitted on May 20, 2011 in Docket Nos. E-7, Sub 986 and E-2, Sub 998 ("Merger Testimony"), over the past seven years, PEC has made a substantial investment to improve the fuel flexibility of its scrubbed coal units. These investments, which have included improvements to the coal-fired boilers, as well as the balance-of-plant components, have expanded the types of coal that PEC can reliably burn at these units. DEC has been able to learn via the Merger from the PEC practices of consuming non-traditional coals at the PEC coal units without impacting reliability or operations. Because of the sharing of best practices across the DEC and PEC coal generation fleet, DEC can now procure a wide variety of coals for its fleet, resulting in overall fuel savings passed on to customers.

Q. WHAT STEPS IS DEC TAKING TO CONTROL COAL COSTS?

A. The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over many years in limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. Aspects of this procurement strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, and pursuing contract extension options that provide flexibility to extend terms within a particular price band.

The Company expects to address forward year coal requirements later this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels. The Company currently is considering alternatives to help mitigate inventory levels including negotiating contract shipment deferrals/buy-outs, and evaluating coal resell market opportunities. Due to lower coal demand for most of the U.S., however, either of these options would likely be difficult to achieve without paying additional costs to the supplier or incurring sales at potential losses.

Q. PLEASE DESCRIBE DEC'S PROCUREMENT PRACTICES FOR NATURAL GAS.

A. Prior to the close of the Merger, DEC primarily utilized a supply manager to provide needed supply, scheduling and balancing services for its overall natural gas needs. As contemplated during integration planning, the Company began transitioning the natural gas procurement and scheduling activities in-house. Effective November 1, 2012, the Company terminated the gas supply manager agreement and began soliciting and contracting with multiple suppliers, and performing all scheduling and balancing activities in-house. The in-house personnel are responsible for natural gas contracting, competitive procurement, scheduling, and balancing efforts for the gas generation fleet. The Company has implemented gas procurement practices that include periodic Request for Proposals ("RFPs") and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply that supports the Company's combustion turbine ("CT") facilities and the Buck and Dan River combined cycle ("CC") facilities.

Lastly, in December 2012 the Company received approval for the Asset Management and Delivered Supply Agreement ("AMA") between DEC and PEC, which was implemented on January 1, 2013. In the AMA, DEC is the designated Asset Manager that procures and manages the combined gas supply needs for DEC and PEC, and performs the necessary scheduling and balancing on the pipelines.

Q. HOW IS NATURAL GAS DELIVERED TO THE COMPANY'S GENERATING FACILITIES?

A. The Company procures long-term firm transportation that provides natural gas to its generating facilities. In addition, as needed, the Company may procure shorter-term firm pipeline capacity through the capacity release market and market supply options that provide the needed natural gas supply to its generating facilities.

Q. DOES DEC MAINTAIN AN INVENTORY OF NATURAL GAS?

A. The Company does not have an agreement for storage capacity, nor does it maintain an inventory of natural gas. Progress Energy Carolinas, however, does have a storage agreement which was released to DEC as part of the AMA. As the Asset Manager, DEC will procure all the needed supply for the combined Carolinas gas needs and as part of that agreement, will have access to the released storage agreement. On any given day, DEC may utilize the storage to balance and support the Carolinas gas needs.

Q. WHAT CHANGES IN VOLUME DOES THE COMPANY ANTICIPATE WITH NATURAL GAS CONSUMPTION?

A. The Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 42 billion cubic feet ("Bcf") of natural gas in 2012, compared to approximately 10 Bcf in 2011. This increase was driven by the downward trend in the natural gas prices as well as the operation of the Buck CC facility for its first full year ending on December 31, 2012. For 2013, DEC's current forecasted natural gas consumption is approximately 74

Bcf. This forecast is based on current natural gas prices which are forecasted to remain low, as noted later in my testimony, and includes a full year of operations of Dan River CC, which went into commercial service in December 2012

Q. PLEASE DESCRIBE THE CURRENT STATE OF THE NATURAL GAS MARKET, INCLUDING THE NATURAL GAS PRICES EXPERIENCED DURING THE TEST PERIOD.

A. The development of shale gas has created a fundamental shift in the nation's natural gas market. Shale gas is natural gas that is trapped within shale formations, and which can provide an abundant source of petroleum and natural gas. Within recent years, improvements in production technologies have allowed greater access to the natural gas trapped in these formations, and has resulted in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for calendar year 2012 was $3.34 per Million British Thermal Units ("MMBtu"), compared to $4.85 per MMBtu in 2011.

Q. PLEASE DESCRIBE THE OUTLOOK FOR THE NATURAL GAS MARKET, INCLUDING THE EXPECTED NATURAL GAS PRICE TREND FOR THE BILLING PERIOD.

A. New production from shale gas has contributed to substantial increases in the supply of U.S. marketed natural gas. This increase has outstripped demand growth. The Company expects the shale gas production percentage of total natural gas domestic production to continue to increase over time. The current forward prices for natural gas reflect this continued increase in competitively priced supply with an average forward Henry Hub[1] price of $4.03 per MMBtu through the proposed fuel rates period.

Q. IN LIGHT OF THE COMPANY'S INCREASED USAGE OF NATURAL GAS, WHAT IS THE COMPANY DOING TO MITIGATE THE EFFECTS THAT INCREASING NATURAL GAS PRICES COULD HAVE ON FUEL COSTS?

A. The Company does not currently employ a hedging strategy to fix prices on a portion of the projected natural gas usage. The lower and unpredictable nature of the Company's historical natural gas usage was not suitable for a structured price hedging program. The Company is currently evaluating the feasibility of a hedging program given the increased and more predictable natural gas consumption associated with the addition of the Buck and Dan River CCs. The Company anticipates having further working discussions with the Public Staff–North Carolina Utilities Commission regarding potential hedging program requirements, recommendations, and timing of implementation.

