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May 8, 2024

VIA ELECTRONIC FILING

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

RE: Duke Energy Carolinas, LLC's Supplemental Testimony
Docket No. E-7, Sub 1304

Dear Ms. Dunston:

Please find enclosed Duke Energy Carolinas, LLC's Supplemental Testimony and Exhibits of Sigourney Clark, in the above-referenced proceeding.

If you have any questions, please do not hesitate to contact me. Thank you for your assistance with this matter.

Sincerely,

Ladawn S. Toon

Enclosures

cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1304

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**SUPPLEMENTAL TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF SIGOURNEY CLARK 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 Sigourney Clark. My business address is 5413 Shearon Harris Road, New Hill, North Carolina.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes, on February 27, 2024, I caused to be pre-filed with the North Carolina Utilities Commission ("NCUC") my direct testimony and 7 exhibits and 12 supporting workpapers.

Q. YOUR SUPPLEMENTAL TESTIMONY INCLUDES FOUR (4) REVISED EXHIBITS AND ONE (1) REVISED WORKPAPER. WERE THESE SUPPLEMENTAL EXHIBITS AND WORKPAPER PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared by me and consist of the following:

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

Clark Revised Exhibit 2: Calculation of the Proposed Fuel and Fuel-Related Cost Factors.

Clark Revised Exhibit 3: Calculation of the Proposed Experience Modification Factor ("EMF") rate.

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

Clark Revised Workpaper 7a: Projected and Adjusted Projected Sales and Costs

Q. **WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?**

A. The purpose of my supplemental testimony is to (1) present revised rates reflecting impacts of the proposed EMF increment for the experienced net under-recovery of fuel and fuel-related costs through March 31, 2024, (2) revise fuel factors for the Industrial customer class to help mitigate their bill impacts on two dates where rates from the current and prior year fuel proceeding would be billed, and (3) revise one of the fuel rate scenarios presented in my direct testimony filing. My testimony is organized into three sections in order to present fuel factors and related customer bill impacts. The first two sections apply to each customer class, whereas the third section only applies to the Industrial customer class.

Regarding update (3) above, the scenario based on the proposed nuclear capacity factor and normalized test period sales (as shown on Clark Revised Exhibit 1, Line 5) is updated to reflect a revision to total company test period sales, as shown on Clark Revised Exhibit 4, Line 1. This scenario is informational only, and the Company is not proposing fuel factors based on this scenario, therefore this revision has no impact to customers' proposed fuel factors. For clarity, the Company is proposing the fuel factors detailed on Clark Revised Exhibit 1, Lines 14 and 15 for the applicable time periods indicated therein.

I. Extending the Experience Modification Factor

Q. NCUC RULE R8-55(D)(3) ALLOWS A UTILITY TO INCORPORATE ITS EXPERIENCED OVER-RECOVERY OR UNDER-RECOVERY OF THE COST OF FUEL AND FUEL-RELATED COSTS UP TO 30 DAYS PRIOR TO THE DATE OF THE HEARING. IS THE COMPANY ELECTING THIS OPTION?

A. Yes, pursuant to NCUC Rule R8-55(d)(3), the Company elects to update its experienced net under-recovery through March 31, 2024, and supplements the direct testimony and exhibits to include the fuel and fuel-related cost recovery balances by customer class, which results in new proposed fuel and fuel-related cost factors.

Q. HOW DID THE FUEL AND FUEL-RELATED COST RECOVERY BALANCE CHANGE IN THE THREE (3) MONTHS BEING INCORPORATED?

A. The Company experienced a net under-collection of $25,850,038 during the months January through March 2024. As shown on Clark Revised Exhibit 3, Page 1, the incorporation of the update period net under-collection balance resulted in a revised, net under-recovered balance of $241,506,658. While the Company experienced a total net under-recovery for the months of January through March 2024, the Residential customer class experienced an over-recovery for this time period of $1,544,321. Therefore, the EMF increment rate requested to be recovered for the Residential customer class has decreased from the Company's original proposed rates in my direct testimony. Conversely, both the General

Service/Lighting and Industrial customer classes experienced under-recoveries for this time period of $18,632,753 and $8,761,606, respectively. Therefore, the EMF increment rate requested to be recovered for the General Service/Lighting and Industrial customer classes has increased.

II. Docket No. E-7, Sub 1282 Experience Modification Factor Update

Q. ARE THERE OTHER UPDATES THE COMPANY WOULD LIKE TO ADDRESS IN THIS SUPPLEMENTAL FILING?

A. Yes. In Docket No. E-7, Sub 1282 (2023 fuel proceeding), the Company and Public Staff entered into an *Agreement and Stipulation of Partial Settlement* ("Partial Settlement") which, amongst other resolved issues, extended the recovery of the Company's under-recovered 2022 test period fuel balance of approximately $998 million to a period of 16 months as opposed to the statutory 12-month recovery period.

The Company has been monitoring the recovery of this $998 million under-recovered balance since rates in that docket became effective on September 1, 2023. At current, through March 31, 2024, the Company has experienced a cumulative, net under-recovery of approximately $8 million. The under-recovery is driven by softer than expected sales, primarily due to mild weather, particularly from December 2023 to March 2024.

Given the magnitude of this under-recovery, the Company is requesting a new EMF increment factor (as shown on Clark Revised Exhibit 1, Line 12) to recover each customer class's portion of this cumulative net under-recovery. This update results in EMF balance increases of approximately $6.5 million for Residential customers and $1.7 million for Industrial customers. However, the Company is seeing an over-recovery for its General Service/Lighting customers of $67 thousand.

Q. IS THE COMPANY SEEKING RECOVERY OF THE APPROXIMATE $8 MILLION UNDER-RECOVERY THROUGH MARCH 31, 2024, IN THIS SUPPLEMENTAL FILING?

A. Yes, the Company has included each customer class's portion of the net under recovered balance from Docket No. E-7, Sub 1282 on Clark Revised Exhibits 1 and 3.

Q. IS THE COMPANY SEEKING ADDITIONAL CARRYING COSTS ASSOCIATED WITH THIS APPROXIMATE $8 MILLION UNDER-RECOVERY?

A. No. The Company is simply seeking recovery of its approved under-recovered fuel balance from its 2023 fuel proceeding of approximately $998 million.

Q. IF THE COMPANY WERE TO OVER-RECOVER THE APPROXIMATE $998 MILLION WHEN THE PRIOR YEAR EMF RATE CEASES TO BE BILLED ON DECEMBER 31, 2024, WOULD IT RETURN THAT OVER-RECOVERY TO CUSTOMERS?

A. Yes, when the Company prepares its 2025 fuel proceeding, if it finds the $998 million has been over-recovered, the Company would seek to flow any over-recovery back to affected customers. Conversely, if the Company finds it has further under-recovered this amount, it would seek to recover that from customers.

Again, the Company is seeking to fully recover its approved fuel expense of approximately $998 million – no more, no less.

Q. WHAT IS THE TOTAL RATE IMPACT OF THESE UPDATES?

A. The Company's aggregate under-recovered amount for North Carolina Retail has increased by $33,999,401 from the amount filed in my direct testimony Exhibit 3, Page 1. This increased under-recovery includes $8,149,363 related to Docket No. E-7, Sub 1282 that the Company is seeking recovery of in this proceeding. Each customer class's proposed EMF rate represents each class's share of the updated under-recovery for the period January 1, 2023, to March 31, 2024. The components of the proposed fuel and fuel-related cost factors by customer class, proposed in this proceeding as shown on Clark Revised Exhibit 1, are as follows:

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh
Total Adjusted Fuel and Fuel Related Costs	2.3061	2.3045	2.2951
EMF Increment (Decrement)	0.4751	0.3221	0.6519
EMF Interest (Decrement)	-	-	0.0060
EMF Increment (Decrement) Docket E-7, Sub 1282	0.0285	(0.0003)	0.0205
Net Fuel and Fuel Related Costs Factors	2.8097	2.6263	2.9735
Net Fuel and Fuel Related Costs Factors cents/kWh (9/1/2024 - 12/31/2024)	4.0760	3.8687	3.6045
Net Fuel and Fuel Related Costs Factors cents/kWh (01/01/2025 - 8/31/2025)	2.8097	2.6263	2.9735

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

A. Consistent with my direct testimony, all customers will see a temporary bill increase on September 1, 2024, when new rates become effective. This temporary increase is solely the result of the customer mitigation agreed to in the 2023 fuel proceeding, which resulted in an extended recovery period of the under-recovery of approximately $998 million through December 31, 2024. However, on January 1, 2025, when that prior year rate ceases to be billed, all customer classes will see a bill decrease.

In light of the requests in my supplemental testimony, for the four-month period September 1, 2024, through December 31, 2024, a typical Residential customer using 1,000 kWh per month would experience an increase of $1.78, or 1.3% (compared to 1.1% from my direct testimony). The impacts for average General Service/Lighting customers and Industrial customers vary by customer, but are approximate increases of 3.6% (compared to 2.9%) and 4.3% (compared to 9.1%), respectively. For the Industrial customer class impacts compared to my direct testimony, please see Section III - Smoothing of Industrial Class Bill Impacts.

Upon the expiration of the additional four-month billing of the EMF and EMF interest increment fuel factors from the 2023 fuel proceeding, customer bills are expected to decrease. A typical Residential customer using 1,000 kWh per month would experience a decrease of $12.68, or 8.9% from fuel factors in effect at that time (no change from my direct testimony). The impacts for average General Service/Lighting customers and Industrial customers vary by customer, but are approximate decreases of 12.5% (no change from direct testimony) and 7.6% (compared to 15.9%), respectively from fuel factors in effect at that time.

III. Smoothing of Industrial Class Bill Impacts

Q. PLEASE REMIND THE COMMISSION OF EACH CUSTOMER CLASS'S TYPICAL BILL IMPACT FROM THE COMPANY'S DIRECT FILING.

A. In the Company's direct filing, I testified that for the four-month period beginning September 1, 2024, and ending December 31, 2024, a typical Residential customer using 1,000 kWh per month would experience a temporary increase of $1.60, or 1.1%. The impacts for average General Service/Lighting customers and Industrial customers vary by customer, but are approximate increases of 2.9% and 9.1%, respectively. As reiterated above, these increases are solely due to the customer mitigation agreed to in the prior fuel proceeding and approved by the Commission that resulted in billing the EMF and EMF interest increment fuel factors over 16 months.

Q. DOES THE COMPANY RECOGNIZE THAT THE INDUSTRIAL CUSTOMER CLASS'S TYPICAL BILL IMPACTS ARE LARGER THAN THAT OF THE OTHER TWO CUSTOMER CLASSES?

A. Yes.

Q. WHAT IS CAUSING THE INDUSTRIAL CUSTOMER CLASS'S TYPICAL BILL IMPACTS TO BE LARGER THAN THE OTHER TWO CUSTOMER CLASSES?

A. Historically, the Company allocated fuel expense under the uniform percentage methodology, otherwise known as the equal percent methodology. In the Company's most recent general rate case in Docket No. E-7, Sub 1276, the

Commission ordered the Company to discontinue the use of the equal percent methodology in its 2024 fuel proceeding, as I described in my direct testimony. Elimination of the equal percent method in this year's fuel proceeding is impacting the Industrial customer class more significantly than other customer classes. In recent fuel proceedings, fuel expense has increased due to volatile fuel commodity prices. Under the equal percent method, when fuel expense increases, the Industrial customer class is allocated less of the increase. Therefore, the Industrial customer class's fuel factors approved in the 2023 fuel proceeding had the inherent benefit of a lower share of higher fuel expense. With the elimination of the equal percent method in this fuel proceeding, the year-over-year change in the Industrial fuel rate is more significant, such that when the change is applied to a typical Industrial customer's bill, the percentage increase is more pronounced.

Q. WHAT IS THE COMPANY PROPOSING TO SMOOTH INDUSTRIAL CUSTOMER BILL IMPACTS?

A. In recognition of the larger bill impacts for the Industrial customer class, the Company is proposing to postpone recovery of the current EMF of $56,017,539 as shown on Clark Revised Exhibit 3, Page 4 (sum of Lines 19 and 22) over an 8-month period, starting January 1, 2025, and continuing through August 31, 2025. By delaying the recovery of the current EMF and allowing only the prior year EMF to be billed through December 31, 2024, the Industrial customers will experience a smaller temporary increase on a typical bill on September 1, 2024, when the prior year EMF fuel factor is still effective. Then, on January 1, 2025, after the prior year EMF fuel factor ceases being billed, Industrial customers would see a decrease in their typical bill of 7.6%.

Q. IS THE COMPANY SEEKING RECOVERY OF CARRYING COSTS ASSOCIATED WITH ITS PROPOSED DELAYED RECOVERY OF THE CURRENT YEAR EMF FROM INDUSTRIAL CUSTOMERS?

A. Yes. By postponing recovery of the current year EMF, the Company is requesting carrying costs of approximately $497 thousand, at a borrowing rate of 5.5%, which represents the Company's current short-term borrowing rate.

Q. WHAT WILL BE THE BILL IMPACTS TO INDUSTRIAL CUSTOMERS IF THE SMOOTHING PROPOSAL IS ADOPTED?

A. If the smoothing proposal is adopted, Industrial customer bill impacts would result in a temporary increase on September 1, 2024, of 4.3% (compared to 9.1% as stated in my direct testimony) and on January 1, 2025, the bill impact would change from a decrease of 15.9% (as stated in my direct testimony) to a decrease of 7.6%.

Q. DOES THE COMPANY CONSIDER THIS SMOOTHING OPTION TO BE THE ONLY AVAILABLE SMOOTHING OPTION TO THE COMPANY TO ASSIST INDUSTRIAL CUSTOMERS?

A. Yes. If this smoothing option is adopted, the Company would experience a cumulative cash flow impact of the difference in revenues collected from September 1, 2024, to December 31, 2024, of approximately $19 million. While N.C. General Statute § 62-133.2 allows the Company to recover its reasonably and prudently incurred costs over a 12-month period, the Company is voluntarily proposing this 8-month recovery option as a gesture of goodwill for its Industrial customers to help mitigate bill impacts during the 4-month period where two EMF fuel factors would be in effect.

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

A. Yes, it does.

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Summary Comparison of Fuel and Fuel Related Cost Factors
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Clark Revised Exhibit 1

Line #	Description	Reference	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
	Current Fuel and Fuel Related Cost Factors (Approved Fuel Rider Docket No. E-7, Sub 1282)					
1	Approved Fuel and Fuel Related Costs Factors	Input	2.6287	2.2596	1.9328	2.3417
2	EMF Increment (Decrement) cents/kWh	Input	1.2579	1.2342	1.3007	1.2568
3	EMF Interest Increment (Decrement) cents/kWh	Input	0.0084	0.0082	0.0087	0.0084
4	Approved Net Fuel and Fuel Related Costs Factors	Sum	**3.8950**	**3.5020**	**3.2422**	**3.6069**
	Fuel and Fuel Related Cost Factors Required by Rule R8-55					
5	Proposed Nuclear Capacity Factor of 95.73%	Exh 2 Sch 2 pg 2	**2.7859**	**2.6024**	**2.9505**	**2.7035**
6	NERC 5 Year Average Nuclear Capacity Factor of 91.90% and Projected Period Sales	Exh 2 Sch 3 pg 2	**2.8851**	**2.7020**	**3.0490**	**2.8027**
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 95.73%					
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	2.2747	2.2832	2.2771	2.2787
8	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.0314	0.0213	0.0180	0.0245
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	2.3061	2.3045	2.2951	2.3032
10	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.4751	0.3221	0.6519	0.4094
11	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	0.0060	0.0008
12	EMF Increment (Decrement) Docket E-7, Sub 1282	Exh 3 pg 2, 3, 4	0.0285	(0.0003)	0.0205	0.0138
13	Net Fuel and Fuel Related Costs Factors cents/kWh	Sum	**2.8097**	**2.6263**	**2.9735**	**2.7272**
14	Net Fuel and Fuel Related Costs Factors cents/kWh (9/1/2024 - 12/31/2024)		**4.0760**	**3.8687**	**3.6045**	
15	Net Fuel and Fuel Related Costs Factors cents/kWh (01/01/2025 - 8/31/2025)		**2.8097**	**2.6263**	**2.9735**	

Note: Fuel factors exclude regulatory fee

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 95.73%
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	60,207,920	0.5518	332,225,252
2	Coal	Workpaper 3 & 4	12,133,505	4.4094	535,009,000
3	Gas CT and CC	Workpaper 3 & 4	25,398,789	3.4009	863,780,065
4	Reagents and Byproducts	Workpaper 8			30,185,368
5	Total Fossil	Sum	37,532,294		1,428,974,434
6	Hydro	Workpaper 3	4,222,386		
7	Net Pumped Storage	Workpaper 3	(3,257,750)		
8	Total Hydro	Sum	964,636		-
9	Solar Distributed Generation	Workpaper 3	431,227		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	99,136,076		1,761,199,685
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(21,752,442)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,116,637)		(77,896,854)
13	Net Generation	Sum Lines 10-13	84,143,439		1,661,550,389
14	Purchased Power	Workpaper 3 & 4	12,586,006	3.1276	393,644,708
15	JDA Savings Shared	Workpaper 5			34,396,187
16	Total Purchased Power		12,586,006		428,040,896
17	Total Generation and Purchased Power	Line 13 + Line 16	96,729,446	2.1602	2,089,591,285
18	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(666,675)	4.1834	(27,889,431)
19	Line losses and Company use	Line 21-Line 18-Line 17	(6,256,346)		-
20	System Fuel Expense for Fuel Factor	Lines 17 + 18 + 19			2,061,701,854
21	Projected System MWh Sales At Meter for Fuel Factor	Workpaper 7	89,806,424		89,806,424
22	Fuel and Fuel Related Costs cents/kWh	Line 20 / Line 21 / 10			2.2957

