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May 26, 2023

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 Revised Rebuttal Testimony
Docket No. E-7, Sub 1282

Dear Ms. Dunston:

Please find enclosed Duke Energy Carolinas, LLC's Revised Rebuttal Testimony of Jeffrey Flanagan and John Swez, as well as the Revised Joint Rebuttal Testimony and Second Revised Exhibits of Sigourney Clark and Chris Bauer, in the above-referenced proceeding.

Certain information contained in the testimony of Mr. Flanagan is a trade secret, and confidential, proprietary, and commercially sensitive information. For this reason, it is being filed under seal pursuant to N.C. Gen. Stat. § 132-1.2. Parties to the docket may contact the Company regarding obtaining copies pursuant to an appropriate confidentiality agreement.

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

Sincerely,

Ladawn S. Toon

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's Revised Rebuttal Testimony, in Docket No. E-7, Sub 1282, 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 26th day of May, 2023.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1282

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH THE COMPANY.

A. My name is Jeffrey Flanagan and my business address is 8320 East Highway 150, Terrell, North Carolina. I am employed by Duke Energy and am the General Manager III of the Carolinas Dispatchable Generation - West Zone including Marshall, Allen, Asheville, and W.S. Lee stations.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN SUPPORT OF THE COMPANY'S APPLICATION IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to: (1) respond to Public Staff Witness Evan Lawrence's testimony that certain outages that occurred at Duke Energy Carolina, LLC's ("DEC" or the "Company") Belews Creek Steam Station Unit 2 and W.S. Lee Combined Cycle Plant during the test-period were preventable; (2) Witness Lawrence's suggestion that the Company has not been responsive to Public Staff's Fossil-Hydro Semi-Annual Data Request; and (3) Mr. Lawrence's request to keep the above-mentioned outages, and corresponding replacement power costs, open beyond the test-period.

Q. WAS THE COMPANY'S MANAGEMENT OF ITS FOSSIL FLEET DURING THE TEST-PERIOD PRUDENT?

A. Yes, the Company's management of its fossil fleet during the test-period was reasonable and prudent, as demonstrated by its longstanding history of executing outages in a prudent manner, following prescribed processes and operating experience to maintain its fleet reliably for DEC's customers.

Q. WHAT IS THE STANDARD OF REVIEW FOR DETERMINING THE PRUDENCE OF THE COMPANY'S MANAGEMENT OF ITS FLEET?

A. While I am not an attorney, it is my understanding that the Commission has determined that the appropriate standard for prudence turns on the question whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was known or reasonably should have been known at the time.[1] The Commission further determined that "this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis -- the judging of events based on subsequent developments -- is not permitted."[2] Contrary to witness Lawrence's testimony, the question in fuel cases is not whether an outage was or was not "preventable" but instead whether the Company's decisions in connection with such outage were prudent.

Q. THE PUBLIC STAFF ASSERTS THAT CERTAIN OUTAGES, IDENTIFIED BELOW, WERE PREVENTABLE EQUIPMENT FAILURES. DO YOU AGREE WITH THAT ASSERTION?

A. No. The Public Staff reviewed post-outage documentation to make their determination that these outages were preventable. Hindsight information, i.e., post-outage documentation, does not give an accurate view of whether an outage was preventable. None of the outages discussed later in this testimony presented pre-outage indicators that there were problems that would have caused forced outages and required immediate attention. Witness Lawrence has failed to offer

[1] North Carolina Utilities Commission *Order Approving Fuel Charge Adjustment* at 24, Docket No. E-7, Sub 1163 (August 20, 2018)
[2] Id.

evidence sufficient to establish that management decisions concerning pre-outage activities were unreasonable given what was known at the time. Therefore, the Public Staff's assertions that these outages were preventable are unfounded.

Q. DO YOU AGREE WITH WITNESS LAWRENCE'S CONTENTION THAT THE BELEWS CREEK UNIT 2 OUTAGE EXTENSION THAT BEGAN ON APRIL 22, 2022, "WAS PREVENTABLE AND LIKELY CAUSED BECAUSE SOMEONE WORKING ON THE TURBINE DID NOT FOLLOW PROPER PROCEDURES?

A. No, I do not believe that the Belews Creek Unit 2 outage extension that began on April 22, 2022, was preventable. By way of background, the March 17th planned outage was scheduled to perform boiler maintenance, technology updates, and turbine valve work. Part of the planned scope also included a routine borescope inspection of the intermediate pressure (IP) turbine to inspect general condition and look for any issues that may need to be addressed in future planned maintenance. Unexpected foreign material was found in the IP turbine blade path during the routine borescope inspection performed on April 1, 2022 during the planned outage.