Q. PLEASE EXPLAIN THE JDA BETWEEN DEC AND PEC.

A. As explained in my Merger Testimony, the JDA is an agreement between PEC and DEC where DEC acts as the Joint Dispatcher for DEC's and PEC's power supply resources. The JDA has allowed DEC's and PEC's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. As a result, the

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

joint dispatch process allows DEC and PEC to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis. The JDA also provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEC and PEC.

Q. HOW DO THE COMPANY'S CUSTOMERS RECEIVE THEIR SAVINGS FROM THE JDA?

A. As I described on pages 12 and 13 of my Merger Testimony, the joint dispatch savings will automatically flow through to the Companies' retail customers through their fuel clauses. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts. Under the joint dispatch process, the energy cost attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the Joint Dispatcher, which are treated as purchases and sales between the Companies. As a result, the energy cost ultimately incurred by DEC and PEC to serve their respective native loads will be equal to the stand-alone costs they would have incurred but for the joint dispatch arrangement, less each utility's share of the joint dispatch savings.

Q. THE COMPANY HAS GUARANTEED A CERTAIN AMOUNT OF MERGER-RELATED SAVINGS TO ITS NORTH CAROLINA RETAIL CUSTOMERS. HOW MUCH SAVINGS HAS DEC ACHIEVED THUS FAR?

A. Through December 2012, the combined merger savings from the JDA and the Companies' fuel procurement activities are $51.9 million. The Company's and PEC's customers are then allocated their share of the combined savings based upon the resource ratios of the combined company. This resource ratio is 58.8% for DEC and 41.2% for PEC through December 2012.

Q. DID ALL OF THE MERGER SAVINGS IN 2012 OCCUR AFTER THE MERGER CLOSE DATE IN JULY 2012?

No. Duke Energy Carolinas and PEC procured coal and reagents in 2011 utilizing joint RFPs assuming a January 2012 Merger close date. The delay in the Merger close in December 2011 occurred after many of the contracts were signed assuming a delivery schedule beginning in January 2012. These contracts were delivered to DEC coal stations and either stockpiled or utilized in limited testing plans. After the Merger close, the savings from these same contracts were shared between DEC and PEC as specified in the merger stipulation agreement. The Companies propose that the pre-merger savings be shared with PEC utilizing the sharing ratio for savings that occurred from July to December 2012.

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

A. Both DEC and PEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider 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 order to determine the most economic and reliable means of serving their customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Duke Energy Carolinas, LLC Fossil Fuel Procurement Practices

__Coal__

- Near and long-term consumption forecasts are computed based on factors such as: load projections, fleet maintenance and availability schedules, coal quality and cost, environmental permit and emissions considerations, wholesale energy imports and exports.
- Station and system inventory targets are determined and designed 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 ascertain additional needs.
- All qualified suppliers are invited to make proposals to satisfy any additional or future contract needs.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, quality, transportation, reliability and flexibility.
- Spot market solicitations are conducted on an on-going basis to supplement contract purchases.
- 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. During the test period the Company utilized both destination and/or origin weights and analysis.

__Gas__

- Near and long-term consumption forecasts are computed based on factors such as load projections, commodity and emission prices, and fleet maintenance and availability schedules.
- Short-term and Long term Periodic Request for Proposal (RFP's) and informal market solicitations will be conducted to potential qualified suppliers to procure a cost competitive, secure and reliable natural gas supply over time 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 to forecasted gas usage to ascertain any additional needs.

__Fuel Oil__

- No. 2 diesel is burned for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All diesel fuel is moved via pipeline to terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, Duke relies on a combination of inventory and reliable suppliers who are responsive and can access multiple terminals. Diesel is

replaced on an "as needed basis" as called for by station personnel with guidance from fuel procurement staff.

- Formal solicitation for supply is conducted periodically, with an emphasis on maintaining a network of reliable suppliers in the region of our generating assets. Contracts are awarded based on the lowest evaluated offer with special value on suppliers' demonstrated ability to move large volumes of fuel with minimal notice.

DUKE ENERGY CAROLINAS
Summary of Coal Purchases
Twelve Months Ended December 31, 2012 & 2011
Tons

Line No.	Month	Contract (Tons)	Spot (Tons)	Adjustment (Tons)	Total (Tons)
1	January 2012	1,099,131	34,300	0	1,133,431
2	February	1,085,149	9,044	0	1,094,193
3	March	795,810	0	0	795,810
4	April	867,257	0	0	867,257
5	May	817,198	0	0	817,198
6	June	664,100	0	0	664,100
7	July	940,875	0	0	940,875
8	August	1,040,679	0	(3,975)	1,036,704
9	September	946,139	10,666	0	956,805
10	October	1,163,874	56,433	0	1,220,307
11	November	870,291	58,669	0	928,960
12	December	880,826	0	0	880,826
13	**Total** (Sum L1:L12)	**11,171,329**	**169,112**	**(3,975)**	**11,336,466**

Line No.	Month	Contract (Tons)	Spot (Tons)	Adjustment (Tons)	Total (Tons)
14	January 2011	1,282,765	154,813	0	1,437,578
15	February	1,301,272	170,753	0	1,472,024
16	March	1,283,553	193,195	0	1,476,749
17	April	1,337,562	52,723	0	1,390,285
18	May	1,356,127	107,037	0	1,463,165
19	June	986,996	51,904	0	1,038,900
20	July	1,064,373	57,088	0	1,121,461
21	August	1,300,837	126,879	0	1,427,716
22	September	1,115,068	168,151	0	1,283,219
23	October	1,203,913	138,531	0	1,342,444
24	November	1,135,876	196,375	(2,600)	1,329,650
25	December	1,200,921	119,862	(10,000)	1,310,783
26	**Total** (Sum L14:L25)	**14,569,263**	**1,537,311**	**(12,600)**	**16,093,974**