Note: Rounding differences may occur

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales at Generator	Workpaper 7	24,198,399	26,115,830	13,078,907	63,393,136
	Calculation of Fuel (Non-Capacity) Rate by Class					Amount
2	System Fuel (Non-Capacity) Costs	Workpaper 7 - Line 11				$ 2,043,629,333
3	NC Portion - Jurisdictional % based on Projected Billing Period MWh Sales at Generator	Workpaper 7				66.69%
4	NC Retail Fuel (Non-Capacity) Costs before 2.5% Purchase Power Test	Line 2 * Line 3				$ 1,362,896,402
5	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 9				-
6	NC Retail Fuel (Non-Capacity) Costs Allowable Under GEN. STAT. § 62-133.2(A2)	Line 4 + Line 5				$ 1,362,896,402
7	NC Retail Projected Billing Period MWh Sales Allocation Factors at Generator	Line 1 / Line 1 Total	**38.17%**	**41.20%**	**20.63%**	**100.00%**
8	Fuel (Non-Capacity) Costs allocated on Projected Billing Period MWh Sales	Line 6 * Line 7	$ 520,244,197	$ 561,467,273	$ 281,184,932	$ 1,362,896,402
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class					Amount
9	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 11,295,326
10	QF Purchased Power - Capacity	Workpaper 4				10,496,458
11	Total of Renewable and QF Purchased Power Capacity	Line 9 + Line 10				$ 21,791,784
12	NC Portion - Jursidicational % based on 2022 Production Demand Allocator	Input				67.12%
13	NC Renewable and QF Purchased Power - Capacity	Line 11 * Line 12				$ 14,626,471
14	2022 Production Demand Allocation Factors	Input	49.05%	35.73%	15.22%	100.00%
15	Renewable and QF Purchased Power - Capacity allocated on 2022 Production Demand Allocator	Line 13 * Line 14	$ 7,174,604	$ 5,226,011	$ 2,225,856	$ 14,626,471
16	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales at Meter	Line 15 / Line 1 / 10	0.0314	0.0213	0.0180	0.0245
	Billed Rates					
17	NC Projected Billing Period MWh Sales at Meter	Workpaper 7	22,870,391	24,590,927	12,348,188	59,809,506
			cents/kWh	**cents/kWh**	**cents/kWh**	**cents/kWh**
18	Fuel (Non-Capacity) cents/kWh based on Projected Billing Period MWh Sales	Line 8 / Line 17 / 10	2.2747	2.2832	2.2771	2.2787
19	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 16	0.0314	0.0213	0.0180	0.0245
20	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 18 + Line 19	2.3061	2.3045	2.2951	2.3032
21	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.4751	0.3221	0.6519	0.4094
22	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	0.0060	0.0008
23	EMF Increment (Decrement) Docket E-7, Sub 1282	Exh 3 pg 2, 3, 4	0.0285	(0.0003)	0.0205	0.0138
24	Net Fuel and Fuel Related Costs Factors cents/kWh	Line 20 + Line 21 + Line 22	2.8097	2.6263	2.9735	2.7272

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 95.73%
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
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Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	60,207,920	0.5518	332,225,252
2	Coal	Workpaper 3 & 4	10,995,097	4.4094	484,812,565
3	Gas CT and CC	Workpaper 3 & 4	25,398,789	3.4009	863,780,065
4	Reagents and Byproducts	Workpaper 8	-		30,185,368
5	Total Fossil	Sum	36,393,885		1,378,777,998
6	Hydro	Workpaper 3	4,222,386		
7	Net Pumped Storage	Workpaper 3	(3,257,750)		
8	Total Hydro	Sum	964,636		
9	Solar Distributed Generation	Workpaper 3	431,227		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	97,997,668		1,711,003,250
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(876,000)		(21,752,442)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,116,637)		(77,896,854)
13	Net Generation	Sum Lines 10-13	83,005,031		1,611,353,953
14	Purchased Power	Workpaper 3 & 4	12,586,006		393,644,708
15	JDA Savings Shared	Workpaper 5	-		34,396,187
16	Total Purchased Power		12,586,006		428,040,896
17	Total Generation and Purchased Power	Line 13 + Line 16	95,591,037		2,039,394,849
18	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(666,675)		(27,889,431)
19	Line losses and Company use	Line 21-Line 18-Line 17	(6,256,346)		-
20	System Fuel Expense for Fuel Factor	Lines 17 + 18 + 19			2,011,505,418
21	Normalized Test Period MWh Sales	Exhibit 4	88,668,015		88,668,015
22	Fuel and Fuel Related Costs cents/kWh	Line 20 / Line 21 / 10			2.2686

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 95.73%
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Normalized Test Period mWh Sales at Generator	Workpaper 7a	24,131,647	25,991,687	12,397,056	62,520,389
	Calculation of Fuel (Non-Capacity) Rate by Class					Amount
2	System Fuel (Non-Capacity) Costs	Workpaper 7a - Line 11				$ 1,993,432,898
3	NC Portion - Jurisdictional % based on Projected Billing Period MWh Sales at Generator	Workpaper 7a				66.72%
4	NC Retail Fuel (Non-Capacity) Costs before 2.5% Purchase Power Test	Line 2 * Line 3				$ 1,329,967,099
5	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 9				-
6	NC Retail Fuel (Non-Capacity) Costs Allowable Under GEN. STAT. § 62-133.2(A2)	Line 4 + Line 5				$ 1,329,967,099
7	NC Retail Projected Billing Period MWh Sales Allocation Factors at Generator	Line 1 / Line 1 Total	**38.60%**	**41.57%**	**19.83%**	**100.00%**
8	Fuel (Non-Capacity) Costs allocated on Projected Billing Period MWh Sales	Line 6 * Line 7	$ 513,341,271	$ 552,909,042	$ 263,716,786	$ 1,329,967,099
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
9	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 11,295,326
10	QF Purchased Power - Capacity	Workpaper 4				10,496,458
11	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 21,791,784
12	NC Portion - Jursidictional % based on 2022 Production Demand Allocator	Input				67.12%
13	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 14,626,471
14	2022 Production Demand Allocation Factors	Input	49.05%	35.73%	15.22%	100.00%
15	Renewable and QF Purchased Power - Capacity allocated on 2022 Production Demand Allocator	Line 6 * Line 7	$ 7,174,604	$ 5,226,011	$ 2,225,856	$ 14,626,471
16	Renewable and QF Purchased Power - Capacity cents/kWh based on Normalized Test Period Sales at Meter	Line 8 / Line 1 / 10	0.0315	0.0214	0.0190	0.0248
	Billed Rates					
17	NC Normalized Test Period MWh Sales at Meter	Exhibit 4	22,807,302	24,474,032	11,704,432	58,985,766
			cents/kWh	**cents/kWh**	**cents/kWh**	**cents/kWh**
18	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.2508	2.2592	2.2531	2.2547
19	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0315	0.0214	0.0190	0.0248
20	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.2823	2.2806	2.2721	2.2795
21	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.4751	0.3221	0.6519	0.4094
22	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	0.0060	0.0008
23	EMF Increment (Decrement) Docket E-7, Sub 1282	Exh 3 pg 2, 3, 4	0.0285	(0.0003)	0.0205	0.0138
24	Net Fuel and Fuel Related Costs Factors cents/kWh	Line 20 + Line 21 + Line 22 + Line 23	2.7859	2.6024	2.9505	2.7035

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor of 91.90% and Projected Period Sales
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Line #	Unit	Reference		Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
				D	E	D * E = F
1	Total Nuclear	Workpaper 1		57,797,776	0.5518	318,926,159
2	Coal	Workpaper 3 & 4		13,978,555	4.4094	616,363,766
3	Gas CT and CC	Workpaper 3 & 4		25,398,789	3.4009	863,780,065
4	Reagents and Byproducts	Workpaper 8		-		30,185,368
5	Total Fossil	Sum		39,377,344		1,510,329,199
6	Hydro	Workpaper 3		4,222,386		
7	Net Pumped Storage	Workpaper 3		(3,257,750)		
8	Total Hydro	Sum		964,636		
9	Solar Distributed Generation	Workpaper 3		431,227		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9		98,570,982		1,829,255,358
11	Less Lee CC Joint Owners	Workpaper 3 & 4		(876,000)		(21,752,442)
12	Less Catawba Joint Owners	Workpaper 3 & 4		(13,551,543)		(74,778,615)
13	Net Generation	Sum Lines 10-13		84,143,439		1,732,724,301
14	Purchased Power	Workpaper 3 & 4		12,586,006		393,644,708
15	JDA Savings Shared	Workpaper 5		-		34,396,187
16	Total Purchased Power		0	12,586,006		428,040,896
17	Total Generation and Purchased Power	Line 13 + Line 16		96,729,446		2,160,765,196
18	Fuel expense recovered through intersystem sales	Workpaper 3 & 4		(666,675)		(27,889,431)
19	Line losses and Company use	Line 21-Line 18-Line 17		(6,256,346)		-
20	System Fuel Expense for Fuel Factor	Lines 17 + 18 + 19				2,132,875,765
21	Projected System MWh Sales At Meter for Fuel Factor	Workpaper 7		89,806,424		89,806,424
22	Fuel and Fuel Related Costs cents/kWh	Line 20 / Line 21 / 10				2.3750

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
NERC 5 Year Average Nuclear Capacity Factor of 91.90% and Projected Period Sales
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales at Generator	Workpaper 7b	24,198,399	26,115,830	13,078,907	63,393,136
	Calculation of Fuel (Non-Capacity) Rate by Class					Amount
2	System Fuel (Non-Capacity) Costs	Workpaper 7b - Line 11				$ 2,114,803,245
3	NC Portion - Jurisdictional % based on Projected Billing Period MWh Sales at Generator	Workpaper 7b				66.58%
4	NC Retail Fuel (Non-Capacity) Costs before 2.5% Purchase Power Test	Line 2 * Line 3				$ 1,408,036,000
5	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 9				-
6	NC Retail Fuel (Non-Capacity) Costs Allowable Under GEN. STAT. § 62-133.2(A2)	Line 4 + Line 5				$ 1,408,036,000
7	NC Retail Projected Billing Period MWh Sales Allocation Factors at Generator	Line 1 / Line 1 Total	**38.17%**	**41.20%**	**20.63%**	**100.00%**
8	Fuel (Non-Capacity) Costs allocated on Projected Billing Period MWh Sales	Line 6 * Line 7	$ 537,474,864	$ 580,063,263	$ 290,497,874	$ 1,408,036,000
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
9	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 11,295,326
10	QF Purchased Power - Capacity	Workpaper 4				10,496,458
11	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 21,791,784
12	NC Portion - Jursidictional % based on 2022 Production Demand Allocator	Input				67.12%
13	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 14,626,471
14	2022 Production Demand Allocation Factors	Input	49.05%	35.73%	15.22%	100.00%
15	Renewable and QF Purchased Power - Capacity allocated on 2022 Production Demand Allocator	Line 6 * Line 7	$ 7,174,604	$ 5,226,011	$ 2,225,856	$ 14,626,471
16	Renewable and QF Purchased Power - Capacity cents/kWh based on Normalized Test Period Sales at Meter	Line 8 / Line 1 / 10	0.0314	0.0213	0.0180	0.0245
	Billed Rates					
17	NC Projected Billing Period MWh Sales at Meter	Workpaper 7b	22,870,391	24,590,927	12,348,188	59,809,506
			cents/kWh	cents/kWh	cents/kWh	cents/kWh
18	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.3501	2.3589	2.3526	2.3542
19	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0314	0.0213	0.0180	0.0245
20	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.3815	2.3802	2.3706	2.3787
21	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.4751	0.3221	0.6519	0.4094
22	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	0.0060	0.0008
23	EMF Increment (Decrement) Docket E-7, Sub 1282	Exh 3 pg 2, 3, 4	0.0285	(0.0003)	0.0205	0.0138
24	Net Fuel and Fuel Related Costs Factors cents/kWh	Line 20 + Line 21 + Line 22 + Lir	2.8851	2.7020	3.0490	2.8027

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Line No.	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)		NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2023				5,297,871	$	79,470,094
2	February				4,651,448	$	25,314,780
3	March				4,457,423	$	15,168,768
4	April				4,384,886	$	(11,360,755)
5	May [1]				4,081,226	$	5,420,934
6	June				4,645,596	$	11,033,435
7	July				5,265,835	$	47,605,379
8	August				5,747,161	$	34,762,091
9	September				5,553,369	$	(6,562,753)
10	October [1]				4,434,405	$	(13,011,598)
11	November [1]				4,239,285	$	20,573,604
12	December				4,771,175	$	7,242,642
13	**Total Test Period**				**57,529,680**	**$**	**215,656,620**
14	January 2024					$	58,961,846
15	February 2024					$	(23,593,264)
16	March 2024					$	(9,518,544)
17	**Total (Over)/Under Recovery - Update Period January - March 2024** [2]					$	25,850,038
18	**Adjusted (Over)/Under Recovery**					**$**	**241,506,658**
19	NC Retail Normalized Test Period MWh Sales			Exhibit 4			58,985,766
20	**Experience Modification Increment (Decrement) cents/kWh**						**0.4094**
21	Total (Over)/Under Recovery from Docket E-7, Sub 1282					$	8,149,363
22	**Docket E-7, Sub 1282 Experience Modification Increment (Decrement) cents/kWh**						**0.0138**
23	Annual Interest Rate						0.0550
24	Monthly Interest Rate						0.0046
25	Number of Months (09/01/2024 - 08/31/2025)						12.0000
26	Interest					$	497,839
27	EMF Interest Increment (Decrement)			(Industrial Class Only)			**0.0008**

[1] Prior period corrections not included in rate incurred but are included in over/(under) recovery total
[2] January, February and March 2024 are included for Commission review in accordance with NC Rule R8-55(d)(3). These periods will be subject to review in the next annual fuel and fuel-related costs filing.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2023	3.1036	2.0003	2,399,460	$	26,474,056
2	February	2.5164	2.0003	1,864,517	$	9,622,919
3	March	2.4815	2.0003	1,655,681	$	7,967,786
4	April	1.9527	2.0003	1,510,762	$	(718,502)
5	May [1]	2.5601	2.0003	1,327,128	$	7,425,845
6	June	2.5914	2.0003	1,572,607	$	9,295,437
7	July	2.9775	2.0003	2,046,660	$	20,000,532
8	August	2.6251	2.0003	2,263,463	$	14,141,807
9	September	2.2559	2.2832	2,114,514	$	(577,804)
10	October [1]	2.7002	2.6287	1,437,145	$	1,049,328
11	November [1]	3.6305	2.6287	1,417,824	$	14,200,655
12	December	2.6817	2.6287	1,934,641	$	1,025,051
13	**Total Test Period**			**21,544,402**	**$**	**109,907,112**
14	Test Period Wtd Avg. ¢/kWh	2.6778	2.1678			
15	January 2024				$	14,838,914
16	February 2024				$	(14,071,667)
17	March 2024				$	(2,311,568)
18	**Total (Over)/Under Recovery - Update Period January - March 2024** [2]				$	(1,544,321)
19	**Adjusted (Over)/Under Recovery**				**$**	**108,362,791**
20	NC Retail Normalized Test Period MWh Sales			Exhibit 4		22,807,302
21	**Experience Modification Increment (Decrement) cents/kWh**					**0.4751**
22	Total (Over)/Under Recovery from Docket E-7, Sub 1282				**$**	**6,508,910**
23	**Docket E-7, Sub 1282 Experience Modification Increment (Decrement) cents/kWh**					**0.0285**

Notes:

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

[2] January, February and March 2024 are included for Commission review in accordance with NC Rule R8-55(d)(3). These periods will be subject to review in the next annual fuel and fuel-related costs filing.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - GS/Lighting
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2023	3.4411	1.8217	2,010,240	$	32,553,429
2	February	2.3598	1.8217	1,844,325	$	9,925,065
3	March	2.0495	1.8217	1,861,027	$	4,239,231
4	April	1.4316	1.8217	1,911,294	$	(7,455,265)
5	May [(1)]	1.7512	1.8217	1,801,039	$	(1,224,776)
6	June	1.8406	1.8217	2,054,971	$	387,410
7	July	2.5540	1.8217	2,212,006	$	16,198,827
8	August	2.2981	1.8217	2,397,091	$	11,419,084
9	September	1.8501	2.0188	2,362,490	$	(3,986,444)
10	October [(1)]	1.7729	2.2596	2,004,937	$	(9,737,062)
11	November [(1)]	2.5369	2.2596	1,862,894	$	5,162,455
12	December	2.3964	2.2596	1,988,005	$	2,719,455
13	**Total Test Period**			**24,310,321**	**$**	**60,201,409**
14	Test Period Wtd Avg. ¢/kWh	2.1937	1.9463			
15	January 2024				$	29,444,988
16	February 2024				$	(6,236,063)
17	March 2024				$	(4,576,172)
18	**Total (Over)/Under Recovery - Update Period January - March 2024** [(2)]				$	18,632,753
19	**Adjusted (Over)/Under Recovery**				**$**	**78,834,162**
20	NC Retail Normalized Test Period MWh Sales			Exhibit 4		24,474,032
21	**Experience Modification Increment (Decrement) cents/kWh**					**0.3221**
22	Total (Over)/Under Recovery from Docket E-7, Sub 1282				$	(67,379)
23	**Docket E-7, Sub 1282 Experience Modification Increment (Decrement) cents/kWh**					**(0.0003)**

Notes:

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

[(2)] January, February and March 2024 are included for Commission review in accordance with NC Rule R8-55(d)(3). These periods will be subject to review in the next annual fuel and fuel-related costs filing.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Industrial
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)		Reported (Over)/ Under Recovery (d)
1	January 2023	4.1413	1.8396	888,171	$	20,442,609
2	February	2.4514	1.8396	942,606	$	5,766,796
3	March	2.1544	1.8396	940,715	$	2,961,751
4	April	1.5086	1.8396	962,830	$	(3,186,988)
5	May [1]	1.7572	1.8396	953,059	$	(780,135)
6	June	1.9723	1.8396	1,018,017	$	1,350,588
7	July	2.9721	1.8396	1,007,169	$	11,406,019
8	August	2.6864	1.8396	1,086,607	$	9,201,200
9	September	1.6959	1.8816	1,076,365	$	(1,998,505)
10	October [1]	1.4960	1.9328	992,323	$	(4,323,864)
11	November [1]	2.0592	1.9328	958,566	$	1,210,494
12	December	2.3451	1.9328	848,529	$	3,498,136
13	**Total Test Period**			**11,674,957**	**$**	**45,548,101**
14	Test Period Wtd Avg. ¢/kWh	2.2558	1.8658			
15	January 2024				$	14,677,944
16	February 2024				$	(3,285,534)
17	March 2024				$	(2,630,804)
18	**Total (Over)/Under Recovery - Update Period January - March 2024** [2]				$	8,761,606
19	**Adjusted (Over)/Under Recovery**				**$**	**54,309,707**
20	NC Retail Projected MWh Sales (1/1/25 to 8/31/25)					8,330,385
21	**Experience Modification Increment (Decrement) cents/KWh**					**0.6519**
22	Total (Over)/Under Recovery from Docket E-7, Sub 1282				$	1,707,832
23	Docket E-7, Sub 1282 Experience Modification Increment (Decrement) cents/kWh					**0.0205**
24	Annual Interest Rate					5.5%
25	Monthly Interest Rate					0.4583%
26	Number of Months (09/01/2024 - 08/31/2025)					12
27	Interest				$	497,839
28	EMF Interest Increment (Decrement)					**0.0060**