The Company considered the risk of potentially catastrophic damage to the turbine blade path and a possible future forced outage and made a prudent and reasonable decision to remove the foreign material from the IP turbine. The scope of work to disassemble and reassemble the IP turbine extended the outage end date from April 22, 2022 to May 8, 2022 (16 days).

The Company believes that the material removed was the metal valve from an inflatable bladder used for foreign material exclusion (FME) prevention during turbine maintenance work. The metal bladder valve was the only component that survived the high temperature steam during turbine operation. The rubber bladder had disintegrated from the high temperature steam exposure.

It is believed that the inflatable bladder was left in the double flow IP turbine inlet piping during the Unit 2 Intermediate Pressure Turbine inspection during the 2018 turbine outage by error while performing final inspection prior to reassembly. There were no operational problems or other indicators of the foreign material in the IP turbine prior to discovery from the borescope inspection in the 2022 planned outage.

In conclusion, Mr. Lawrence has presented no evidence to identify specific imprudent actions or inactions but has simply made the conclusory allegation that the outage was "preventable" (which is not the Commission's prudence standard) and was "likely caused" by someone "not follow[ing] proper procedures." This is an insufficient basis for disallowance.

Q. DO YOU AGREE WITH MR. LAWRENCE'S ASSERTION THAT THE BELEWS CREEK UNIT 2 OUTAGE THAT BEGAN ON AUGUST 31, 2022, WAS PREVENTABLE?

A. No, I do not agree. A review of the events that led up to this outage show the Company responded and took prudent actions. In 2018 Fall Unit 2 outage the low pressure (LP) turbine crossovers were sent offsite to a specialty vendor for expansion joint replacement. The crossovers are shipped to the vendor fully assembled and return fully assembled. The turbine was reassembled, and no problems were noted until September 4, 2019 when a tie rod nut was observed loosened by an operator during normal operator rounds. The Company consulted the specialty vendor and was provided guidance on how to retighten the loose nut with Loctite Threadlocker 272. Additionally, the Company took the prudent step to conduct an inspection of all tie rods during the 2019 Fall Unit 2 outage on October 10, 2019. The inspection revealed one tie rod with a cracked circumferential weld and loose spherical fasteners on another tie rod. The station performed a weld repair on the cracked weld and followed vendor guidance to tighten the loosened fastener securing the nuts with Loctite. The crossover presented no other abnormal indications until returning to service after a brief outage on August 31, 2022 when an operator noticed another loose tie rod nut and created a work order to have it retorqued during the next unit outage. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** the Company consulted with subject matter experts and took the recommended steps. With no original design criteria available from the OEM, only during the post event investigation using destructive testing and finite element analysis, was the design and associated margin fully understood. The analysis showed the design margin was inadequate to handle the loading condition that results from a loose fastener. The failure of the vendor to use Loctite Threadlocker, lack of original design margins, and understanding of subject matter experts lead to the failure. This was not apparent or preventable at the time decisions were made on the actions to take.

Q. DO YOU AGREE WITH MR. LAWRENCE'S CONCLUSION THAT THE W.S. LEE OUTAGE THAT BEGAN ON DECEMBER 11, 2022, WAS PREVENTABLE?

A. No, I do not agree. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. There were no indications of a problem with the turning gear unit prior to the outage and no work was performed on the turning gear unit as part of the outage. The failure occurred due to a malfunction causing the turning gear not to disengage properly during turbine startup. There is nothing the Company did to cause this and no indications that could have been acted on to prevent it. This was not a preventable event.

Q. PLEASE COMMENT GENERALLY ON WITNESS LAWRENCE'S RECOMMENDATION TO DEFER COMMISSION DETERMINATION ON OUTAGES THAT OCCURRED IN THE TEST-PERIOD.

A The Company emphatically disagrees with witness Lawrence's recommendation to defer consideration of outages that occurred in the test period to the next fuel case proceeding. First, this recommendation is inconsistent the fuel cost recovery construct in North Carolina and introduces uncertainty and delay to a process that is designed to be predictable and timely. Second, the reasons given to justify the deferred consideration are insufficient.