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1033

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**DIRECT TESTIMONY OF**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**JOSEPH A. MILLER, JR. FOR**
R8-55 Relating to Fuel and Fuel-Related	)	**DUKE ENERGY CAROLINAS, LLC**
Charge Adjustments for Electric Utilities	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph A. Miller, Jr. and 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 currently Director of Strategic Engineering for Duke Energy Business Services, LLC ("DEBS"). DEBS is a service company subsidiary of Duke Energy Corporation ("Duke Energy"), which provides services to Duke Energy and its subsidiaries, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas", "DEC" or "the Company"). Prior to the merger between Duke Energy and Progress Energy, Inc., (the "Merger"), I served as General Manager of Analytical and Investments Engineering for DEBS.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Purdue University with a Bachelor of Science degree in mechanical engineering. I also completed twelve post graduate level courses in Business Administration at Indiana State University. My career began with Duke Energy (d/b/a Public Service of Indiana) in 1991 as a staff engineer at Duke Energy Indiana's Cayuga Steam Station. Since that time, I have held various roles of increasing responsibility in the generation engineering, maintenance, and operations areas, including the role of station manager, first at Duke Energy Kentucky's East Bend Steam Station, followed by Duke Energy Ohio's Zimmer Steam Station. I was named General Manager of Analytical and

Investments Engineering in 2010, and was named to my current role following the Merger.

Q. WHAT WERE YOUR DUTIES PRIOR TO THE MERGER AND WHAT ARE YOUR DUTIES AS DIRECTOR OF STRATEGIC ENGINEERING?

A. Prior to the Merger, my responsibilities included leading the groups responsible for project controls and engineering analysis of capital projects for the Company's generation fleet of nuclear, fossil, and hydroelectric ("hydro" and collectively, "fossil/hydro") facilities. My responsibilities also included, and continue to include, environmental compliance planning and strategy, fuel flexibility, assessment of new technology developments, and analysis of plant retirements and new fossil generation.

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

A. No. I did file testimony before this Commission, however, in the Company's 2012 annual fuel proceeding in Docket No. E-7, Sub 1002 ("2012 Fuel Filing"), and have filed testimony in the Company's recent base rate adjustment filing in Docket No. E-7, Sub 1026. I have also testified on behalf of Duke Energy in proceedings before other state commissions, most recently in January 2013.

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

A. The purpose of my testimony is to (1) describe the Company's generation portfolio and changes made since the 2012 Fuel Filing, as well as those expected in the near term, (2) discuss the performance of the Company's fossil/hydro facilities during the test period of January 1, 2012 through December 31, 2012 (the "test period"), and (3) provide information on significant outages that occurred during the test period.

Q. PLEASE DESCRIBE THE COMPANY'S FOSSIL/HYDRO GENERATION PORTFOLIO.

A. The Company's fossil/hydro generation portfolio as of December 31, 2012 consists of approximately 15,000 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	7,882 MWs
Hydro -	3,229 MWs
Combustion Turbines -	2,769 MWs
Combined Cycle Turbines -	1,240 MWs

The coal-fired assets consist of seven generating stations and a total of 22 units. The Company has 13 units that are larger coal-fired facilities with a total of 6,802 MWs of capacity. Each of these units is equipped with emission control equipment, including selective catalytic or selective non-catalytic reduction ("SCR" or "SNCR") equipment for removing nitrogen oxides ("NOx"), and flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"). The remaining nine coal-fired units – considered to be intermediate or cycling units – include six that are also equipped with SNCRs. In addition, all 22 coal-fired units are equipped with low NOx burners.

The Company has a total of 31 simple cycle combustion turbine ("CT") units, of which 29 are considered the larger group providing approximately 2,687 MWs of capacity. These 29 units are located at Lincoln, Mill Creek and Rockingham Stations, and are equipped with water injection systems that reduce NOx and/or have low NOx burner equipment in use. The Lee CT facility includes two units with a total capacity of 82 MWs equipped with fast-start ability in support of the Company's Oconee Nuclear Station. The 1,240 MWs shown earlier as "combined cycle turbines" ("CC") represent the Buck CC and Dan River CC facilities that began commercial operation in late 2011 and late 2012, respectively. These facilities are equipped with the latest technology for emission control including SCRs, low NOx burners, and carbon monoxide/volatile organic compounds catalysts. The Company's hydro fleet includes two pumped storage hydro facilities that provide a total capacity of 2,140 MWs along with conventional hydro assets consisting of 82 units providing approximately 1,089 MWs of capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO PORTFOLIO SINCE THE COMPANY'S 2012 FUEL FILING?

A. Changes within the portfolio include the addition of 1,445 MWs of new generation when Dan River CC and Cliffside Steam Station ("Cliffside") Unit 6 were declared available for commercial operation in December 2012. The Company received certificates of public convenience and necessity ("CPCN") from the Commission to construct Dan River CC and Cliffside Unit 6 in Docket No. E-7, Subs 832 and 790, respectively. The Company retired coal-fired Units

1 through 4 at Cliffside, 3 and 4 at Buck Steam Station ("Buck"), and 1 through 3 at Dan River Steam Station ("Dan River"). This total reduction of 587 MWs of coal-fired capacity moved DEC forward to meeting requirements set forth in the CPCN and the Air Permit, issued by the North Carolina Department of Environment & Natural Resources, Division of Air Quality, for Cliffside Unit 6. Lastly, due to age and obsolescence, the Company retired older CTs at Buck, Buzzard Roost, Dan River, and Riverbend Stations for a reduction of 350 MWs.

Q. **ARE OTHER CAPACITY CHANGES EXPECTED WITHIN THE FOSSIL/HYDRO PORTFOLIO FOR THE NEAR FUTURE?**

A. Yes. As part of the fleet modernization program, the Company will retire the remaining two units at Buck, Units 5 and 6 (256 MWs), along with Riverbend Steam Station, Units 4 through 7 (454 MWs) by April 1, 2013. These assets have served customers well for multiple decades and, at 58 to 60 years old, are at the end of their useful lives. The Company had planned to retire these units in April 2015, but has operated them infrequently in recent years and would operate them even less due to low natural gas prices and new generation resources that are more efficient. Additionally, the Company had already agreed to retire these units in progressive fashion under the Cliffside Unit 6 air permit and Merger agreements.