Notes:

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

[2] January, February and March 2024 are included for Commission review in accordance with NC Rule R8-55(d)(3). These periods will be subject to review in the next annual fuel and fuel-related costs filing.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Sales, Fuel Revenue, Fuel Expense and System Peak
Test Period Ended December 31, 2023
Billing Period Sept 2024 through Aug 2025
Docket E-7, Sub 1304

Clark Revised Exhibit 4

Line #	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina General Service/Lighting	North Carolina Industrial
1	Test Period MWh Sales (excluding inter system sales)	Exhibit 6 Schedule 1 (Line 4) and Workpaper 11 (NC Retail)	86,356,724	57,529,680	21,544,402	24,310,321	11,674,957
2	Customer Growth MWh Adjustment	Workpaper 12 Pg 1	404,481	184,058	216,090	(44,343)	12,311
3	Weather MWh Adjustment	Workpaper 11 Pg 1	1,756,476	1,272,028	1,046,809	208,055	17,164
4	Remove Impact of SC DERP Net Metered MWh	Workpaper 7a	150,334				
5	Total Normalized MWh Sales at Meter	Sum	88,668,015	58,985,766	22,807,302	24,474,032	11,704,432
6	Total Normalized MWh Sales at Generation	Workpaper 7a	93,709,236	62,520,389	24,131,647	25,991,687	12,397,056
7	Test Period Fuel and Fuel Related Revenue *		$ 2,052,616,593	$ 1,158,026,193			
8	Test Period Fuel and Fuel Related Expense *		$ 2,055,925,006	$ 1,373,682,811			
9	Test Period Unadjusted (Over)/Under Recovery		$ 3,308,413	$ 215,656,620			

Line #	Description	2022 Summer Coincidental Peak (CP) kW
10	Total System Peak	17,857,406
11	NC Retail Peak	12,050,576
12	NC Residential Peak	5,580,183
13	NC General Service/Lighting Peak	4,572,446
14	NC Industrial Peak	1,897,947

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

Rounding differences may occur

Duke Energy Carolinas, LLC **Clark Exhibit 5**

North Carolina Annual Fuel and Fuel Related Expense

Nuclear Capacity Ratings

Test Period Ended December 31, 2023

Billing Period Sept 2024 through Aug 2025

Docket E-7, Sub 1304

Unit	Rate Case Docket E-7, Sub 1276	Fuel Docket E-7, Sub 1282	Proposed Capacity Rating MW
Oconee Unit 1	847.0	847.0	847.0
Oconee Unit 2	848.0	848.0	848.0
Oconee Unit 3	859.0	859.0	859.0
McGuire Unit 1	1,158.0	1,158.0	1,158.0
McGuire Unit 2	1,157.6	1,157.6	1,157.6
Catawba Unit 1	1,160.0	1,160.0	1,160.0
Catawba Unit 2	1,150.1	1,150.1	1,150.1
Total Company	7,179.7	7,179.7	7,179.7

Clark Exhibit 6

DECEMBER 2023 MONTHLY FUEL FILING

Clark Exhibit 6
Schedule 1

DUKE ENERGY CAROLINAS
SUMMARY OF MONTHLY FUEL REPORT

Docket No. E-7, Sub 1286

Line No.		Dec 2023	12 Months Ended Dec 2023
1	Fuel and fuel-related costs	$ 186,262,825	$ 2,061,091,081
	MWH sales:		
2	Total system sales	7,615,641	87,788,693
3	Less intersystem sales	172,087	1,431,969
4	Total sales less intersystem sales	7,443,554	86,356,724
5	Total fuel and fuel-related costs (¢/KWH) (line 1/line 4)	2.5023	2.3867
6	Current fuel and fuel-related cost component (¢/KWH) (per Schedule 4, Line 7a Total)	2.3511	
	Generation Mix (MWH):		
	Fossil (by primary fuel type):		
7	Coal	1,389,854	9,078,965
8	Fuel Oil	1,754	15,482
9	Natural Gas - Combined Cycle	1,177,078	13,475,644
10	Natural Gas - Combined Heat and Power	10,026	108,527
11	Natural Gas - Combustion Turbine	14,722	855,196
12	Natural Gas - Steam	703,590	11,625,388
13	Biogas	593	14,577
14	Total fossil	3,297,617	35,173,779
15	Nuclear 100%	5,469,952	59,480,629
16	Hydro - Conventional	122,764	1,601,256
17	Hydro - Pumped storage	(67,518)	(683,260)
18	Total hydro	55,246	917,996
19	Solar Distributed Generation	19,907	326,179
20	Total MWH generation	8,842,722	95,898,583
21	Less joint owners' portion - Nuclear	1,412,832	15,476,926
22	Less joint owners' portion - Combined Cycle	68,062	756,644
23	Adjusted total MWH generation	7,361,828	79,665,013

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

Clark Exhibit 6
Schedule 2

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS

Docket No. E-7, Sub 1286

Fuel and fuel-related costs:	Dec 2023	12 Months Ended Dec 2023
0501110 coal consumed - steam	$ 64,204,474	$ 402,470,111
0501310 fuel oil consumed - steam	249,296	1,682,292
0501330 fuel oil light-off - steam	-	1,153,853
Total Steam Generation - Account 501	64,453,770	405,306,256
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	20,904,329	238,755,271
Other Generation - Account 547		
0547100, 0547124 - natural gas consumed - Combustion Turbine	1,036,895	44,738,939
0547100 - Combustion Turbine - credit for inefficient fuel cost	-	(21,987)
0547100 natural gas consumed - Steam	39,534,000	591,311,676
0547101 natural gas consumed - Combined Cycle	44,295,041	447,172,537
0547100 natural gas consumed - Combined Heat and Power	722,824	7,207,756
0547106 biogas consumed - Combined Cycle	38,294	782,075
0547200 fuel oil consumed - Combustion Turbine	365,355	1,901,237
Total Other Generation - Account 547	85,992,409	1,093,092,233
Reagents		
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	1,621,249	18,052,781
Total Reagents	1,621,249	18,052,781
By-products		
Net proceeds from sale of by-products	1,023,481	2,891,104
Total By-products	1,023,481	2,891,104
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	173,995,238	1,758,097,645
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (economic)	-	-
Capacity component of purchased power (renewables)	541,362	15,808,462
Capacity component of purchased power (PURPA)	350,819	9,544,414
Fuel and fuel-related component of purchased power	17,030,821	320,483,742
Total Purchased Power and Net Interchange - Account 555	17,923,002	345,836,618
Less:		
Fuel and fuel-related costs recovered through intersystem sales	5,515,413	41,383,538
Fuel in loss compensation	130,913	1,170,607
Solar Integration Charge	(174)	(3,523)
Lincoln CT marginal fuel revenue	8,664	260,460
Miscellaneous Fees Collected	600	32,100
Total Fuel Credits - Accounts 447 /456	5,655,415	42,843,182
Total Fuel and Fuel-related Costs	$ 186,262,825	$ 2,061,091,081

Notes: Detail amounts may not add to totals shown due to rounding.
Report reflects net ownership costs of jointly owned facilities.
*These amounts are based on estimates and will be considered final during the next Annual Fuel proceeding.

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

DEC 2023

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Associated Electric Cooperative, Inc.	-	-	-	(3,245)	3,245	
Carolina Power Partners, LLC	$ 167,280	-	4,080	$ 44,446	$ 122,834	
Constellation	-	-	-	(35,149)	35,149	
Cube Yadkin Generation LLC	23,775	-	1,575	8,811	14,964	
DE Progress - Native Load Transfer	8,329,362	-	415,912	7,682,911	616,245	$ 30,205
DE Progress - Native Load Transfer Benefit	1,080,684	-	-	1,080,684	-	
DE Progress - Fees	(1,710)	-	-	-	(1,710)	
Haywood Electric - Economic	21,702	19,590	51	(2,837)	4,949	
LGE/KU	-	-	-	(9,215)	9,215	
Macquarie Energy, LLC	1,171,300	-	23,527	597,984	573,316	
Midwest Independent System Operator	-	-	-	(163)	163	
Morgan Stanley Capital Group	-	-	-	(9,969)	9,969	
NCEMC - Economic	1,300	-	84	(6,454)	7,754	
NCMPA - Economic	-	-	-	(109,309)	109,309	
NCMPA Instantaneous - Economic	1,023,034	-	40,454	598,475	424,559	
Oglethorpe Power	3,214	-	245	125	3,089	
Piedmont Municipal Power Agency	412,504	-	18,141	251,627	160,877	
PJM Interconnection, LLC.	5,606	-	-	(39,774)	45,380	
South Carolina Electric & Gas Company / Dominion Er	-	-	-	(481)	481	
Southern Company Services, Inc.	20,258	-	403	(15,461)	35,719	
Southern Company Services, Inc. - T	-	-	-	(14)	14	
Tampa Electric Company	19,818	-	990	3,295	16,524	
Tennessee Valley Authority	204,013	-	7,830	(77,940)	281,954	
Tennessee Valley Authority - T	-	-	-	(35)	35	
The Energy Authority	10,225	-	320	3,565	6,660	
Town of Forest City	20,417	20,417	-	-	-	
	$ 12,512,783	**$ 40,007**	**513,612**	**$ 9,961,878**	**$ 2,480,693**	**$ 30,205**
Renewable Energy						
NC Renewable Energy	$ 3,828,970	$ 525,161	70,698	$ -	$ 3,303,809	
SC DERP - Purchased Power	260,474	16,201	4,332	-	169,028	75,244
SC DERP - Net Metering Excess Generation	368	-	13			368
SC Act 62 Net Metering Excess Generation	14,949	-	570		13,237	1,712
	$ 4,104,761	**$ 541,362**	**75,613**	**$ -**	**$ 3,486,075**	**$ 77,324**
HB589 PURPA Purchases						
NC CPRE - Purchased Power	$ 841,334	-	23,562			841,334
NC Other Qualifying Facilities	$ 2,707,007	350,819	50,853		2,281,872	74,316
	$ 3,548,341	**$ 350,819**	**74,415**	**$ -**	**$ 2,281,872**	**$ 915,650**
Non-dispatchable / Other						
Blue Ridge Electric Membership Corp.	1,125,993	$ 682,856	24,738	(62,381)		505,519
Carolina Power Partners, LLC	-	-	-	(166,441)		166,441
Constellation	-	-	-	(70,369)		70,369
Haywood Electric	122,727	72,222	2,350	(6,666)		57,171
Macquarie Energy, LLC	44,800	-	800	(1,100,336)		1,145,136
NCEMC - Other	3,305	3,305	-	(133,902)		133,902
NCMPA	-	-	-	(79,819)		79,819
Piedmont Electric Membership Corp.	527,997	317,381	11,904	(26,581)		237,197
PJM Interconnection, LLC - Other	-	-	-	(13,988)		13,988
Southern Company Services, Inc.	-	-	-	(6,442)		6,442
Tennessee Valley Authority	-	-	-	(27,435)		27,435
Generation Imbalance	157,187	-	4,726	74,136		83,051
Energy Imbalance - Purchases	24,704	-	(13,460)	14,401		10,303
Energy Imbalance - Sales	(471,761)	-	-	(379,541)		(92,220)
Other Purchases	398	-	16	-		398
	$ 1,535,351	**$ 1,075,765**	**31,074**	**$ (1,985,364)**	**$ -**	**$ 2,444,950**
Total Purchased Power	**$ 21,701,236**	**$ 2,007,953**	**694,714**	**$ 7,976,514**	**$ 8,248,640**	**$ 3,468,129**
Interchanges In						
Other Catawba Joint Owners	7,324,397	-	707,910	4,139,155		3,185,243
WS Lee Joint Owner	1,068,833		30,141	946,126		122,707
Total Interchanges In	8,393,230	-	738,051	5,085,281	-	3,307,950
	-					
Interchanges Out						
Other Catawba Joint Owners	(7,184,252)	(134,209)	(691,654)	(4,044,098)		(3,005,944)
Catawba- Net Negative Generation	-	-	-	-		-
WS Lee Joint Owner	(270,480)		(7,626)	(235,516)		(34,964)
Total Interchanges Out	(7,454,732)	(134,209)	(699,280)	(4,279,614)	-	(3,040,908)
Net Purchases and Interchange Power	**$ 22,639,734**	**$ 1,873,744**	**733,485**	**$ 8,782,181**	**$ 8,248,640**	**$ 3,735,171**

NOTE: Detail amounts may not add to totals shown due to rounding.
CPRE purchased power amounts are recovered through the CPRE Rider.
Not Fuel $/Not Fuel-related $" amounts are based on estimates and are subject to change

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

December 2023

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Market Based:					
Associated Electric Cooperative, Inc.	757	-	27	757	-
Macquarie Energy, LLC	304,600	-	9,800	227,648	76,952
Municipal Electric Authority of Georgia	(380)	-	-	-	(380)
NCMPA	89,278	87,500	56	4,802	(3,024)
Oglethorpe Power Corporation	15,419	-	518	15,419	0
PJM Interconnection, LLC.	(3,243)	-	-	-	(3,243)
SC Electric & Gas / Dominion Energy	9,895	-	274	7,300	2,596
South Carolina Electric & Gas - T	(110)	-	-	-	(110)
Southern Company	27,148	-	1,615	34,547	(7,399)
Southern Company Services, Inc. - T	(216)	-	-	-	(216)
Tampa Electric Company	422	-	21	422	-
Tennessee Valley Authority	5,009	-	234	5,042	(33)
The Energy Authority	136,317	-	5,447	135,638	679
Other:					
DE Progress - Native Load Transfer Benefit	708,962	-	-	708,962	-
DE Progress - Native Load Transfer	4,792,684	-	152,885	4,348,433	444,250
Generation Imbalance	15,155	-	1,210	26,443	(11,288)
BPM Transmission	(48,492)	-	-	-	(48,492)
Total Intersystem Sales	**$ 6,053,205**	**$ 87,500**	**172,087**	**$ 5,515,413**	**$ 450,292**

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

Twelve Months Ended DEC 2023

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Associated Electric Cooperative, Inc.	42,470	-	1,444	32,855	9,615	
Carolina Power Partners, LLC	$ 1,279,350	-	36,626	$ 989,705	$ 289,645	
Constellation	460,069	-	11,537	355,909	104,160	
Cube Yadkin Generation LLC	149,187	-	9,915	115,411	33,776	
DE Progress - Native Load Transfer	149,596,180	-	7,291,156	132,877,311	12,641,863	$ 4,077,006
DE Progress - Native Load Transfer Benefit	27,303,379	-	-	27,303,379	-	
DE Progress - Fees	3,678	-	-	-	3,678	
Haywood Electric - Economic	367,676	258,772	2,519	84,249	24,655	
LGE/KU	120,619	-	2,995	93,311	27,308	
Macquarie Energy, LLC	5,204,458	-	125,892	4,026,169	1,178,289	
Midwest Independent System Operator	2,134	-	-	1,651	483	
Morgan Stanley Capital Group	130,482	-	3,786	100,941	29,541	
NCEMC	98,942	-	4,817	76,542	22,400	
NCMPA	1,430,740	-	49,360	1,106,820	323,920	
NCMPA Load Following Economic	9,082,211	-	462,545	5,139,442	3,942,769	
Oglethorpe Power	34,124	-	2,097	26,398	7,726	
Piedmont Municipal Power Agency	4,171,619	-	189,815	2,341,457	1,830,162	
PJM Interconnection, LLC.	582,973	-	22,586	450,988	131,985	
South Carolina Electric & Gas Company / Dominion Energy	6,291	-	217	4,860	1,430	
Southern Company Services, Inc.	427,750	-	15,730	330,907	96,843	
Southern Company Services, Inc. - T	177	-	-	137	40	
Tampa Electric Company	177,367	-	7,635	137,211	40,156	
Tennessee Valley Authority	3,289,947	-	112,737	2,545,103	744,844	
Tennessee Valley Authority - T	453	-	-	351	103	
The Energy Authority	67,094	-	2,327	51,904	15,190	
Town of Forest City	245,000	245,000	-	-	-	
	$ 204,274,369	**$ 503,772**	**8,355,736**	**$ 178,193,010**	**$ 21,500,581**	**$ 4,077,006**
Renewable Energy						
NC Renewable Energy	$ 74,288,807	$ 15,540,372	1,216,336	$ -	$ 58,748,435	$ -
SC DERP - Purchased Power	4,081,315	268,091	70,578	-	2,760,721	1,052,503
SC DERP - Net Metering Excess Generation	84,303	-	3,122	-		84,303
SC Act 62 Net Metering Excess Generation	132,031	-	5,012	-	118,936	13,096
	$ 78,586,456	**$ 15,808,463**	**1,295,047**	**$ -**	**$ 61,628,091**	**$ 1,149,901**
HB589 PURPA Purchases						
NC CPRE - Purchased Power	$ (20,832,293)	$ -	466,282			$ (20,832,293)
NC Other Qualifying Facilities	47,359,889	9,544,415	819,162		$ 36,845,496	969,978
	$ 26,527,596	**$ 9,544,415**	**1,285,444**	**$ -**	**$ 36,845,496**	**$ (19,862,315)**
Non-dispatchable / Other						
Blue Ridge Electric Membership Corp.	13,625,978	7,879,269	294,688	4,445,654		1,301,055
Carolina Power Partners, LLC	2,178,541	-	35,939	1,685,319		493,222
Constellation (Reliability)	921,065	-	14,045	712,536		208,529
DE Progress - As Available Capacity	25,969	25,969	-	-		-
Haywood Electric	1,644,562	995,376	28,588	502,210		146,976
Macquarie Energy, LLC	14,900,736	-	210,470	11,527,209		3,373,527
NCEMC - Other	1,794,673	39,671	24,285	1,358,184		396,818
NCMPA - Reliability	1,044,750	-	16,425	808,219		236,531
Piedmont Electric Membership Corp.	6,532,466	3,841,310	139,944	2,081,878		609,278
PJM Interconnection, LLC - Other	183,095	-	5,843	141,642		41,453
Southern Company Services, Inc.	84,320	-	1,240	65,230		19,090
Tennesse Valley Authority	359,095	-	9,098	277,796		81,299
Generation Imbalance	1,069,991		50,931	139,397		930,594
Energy Imbalance - Purchases	54,937		(147,715)	55,654		(717)
Energy Imbalance - Sales	(2,576,011)		-	(2,964,653)		388,642
Other Purchases	7,585	-	278	-		7,585
	$ 41,851,752	**$ 12,781,595**	**684,059**	**$ 20,836,275**	**$ -**	**$ 8,233,881**
Total Purchased Power	**$ 351,240,173**	**$ 38,638,245**	**11,620,286**	**$ 199,029,285**	**$ 119,974,168**	**$ (6,401,527)**
						-
Interchanges In						
Other Catawba Joint Owners	77,065,086	-	7,766,017	43,760,368		33,304,718
WS Lee Joint Owner	15,234,963	-	446,372	13,415,999		1,818,964
Total Interchanges In	92,300,049	-	8,212,388	57,176,366	-	35,123,682
Interchanges Out						
Other Catawba Joint Owners	(71,528,020)	(1,580,207)	(7,088,258)	(40,585,344)		(29,362,469)
Catawba- Net Negative Generation	(146,879)	-	(7,910)	(117,097)		(29,782)
WS Lee Joint Owner	(16,671,042)	-	(366,406)	(14,993,640)		(1,677,402)
Total Interchanges Out	(88,345,941)	(1,580,207)	(7,462,574)	(55,696,081)	-	(31,069,653)
Net Purchases and Interchange Power	**$ 355,194,281**	**$ 37,058,038**	**12,370,100**	**$ 200,509,570**	**$ 119,974,168**	**$ (2,347,498)**

NOTES: Detail amounts may not add to totals shown due to rounding.
CPRE purchased power amounts are recovered through the CPRE Rider.
Not Fuel $/Not Fuel-related $" amounts are based on estimates and are subject to change

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

Twelve Months Ended December 2023

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
DE Progress - Emergency	$ 154,037	-	5,320	$ 134,480	$ 19,557
SC Public Service Authority - Emergency	93,804	-	2,400	82,892	10,912
SC Electric & Gas / Dominion Energy - Emergency	1,671,595	-	6,947	(165,700)	1,837,295
Tennessee Valley Authority - Emergency	4,871,425	-	980	111,462	4,759,963
Market Based:					
Associated Electric Cooperative, Inc.	68,864	-	2,999	59,101	9,762
Carolina Power Partners, LLC	25,920	-	810	20,265	5,655
Central Electric Power Cooperative, Inc.	5,318,929	5,221,200	3,420	88,426	9,303
Constellation Power Sources	1,120	-	40	1,027	93
Georgia Transmission Corporation	(35)	-	-	-	(35)
LGE/KU	71,275	-	4,565	69,035	2,240
Macquarie Energy, LLC	5,781,900	-	157,425	3,918,649	1,863,251
Midwest Independent System Operator	(58)	-	-	-	(58)
Municipal Electric Authority of Georgia	(4,931)	-	-	-	(4,931)
NCEMC	28,160	-	640	23,373	4,787
NCMPA	1,227,277	1,050,000	5,163	189,008	(11,731)
Oglethorpe Power Corporation	485,751	-	11,420	487,014	(1,263)
PJM Interconnection, LLC.	645,915	-	15,975	394,705	251,210
SC Electric & Gas / Dominion Energy	1,874,175	-	46,481	1,159,658	714,518
South Carolina Electric & Gas - T	(2,953)	-	-	-	(2,953)
SC Public Service Authority	(2,533)	-	-	-	(2,533)
South Carolina Public Service Authority - T	(1,577)	-	-	-	(1,577)
Southern Company	2,143,016	-	73,679	2,008,733	134,283
Southern Company Services, Inc. - T	(2,905)	-	-	-	(2,905)
Tampa Electric Company	4,245	-	182	4,245	-
Tennesse Valley Authority	430,649	-	17,066	411,293	19,356
Tennessee Valley Authority - T	(5,158)	-	-	-	(5,158)
The Energy Authority	1,983,859	-	76,873	1,807,753	176,106
Other:					
DE Progress - Native Load Transfer Benefit	3,871,518	-	-	3,871,518	-
DE Progress - Native Load Transfer	29,817,634	6,583	980,018	26,604,734	3,206,318
Generation Imbalance	(414,064)	-	19,566	101,867	(515,931)
BPM Transmission	(497,926)	-	-	-	(497,926)
Total Intersystem Sales	**$ 59,638,929**	**$ 6,277,783**	**1,431,969**	**$ 41,383,538**	**$ 11,977,608**

* Sales for resale other than native load priority.

Clark Exhibit 6

Duke Energy Carolinas
(Over) / Under Recovery of Fuel Costs
December 2023

Line No.			Residential	Commercial	Industrial	Total
1	Actual System kWh sales	Input				7,443,553,219
2	DERP Net Metered kWh generation	Input				11,234,029
3	Adjusted System kWh sales	L1 + L2				7,454,787,248
4	N.C. Retail kWh sales	Input	1,934,641,331	1,988,005,400	848,528,620	4,771,175,352
5	NC kWh sales % of actual system kWh sales	L4 T / L1				64.10%
6	NC kWh sales % of adjusted system kWh sales	L4 T / L3				64.00%
7	Approved fuel and fuel related rates (¢/kWh)					
	7a Billed rates by class (¢/kWh)	L7g	2.6287	2.2596	1.9328	2.3511
	7b Billed fuel expense	L7a * L4 / 100	$50,855,917	$44,920,970	$16,400,361	$112,177,248
	Rate changes:					
	7c New approved rates	Input	2.6287	2.2596	1.9328	
	7d Ratio of days to rate	Input	100.00%	100.00%	100.00%	
	7e Prior approved rates	Input	2.0003	1.8217	1.8396	
	7f Ratio of days to rate	Input	0.00%	0.00%	0.00%	
	7g Total prorated ¢/KWH	(L7c * L7d) + (L7e * L7f)	2.6287	2.2596	1.9328	
8	Incurred base fuel and fuel related (¢/kWh) (less renewable purchased power capacity)					
	Allocation changes:					
	8a New approved Docket E-7, Sub 1282 allocation factor	Input	43.43%	39.90%	16.67%	
	8b System incurred expense	Input				$185,647,066
	8c Incurred base fuel and fuel related expense	L8b * L6 * 8a	$51,601,723	$47,411,616	$19,803,561	$118,816,899
	8d Incurred base fuel rates by class (¢/kWh)	L8c / L4 * 100	2.6673	2.3849	2.3339	2.4903
9	Incurred renewable purchased power capacity rates (¢/kWh)					
	9a NC retail production plant %	Input				67.59%
	9b Production plant allocation factors	Input	46.31%	37.95%	15.74%	100.00%
	9c System incurred expense	Input				$892,181
	9d Incurred renewable capacity expense	L9a * L9b * L9c	$279,244	$228,809	$94,937	$602,990
	9e Incurred renewable capacity rates by class (¢/kWh)	((L9a * L9c) * L9b) / L4 * 100	0.0144	0.0115	0.0112	0.0126
10	Total incurred rates by class (¢/kWh)	L8d + 9e	2.6817	2.3964	2.3451	2.5029
11	Difference in ¢/kWh (incurred - billed)	L10 - L7a	0.0530	0.1368	0.4123	0.1518
12	(Over) / under recovery [See footnote]	(L4 * L11) / 100	$1,025,051	$2,719,455	$3,498,136	$7,242,642
13	Prior period adjustments	Input	0	0	0	0
14	Total (over) / under recovery	L12 + L13	**$1,025,051**	**$2,719,455**	**$3,498,136**	**$7,242,642**

15	Total system incurred expense	L8f + L9c	**$186,539,247**
16	Less: Jurisdictional allocation adjustment(s)	Input	276,422
17	Total Fuel and Fuel-related Costs per Schedule 2	L15 + L16	**$186,262,825**

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

		(Over) / Under Recovery				
	Year 2023	Total To Date	Residential	Commercial	Industrial	Total Company
	January	$79,470,094	$26,474,056	$32,553,429	$20,442,609	$79,470,094
	February	$104,784,874	$9,622,919	$9,925,065	$5,766,796	25,314,780
	March	$119,953,642	7,967,786	4,239,231	2,961,751	15,168,768
	April	$108,592,887	(718,502)	(7,455,265)	(3,186,988)	(11,360,755)
	May	$114,013,821	7,425,845	(1,224,776)	(780,135)	5,420,934
_/1	June	$125,047,256	9,295,437	387,410	1,350,588	11,033,435
	July	$172,652,635	20,000,533	16,198,827	11,406,019	47,605,379
	August	$207,414,726	14,141,807	11,419,084	9,201,200	34,762,091
_/2	September	$200,851,973	(577,804)	(3,986,444)	(1,998,505)	(6,562,753)
_/2	October	$187,840,375	1,049,328	(9,737,062)	(4,323,864)	(13,011,598)
	November	$208,413,979	14,200,655	5,162,455	1,210,494	20,573,604
	December	$215,656,621	1,025,051	2,719,455	3,498,136	7,242,642
			$109,907,111	$60,201,409	$45,548,101	$215,656,621

Notes:

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

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

_/1 Includes prior period adjustments.

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

Clark Exhibit 6
Schedule 5
Page 1 of 2

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
DEC 2023

Description	Buck CC	Dan River CC	Lee CC	Clemson CHP	Lee Steam/CT	Lincoln CT	(A) Lincoln (Unit17) CT	Mill Creek CT	Rockingham CT
Cost of Fuel Purchased ($)									
Coal									
Oil	-	-	-		-	-	-	-	-
Gas - CC	$13,980,435	$11,426,257	$21,057,461						
Gas - CHP				$722,824					
Gas - CT					$16,634	$4,292	($196)	$53,680	$962,484
Gas - Steam					-				
Biogas	-	(64,563)	-						
Total	$13,980,435	$11,361,693	$21,057,461	$722,824	$16,634	$4,292	($196)	$53,680	$962,484
Average Cost of Fuel Purchased (¢/MBTU)									
Coal		-							
Oil					-	-	-	-	-
Gas - CC	551.17	550.69	552.80						
Gas - CHP				635.01					
Gas - CT					3,569.55	6,027.98	433.21	572.96	574.59
Gas - Steam					-				
Biogas	-	(1,513.08)	-						
Weighted Average	551.17	546.45	552.80	635.01	3,569.55	6,027.98	433.21	572.96	574.59
Cost of Fuel Burned ($)									
Coal		-	-		-				
Oil - CC	-	-	-						
Oil - Steam/CT					$118,981	$0	$0	$246,373	$0
Gas - CC	$13,980,435	$11,426,257	$21,057,461						
Gas - CHP				$722,824					
Gas - CT					16,634	4,292	(196)	53,680	962,484
Gas - Steam					-				
Biogas	-	(64,563)	-						
Nuclear									
Total	$13,980,435	$11,361,693	$21,057,461	$722,824	$135,616	$4,292	($196)	$300,054	$962,484
Average Cost of Fuel Burned (¢/MBTU)									
Coal					-				
Oil - CC									
Oil - Steam/CT					1,789.73	-	-	2,178.95	-
Gas - CC	551.17	550.69	552.80						
Gas - CHP				635.01					
Gas - CT					3,569.55	6,027.98	433.21	572.96	574.59
Gas - Steam					-				
Biogas	-	(1,513.08)	-						
Nuclear									
Weighted Average	551.17	546.45	552.80	635.01	1,906.32	6,027.98	433.21	1,451.22	574.59
Average Cost of Generation (¢/kWh)									
Coal		-	-		-	-	-		
Oil - CC	-	-	-						
Oil - Steam/CT		-	-		-	-	-	46.62	-
Gas - CC	3.95	3.96	3.94						
Gas - CHP				7.21					
Gas - CT					-	-	-	11.13	6.16
Gas - Steam					-	-	-	-	-
Biogas	-	(10.89)	-						
Nuclear									
Weighted Average	3.95	3.93	3.94	7.21	-	-	-	29.68	6.16
Burned MBTU's									
Coal					-				
Oil - CC									
Oil - Steam/CT					6,648	-	-	11,307	-
Gas - CC	2,536,490	2,074,897	3,809,258						
Gas - CHP				113,828					
Gas - CT					466	71	(45)	9,369	167,509
Gas - Steam					-				
Biogas	-	4,267	-						
Nuclear									
Total	2,536,490	2,079,164	3,809,258	113,828	7,114	71	(45)	20,676	167,509
Net Generation (mWh)									
Coal									
Oil - CC									
Oil - Steam/CT		-	-		(18)	-	-	529	-
Gas - CC	354,375	288,252	534,451		-				
Gas - CHP				10,026					
Gas - CT					(7)	(920)	(462)	482	15,629
Gas - Steam									
Biogas	-	593	-						
Nuclear 100%									
Hydro (Total System)									
Solar (Total System)									
Total	354,375	288,845	534,451	10,026	(25)	(920)	(462)	1,011	15,629
Cost of Reagents Consumed ($)									
Ammonia	$19,706	$0	$31,463						
Limestone									
Sorbents									
Urea									
Re-emission Chemical									
Dibasic Acid									
Activated Carbon									
Lime (water emissions)									
Total	$19,706	$0	$31,463						

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

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
DEC 2023

Description	Allen	Marshall	Belews Creek	Cliffside	Catawba	McGuire	NC Retail	Oconee	Current Month	Total 12 ME December 2023
	Steam	Steam - Dual Fuel	Steam - Dual Fuel	Steam - Dual Fuel	Nuclear	Nuclear		Nuclear		
Cost of Fuel Purchased ($)										
Coal	$28,236	$12,217,542	$13,873,577	$16,627,261					42,746,616	$443,166,959
Oil	-	-	76,938	218,631					295,568	21,566,161
Gas - CC									46,464,152	470,490,711
Gas - CHP									722,824	7,207,756
Gas - CT									1,036,895	44,716,952
Gas - Steam		15,555,366	15,449,049	8,529,586					39,534,000	591,311,676
Biogas									(64,563)	2,231,383
Total	$28,236	$27,772,907	$29,399,564	$25,375,478					$130,735,492	$1,580,691,598
Average Cost of Fuel Purchased (¢/MBTU)										
Coal	-	498.73	500.49	561.70					522.45	509.73
Oil	-	-	1,860.57	1,924.05					1,907.11	2,393.54
Gas - CC									551.79	489.81
Gas - CHP									635.01	578.17
Gas - CT									584.56	455.10
Gas - Steam		550.45	550.29	558.98					552.20	498.63
Biogas				.					(1,513.08)	2,123.59
Weighted Average	-	526.43	526.54	564.22					543.08	503.95
Cost of Fuel Burned ($)										
Coal	$0	$15,814,799	$28,081,001	$20,308,674					$64,204,474	$402,470,111
Oil - CC									-	-
Oil - Steam/CT	-	2,092	-	$247,204			-		614,651	4,737,381
Gas - CC									46,464,152	470,490,711
Gas - CHP									722,824	7,207,756
Gas - CT							-		1,036,895	44,716,952
Gas - Steam		15,555,366	15,449,049	8,529,586					39,534,000	591,311,676
Biogas									(64,563)	2,231,383
Nuclear					$10,225,832	$8,450,638		$10,485,627	29,162,098	329,081,650
Total	$0	$31,372,257	$43,530,050	$29,085,463	$10,225,832	$8,450,638	$0	$10,485,627	$181,674,530	$1,852,247,620
Average Cost of Fuel Burned (¢/MBTU)										
Coal	-	481.10	431.39	505.42					464.75	444.60
Oil - CC									-	-
Oil - Steam/CT	-	1,442.88	-	2,135.30			-		2,071.14	2,093.81
Gas - CC									551.79	489.81
Gas - CHP									635.01	578.17
Gas - CT							-		584.56	455.10
Gas - Steam		550.45	550.29	558.98					552.20	498.63
Biogas									(1,513.08)	2,123.59
Nuclear					58.65	48.03		53.59	53.41	54.93
Weighted Average	-	513.18	467.21	523.53	58.65	48.03	-	53.59	215.47	202.29
Average Cost of Generation (¢/kWh)										
Coal	-	4.99	4.16	5.06					4.62	4.43
Oil - CC									-	-
Oil - Steam/CT	-	15.04	-	20.11			-		35.04	30.60
Gas - CC									3.95	3.49
Gas - CHP									7.21	6.64
Gas - CT							-		7.04	5.23
Gas - Steam		5.57	5.64	5.68					5.62	5.09
Biogas									(10.89)	15.31
Nuclear					0.58	0.48		0.54	0.53	0.55
Weighted Average	-	5.26	4.59	5.26	0.58	0.48		0.54	2.05	1.93
Burned MBTU's										
Coal	-	3,287,205	6,509,479	4,018,154					13,814,838	90,524,510
Oil - CC									-	-
Oil - Steam/CT	-	145	-	11,577			-		29,677	226,256
Gas - CC									8,420,645	96,056,376
Gas - CHP									113,828	1,246,646
Gas - CT							-		177,370	9,825,799
Gas - Steam		2,825,954	2,807,442	1,525,931					7,159,327	118,586,773
Biogas									4,267	105,076
Nuclear					17,436,126	17,594,430		19,566,757	54,597,313	599,090,392
Total	-	6,113,304	9,316,921	5,555,662	17,436,126	17,594,430	-	19,566,757	84,317,265	915,661,828
Net Generation (mWh)										
Coal	(3,111)	316,812	674,602	401,551					1,389,854	9,078,965
Oil - CC									-	-
Oil - Steam/CT	-	14	-	1,229			-		1,754	15,482
Gas - CC									1,177,078	13,475,644
Gas - CHP									10,026	108,527
Gas - CT							-		14,722	855,196
Gas - Steam		279,461	273,852	150,277					703,590	11,625,388
Biogas									593	14,577
Nuclear 100%					1,749,551	1,767,184		1,953,217	5,469,952	59,480,629
Hydro (Total System)									55,246	917,996
Solar (Total System)									19,907	326,179
Total	(3,111)	596,287	948,454	553,057	1,749,551	1,767,184	-	1,953,217	8,842,723	95,898,584
Cost of Reagents Consumed ($)										
Ammonia			($169,474)	$76,019					($42,287)	$6,036,286
Limestone	$0	$254,278	409,942	860,175					$1,524,396	10,512,574
Sorbents	-	104,595	-						$104,595	1,127,798
Urea	-	38,551							$38,551	289,921
Re-emission Chemical	-	-	-	-					$0	107,876
Dibasic Acid	-								$0	-
Activated Carbon	-	-							$0	93,919
Lime (water emissions)	-	-	-						$0	33,407
Total	-	397,425	$240,468	$936,195					$1,625,255	$18,201,781