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

A. The primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC's customers. The

Company achieves this objective by focusing on a number of key areas. 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.

Like safety, environmental compliance is a "first principle" and DEC works very hard to achieve high level results. Duke Energy Carolinas achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. 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 for its customers. Equipment inspection and maintenance outages are scheduled during the spring and fall months when electricity demand is reduced due to weather conditions. These outages are well-planned and executed with the primary purpose of preparing the unit for reliable operation until the next planned outage.

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

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy. Over the test period, the average heat rate for DEC's coal fleet was 9,539 Btu/kWh. The Company's largest units – those with the highest usage rates – achieved an average heat rate of 9,497 Btu/kWh for the test period. In operating performance data for 2011, published in the December 2012 issue of *Electric Light and Power* magazine, the Company's Belews Creek Steam Station ("Belews Creek") and Marshall Steam Station ("Marshall") ranked as the country's fourth and eighth most energy efficient coal-fired generators, with heat rates of 9,210 and 9,480 Btu/kWh, respectively. These results compare favorably to the average heat rate of 10,450 Btu/kWh for the North American coal generators. For the test period, the Belews Creek units provided the majority (50.0%) of coal-fired generation for the Company, with the Marshall units providing the second highest percentage (34.4%).

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

A. The Company's system generation totaled 90,527,227 MW hours ("MWHs") for the test period. The fossil/hydro fleet provided 34,071,818 MWHs, or approximately 38% of the total generation. The breakdown includes a 31% contribution from the coal-fired stations, approximately 1% contribution each for the CTs and hydro facilities, and approximately 5% from the CC operations.

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

A. The Company's generating units operated efficiently and reliably during the test period. The Company uses key measures to evaluate the operational performance of generating facilities: (1) equivalent availability factor; and (2) capacity factor. Equivalent availability factor refers to the percent of a given time period a facility was available to operate at full power, if needed. Equivalent availability is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (*i.e.*, forced) outage time. Capacity factor 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. Capacity factor is affected by the dispatch of the unit to serve customer needs. Further, the performance reporting is categorized in order to appropriately reflect operational characteristics -- large coal-fired facilities, which have a higher usage rate and are the most cost effective generators within the generator type group.

The Company's larger coal-fired units achieved results of 88.5% equivalent availability factor and 50.8% capacity factor over the test period. During the 2012 peak summer season (e.g., June through August 2012), these larger units achieved results of 96.2% equivalent availability factor and 65.5% capacity factor. The Company's nine cycling coal-fired units achieved results of 98.5% equivalent availability factor and 5.3% capacity factor over the review period, and during the 2012 summer peak months they achieved results of 98.1% equivalent availability and a capacity factor of 11.5%. The low capacity factors for these coal-fired units are a result of their minimal operation due to the Company running its natural gas units more frequently to take advantage of low prices and as a result of the Joint Dispatch Agreement, and are a direct example of the impact that the low pricing of shale gas, as described in Company Witness Weintraub's testimony, has had on many utilities' generation dispatch orders.

On a total coal-fired fleet basis, the capacity factor was 43.9% for the review period and 57.3% during the 2012 summer peak months. Overall, the coal-fired units achieved a fleet-wide availability factor of 90.0% for the review period, and 96.5% during the 2012 summer peak months. These results compare favorably with the most recently published North American Electric Reliability Council ("NERC") average equivalent availability results for all North American coal plants of 83.5%. The results, included in the NERC Generating Availability Report ("NERC Report"), represent the period 2007 through 2011. Typically, the Company obtains this data from NERC's Generating Unit Statistical Brochure ("NERC Brochure"). The most recent NERC Brochure, however, has not yet been published, and as a result, the Company computed this data from the NERC Report.

The Company's CTs located at Lincoln, Mill Creek, Rockingham, and Lee Stations were available as needed in this time period, with a 99.2% starting reliability, outperforming the average of 97.4% reported by NERC in the above-referenced report. The Buck CC facility reported a capacity factor of 76.5%, which is above the NERC reported average of 40.4%. With an overall availability factor of 93.4%, the hydroelectric fleet had outstanding operational performance during the review period, and also exceeded the NERC reported average availability factor of 85.2%.

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

A. In general, planned maintenance outages for all fossil and larger hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most of these units had at least one small planned outage during this test period to inspect and maintain plant equipment. Five of the 22 coal-fired units had planned outages of three weeks or more. In the spring of 2012, maintenance outages included Belews Creek Unit 2, which involved significant work on boiler waterwall replacement and relining FGD absorber structures along with inspections on the turbine and generator. Outage work on Marshall Unit 4 included FGD maintenance, boiler waterwall work, piping and valve installations for the desuperheater, and replacement of preheater baskets, along with maintenance on mills/feeders, precipitators and flyash systems. In the fall of 2012, Allen Units 1, 2 and 5 had outages for FGD absorber maintenance and warranty work along with air preheater basket replacement for Unit 5. Significant work during these outages included installation of a potential adjustment protection system for the absorber reaction tank, battery bank replacement, and the rebuild of multiple valves.

Combustion turbine outages included Lincoln Units 11 and 12 in the spring which involved hot gas path inspections along with annual maintenance activities. A borescope inspection and fuel nozzle replacement was also performed on Unit 12. Outages for Mill Creek Units 5 and 6 were completed to perform combustion and generator inspections, and a hot gas path inspection on Unit 6 in addition to annual maintenance activities. Also, in the spring, a planned outage for Rockingham Unit 3 was conducted for a hot gas path inspection as well as a generator inspection and annual maintenance activities. In the fall, outages occurred for Lincoln Units 3 and 4 that involved generator inspections along with annual maintenance activities.