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

Clark Exhibit 6
Schedule 6

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED CONSUMPTION AND INVENTORY REPORT
DEC 2023

Description	Buck	Dan River	Lee	Clemson	Lee	Lincoln	(A) Lincoln (Unit17)	Mill Creek	Rockingham	Allen	Marshall	Belews Creek	Cliffside	Current Month	Total 12 ME December 2023
	CC	CC	CC	CHP	Steam/CT	CT	CT	CT	CT	Steam	Steam - Dual Fuel	Steam - Dual Fuel	Steam - Dual Fuel		
Coal Data:															
Beginning balance					-					60,097	864,521	1,168,306	488,541	2,581,466	2,491,097.54
Tons received during period										-	97,786	112,563	119,903	330,252	3,510,747.00
Inventory adjustments					-					-	-	-	-	-	(13,351.00)
Tons burned during period					-					-	130,278	255,716	159,070	545,064	3,621,838.49
Ending balance					-					60,097	832,030	1,025,153	449,375	2,366,655	2,366,654.57
MBTUs per ton burned					-					-	25.23	25.46	25.26	25.35	24.99
Cost of ending inventory ($/ton)					-					114.33	121.39	109.81	127.67	117.39	117.39
Oil Data:															
Beginning balance	-	-	-		707,467	8,552,720	1,111,880	3,487,079	2,891,700	94,109	262,701	69,034	217,704	17,394,394	12,540,723
Gallons received during period	-	-	-		-	-	-	-	-	-	-	29,965	82,341	112,306	6,529,088
Miscellaneous adjustments	-	-	-		-	-	-	-	-	-	-	(17,072)	(11,448)	(28,002)	(165,806)
Gallons burned during period		-	-		48,440	-	-	82,147	-	-	1,055	-	84,052	216,212	1,641,519
Ending balance	-	-	-		659,027	8,552,720	1,111,880	3,404,932	2,891,700	94,109	261,646	81,927	204,545	17,262,486	17,262,486
Cost of ending inventory ($/gal)	-	-	-		2.46	2.46	2.62	3.00	2.81	3.08	1.98	2.83	2.94	2.64	2.64
Natural Gas Data:															
Beginning balance															
MCF received during period	2,455,721	2,004,820	3,689,236	110,224	452	69	(44)	9,084	161,965		2,736,757	2,708,335	1,476,173	15,352,791	218,715,204
MCF burned during period	2,455,721	2,004,820	3,689,236	110,224	452	69	(44)	9,084	161,965		2,736,757	2,708,335	1,476,173	15,352,791	218,715,204
Ending balance															
Biogas Data:															
Beginning balance															
MCF received during period	-	4,123	-											4,123	101,735
MCF burned during period	-	4,123	-											4,123	101,735
Ending balance															
Limestone Data:															
Beginning balance										15,205	65,493	44,580	27,104	152,381	127,789
Tons received during period										-	-	-	22,884	22,884	202,879
Inventory adjustments										-	-	-	0	-	19,732
Tons consumed during period										-	5,712	9,824	12,064	27,600	202,735
Ending balance										15,205	59,781	34,756	37,924	147,666	147,666
Cost of ending inventory ($/ton)										59.58	44.52	41.73	50.26	46.71	46.71

Description	Buck	Qtr Ending December 2023	Total 12 ME December 2023
Ammonia Data: (B)			
Beginning balance	4,601	4,601	3,831
Tons received/adjusted during period	637	637	4,316
Inventory adjustments	196	196	196
Tons consumed during period	714	714	3,427
Ending balance	4,720	4,720	4,720
Cost of ending inventory ($/ton)	100.83	100.83	100.83

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit and terminal activity.
Gas is burned as received; therefore, inventory balances are not maintained.
(A) Lincoln (Unit 17) fuel and fuel related costs represents pre-commercial generation during an extended testing and validation period.

Clark Exhibit 6
Schedule 7

DUKE ENERGY CAROLINAS
ANALYSIS OF COAL PURCHASED
DEC 2023

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ALLEN	SPOT	-	$ -	$ -
	CONTRACT	-	4,820	-
	FUEL MANAGEMENT AGREEMENT		(4,820)	
	FIXED TRANSPORTATION / ADJUSTMENTS	-	28,236	-
	TOTAL	0	28,236	-
BELEWS CREEK	SPOT	-	-	-
	CONTRACT	112,563	13,866,779	123.19
	FUEL MANAGEMENT AGREEMENT		(606,209)	
	FIXED TRANSPORTATION / ADJUSTMENTS	-	613,008	-
	TOTAL	112,563	13,873,577	123.25
CLIFFSIDE	SPOT	-	-	-
	CONTRACT	119,903	15,827,496	132.00
	FUEL MANAGEMENT AGREEMENT		471,083	
	FIXED TRANSPORTATION / ADJUSTMENTS	-	328,682	-
	TOTAL	119,903	16,627,261	138.67
MARSHALL	SPOT	-	-	-
	CONTRACT	97,786	11,974,515	122.46
	FUEL MANAGEMENT AGREEMENT		(158,367)	
	FIXED TRANSPORTATION / ADJUSTMENTS	-	401,395	-
	TOTAL	97,786	12,217,542	124.94
ALL PLANTS	SPOT	-	-	-
	CONTRACT	330,253	41,673,609	126.19
	FUEL MANAGEMENT AGREEMENT		(298,313)	
	FIXED TRANSPORTATION / ADJUSTMENTS	-	1,371,320	-
	TOTAL	330,253	42,746,616	$ 129.44

Clark Exhibit 6

Schedule 8

DUKE ENERGY CAROLINAS
ANALYSIS OF COAL QUALITY RECEIVED
DEC 2023

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
BELEWS CREEK	7.11	10.51	12,313	1.58
CLIFFSIDE	9.14	8.39	12,344	2.00
MARSHALL	6.28	10.26	12,526	1.61

Clark Exhibit 6

Schedule 9

DUKE ENERGY CAROLINAS
ANALYSIS OF OIL PURCHASED
DEC 2023

	ALLEN	BELEWS CREEK
VENDOR	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract
SULFUR CONTENT %	-	-
GALLONS RECEIVED	-	29,965
TOTAL DELIVERED COST	$ -	$ 76,938
DELIVERED COST/GALLON	$ -	$ 2.57
BTU/GALLON	138,000	138,000

	CLIFFSIDE	MARSHALL
VENDOR	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract
SULFUR CONTENT %	-	-
GALLONS RECEIVED	82,341	-
TOTAL DELIVERED COST	$ 218,631	$ -
DELIVERED COST/GALLON	$ 2.66	$ -
BTU/GALLON	138,000	138,000

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: December 2023 - December 2023

Station	Unit	Date of Outage	Duration of Outage (Hours)	Scheduled / Unscheduled	Cause of Outage	Reason Outage Occurred	Remedial Actions Taken
Oconee	1						
	2						
	3						
McGuire	1						
	2						
Catawba	1						
	2						

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2023

Belews Creek Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
2	12/5/2023 5:00:00 PM To 12/11/2023 4:00:00 AM	Unsch	1050	Second superheater	Unit off with a tube leak.	

Buck Combined Cycle Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
11	11/11/2023 12:11:00 AM To 12/2/2023 6:00:00 PM	Sch	1799	Other boiler instrumentation and control problems	Winterization Project	
12	11/11/2023 12:11:00 AM To 12/2/2023 6:00:00 PM	Sch	1799	Other boiler instrumentation and control problems	Winterization Project	
ST10	11/10/2023 11:43:00 PM To 12/2/2023 6:00:00 PM	Sch	7930	Controls and instrumentation	Winterization Project	

Clemson CHP

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
1	12/12/2023 7:25:00 AM To 12/12/2023 6:22:00 PM	Sch	5110	Lube oil system - general	Planned maintenance outage to address TT66B lube oil temp transmitter.	

Dan River Combined Cycle Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
8	12/1/2023 12:00:00 PM To 12/8/2023 10:28:00 AM	Unsch	4260	Main stop valves	Main Steam Stop valve not opening during startup of Steam Turbine	
9	12/1/2023 12:00:00 PM To 12/8/2023 10:53:00 AM	Unsch	4260	Main stop valves	Steam Turbine Main Stop Valve would not open during startup	
ST7	11/30/2023 6:00:00 PM To 12/8/2023 12:42:00 PM	Unsch	4260	Main stop valves	Steam Turbine Main Steam Stop Valve not opening during startup	

Notes:

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

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2023

Marshall Station

No Outages at Baseload Units During the Month.

WS Lee Combined Cycle

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
WS Lee CC ST 10	12/9/2023 11:58:00 AM To 12/9/2023 4:29:00 PM	Sch	4293	Hydraulic system pipes and valves	Steam turbine control valve #1 servo replacement	
WS Lee CC ST 10	12/16/2023 10:04:00 AM To 12/16/2023 9:12:00 PM	Sch	4293	Hydraulic system pipes and valves	Replacement of steam turbine control valve servos	

Notes:

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

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: December 2023 - December 2023

	Oconee 1	Oconee 2	Oconee 3	McGuire 1	McGuire 2	Catawba 1	Catawba 2
(A) MDC (MW)	847	848	859	1158	1158	1160	1150
(B) Period Hours	744	744	744	744	744	744	744
(C1) Net Gen (MWH)	649,611	649,503	654,103	886,807	880,377	877,938	871,613
(C2) Capacity Factor (%)	103.09	102.95	102.35	102.93	102.19	101.73	101.87
(D1) Net MWH Not Gen. Due to Full Schedule Outages	0	0	0	0	0	0	0
(D2) % Net MWH Not Gen. Due to Full Schedule Outages	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(E1) Net MWH Not Gen. Due to Partial Scheduled Outages	0	0	0	0	0	0	584
(E2) % Net MWH Not Gen. Due to Partial Scheduled Outages	0.00	0.00	0.00	0.00	0.00	0.00	0.07
(F1) Net MWH Not Gen Due to Full Forced Outages	0	0	0	0	0	0	0
(F2) % Net MWH Not Gen Due to Full Forced Outages	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(G1) Net MWH Not Gen due to Partial Forced Outages	-19,443	-18,591	-15,007	-25,255	-18,825	-14,898	-16,597
(G2) % Net MWH Not Gen Due to Partial Forced Outages	-3.09	-2.95	-2.35	-2.93	-2.19	-1.73	-1.94
(H1) Net MWH Not Gen Due to Economic Dispatch	0	0	0	0	0	0	0
(H2) %Net MWH Not Gen Due to Economic Dispatch	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(I1) Core Conservation	0	0	0	0	0	0	0
(I2) % Core Conservation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(J1) Net MWH Possible in Period	630,168	630,912	639,096	861,552	861,552	863,040	855,600
(J2) % Net mwh Possible in Period	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
(K) Equivalent Availability (%)	100.00	100.00	100.00	100.00	100.00	100.00	99.93
(L) Output Factor (%)	103.09	102.95	102.35	102.93	102.19	101.73	101.87
(M) Heat Rate (BTU/Net KWH)	10,045	10,040	9,969	9,921	9,991	10,015	9,916

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

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2023

Belews Creek Station

	Unit 1	Unit 2
(A) MDC (mW)	1,110	1,110
(B) Period Hrs	744	744
(C) Net Generation (mWh)	527,383	421,071
(D) Capacity Factor (%)	63.86	50.99
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	390	0
(H) Scheduled Derates: percent of Period Hrs	0.05	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	145,410
(J) Forced Outages: percent of Period Hrs	0.00	17.61
(K) Net mWh Not Generated due to Partial Forced Outages	49,290	8,190
(L) Forced Derates: percent of Period Hrs	5.97	0.99
(M) Net mWh Not Generated due to Economic Dispatch	248,778	251,169
(N) Economic Dispatch: percent of Period Hrs	30.12	30.41
(O) Net mWh Possible in Period	825,840	825,840
(P) Equivalent Availability (%)	93.98	81.40
(Q) Output Factor (%)	63.86	61.88
(R) Heat Rate (BTU/NkWh)	8,679	10,634

Notes:

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

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2023

Buck Combined Cycle Station

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	206	206	306	718
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	98,114	118,300	137,961	354,375
(D) Capacity Factor (%)	64.02	77.19	60.60	66.34
(E) Net mWh Not Generated due to Full Scheduled Outages	8,652	8,652	12,852	30,156
(F) Scheduled Outages: percent of Period Hrs	5.65	5.65	5.65	5.65
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	46,498	26,312	76,851	149,661
(N) Economic Dispatch: percent of Period Hrs	30.34	17.17	33.76	28.02
(O) Net mWh Possible in Period	153,264	153,264	227,664	534,192
(P) Equivalent Availability (%)	94.35	94.35	94.35	94.35
(Q) Output Factor (%)	83.49	83.60	65.75	75.58
(R) Heat Rate (BTU/NkWh)	10,067	10,024	1,587	6,751

Notes:

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

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2023

Clemson CHP

	Clemson CHP1
(A) MDC (mW)	16
(B) Period Hrs	744
(C) Net Generation (mWh)	10,026
(D) Capacity Factor (%)	86.94
(E) Net mWh Not Generated due to Full Scheduled Outages	170
(F) Scheduled Outages: percent of Period Hrs	1.47
(G) Net mWh Not Generated due to Partial Scheduled Outages	0
(H) Scheduled Derates: percent of Period Hrs	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0
(J) Forced Outages: percent of Period Hrs	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0
(L) Forced Derates: percent of Period Hrs	0.00
(M) Net mWh Not Generated due to Economic Dispatch	1,336
(N) Economic Dispatch: percent of Period Hrs	11.59
(O) Net mWh Possible in Period	11,532
(P) Equivalent Availability (%)	98.53
(Q) Output Factor (%)	88.24
(R) Heat Rate (BTU/NkWh)	11,357

Notes:

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

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2023

Clark Exhibit 6,
Schedule 10

Dan River Combined Cycle Station

	Unit 8	Unit 9	Unit ST07	Block Total
(A) MDC (mW)	206	206	308	720
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	77,382	99,043	112,420	288,845
(D) Capacity Factor (%)	50.49	64.62	49.06	53.92
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	425	425	756	1,607
(H) Scheduled Derates: percent of Period Hrs	0.28	0.28	0.33	0.30
(I) Net mWh Not Generated due to Full Forced Outages	34,292	34,378	55,656	124,326
(J) Forced Outages: percent of Period Hrs	22.37	22.43	24.29	23.21
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	41,164	19,418	60,320	120,902
(N) Economic Dispatch: percent of Period Hrs	26.86	12.67	26.32	22.57
(O) Net mWh Possible in Period	153,264	153,264	229,152	535,680
(P) Equivalent Availability (%)	77.35	77.29	75.38	76.49
(Q) Output Factor (%)	80.84	83.31	64.80	74.42
(R) Heat Rate (BTU/NkWh)	10,179	10,029	1,560	6,773

Notes:

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

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2023

Marshall Station

	Unit 3	Unit 4
(A) MDC (mW)	658	660
(B) Period Hrs	744	744
(C) Net Generation (mWh)	259,401	261,354
(D) Capacity Factor (%)	52.99	53.22
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	6,888	6,930
(H) Scheduled Derates: percent of Period Hrs	1.41	1.41
(I) Net mWh Not Generated due to Full Forced Outages	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	223,263	222,756
(N) Economic Dispatch: percent of Period Hrs	45.61	45.36
(O) Net mWh Possible in Period	489,552	491,040
(P) Equivalent Availability (%)	98.59	98.59
(Q) Output Factor (%)	52.99	53.22
(R) Heat Rate (BTU/NkWh)	10,512	10,412

Notes:

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

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2023

WS Lee Combined Cycle

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	248	248	313	809
(B) Period Hrs	744	744	744	744
(C) Net Generation (mWh)	160,102	169,267	205,082	534,451
(D) Capacity Factor (%)	86.77	91.74	88.07	88.79
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	4,898	4,898
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	2.10	0.81
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	24,410	15,245	22,892	62,547
(N) Economic Dispatch: percent of Period Hrs	13.23	8.26	9.83	10.39
(O) Net mWh Possible in Period	184,512	184,512	232,872	601,896
(P) Equivalent Availability (%)	100.00	100.00	97.90	99.19
(Q) Output Factor (%)	86.77	91.74	89.96	89.52
(R) Heat Rate (BTU/NkWh)	10,897	10,337	1,812	7,234

Notes:

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

Duke Energy Carolinas
Intermediate Power Plant Performance Review Plan
December 2023

		Cliffside Station
		Cliffside 6
(A)	**MDC (mW)**	849
(B)	**Period Hrs**	744
(C)	**Net Generation (mWh)**	425,013
(D)	**Net mWh Possible in Period**	631,656
(E)	**Equivalent Availability (%)**	99.72
(F)	**Output Factor (%)**	67.29
(G)	**Capacity Factor (%)**	67.29

Notes:

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

Duke Energy Carolinas
Peaking Power Plant Performance Review Plan
December 2023

		Cliffside Station
		Unit 5
(A)	MDC (mW)	546
(B)	Period Hrs	744
(C)	Net Generation (mWh)	128,044
(D)	Net mWh Possible in Period	406,224
(E)	Equivalent Availability (%)	98.72
(F)	Output Factor (%)	56.01
(G)	Capacity Factor (%)	31.52

Notes:

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

Clark Exhibit 6, Schedule 10

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: January 2023 - December 2023

	Oconee 1	Oconee 2	Oconee 3	McGuire 1	McGuire 2	Catawba 1	Catawba 2
(A) MDC (MW)	847	848	859	1158	1158	1160	1150
(B) Period Hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760
(C1) Net Gen (MWH)	7,589,742	7,068,006	7,588,987	9,202,099	8,866,273	8,988,094	10,177,428
(C2) Capacity Factor (%)	102.29	95.15	100.85	90.71	87.40	88.45	101.03
(D1) Net MWH Not Gen. Due to Full Schedule Outages	0	509,083	0	1,082,035	1,221,690	1,089,994	0
(D2) % Net MWH Not Gen. Due to Full Schedule Outages	0.00	6.85	0.00	10.67	12.04	10.73	0.00
(E1) Net MWH Not Gen. Due to Partial Scheduled Outages	0	6,135	0	41,192	23,652	111,819	897
(E2) % Net MWH Not Gen. Due to Partial Scheduled Outages	0.00	0.08	0.00	0.41	0.23	1.10	0.01
(F1) Net MWH Not Gen Due to Full Forced Outages	0	0	43,480	0	35,241	0	0
(F2) % Net MWH Not Gen Due to Full Forced Outages	0.00	0.00	0.58	0.00	0.35	0.00	0.00
(G1) Net MWH Not Gen due to Partial Forced Outages	-170,022	-154,744	-107,627	-181,246	-2,776	-28,307	-104,325
(G2) % Net MWH Not Gen Due to Partial Forced Outages	-2.29	-2.08	-1.43	-1.79	-0.02	-0.28	-1.04
(H1) Net MWH Not Gen Due to Economic Dispatch	0	0	0	0	0	0	0
(H2) %Net MWH Not Gen Due to Economic Dispatch	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(I1) Core Conservation	0	0	0	0	0	0	0
(I2) % Core Conservation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(J1) Net MWH Possible in Period	7,419,720	7,428,480	7,524,840	10,144,080	10,144,080	10,161,600	10,074,000
(J2) % Net mwh Possible in Period	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
(K) Equivalent Availability (%)	99.89	92.96	99.29	88.98	86.45	88.00	99.99
(L) Output Factor (%)	102.29	102.15	101.44	101.55	99.77	99.08	101.03
(M) Heat Rate (BTU/Net KWH)	10,105	10,100	10,046	10,017	10,108	10,135	10,003

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

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2023 through December, 2023
Belews Creek Station

	Unit 1	Unit 2
(A) MDC (mW)	1,110	1,110
(B) Period Hrs	8,760	8,760
(C) Net Generation (mWh)	3,849,391	4,638,550
(D) Capacity Factor (%)	39.59	47.70
(E) Net mWh Not Generated due to Full Scheduled Outages	2,342,655	1,878,120
(F) Scheduled Outages: percent of Period Hrs	24.09	19.32
(G) Net mWh Not Generated due to Partial Scheduled Outages	30,436	13,531
(H) Scheduled Derates: percent of Period Hrs	0.31	0.14
(I) Net mWh Not Generated due to Full Forced Outages	412,365	159,840
(J) Forced Outages: percent of Period Hrs	4.24	1.64
(K) Net mWh Not Generated due to Partial Forced Outages	158,675	88,989
(L) Forced Derates: percent of Period Hrs	1.63	0.92
(M) Net mWh Not Generated due to Economic Dispatch	2,930,078	2,944,570
(N) Economic Dispatch: percent of Period Hrs	30.13	30.28
(O) Net mWh Possible in Period	9,723,600	9,723,600
(P) Equivalent Availability (%)	69.72	77.99
(Q) Output Factor (%)	56.11	60.35
(R) Heat Rate (BTU/NkWh)	9,140	9,760

Notes:

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

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2023 through December, 2023
Buck Combined Cycle Station

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	206	206	306	718
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,111,803	1,126,791	1,581,365	3,819,959
(D) Capacity Factor (%)	61.61	62.44	58.99	60.73
(E) Net mWh Not Generated due to Full Scheduled Outages	341,385	342,135	492,183	1,175,703
(F) Scheduled Outages: percent of Period Hrs	18.92	18.96	18.36	18.69
(G) Net mWh Not Generated due to Partial Scheduled Outages	94,432	94,772	22,561	211,766
(H) Scheduled Derates: percent of Period Hrs	5.23	5.25	0.84	3.37
(I) Net mWh Not Generated due to Full Forced Outages	58,792	60,941	89,015	208,749
(J) Forced Outages: percent of Period Hrs	3.26	3.38	3.32	3.32
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	13,528	13,528
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.50	0.22
(M) Net mWh Not Generated due to Economic Dispatch	198,147	179,921	481,907	859,975
(N) Economic Dispatch: percent of Period Hrs	10.98	9.97	17.98	13.67
(O) Net mWh Possible in Period	1,804,560	1,804,560	2,680,560	6,289,680
(P) Equivalent Availability (%)	72.59	72.41	76.97	74.41
(Q) Output Factor (%)	81.84	81.68	76.53	79.51
(R) Heat Rate (BTU/NkWh)	10,533	10,439	2,193	7,053

Notes:

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

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2023 through December, 2023
Clemson CHP

	Clemson CHP1
(A) MDC (mW)	16
(B) Period Hrs	8,760
(C) Net Generation (mWh)	108,527
(D) Capacity Factor (%)	79.93
(E) Net mWh Not Generated due to Full Scheduled Outages	6,251
(F) Scheduled Outages: percent of Period Hrs	4.60
(G) Net mWh Not Generated due to Partial Scheduled Outages	14,509
(H) Scheduled Derates: percent of Period Hrs	10.69
(I) Net mWh Not Generated due to Full Forced Outages	13
(J) Forced Outages: percent of Period Hrs	0.01
(K) Net mWh Not Generated due to Partial Forced Outages	0
(L) Forced Derates: percent of Period Hrs	0.00
(M) Net mWh Not Generated due to Economic Dispatch	6,480
(N) Economic Dispatch: percent of Period Hrs	4.77
(O) Net mWh Possible in Period	135,780
(P) Equivalent Availability (%)	84.70
(Q) Output Factor (%)	83.79
(R) Heat Rate (BTU/NkWh)	11,420

Notes:

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

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2023 through December, 2023
Dan River Combined Cycle Station

	Unit 8	Unit 9	Unit ST07	Block Total
(A) MDC (mW)	206	206	308	720
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,056,369	1,096,342	1,576,101	3,728,812
(D) Capacity Factor (%)	58.54	60.75	58.42	59.12
(E) Net mWh Not Generated due to Full Scheduled Outages	369,857	371,721	528,811	1,270,389
(F) Scheduled Outages: percent of Period Hrs	20.50	20.60	19.60	20.14
(G) Net mWh Not Generated due to Partial Scheduled Outages	123,174	124,346	23,904	271,423
(H) Scheduled Derates: percent of Period Hrs	6.83	6.89	0.89	4.30
(I) Net mWh Not Generated due to Full Forced Outages	45,324	49,125	97,673	192,122
(J) Forced Outages: percent of Period Hrs	2.51	2.72	3.62	3.05
(K) Net mWh Not Generated due to Partial Forced Outages	14,439	15,677	0	30,115
(L) Forced Derates: percent of Period Hrs	0.80	0.87	0.00	0.48
(M) Net mWh Not Generated due to Economic Dispatch	195,398	147,350	471,591	814,339
(N) Economic Dispatch: percent of Period Hrs	10.83	8.17	17.48	12.91
(O) Net mWh Possible in Period	1,804,560	1,804,560	2,698,080	6,307,200
(P) Equivalent Availability (%)	69.37	68.92	75.89	72.03
(Q) Output Factor (%)	78.10	79.31	76.08	77.58
(R) Heat Rate (BTU/NkWh)	10,909	10,736	2,115	7,141

Notes:

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

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2023 through December, 2023
Marshall Station

	Unit 3	Unit 4
(A) MDC (mW)	658	660
(B) Period Hrs	8,760	8,760
(C) Net Generation (mWh)	2,294,386	3,018,573
(D) Capacity Factor (%)	39.80	52.21
(E) Net mWh Not Generated due to Full Scheduled Outages	1,489,153	674,263
(F) Scheduled Outages: percent of Period Hrs	25.84	11.66
(G) Net mWh Not Generated due to Partial Scheduled Outages	37,861	23,166
(H) Scheduled Derates: percent of Period Hrs	0.66	0.40
(I) Net mWh Not Generated due to Full Forced Outages	422,640	208,309
(J) Forced Outages: percent of Period Hrs	7.33	3.60
(K) Net mWh Not Generated due to Partial Forced Outages	137,121	85,694
(L) Forced Derates: percent of Period Hrs	2.38	1.48
(M) Net mWh Not Generated due to Economic Dispatch	1,382,919	1,771,595
(N) Economic Dispatch: percent of Period Hrs	23.99	30.64
(O) Net mWh Possible in Period	5,764,080	5,781,600
(P) Equivalent Availability (%)	63.80	82.85
(Q) Output Factor (%)	60.04	64.10
(R) Heat Rate (BTU/NkWh)	10,138	10,145

Notes:

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

Clark Exhibit 6,
Schedule 10

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
January, 2023 through December, 2023
WS Lee Combined Cycle

	Unit 11	Unit 12	Unit ST10	Block Total
(A) MDC (mW)	248	248	313	809
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,736,246	1,775,803	2,429,400	5,941,449
(D) Capacity Factor (%)	79.92	81.74	88.60	83.84
(E) Net mWh Not Generated due to Full Scheduled Outages	93,429	96,611	125,817	315,857
(F) Scheduled Outages: percent of Period Hrs	4.30	4.45	4.59	4.46
(G) Net mWh Not Generated due to Partial Scheduled Outages	69,256	74,021	0	143,277
(H) Scheduled Derates: percent of Period Hrs	3.19	3.41	0.00	2.02
(I) Net mWh Not Generated due to Full Forced Outages	64,877	66,724	88,789	220,390
(J) Forced Outages: percent of Period Hrs	2.99	3.07	3.24	3.11
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	208,672	159,321	97,874	465,867
(N) Economic Dispatch: percent of Period Hrs	9.61	7.33	3.57	6.57
(O) Net mWh Possible in Period	2,172,480	2,172,480	2,741,880	7,086,840
(P) Equivalent Availability (%)	89.53	89.07	92.17	90.41
(Q) Output Factor (%)	86.79	89.37	96.77	91.44
(R) Heat Rate (BTU/NkWh)	10,717	10,472	2,401	7,243

Notes:

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

Duke Energy Carolinas
Intermediate Power Plant
Performance Review Plan
January, 2023 through December, 2023

Cliffside Station

Units	Unit 6
(A) MDC (mW)	849
(B) Period Hrs	8,760
(C) Net Generation (mWh)	4,293,742
(D) Net mWh Possible in Period	7,437,240
(E) Equivalent Availability (%)	78.12
(F) Output Factor (%)	73.56
(G) Capacity Factor (%)	57.73

Notes:

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

Duke Energy Carolinas
Peaking Power Plant
Performance Review Plan
January, 2023 through December, 2023

Cliffside Station

Units	Unit 5
(A) MDC (mW)	546
(B) Period Hrs	8,760
(C) Net Generation (mWh)	951,065
(D) Net mWh Possible in Period	4,782,960
(E) Equivalent Availability (%)	51.39
(F) Output Factor (%)	52.03
(G) Capacity Factor (%)	19.88

Notes:

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

Duke Energy Carolinas, LLC **Clark Exhibit 7**
North Carolina Annual Fuel and Fuel Related Expense
Proposed Base Rate Decrement Adjustment Related to Voltage Differential
Test Period Ended December 31, 2023
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales at Meter	Workpaper 7	22,870,391	24,590,927	12,348,188	59,809,506
	Calculation of Fuel (Non-Capacity) Rate by Class					Amount
2	System Fuel (Non-Capacity) Costs	Workpaper 7 - Line 11				$ 2,043,629,333
3	NC Portion - Jurisdictional % based on Projected Billing Period MWh Sales at Meter	Workpaper 7				66.49%
4	NC Retail Fuel (Non-Capacity) Costs before 2.5% Purchase Power Test	Line 2 * Line 3				$ 1,358,809,144
5	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 9				-
6	NC Retail Fuel (Non-Capacity) Costs Allowable Under GEN. STAT. § 62-133.2(A2)	Line 4 + Line 5				$ 1,358,809,144
7	NC Retail Projected Billing Period MWh Sales Allocation Factors at Generator	Line 1 / Line 1 Total	**38.24%**	**41.12%**	**20.65%**	**100.00%**
8	Fuel (Non-Capacity) Costs allocated on Projected Billing Period MWh Sales	Line 6 * Line 7	$ 519,591,257	$ 558,680,028	$ 280,537,859	$ 1,358,809,144
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class					Amount
9	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 11,295,326
10	QF Purchased Power - Capacity	Workpaper 4				10,496,458
11	Total of Renewable and QF Purchased Power Capacity	Line 9 + Line 10				$ 21,791,784
12	NC Portion - Jursidicational % based on 2022 Production Demand Allocator	Input				67.12%
13	NC Renewable and QF Purchased Power - Capacity	Line 11 * Line 12				$ 14,626,471
14	2022 Production Demand Allocation Factors	Input	49.05%	35.73%	15.22%	100.00%
15	Renewable and QF Purchased Power - Capacity allocated on 2022 Production Demand Allocator	Line 13 * Line 14	$ 7,174,604	$ 5,226,011	$ 2,225,856	$ 14,626,471
16	Total Fuel Expense Using NC Projected Billing Period MWh Sales at Meter	Line 8 + Line 15	$ 526,765,861	$ 563,906,038	$ 282,763,715	$ 1,373,435,615
17	Total Fuel Expense Using NC Projected Billing Period MWh Sales at Generatoı	Exh2 Sch 1 Page 2 of 2	$ 527,418,801	$ 566,693,284	$ 283,410,788	$ 1,377,522,873
18	Difference in Fuel Total Fuel Expense Attributable to Voltage Differential	Line 16 - Line 17	$ (652,940)	$ (2,787,246)	$ (647,073)	$ (4,087,259)
19	NC Projected Sales at Meter	Workpaper 7	22,870,391	24,590,927	12,348,188	59,809,506
20	Proposed Decrement Rider Attributable to Voltage Differentia	Line 18 / Line 19 / 10	(0.0029)	(0.0113)	(0.0052)	(0.0068)

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 1

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs	9,447,231	10,027,396	9,446,071	9,372,290	6,881,925	7,468,908	7,564,100	60,207,920
Cost (Gross of Joint Owners)	$ 53,807,708	$ 57,846,842	$ 46,989,141	$ 52,105,691	$ 38,433,497	$ 38,833,229	$ 44,209,143	$ 332,225,252
$/MWh	5.6956	5.7689	4.9745	5.5595	5.5847	5.1993	5.8446	
Avg $/MWh		**5.5180**						
Cents per kWh		**0.5518**						

			Sept 2024 - August 2025
MDC			
CATA_UN01	Catawba	MW	1,160.0
CATA_UN02	Catawba	MW	1,150.1
MCGU_UN01	McGuire	MW	1,158.0
MCGU_UN02	McGuire	MW	1,157.6
OCON_UN01	Oconee	MW	847.0
OCON_UN02	Oconee	MW	848.0
OCON_UN03	Oconee	MW	859.0
			7,179.7
Hours In Year			8,760
Generation GWhs			
CATA_UN01	Catawba	GWh	9,447
CATA_UN02	Catawba	GWh	10,027
MCGU_UN01	McGuire	GWh	9,446
MCGU_UN02	McGuire	GWh	9,372
OCON_UN01	Oconee	GWh	6,882
OCON_UN02	Oconee	GWh	7,469
OCON_UN03	Oconee	GWh	7,564
			60,208
	Proposed Nuclear Capacity Factor		95.73%

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 2

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs with NERC applied	9,294,816	9,215,489	9,278,790	9,275,585	6,875,855	6,883,972	6,973,269	57,797,776
Hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
MDC	1,160.0	1,150.1	1,158.0	1,157.6	847.0	848.0	859.0	7,179.7
Capacity factor	91.47%	91.47%	91.47%	91.47%	92.67%	92.67%	92.67%	91.90%
Cost	$ 51,288,476	$ 50,850,755	$ 51,200,047	$ 51,182,362	$ 37,940,731	$ 37,985,525	$ 38,478,262	$ 318,926,159

Avg $/MWh	**5.5180**
Cents per kWh	**0.5518**

2018-2022	Capacity Rating	NCF Rating	Weighted Average	
Oconee 1	847.0	92.67	10.93%	
Oconee 2	848.0	92.67	10.95%	
Oconee 3	859.0	92.67	11.09%	
McGuire 1	1,158.0	91.47	14.75%	
McGuire 2	1,157.6	91.47	14.75%	
Catawba 1	1,160.0	91.47	14.78%	
Catawba 2	1,150.1	91.47	14.65%	
	7,179.7		**91.90%**	Wtd Avg on Capacity Rating

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation and Purchased Power in MWhs
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 3

Resource Type	Sept 2024 - August 2025	
NUC Total (Gross)	60,207,920	
COAL Total	12,133,505	
Gas CT and CC total (Gross)	25,398,789	
Run of River	4,222,386	
Net pumped Storage	(3,257,750)	
Total Hydro	964,636	
Catawba Joint Owners	(14,116,637)	
Lee CC Joint Owners	(876,000)	
DEC owned solar	431,227	
Total Generation		84,143,439
Purchases for REPS Compliance	1,064,067	
Qualifying Facility Purchases - Non-REPS compliance	2,075,391	
Other Purchases	313,719	
Allocated Economic Purchases	467,186	
Joint Dispatch Purchases	8,665,644	
	12,586,006	
Total Generation and Purchased Power		96,729,446
Fuel Recovered Through Intersystem Sales	(666,675)	

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Fuel and Fuel Related Costs
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 4

Resource Type		**Sept 2024 - August 2025**	
Nuclear Total (Gross)	$	332,225,252	
COAL Total		535,009,000	
Gas CT and CC total (Gross)		863,780,065	
Catawba Joint Owner costs		(77,896,854)	
CC Joint Owner costs		(21,752,442)	
Reagents and gain/loss on sale of By-Products		30,185,368	Workpaper 8
Purchases for REPS Compliance - Energy		51,648,652	
Purchases for REPS Compliance - Capacity		11,295,326	
Purchases of Qualifying Facilities - Energy		50,840,078	
Purchases of Qualifying Facilities - Capacity		10,496,458	
Other Purchases		10,583,349	
JDA Savings Shared		34,396,187	Workpaper 5
Allocated Economic Purchase cost		18,114,953	Workpaper 5
Joint Dispatch purchases		240,665,893	Workpaper 6
Total Purchases		428,040,896	
Fuel Expense recovered through intersystem sales		(27,889,431)	Workpaper 5
Total System Fuel and Fuel Related Costs	**$**	**2,061,701,854**	

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Joint Dispatch Fuel Impacts
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 5

Positive numbers represent costs to ratepayers, Negative numbers represent removal of costs to ratepayers