Outages began for Rockingham Units 1 and 3 for borescope inspections. The inspections revealed cracks and material loss in transition pieces with downstream damage to turbine blades and vanes. The Company opted to take Units 2 and 4, which are equipped with the same style and vintage pieces, offline and perform borescope inspections. The inspections on Units 2 and 4 revealed suspect areas in the transition pieces for Unit 2 and several cracked transition pieces but without material loss for Unit 4. Purchase of new components -- Units 1 and 3 had sustained in-service damage to certain components that were not repairable -- reduced the lead-time on repairs, and the units were returned to service late in December 2012. The components for Units 2 and 3 were repairable, which reduces the costs but increases the lead-time; these units are scheduled to return to service in late March 2013.

Q. PLEASE DESCRIBE THE ROCKINGHAM UNIT 5 OUTAGE FROM THE PRIOR YEAR THAT EXTENDED INTO THE TEST PERIOD.

A. In October 2011, a planned annual borescope inspection on Rockingham Unit 5 revealed damage to turbine blades. After preliminary evaluation of the damage, the unit was placed in an outage. The finding of the turbine blade failure analysis was the failure of one or more row 1 turbine blade tip caps which caused domestic object damage to the row 1 through row 4 turbine blades and turbine vanes, which were damaged to the extent of needing extensive repairs. The lead time for the repairs was 16 weeks with a ship date of April 2, 2012 from Siemens Energy's Houston Texas repair center.

Unit 5 had been experiencing unexpectedly higher than usual NOx emissions since it was returned to service from a hot gas path inspection in the spring of 2010, making compliance with NOx emissions limits difficult at full load. Several attempts had been made to reduce the NOx emissions including controls tuning, fuel nozzle replacements, and change out of combustor baskets with Siemens' extra thick thermal barrier coating baskets. Although some improvements were achieved, DEC took the opportunity afforded by the forced outage to make improvements to fuel nozzles that have restored NOx performance. Following return to service in late May 2012, Unit 5 achieved an equivalent availability factor of 96.2% for the remainder of the test period.

Q. HOW DOES THE COMPANY ENSURE EMISSION REDUCTIONS FOR ENVIRONMENTAL COMPLIANCE?

A. As noted above, DEC 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 NO_x and SO_2 emissions. The SCR technology that the Company currently operates uses ammonia or, in the case of Marshall Unit 3, urea, which is converted to ammonia for NO_x removal.

The SNCR technology injects urea into the boiler for NO_x removal and the scrubber technology employed by the Company uses crushed limestone for SO_2 removal. Dibasic acid can also be used with the scrubber technology for additional SO_2 removal. SCR equipment is also an integral part of the design of the Buck and Dan River CC Stations. Aqueous ammonia (19% solution of NH_3) is introduced for NO_x removal.

Overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emission reduction required. As a result, the Company uses chemicals such as the aforementioned limestone, ammonia, urea, and dibasic acid, as well as chemicals such as magnesium hydroxide and calcium carbonate, which are used in order to mitigate increased sulfur trioxide ("SO_3") emissions due to consumption of higher sulfur coals pursuant to DEC's fuel flexibility efforts as described by Company Witness Weintraub. The Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. The goal is to effectively comply with emission regulations and provide the most efficient total-cost solution for operation of the unit.

For the test period, the Company spent a total of $25 million on chemicals used to reduce emissions and has included $42 million for the proposed fuel factor. The proposed costs show an increase most notably to support new generation resources at Cliffside and Dan River as noted earlier.

Q. **DOES THAT CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1033

In the Matter of Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	**DIRECT TESTIMONY OF ROBERT J. DUNCAN, II FOR DUKE ENERGY CAROLINAS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert J. ("Bob") Duncan, II. 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 Carolinas, LLC's ("DEC" or the "Company") McGuire Nuclear Station ("McGuire") in Mecklenburg County, North Carolina, Catawba Nuclear Station ("Catawba") in York County, South Carolina, and Progress Energy Carolinas, Inc.'s ("PEC") Shearon Harris Nuclear Generating Station ("Harris") in Wake County, North Carolina.

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES?

A. As Senior Vice President of Nuclear Operations for McGuire, Catawba, and Harris, I am responsible for providing direct oversight for the day-to-day safe and reliable operation of those nuclear stations.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor's degree in Nuclear Engineering from the University of Florida at Gainesville and a Master's in Business Administration from the University of North Carolina at Chapel Hill. I began my career with Progress Energy, Inc. ("Progress Energy") in 1980 as a start-up engineer at Harris, and I received my senior reactor operator certification in 1997. Through the years I have held leadership roles in several areas within the nuclear organization including engineering, mechanical systems, technical support, reactor and performance engineering, and plant management. In 2007, I was named vice president of Harris, where I was responsible for managing all activities to ensure the safe and efficient operation of the facility. I also served as vice president of nuclear operations for Progress Energy from 2008 to 2010, and again from 2011 to July 2012. In that role, I was responsible for ensuring safe and reliable operations, improving work efficiencies, and effectively aligning practices, policies, and procedures. From 2010 to 2011, I was on special assignment as vice president of PEC's Robinson Nuclear Generating Station. I assumed my current position following the merger between Duke Energy Corporation and Progress Energy in July 2012.

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 McGuire and Catawba nuclear stations, as well as DEC's Oconee Nuclear Station ("Oconee"), located in Oconee County, South Carolina, during the test period of January 1, 2012 through December 31, 2012 ("test period"). I also discuss the nuclear capacity factor being proposed by DEC and used in this proceeding for determining the fuel factor to be reflected in rates during the billing period of September 1, 2013 through August 31, 2014 ("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 the Company's nuclear units through the billing period. This exhibit represents the Company's current plan, which is subject to change based on fluctuations in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEC'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 5,200 megawatts ("MWs") of generating capacity, made up as follows:

Oconee -	2,538 MWs
McGuire -	2,258 MWs [1]
Catawba -	435 MWs [2]

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

A. The Company's nuclear fleet consists of three generating stations and a total of seven units. Oconee began commercial operation in 1973 and was the first nuclear station designed, built, and operated by DEC. It has the distinction of being the second nuclear station in the country to have its license, originally issued for 40 years, renewed for up to an additional 20 years by the Nuclear Regulatory Commission ("NRC"). The license renewal, which was obtained in 2000, extends operations to 2033, 2033, and 2034 for Oconee Units 1, 2, and 3 respectively.