	Allocated Economic Purchase Cost		**Economic Sales Cost**		**Fuel Transfer Payment**		**JDA Savings Payment**	
	DEP	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**
9/1/2024	$ 436,812	$ 645,500	$ (632,756)	$ (817,493)	$ (23,633,592)	$ 23,633,592	$ (5,606,498)	$ 5,606,498
10/1/2024	$ 271,867	$ 414,509	$ (655,410)	$ (994,763)	$ (22,697,388)	$ 22,697,388	$ (5,774,653)	$ 5,774,653
11/1/2024	$ 368,297	$ 557,717	$ (768,230)	$ (870,196)	$ (15,549,159)	$ 15,549,159	$ (1,949,764)	$ 1,949,764
12/1/2024	$ 524,633	$ 753,841	$ (1,304,569)	$ (1,477,550)	$ (17,819,465)	$ 17,819,465	$ (1,388,719)	$ 1,388,719
1/1/2025	$ 2,446,075	$ 3,483,576	$ (2,052,991)	$ (2,574,603)	$ (20,822,899)	$ 20,822,899	$ (2,918,522)	$ 2,918,522
2/1/2025	$ 1,393,923	$ 2,027,148	$ (1,828,720)	$ (2,527,737)	$ (23,044,391)	$ 23,044,391	$ (2,629,204)	$ 2,629,204
3/1/2025	$ 248,720	$ 353,347	$ (1,944,697)	$ (2,148,243)	$ (10,835,036)	$ 10,835,036	$ (1,577,570)	$ 1,577,570
4/1/2025	$ 281,105	$ 419,737	$ (1,108,299)	$ (1,589,401)	$ (20,154,107)	$ 20,154,107	$ (4,214,847)	$ 4,214,847
5/1/2025	$ 306,089	$ 440,371	$ (1,330,210)	$ (1,812,063)	$ (14,494,693)	$ 14,494,693	$ (2,689,742)	$ 2,689,742
6/1/2025	$ 2,127,583	$ 3,104,942	$ (991,750)	$ (1,133,216)	$ (20,285,202)	$ 20,285,202	$ (1,053,147)	$ 1,053,147
7/1/2025	$ 2,373,137	$ 3,320,464	$ (1,439,263)	$ (1,566,216)	$ (21,552,596)	$ 21,552,596	$ (4,053,576)	$ 4,053,576
8/1/2025	$ 1,822,499	$ 2,593,800	$ (1,347,905)	$ (1,499,489)	$ (20,898,904)	$ 20,898,904	$ (539,944)	$ 539,944
Sept 24 - Aug 25		$ 18,114,953		$ (19,010,968)		$ 231,787,430		$ 34,396,187

$ 240,665,893	Workpaper 6 - Transfer - Purchases
$ (8,878,463)	Workpaper 6 - Transfer - Sales
$ 231,787,430	Sept 24 - Aug 25 Net Fuel Transfer Payment
$ (8,878,463)	Workpaper 6 - Transfer - Sales
$ (19,010,968)	Sept 24 - Aug 25 Economic Sales Cost
$ (27,889,431)	**Total Fuel expense recovered through intersystem sales**

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Merger Payments
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 6

					Purchase	Sale			Sale	Purchase
	Transfer Projection		Purchase Allocation Delta		Adjusted Transfer		Fossil Gen Cost		Pre-Net Payments	
	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC
9/1/2024	1,034,410	3,988	(107)	107	1,034,410	4,095	22.95	24.73	101,264	23,734,856
10/1/2024	1,053,555	2,994	960	(960)	1,054,515	2,994	21.59	24.35	72,890	22,770,277
11/1/2024	663,811	23,847	(163)	163	663,811	24,011	24.35	25.48	611,700	16,160,859
12/1/2024	666,108	31,407	13	(13)	666,120	31,407	28.12	28.96	909,705	18,729,170
1/1/2025	674,906	36,360	(5,034)	5,034	674,906	41,394	33.01	35.10	1,453,104	22,276,003
2/1/2025	751,943	16,326	(3,124)	3,124	751,943	19,449	31.56	35.21	684,894	23,729,285
3/1/2025	442,991	53,865	(67)	67	442,991	53,932	27.73	26.88	1,449,862	12,284,897
4/1/2025	745,064	11,720	874	(874)	745,938	11,720	27.44	27.13	317,906	20,472,012
5/1/2025	573,643	25,667	160	(160)	573,803	25,667	26.52	28.07	720,462	15,215,155
6/1/2025	701,331	14,494	(5,841)	5,841	701,331	20,334	29.81	30.73	624,928	20,910,130
7/1/2025	685,572	23,909	(7,263)	7,263	685,572	31,173	32.95	33.16	1,033,842	22,586,438
8/1/2025	670,304	19,461	(7,752)	7,752	670,304	27,213	32.52	33.00	897,907	21,796,812
Sept 24 - Aug 25	8,663,637	264,038	(27,345)	27,345	8,665,644	293,389			$ 8,878,463	$ 240,665,893
									Net Pre-Net Payments	$ 231,787,430

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 95.73%
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Fall 2023 Forecast
Billed Sales Forecast
Sales Forecast - MWhs (000)

		Projected sales At Meter for the Billing Period	Remove impact of SC DERP Net Metered Generation	Adjusted Sales	2022 Cost of Service Line Loss Factors	Adjusted Projected Sales at Generation
North Carolina:						
	Residential	22,870,391		22,870,391	5.4880%	24,198,399
	General	24,349,887		24,349,887	5.8390%	25,859,843
	Industrial	12,348,188		12,348,188	5.5870%	13,078,907
	Lighting	241,040		241,040	5.8390%	255,987
	NC RETAIL	59,809,506	-	59,809,506		63,393,136
South Carolina:						
	Residential	7,051,738		7,051,738		
	General	5,570,198		5,570,198		
	Industrial	8,525,790		8,525,790		
	Lighting	48,602		48,602		
	SC RETAIL	21,196,328	150,334	21,346,662	5.8280%	22,667,738
Total Retail Sales						
	Residential	29,922,129	-	29,922,129		
	General	29,920,085	-	29,920,085		
	Industrial	20,873,978	-	20,873,978		
	Lighting	289,642	-	289,642		
	Retail Sales	81,005,834	150,334	81,005,834		86,060,874
	Wholesale	8,800,590	-	8,800,590	2.1900%	8,997,638
	Projected System MWH Sales for Fuel Factor	89,806,424	150,334	89,956,758		95,058,512
	NC as a percentage of total	**66.60%**		**66.49%**		**66.69%**
	SC as a percentage of total	23.60%		23.73%		23.85%
	Wholesale as a percentage of total	9.80%		9.78%		9.47%
		100.00%		100.00%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	150,334
Marginal fuel rate per MWh for SC NEM	$ 24.74
Fuel benefit to be directly assigned to SC Retail	$ 3,719,263

System Fuel Expense	$ 2,061,701,854	Clark Exhibit 2 Schedule 1 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 3,719,263	
Total Fuel Costs for Allocation	$ 2,065,421,117	Clark Exhibit 2 Schedule 1 Page 3 of 3, L5

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 95.73% and Normalized Test Period Sales
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Fall 2023 Forecast
Billed Sales Forecast - Normalized Test Period Sales
Sales Forecast - MWhs (000)

		Test Period Sales	Customer Growth Adjustment	Weather Adjustment	Remove impact of SC DERP Net Metered generation	Normalized Test Period Sales	2022 Cost of Service Line Loss Factors	Normalized Test Period Sales MWhs at Generation
NC RETAIL								
	Residential	21,544,402	216,090	1,046,809		22,807,302	5.4880%	24,131,647
	General & Lighting	24,310,321	(44,343)	208,055		24,474,032	5.8390%	25,991,687
	Industrial	11,674,957	12,311	17,164		11,704,432	5.5870%	12,397,056
NC RETAIL		57,529,680	184,058	1,272,028	-	58,985,766		62,520,389
SC RETAIL		20,649,066	131,233	387,779	150,334	21,318,412	5.8280%	22,637,740
Wholesale		8,177,978	89,190	96,670	-	8,363,838	2.1900%	8,551,107
Normalized System MWH Sales for Fuel Factor		86,356,724	404,481	1,756,476	150,334	88,668,017		93,709,236
NC as a percentage of total		**66.62%**				**66.52%**		**66.72%**
SC as a percentage of total		23.91%				24.04%		24.16%
Wholesale as a percentage of total		9.47%				9.43%		9.13%
		100.00%				100.00%		100.00%

SC Net Metering allocation adjustment		
Total projected SC NEM MWhs	150,334	
Marginal fuel rate per MWh for SC NEM	$ 24.74	
Fuel benefit to be directly assigned to SC Retail	$ 3,719,263	
System Fuel Expense	$ 2,011,505,418	Clark Exhibit 2 Schedule 2 Page 1 of 2
Fuel benefit to be directly assigned to SC Retail	3,719,263	
Total Fuel Costs for Allocation	$ 2,015,224,681	

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
NERC 5 Year Average Nuclear Capacity Factor of 91.90% and Projected Period Sales
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 7b

Fall 2023 Forecast
Billed Sales Forecast
Sales Forecast - MWhs (000)

		Projected sales for the Billing Period	Remove impact of SC DERP Net Metered generation	Adjusted Sales	2022 Cost of Service Line Loss Factors	Adjusted Projected Sales at Generation
North Carolina:						
	Residential	22,870,391		22,870,391	5.4880%	24,198,399
	General	24,349,887		24,349,887	5.8390%	25,859,843
	Industrial	12,348,188		12,348,188	5.5870%	13,078,907
	Lighting	241,040		241,040	5.8390%	255,987
	NC RETAIL	59,809,506	-	59,809,506		63,393,136
South Carolina:						
	Residential	7,051,738		7,051,738		
	General	5,570,198		5,570,198		
	Industrial	8,525,790		8,525,790		
	Lighting	48,602		48,602		
	SC RETAIL	21,196,328	150,334	21,346,662	5.8280%	22,667,738
Total Retail Sales						
	Residential	29,922,129	-	29,922,129		
	General	29,920,085	-	29,920,085		
	Industrial	20,873,978	-	20,873,978		
	Lighting	289,642	-	289,642		
	Retail Sales	81,005,834	150,334	81,156,168		86,211,208
	Wholesale	8,800,590	-	8,800,590	2.1900%	8,997,638
	Projected System MWh Sales for Fuel Factor	89,806,424	150,334	89,956,758		95,208,846
	NC as a percentage of total	**66.60%**		**66.49%**		**66.58%**
	SC as a percentage of total	23.60%		23.73%		23.81%
	Wholesale as a percentage of total	9.80%		9.78%		9.45%
		100.00%		100.00%		99.80%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	150,334	
Marginal fuel rate per MWh for SC NEM	$ 24.74	
Fuel benefit to be directly assigned to SC Retail	$ 3,719,263	
System Fuel Expense	$ 2,132,875,765	Clark Exhibit 2 Schedule 3 Page 1 of 2
Fuel benefit to be directly assigned to SC Retail	$ 3,719,263	
Total Fuel Costs for Allocation	$ 2,136,595,028	

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Line Loss Calculation Factors - 12 Months Ending December 31, 2022
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 7c

	MWh at Meter	MWh at Meter Allocation	MWh at at Generation (high side of GSU)	MWh at Generation Allocation	Losses
North Carolina					
Residential	22,375,068	25.44%	23,603,052	25.46%	1,227,984
General Service/Ligl	24,374,324	27.71%	25,797,639	27.83%	1,423,316
Industrial	12,309,569	13.99%	12,997,365	14.02%	687,796
Total NCR	59,058,961	67.14%	62,398,056	67.31%	3,339,095
NCWHS incl. NCEMPA	3,299,248	3.75%	3,373,119	3.64%	73,871
Total NC	62,358,208	70.89%	65,771,175	70.95%	3,412,967
South Carolina					
Residential	6,858,353	7.80%	7,234,752	7.80%	376,399
General Service/Ligl	5,679,157	6.46%	6,025,412	6.50%	346,255
Industrial	8,371,712	9.52%	8,867,745	9.57%	496,033
Total SCR	20,909,221	23.77%	22,127,908	23.87%	1,218,687
SC Greenwood	46,046	0.05%	48,600	0.05%	
SCWHS	4,650,971	5.29%	4,755,107	5.13%	104,137
Total SC	25,606,238	29.11%	26,931,615	29.05%	1,322,824
Total System	87,964,446	100.00%	92,702,790	100.00%	4,738,344
			-		

Cost of Service Data Summarized

	MWh @ Meter	MWh @ Generator	Losses (MWh)	Loss Percent
Residential	22,375,068	23,603,052	1,227,984	5.4880%
GS/Lighting	24,374,324	25,797,639	1,423,316	5.8390%
Industrial	12,309,569	12,997,365	687,796	5.5870%
Total NC Retail	59,058,961	62,398,056	3,339,095	5.6540%
Total NC Retail	59,058,961	62,398,056	3,339,095	5.6540%
SC Retail	20,909,221	22,127,908	1,218,687	5.8280%
12ME NEM Generation	**150,334**	159,095	8,761	5.8280%
Total SC Retail	21,059,555	22,287,004	1,227,448	5.8280%
Wholesale	7,845,930	8,017,730	171,800	2.1900%
Total System	87,964,446	92,702,790	4,738,344	5.3870%

Line Loss Calculations for Projected Fuel Costs	MWh @ Meter	MWh @ Generator	
Residential	22,870,391	24,198,399	
GS/Lighting	24,590,927	26,115,830	
Industrial	12,348,188	13,078,907	
Total NC Retail	59,809,506	63,393,136	
Total SC Retail	21,346,662	22,667,738	
Wholesale	8,800,590	8,997,638	
Total System	89,956,758	95,058,512	
Allocation percent - NC retail	66.49%	66.69%	WP 7, WP 7b

Line Loss Calculations for Normalized Test Period Sales	MWh @ Meter	MWh @ Generator	
Residential	22,807,302	24,131,647	
GS/Lighting	24,474,032	25,991,687	
Industrial	11,704,432	12,397,056	
Total NC Retail	58,985,766	62,520,389	
Total SC Retail	21,318,412	22,637,740	
Wholesale	8,509,735	8,700,271	
Total System	88,813,913	93,858,399	
Allocation percent - NC retail	66.42%	66.61%	WP 7a

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Reagents and ByProducts
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 8

Reagent and ByProduct projections

Date	Ammonia	Urea	Limestone	Magnesium Hydroxide	Calcium Carbonate	Lime	**Reagent Cost**	**Gypsum (Gain)/ Loss**	**Ash (Gain)/Loss**	**Steam (Gain)/Loss**	**Sale of By-Products (Gain)/Loss**
9/1/2024	$ 820,679	$ 78,192	$ 984,788	$ 36,763	$ 22,497	$ 18,972	**$ 1,961,891**	$ 341,938	$ (82,102)	$ (187,229)	**$ 72,608**
10/1/2024	$ 518,622	$ 49,413	$ 622,329	$ 15,829	$ 9,686	$ 18,972	**$ 1,234,850**	$ 184,644	$ (73,654)	$ (187,229)	**$ (76,238)**
11/1/2024	$ 739,868	$ 70,493	$ 887,817	$ 68,073	$ 41,657	$ 18,972	**$ 1,826,879**	$ 285,203	$ (99,874)	$ (187,229)	**$ (1,900)**
12/1/2024	$ 1,205,312	$ 114,839	$ 1,446,334	$ 124,781	$ 76,359	$ 18,972	**$ 2,986,596**	$ 534,190	$ (133,045)	$ (187,229)	**$ 213,916**
1/1/2025	$ 1,668,119	$ 158,934	$ 2,001,687	$ 169,764	$ 103,885	$ 18,972	**$ 4,121,360**	$ 778,575	$ (165,059)	$ (187,229)	**$ 426,287**
2/1/2025	$ 1,580,992	$ 150,633	$ 1,897,137	$ 148,850	$ 91,087	$ 18,972	**$ 3,887,671**	$ 772,758	$ (125,188)	$ (187,229)	**$ 460,341**
3/1/2025	$ 325,983	$ 31,059	$ 391,169	$ 49,658	$ 30,387	$ 18,972	**$ 847,228**	$ 161,566	$ (25,768)	$ (187,229)	**$ (51,430)**
4/1/2025	$ 263,450	$ 25,101	$ 316,132	$ 36,766	$ 22,499	$ 18,972	**$ 682,920**	$ 134,964	$ (26,688)	$ (187,229)	**$ (78,952)**
5/1/2025	$ 317,527	$ 30,253	$ 381,021	$ 39,899	$ 24,416	$ 18,972	**$ 812,088**	$ 159,994	$ (30,802)	$ (187,229)	**$ (58,036)**
6/1/2025	$ 989,053	$ 94,234	$ 1,186,830	$ 62,303	$ 38,126	$ 18,972	**$ 2,389,518**	$ 454,795	$ (94,572)	$ (187,229)	**$ 172,995**
7/1/2025	$ 1,616,811	$ 154,045	$ 1,940,118	$ 72,971	$ 44,654	$ 18,972	**$ 3,847,571**	$ 738,176	$ (150,146)	$ (221,902)	**$ 366,128**
8/1/2025	$ 1,592,680	$ 151,746	$ 1,911,162	$ 70,000	$ 42,836	$ 18,972	**$ 3,787,397**	$ 731,125	$ (155,541)	$ (221,902)	**$ 353,682**
	$ 11,639,095	$ 1,108,942	$ 13,966,522	$ 895,657	$ 525,592	$ 227,663	**$ 28,385,967**	$ 5,277,930	$ (1,162,439)	$ (2,316,089)	**$ 1,799,401**

Total Reagent cost and Sale of By-products **$ 30,185,368**

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Twelve Months Ended December 31, 2023
Billing Period September 2024 through August 2025
Docket E-7, Sub 1304

Clark Workpaper 9

Line No.	Description	Forecast $	(Over)/Under Collection $	Total $
1	Amount in current docket	101,757,298	2,705,033	104,462,331
2	Amount in Sub 1282, prior year docket	108,889,655	70,794,129	179,683,784
3	Increase/(Decrease)	(7,132,357)	(68,089,097)	(75,221,453)
4	2.5% of 2023 NC retail revenue of $5,417,293,543			135,432,339
	Excess of purchased power growth over 2.5% of revenue			0
	E-7, Sub 1304			
WP 4	Purchases for REPS Compliance - Energy	51,648,652	66.49%	34,341,189
WP 4	Purchases for REPS Compliance - Capacity	11,295,326	66.68%	7,531,868
WP 4	Purchases	10,583,349	66.49%	7,036,869
WP 4	QF Energy	50,840,078	66.49%	33,803,568
WP 4	QF Capacity	10,496,458	66.68%	6,999,173
WP 4	Allocated Economic Purchase cost	18,114,953	66.49%	12,044,632
		152,978,816		101,757,298
	E-7, Sub 1282			
	Purchases for REPS Compliance	68,804,621	67.00%	46,099,096
	Purchases for REPS Compliance Capacity	14,936,094	66.68%	9,959,579
	Purchases	442,692	67.00%	296,604
	QF Energy	46,784,121	67.00%	31,345,361
	QF Capacity	9,663,863	66.68%	6,443,988
	Allocated Economic Purchase cost	22,007,503	67.00%	14,745,027
		162,638,895		108,889,655

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Twelve Months Ended December 31, 2023
Docket E-7, Sub 1304

Clark Workpaper 9a

2023	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**12 ME**
System kWh Sales - Sch 4, Actuals	7,843,597,546	6,924,227,615	6,631,247,215	6,503,583,986	6,136,163,890	7,008,836,135	7,969,442,680	8,657,828,158	8,266,012,697	6,726,216,362	6,246,014,428	7,443,553,219	86,356,723,933
System kWh Sales - Sch 4, Adjusted	7,854,287,999	6,934,846,782	6,641,557,020	6,514,366,828	6,146,930,258	7,019,586,081	7,980,161,318	8,668,518,310	8,276,682,129	6,736,893,311	6,257,253,723	7,454,787,248	86,485,871,009
NC Retail kWh Sales - Sch 4	5,297,871,075	4,651,448,264	4,457,422,794	4,384,886,138	4,081,225,729	4,645,595,587	5,265,835,034	5,747,161,460	5,553,369,282	4,434,404,716	4,239,284,678	4,771,175,352	57,529,680,110
NC Retail % of Sales, Actuals (Calc)	67.54%	67.18%	67.22%	67.42%	66.51%	66.28%	66.08%	66.38%	67.18%	65.93%	67.87%	64.10%	66.62%
NC Retail % of Sales, Adjusted (Calc)	67.45%	67.07%	67.11%	67.31%	66.39%	66.18%	65.99%	66.30%	67.10%	65.82%	67.75%	64.00%	66.52%
NC retail production plant%	66.68%	66.68%	66.68%	66.68%	67.59%	67.59%	67.59%	67.59%	67.59%	67.59%	67.59%	67.59%	67.40%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 16,094,191	$ 3,933,514	$ 11,713,010	$ 8,938,848	$ 12,094,329	$ 11,531,053	$ 16,165,913	$ 20,551,811	$ 19,251,830	$ 24,023,842	$ 23,932,793	$ 9,961,878	$ 178,193,012
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	4,490,389	695,666	1,243,143	916,124	952,826	1,326,377	1,881,336	2,622,880	1,602,457	1,568,493	1,720,196	2,480,693	$ 21,500,580
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	3,611,490	7,870,147	3,867,355	5,211,256	5,135,046	5,506,547	5,557,340	5,455,614	5,098,575	4,206,666	3,924,590	3,303,809	$ 58,748,435
System Actual$ - Sch 3 Fuel-related$; SC DERP	150,010	263,513	161,232	259,030	244,568	242,598	269,439	270,334	237,447	261,069	232,453	169,028	$ 2,760,721
System Actual$ - Sch 3 Fuel-related$; SC ACT 62 (Solar Choice)										102,653	3,046	13,237	
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	2,294,533	3,127,298	2,300,057	3,268,409	3,390,357	3,491,315	3,450,044	3,587,125	3,238,065	3,440,066	2,976,354	2,281,872	$ 36,845,496
Total System Economic & QF$	26,640,613	15,890,138	19,284,797	18,593,667	21,817,127	22,097,890	27,324,072	32,487,764	29,428,373	33,602,789	32,789,431	18,210,518	298,167,179
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 12,596,278	$ 2,192,181	$ 11,669,944	$ 8,737,817	$ 12,131,496	$ 11,592,645	$ 16,561,057	$ 21,669,458	$ 19,697,648	$ 23,609,791	$ 22,989,786	$ 9,378,130	$ 172,826,231
Total System Economic $ without Native Load Transfers	$ 14,044,335	$ 13,697,957	$ 7,614,853	$ 9,855,850	$ 9,685,631	$ 10,505,245	$ 10,763,016	$ 10,818,306	$ 9,730,725	$ 9,890,346	$ 9,796,600	$ 8,819,150	$ 125,222,013
NC Actual $ (Calc)	$ 9,473,179	$ 9,187,707	$ 5,110,642	$ 6,634,072	$ 6,430,730	$ 6,952,421	$ 7,102,145	$ 7,172,454	$ 6,528,982	$ 6,510,092	$ 6,637,189	$ 5,644,388	$ 83,384,001
Billed rate (¢/kWh):	0.1409	0.1409	0.1409	0.1409	0.1409	0.1409	0.1409	0.1409	0.1357	0.1409	0.1409	0.1409	
Billed $:	$ 7,463,993	$ 6,553,270	$ 6,279,914	$ 6,177,719	$ 5,749,902	$ 6,545,024	$ 7,418,858	$ 8,096,983	$ 7,535,841	$ 6,247,484	$ 5,972,586	$ 6,721,949	$ 80,763,523
(Over)/ Under $:	$ 2,009,186	$ 2,634,437	$ (1,169,272)	$ 456,353	$ 680,827	$ 407,397	$ (316,713)	$ (924,529)	$ (1,006,859)	$ 262,608	$ 664,603	$ (1,077,561)	$ 2,620,478
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Actual $ - Capacity component of Purchased Power for REPS Compliance	563,042	1,526,511	652,726	802,906	714,202	872,972	2,529,735	2,398,512	2,301,403	2,088,004	565,199	525,161	$ 15,540,372
System Actual $ - Capacity component of SC DERP	14,465	25,269	15,564	24,547	24,652	22,927	26,605	26,529	23,759	25,124	22,450	16,201	$ 268,091
System Actual $ - Capacity component of 5589 PURPA Purchases	350,921	371,971	360,503	458,527	390,711	654,705	1,628,121	1,569,122	1,497,533	1,372,274	539,208	350,819	$ 9,544,415
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 928,428	$ 1,923,752	$ 1,028,793	$ 1,285,979	$ 1,129,564	$ 1,550,603	$ 4,184,461	$ 3,994,163	$ 3,822,694	$ 3,485,402	$ 1,126,858	$ 892,181	$ 25,352,878
NC Actual $ (Calc) (1)	$ 619,088	$ 1,282,782	$ 686,012	$ 857,507	$ 763,429	$ 1,047,993	$ 2,828,114	$ 2,699,499	$ 2,583,610	$ 2,355,647	$ 761,599	$ 602,990	$ 17,088,272
Billed rate (¢/kWh):	0.0297	0.0297	0.0297	0.0297	0.0297	0.0297	0.0297	0.0297	0.0280	0.0297	0.0297	0.0297	
Billed $:	$ 1,574,440	$ 1,382,334	$ 1,324,673	$ 1,303,116	$ 1,212,873	$ 1,380,595	$ 1,564,920	$ 1,707,962	$ 1,557,210	$ 1,317,832	$ 1,259,846	$ 1,417,915	$ 17,003,717
(Over)/Under $:	$ (955,353)	$ (99,552)	$ (638,661)	$ (445,609)	$ (449,445)	$ (332,602)	$ 1,263,195	$ 991,537	$ 1,026,400	$ 1,037,815	$ (498,247)	$ (814,925)	$ 84,555
TOTAL (Over)/ Under $:	**$ 1,053,833**	**$ 2,534,886**	**$ (1,807,932)**	**$ 10,744**	**$ 231,383**	**$ 74,795**	**$ 946,481**	**$ 67,008**	**$ 19,541**	**$ 1,300,423**	**$ 166,356**	**$ (1,892,486)**	**$ 2,705,033**

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

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Twelve Months Ended December 31, 2022
Docket E-7, Sub 1304

Clark Workpaper 9b

2022	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	12 ME
System kWh Sales - Sch 4, Adjusted	7,587,345,694	7,631,271,992	6,790,067,074	6,455,104,305	6,544,372,277	7,852,382,055	8,386,958,942	8,886,608,895	8,009,959,106	6,516,474,006	6,148,600,623	7,600,126,412	88,409,271,381
NC Retail kWh Sales - Sch 4	4,988,913,451	5,189,555,709	4,642,701,985	4,283,391,409	4,361,033,505	5,223,755,139	5,560,704,210	6,010,616,462	5,369,219,189	4,315,776,539	4,103,701,351	5,009,748,290	59,059,117,240
NC Retail % of Sales, Actuals (Calc)	69.73%	70.21%	69.17%	69.31%	69.39%	70.06%	66.93%	69.27%	62.78%	63.80%	66.07%	72.66%	68.21%
NC Retail % of Sales, Adjusted (Calc)	65.75%	68.00%	68.37%	66.36%	66.64%	66.52%	66.30%	67.64%	67.03%	66.23%	66.74%	65.92%	66.80%
NC retail production demand %	66.68%	66.68%	66.68%	66.68%	66.68%	66.68%	66.68%	66.68%	66.68%	66.68%	66.68%	66.68%	66.68%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 37,348,658	$ 40,334,882	$ 28,936,616	$ 49,553,437	$ 53,977,979	$ 76,187,119	$ 84,243,384	$ 92,288,328	$ 54,398,279	$ 11,798,321	$ 41,689,819	$ 94,911,581	$ 665,668,403
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	7,928,235	(1,570,627)	3,557,135	4,369,558	7,286,679	6,129,379	10,685,578	9,921,881	9,510,435	1,184,100	3,142,043	8,875,341	$ 71,019,737
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	4,142,352	3,490,134	3,995,856	3,290,332	5,192,821	5,283,840	5,430,924	5,998,047	5,270,163	5,163,446	4,802,114	4,257,583	$ 56,317,611
System Actual$ - Sch 3 Fuel-related$; SC DERP	153,840	153,265	196,932	137,675	248,854	297,053	290,834	285,229	257,994	240,417	248,173	229,623	$ 2,739,889
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	1,977,570	1,777,710	2,215,962	1,745,571	2,647,918	3,816,224	3,554,345	3,225,136	3,434,693	3,359,816	3,414,696	2,956,940	$ 34,126,582
Total System Economic & QF$	51,550,655	44,185,364	38,902,502	59,096,573	69,354,250	91,713,615	104,205,065	111,718,622	72,871,564	21,746,101	53,296,844	111,231,068	829,872,222
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 30,480,569	$ 37,453,029	$ 26,486,545	$ 48,026,753	$ 49,193,125	$ 74,564,244	$ 75,622,595	$ 87,008,500	$ 47,113,469	$ 10,577,023	$ 40,068,662	$ 74,950,979	$ 601,545,494
Total System Economic $ without Native Load Transfers	$ 21,070,086	$ 6,732,335	$ 12,415,956	$ 11,069,820	$ 20,161,125	$ 17,149,371	$ 28,582,470	$ 24,710,121	$ 25,758,095	$ 11,169,078	$ 13,228,182	$ 36,280,089	$ 228,326,728
NC Actual $ (Calc)	$ 13,854,230	$ 4,578,244	$ 8,489,398	$ 7,345,562	$ 13,434,954	$ 11,408,527	$ 18,950,690	$ 16,713,131	$ 17,266,113	$ 7,397,136	$ 8,828,758	$ 23,914,617	$ 152,181,363
Billed rate (¢/kWh):	0.1378	0.1378	0.1378	0.1378	0.1378	0.1378	0.1378	0.1378	0.1367	0.1378	0.1378	0.1378	
Billed $:	$ 6,874,552	$ 7,151,030	$ 6,397,484	$ 5,902,367	$ 6,009,355	$ 7,198,156	$ 7,662,460	$ 8,282,423	$ 7,340,000	$ 5,946,992	$ 5,654,760	$ 6,903,261	$ 81,322,839
(Over)/ Under $:	$ 6,979,678	$ (2,572,786)	$ 2,091,914	$ 1,443,196	$ 7,425,600	$ 4,210,372	$ 11,288,231	$ 8,430,708	$ 9,926,113	$ 1,450,144	$ 3,173,998	$ 17,011,356	$ 70,858,524
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ -	$ (215,310)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (215,310)
System Actual $ - Capacity component of Purchased Power for REPS Compliance	631,201	645,219	680,737	463,766	802,115	701,461	827,443	2,753,196	2,319,960	2,511,631	2,238,491	639,202	$ 15,214,422
System Actual $ - Capacity component of HB589 Purpa QF purchases	14,255	14,801	19,366	14,471	24,039	29,036	28,404	28,368	25,409	23,627	24,299	22,399	$ 268,474
System Actual $ - Capacity component of SC DERP	312,476	340,840	349,198	316,395	389,774	481,428	581,279	1,661,830	1,443,022	1,553,118	1,525,519	414,939	$ 9,369,818
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 957,932	$ 785,549	$ 1,049,301	$ 794,633	$ 1,215,927	$ 1,211,925	$ 1,437,127	$ 4,443,394	$ 3,788,390	$ 4,088,375	$ 3,788,310	$ 1,076,540	$ 24,637,403
NC Actual $ (Calc) (1)	$ 638,761	$ 523,814	$ 699,688	$ 529,871	$ 810,796	$ 808,127	$ 958,294	$ 2,962,912	$ 2,526,147	$ 2,726,181	$ 2,526,093	$ 717,850	$ 16,428,536
Billed rate (¢/kWh):	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0294	0.0291	0.0289	0.0289	0.0289	
Billed $:	$ 1,390,793	$ 1,446,727	$ 1,294,277	$ 1,194,110	$ 1,215,755	$ 1,456,261	$ 1,550,195	$ 1,675,620	$ 1,525,438	$ 1,203,138	$ 1,144,016	$ 1,396,601	$ 16,492,931
(Over)/Under $:	$ (752,032)	$ (922,913)	$ (594,589)	$ (664,238)	$ (404,959)	$ (648,134)	$ (591,900)	$ 1,287,293	$ 1,000,709	$ 1,523,043	$ 1,382,077	$ (678,752)	$ (64,395)
TOTAL (Over)/ Under $:	**$ 6,227,647**	**$ (3,495,699)**	**$ 1,497,325**	**$ 778,957**	**$ 7,020,641**	**$ 3,562,238**	**$ 10,696,330**	**$ 9,718,001**	**$ 10,926,822**	**$ 2,973,187**	**$ 4,556,076**	**$ 16,332,604**	**$ 70,794,129**

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

rounding differences may occur

Duke Energy Carolinas, LLC **Clark Workpaper 10**
North Carolina Annual Fuel and Fuel Related Expense
Actual Sales by Jursidiction - Subject to Weather
Twelve Months Ended December 31, 2023
Docket E-7, Sub 1304

			MWhs				
Line #	Description	Reference	NORTH CAROLINA	SOUTH CAROLINA	TOTAL COMPANY	% NC	% SC
1	Residential	Company Records	21,544,402	6,701,513	28,245,915	76.27	23.73
2	Total General Service	Company Records	24,310,321	5,910,025	30,220,346		
3	less Lighting and Traffic Signals		558,737	170,306	729,044		
4	General Service subject to weather		23,751,583	5,739,719	29,491,302	80.54	19.46
5	Industrial	Company Records	11,674,957	8,037,528	19,712,485	59.23	40.77
6	Total Retail Sales	1+2+5	57,529,680	20,649,066	78,178,746		
7	Total Retail Sales subject to weather	1+4+5	56,970,943	20,478,760	77,449,703	73.56	26.44

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

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment
Twelve Months Ended December 31, 2023
Docket E-7, Sub 1304

Line #	Description	REFERENCE	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Total Residential		1,372,504	76.27	1,046,809	23.73	325,695
	General Service						
2	Total General Service		258,325	80.54	208,055	19.46	50,270
	Industrial						
3	Total Industrial		28,978	59.23	17,164	40.77	11,814
4	Total Retail	L1+ L2+ L3	1,659,807		1,272,028		387,779
5	Wholesale		96,670				
6	Total Company	L4 + L5	1,756,476		1,272,028		387,779

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Normalization Adjustment by Class by Month
Twelve Months Ended December 31, 2023
Docket E-7, Sub 1304

	Residential	Commercial	Industrial	
2023	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	
JAN	3,252	174	63	
FEB	448,879	57,747	(3,691)	
MAR	510,625	61,216	(232)	
APR	(2,771)	(13,121)	(2,366)	
MAY	(17,315)	504	97	
JUN	195,771	81,420	18,779	
JUL	238,738	97,595	24,057	
AUG	39,565	14,459	2,857	
SEP	(78,495)	(33,878)	(5,882)	
OCT	6,510	9,725	2,870	
NOV	(43,933)	(16,036)	(3,982)	
DEC	71,678	(1,480)	(3,592)	
Total	**1,372,504**	**258,325**	**28,978**	**1,659,807**

Wholesale

2023	**TOTAL MWH ADJUSTMENT**
JAN	30,698
FEB	28,349
MAR	9,055
APR	4
MAY	6,787
JUN	16,729
JUL	(4,162)
AUG	(4,297)
SEP	886
OCT	1,185
NOV	(2,457)
DEC	13,892
Total	**96,670**

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

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

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales
Twelve Months Ended December 31, 2023
Docket E-7, Sub 1304

Line	Estimation Method [1]	Rate Schedule	NC Proposed kWh [1] Adjustment	SC Proposed kWh Adjustment	Wholesale Proposed kWh Adjustment	Total Company
1	*Regression*	Residential	216,090,295	85,430,235		
2						
3		**General Service (Excluding Lighting):**				
4	*Customer*	General Service Small and Large	(44,006,237)	38,784,745		
5	*Regression*	Miscellaneous	(1,237,688)	(879,613)		
6		Total General	(45,243,925)	37,905,132		
7						
8		**Lighting:**				
9	*Regression*	T & T2 (GL/FL/PL/OL)[2]	901,291	513,822		
10	*Regression*	TS	(783)	9,422		
11		Total Lighting	900,508	523,244		
12						
13		**Industrial:**				
14	*Customer*	I - Textile	(6,516,599)	382,943		
15	*Customer*	I - Nontextile	18,827,765	6,991,721		
16		Total Industrial	12,311,166	7,374,664		
17						
18						
19		Total	184,058,044	131,233,275	89,189,968	404,481,287
					WP 12-2	

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

Calculation of Customer Growth Adjustment to kWh Sales - Wholesale

Line No.		Reference	
1	Total System Resale (kWh Sales)	Company Records	9,787,128,802
2	Less Intersystem Sales	Exhibit 6, Sch 1	1,431,968,808
3	Total kWh Sales Excluding Intersystem Sales	L1 - L2	8,355,159,994
4	Residential Growth Factor	Line 8	1.0675
5	Adjustment to kWhs - Wholesale	L3 * L4 / 100	89,189,968
6	Total System Retail Residential kWh Sales	Company Records	28,245,915,203
7	2023 Proposed Adjustment kWh - Residential (NC+SC)	WP 12-1	301,520,530
8	Percent Adjustment	L7 / L6 * 100	1.0675

rounding differences may occur

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's Supplemental Testimony and Exhibits, in Docket No. E-7, Sub 1304, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the parties of record.

This the 8th day of May, 2024.

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