McGuire began commercial operation in 1981, and Catawba began commercial operation in 1985. In 2003, the NRC renewed the licenses for McGuire and Catawba for up to an additional 20 years each. This renewal extends operations until 2041 for McGuire Unit 1 and 2043 for McGuire Unit 2,

[1] As of December 31, 2012 – includes capacity increases associated to low pressure turbine upgrades.
[2] Reflects DEC's 19.2% ownership of Catawba Nuclear Station.

and Catawba Units 1 and 2. The Company jointly owns Catawba with North Carolina Municipal Power Agency Number One, North Carolina Electric Membership Corporation, and Piedmont Municipal Power Agency.

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

A. The primary objective of DEC's nuclear generation department is to safely provide reliable and cost-effective electricity to the Company's Carolinas customers. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with detailed procedures. 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 effectively ready the plant for operation until the next planned outage.

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

A. Overall, DEC's nuclear stations operated well during 2012, and supplied 62% of the power used by its Carolinas customers in the test period. The seven nuclear units operated at a system average capacity factor of 91.85%. The capacity factor for McGuire Unit 1 was 104.67%, an annual record for the unit. McGuire Unit 2 concluded a 528-day continuous run leading up to the fall refueling outage – the longest continuous run in McGuire history. This also ended a 335-day continuous dual-unit run setting another station record. Oconee Unit 3 set a unit record by concluding a 446-day continuous run leading up to its refueling outage, and Oconee set a new record in the 2nd quarter of 2012 with a capacity factor of 102.68%.

Also of note, in 2012 the Company implemented the second upgrade of an integrated digital reactor protection system and engineering safeguards ("RPS/ES") technology on Oconee Unit 3. The Company was able to reduce the length of the outage on this second upgrade by 14 days, and more efficiently completed the refueling and maintenance work due in large part to the application of lessons learned from the Unit 1 RPS/ES implementation. As a follow-up to the Unit 1 upgrade, the Company was recognized and received multiple awards, including the "Engineering Project of the Year" award at the 13th Annual Platt's Global Energy Awards ceremony, and the Nuclear Energy Institute's "Best of the Best" Top Industry Practice award.

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

A. Utilizing the North American Electric Reliability Council's ("NERC") Generating Availability Report ("NERC Report"), which is considered by the North Carolina Utilities Commission in establishing fuel factors in proceedings such as this, the Company's nuclear fleet compares favorably. The most recently published NERC Report, which represents the period 2007 through 2011, indicates an average capacity factor of 89.79%. Typically, the Company obtains this figure from NERC's Generating Unit Statistical Brochure ("NERC Brochure"). The most recent NERC Brochure, however, has not yet been published, and as a result, the Company computed this number from the NERC Report. The 89.79% capacity factor represents an average of comparable units, which are pressurized water reactors on a capacity-rated basis with capacity ratings at and above 800 MWs. The Company's capacity factor of 91.85% for 2012 exceeds the NERC average of 89.79%. Overall, the Company's system average nuclear capacity factor has been above 90% for 13 consecutive years. These performance results support DEC's continued commitment to achieving high performance without compromising safety and reliability.

Q. WHAT IMPACTS A UNIT'S AVAILABILITY AND WHAT IS THE COMPANY'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 DEC's nuclear system. The Company's nuclear performance has improved significantly over the course of the years of operating its nuclear fleet. In particular, shorter refueling outages and improved forced outage rates have contributed to increasing the capacity factors achieved by the Company's nuclear fleet as discussed above.

The Company's scheduling philosophy is to plan for a best possible outcome with minimal contingency days included in the outage plan. When an extension is necessary, however, the Company believes that such extensions result 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, 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 return the unit to service as quickly as possible.

Q. WERE OUTAGE EXTENSIONS REQUIRED FOR REFUELING AND MAINTENANCE OUTAGES THAT OCCURED AT THE COMPANY'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. Yes, there were five refueling and maintenance outages during the test period and additional time was required during three of these outages to complete activities needed for on-line reliability. The spring 2012 refueling and maintenance outage on Catawba Unit 2 required an 11-day extension most notably due to a loss of offsite power event at the station, which I describe in more detail later in my testimony. Other efforts included in the refueling outage for Unit 2 included replacing service water and cooling water piping, which completed phase II of a major project effort, and valve conversions and replacements.

In the fall of 2012, Oconee Unit 1 began a refueling and maintenance outage which required a five-day extension due to work associated with vent valve replacement. Major work activities included with this refueling outage were removing reactor vessel internals for extensive inspections, seal replacements on 1A1 and 1B2 reactor core pumps, and installation of a redundant bus line differential relaying to CT-1 transformer.

The McGuire Unit 2 refueling and maintenance outage took place in the fall and required a 31-day extension. The most prominent delays involved challenges with major projects incorporated into the outage duration window, rework required due to foreign material, turbine bearing damage discovered during startup, and an isolation valve problem that required returning to Mode 3 for repair. This refueling and maintenance outage was a milestone effort in the Company's uprate program involving replacement of the rotor for the high pressure turbine and upgraded measurement uncertainty recapture instrumentation. Although final analysis continues, the Company estimates an increased capacity of 30 MWs for the unit as a result of these upgrades. Also, to address end-of-life for the unit, the generator stator, exciter and support systems were replaced. Other major work efforts during this outage included upper, lower, and volumetric reactor head inspections, replacement of the 2C reactor coolant pump motor, and overhauling the 2A service water pump.

Q. PLEASE DESCRIBE THE LOSS OF OFFSITE POWER EVENT AT CATAWBA.

A. The loss of offsite power event that occurred at Catawba in April 2012 was triggered by an electric fault on a cable associated with the 1D reactor coolant pump motor. This electric fault brought to light a protective relay scheme issue for the main generator, which resulted in four Unit 1 switchyard breakers opening unnecessarily. The issue with the protective relaying scheme was associated to a modification implemented in the prior year which was designed to provide additional frequency protection for the main generator. The Company completed repairs to the cable that faulted and corrected the relaying scheme issue for Unit 1, thereby ensuring the implementation of the relay scheme for the Unit 2 modification during the then current Unit 2 refueling and maintenance outage. Additionally, the Company verified that other stations were not vulnerable to the same situation and worked closely with the NRC's inspection team sent to review the situation and the corrective actions taken by the Company.

Importantly, when the unit automatically shut down, the emergency diesel generators started and supplied the power needed for essential equipment. The plant operators responded well to this extremely challenging event, as did the emergency organization that assembled to support them. Although the cause of the event was external to the station, it demonstrated the effectiveness of the station's protective systems and the ability of its operators to successfully manage the challenge.

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

A. The Company proposes to use a 92.84% capacity factor and believes that this capacity factor is reasonable for use in this proceeding based upon the operational history of DEC's nuclear units and the number of planned outage days scheduled during the billing period. This proposed percentage is reflected in the testimony and exhibits of Company Witness Smith and exceeds the five-year industry weighted average capacity factor of 89.79% for pressurized water reactors rated at and above 800 MWs as reported in the NERC Report representing the period of 2007 to 2011.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Duncan Exhibit 1

CONFIDENTIAL

Duke Energy Carolinas, LLC
Planned Nuclear Outages
Period: January 1, 2013 through August 31, 2014

[redacted]

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1033

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David C. Culp 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 Carolinas, LLC ("DEC" or the "Company") and Progress Energy Carolinas, Inc. ("PEC").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEC?

A. I am responsible for nuclear fuel procurement, spent fuel management, reactor core design, nuclear safety analysis, and reload analysis methods for the nuclear units owned and operated by DEC and Progress Energy Inc.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of South Carolina with a Bachelor of Science degree in mechanical engineering and a Master's degree in business administration. I began my career with the Company in 1986 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 in 1995. Beginning in 1999, I incrementally assumed responsibility for spent nuclear fuel management, nuclear fuel mechanical and thermal hydraulic design, and reactor core design. In 2003, I was named vice president of Claiborne Energy Services – a partner in the

Louisiana Energy Services venture to license, construct, and operate a new uranium enrichment plant in the United States. I assumed my current role in 2011.

I have served as Chairman of the World Nuclear Fuel Market's Board of Governors, an organization that promotes efficiencies in the nuclear fuel markets. I have also served as Chairman of the Ad Hoc Utilities Group ("AHUG"), an association that promotes free trade in nuclear fuel, and Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use. I am a registered professional engineer in the states of North Carolina and South Carolina.

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

A. The purpose of my testimony is to (1) provide information regarding DEC's nuclear fuel purchasing practices, (2) provide costs for the January 1, 2012 through December 31, 2012 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2013 through August 31, 2014 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 Culp Exhibit 1, which is a Graphical Representation of the

Nuclear Fuel Cycle, and Culp Exhibit 2, which sets forth the Company's Nuclear Fuel Procurement Practices.

Q. MR. CULP, 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 Culp 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% U-235 and 99.3% U-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. The two commercially available enrichment processes, gaseous diffusion and gas centrifuge, first heat 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 UF6 is enriched to the desired level, it is converted to uranium dioxide ("UO_2") powder and formed into pellets. This process and subsequent steps of inserting the fuel pellets into fuel rods and bundling the rods into fuel assemblies for use in nuclear reactors is referred to as fabrication.

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

A. As set forth in Culp Exhibit 2, DEC's nuclear fuel procurement practices involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of spot and long-term contracts from diverse sources of supply, assessing spot market opportunities, 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. The typical initial delivery under new long-term contracts has grown to several years after contract execution because many proven, reliable producers have sold their near-term capacity. For this reason, DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, 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. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Q. WHAT CHANGES HAVE OCCURRED IN THE UNIT COST OF THE VARIOUS STAGES OF NUCLEAR FUEL DURING THE TEST PERIOD?

A. During the test period, the published long-term market price for uranium concentrates was in the range of \$56.00/lb to \$61.50/lb. During this same period, the published spot market price, which is referenced in a segment of long-term contracts in order to establish delivery price, ranged from a low of \$42.00/lb to a high of \$52.00/lb. The impact of the spot market volatility on

DEC was mitigated by the portfolio of supply contracts negotiated in prior years which use a mixture of pricing mechanisms. The Company's portfolio of diversified contract pricing yielded an average unit cost of $47.13/lb for uranium concentrates during the test period.

Industry consultants believe market prices need to increase from current levels in order to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements. As a portion of DEC's existing supply contracts expire each year, they will be replaced by contracts that are anticipated to contain higher delivery prices.

During the test period, the published long-term market price for enrichment services was in the range of $134.00/Separative Work Unit ("SWU") to $148.00/SWU. One hundred percent of DEC's enrichment purchases during the test period were delivered under long-term contracts negotiated at market prices prior to the test period. This mitigated the impact of price uncertainty on DEC during the test period. The average unit cost of DEC's purchases of enrichment services during the test period was $117.19/SWU. As existing enrichment contracts in DEC's portfolio expire, they will be replaced with contracts that are anticipated to contain higher delivery prices.

Fabrication and conversion prices generally trended upward during the test period. These costs, however, have a limited impact on the overall fuel expense rate given that the dollar amounts for these purchases represent a substantially smaller percentage – 14% and 4%, respectively, for the fuel batches recently loaded into DEC's reactors – of the Company's total direct fuel cost relative to uranium concentrates or enrichment, which are 43% and 39%, respectively.

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

A. The Company anticipates an increase in nuclear fuel expense through the next billing period. Because fuel is typically expensed over two to three operating cycles – roughly three to five years – DEC's nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period, as well as prior periods. A portion of the fuel residing in the reactors during the billing period will have been obtained under contracts negotiated prior to the recent market price increases. Newer contracts reflecting increasing price trends, however, are now contributing to a portion of the uranium, enrichment, and fabrication costs reflected in the total fuel expense.

As a result of the above noted changes, the average fuel expense is expected to increase from 0.574 cents per kilowatt hour ("kWh") incurred in the test period, to approximately 0.676 cents per kWh in the billing period. As fuel with a low cost basis is discharged from the reactor and lower priced legacy contracts continue to expire, nuclear fuel expense is anticipated to experience further increases in the future.

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

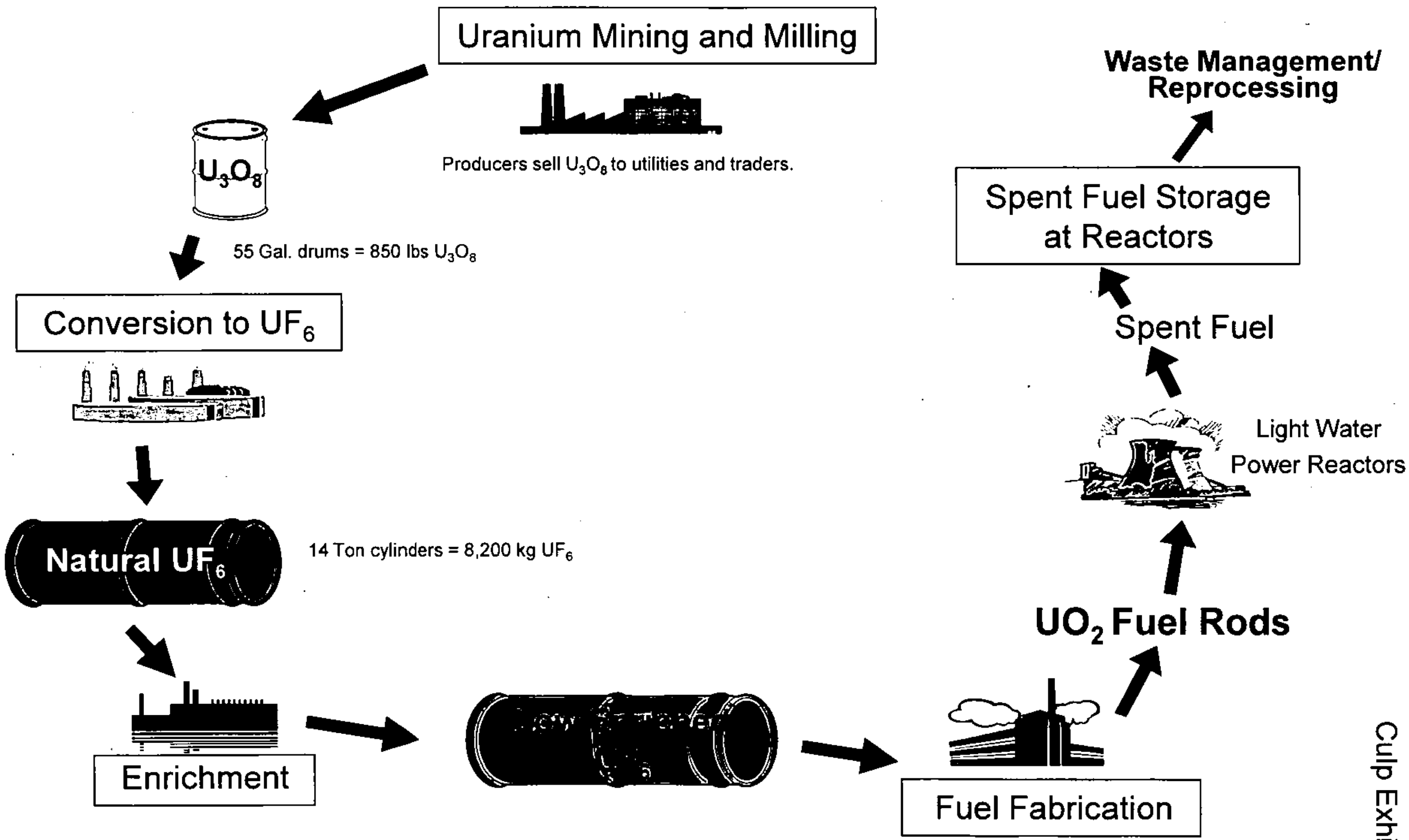
A. As I discussed earlier and as described in Culp Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEC relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating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

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 the Company'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 TESTIMONY?**

A. Yes, it does.

The Nuclear Fuel Cycle



Culp Exhibit 1

Duke Energy Carolinas, LLC Nuclear Fuel Procurement Practices

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

- The Company computes near and long-term consumption forecasts 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.
- The Company determines and designs nuclear system inventory targets to provide: reliability, insulation from short-term market volatility, and sensitivity to evolving market conditions. The Company monitors inventories on an ongoing basis.
- On an ongoing basis, the Company compares existing purchase commitments with consumption and inventory requirements to ascertain additional needs.
- The Company invites qualified suppliers to make proposals to satisfy additional or future contract needs.
- The Company awards contracts 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, the Company relies upon long term supply contracts 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, the Company generally sources fabrication services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.
- The Company evaluates spot market opportunities from time to time to supplement long term contract supplies as appropriate based on comparison to other supply options.
- The Company monitors delivered volumes of nuclear fuel products and services against contract commitments. The Company confirms the quality and volume of deliveries with the delivery facility to which it has instructed delivery. Payments for such delivered volumes are made after Duke Energy Carolinas' receipt of such delivery facility confirmations.