Q. DID THE COMPANY PROVIDE THE REQUISITE SEMI-ANNUAL OUTAGE INFORMATION TO THE PUBLIC STAFF FOR TEST-PERIOD 2022?

A. Yes. As background, the semi-annual provision of outage information is in itself an accommodation agreed to by the Company that provides Public Staff with information outside and in advance of the cadence of the actual fuel cost proceedings. In this particular case, the Company did in fact provide all of responsive information for the outages in question. Witness Lawrence identifies a vague and unspecified "concern" that the documents provide by the Company "do not satisfy the intent of this agreement as understood by the Public Staff." The Company believes that it did provide all required information and moreover, Public Staff has had ample time to issue further discovery or engage the Company if it believed more information was needed. The Company is certainly willing to discuss whether any changes are needed to this particular agreement but any difference of opinion on this matter is an insufficient basis to defer outages that occurred in this test period from this case to the next.

For all outages, the Company has provided any available outage reports. Consistent with past practice, the Company provides the requested outage reports, if the Company has created one. Where the Company has not created an outage report, the Company indicates as such and instead provides a summary of the outage. It should be noted that both DEC and DEP responded to the exact same semi-annual data request, in the same manner, for completed outages for calendar years 2020 through 2022. There have been no objections to the data provided over the past three years until now.

Once again, Public Staff should not be permitted to hold over any test-period outages or corresponding replacement power costs. Public Staff has had numerous opportunities to raise its concern and subsequently revise its own data request, considering the number of years the semi-annual request has been in place. As the Company has indicated on many occasions, the Company is available to meet (and will make every reasonable effort to accommodate Public Staff's schedule) to discuss the Company's outage process and documentation it now seeks to receive as part of its semi-annual data request going forward.

Certainly, the Public Staff is not limited to the semi-annual data request. The Commission issued a scheduling order in this Docket wherein the Commission establishes the discovery period. Separate and apart from the semi-annual data request or in response thereto, the Public Staff could have issued discovery for additional outage documentation, explanation, and further clarification to complete its investigation of test -period outages, and in fact, Public Staff did issue substantial discovery regarding test-period outages, as further detailed below.

Q. SHOULD THE PUBLIC STAFF BE ALLOWED TO KEEP ITS INVESTIGATION OF OUTAGES OPEN BEYOND THE TEST PERIOD?

A. No. Company maintains that it was responsive to the semi-annual outage request and subsequent- discovery, as the Public Staff was provided all outage information it asked for within the discovery period. Public Staff propounded extensive outage discovery including a request for *outage report, root cause analysis, contributory* *cause analysis, internal memos, vendor OEM findings or other like/similar documentation that provides context to the underpinnings of the outage/event* for eleven outages between Belews Creek and W.S. Lee. The Company provided requested documentation and detailed narratives. More specifically, during the discovery period for this fuel case, the Company provided the following information regarding outages to the Public Staff:

Public Staff Data Request **("PSDR") Set No. 7**, served on DEC 3/27; DEC responded on 4/7. Initial information on 11 outages at Belews Creek and W.S. Lee.

PSDR Set No. 8, served on DEC 3/27; DEC responded on 4/6. Standard outage information on all DEC outages for the test-period.

PSDR Set No. 21, served on DEC 4/20; DEC responded on 4/27. Detailed information on the Belews Creek 2 outage that began on 4/22/22.

PSDR Set No. 22, served on DEC 4/21; DEC responded on 4/28. Detailed information on the Belews Creek 2 outage that began on 5/8/22.

PSDR Set No. 23, served on DEC 4/24; DEC responded on 5/1. Detailed information on the Belews Creek 2 outage that began on 8/31/22.

There is no basis for the Public Staff to keep outages open beyond the test-period when the Company has responded to all requests presented. All test-period outages should be considered reviewed and complete at the end of this proceeding. Accordingly, the Company's position is that Public Staff should not be allowed to extend its investigation.

Q. DID THE COMPANY PROVIDE ALL REQUESTED INFORMATION TO THE PUBLIC STAFF AND MADE ITSELF AVAILABLE FOR FOLLOW UP CONVERSATIONS FOR ISSUES?

A. Yes. The Company provided all requested information, as listed above in the testimony, and made itself available for follow up discussions as requested. As Mr. Lawrence states in his testimony on page 16, the Company had to reschedule the April 14, 2023, phone call. The Company requested to reschedule that call because a key subject matter expert was unavailable, in response to such request, the Public Staff stated that they were "just too busy" to meet. The Public Staff did not indicate that April 14, 2023, was the only time Public Staff would be available to meet, nor did it provide alternative dates or times. The Company would suggest that in lieu of a meeting, the Public Staff issued the additional discovery, which again the Company responded to further explain the facts and circumstances regarding test period outages in question.

Q. WHAT OTHER REASONS WERE PROVIDED BY WITNESS LAWRENCE FOR THE DEFERRAL OF CONSIDERATION?

A Witness Lawrence also refers to the ongoing investigation in Docket M-100 Sub 163 and the fact that one of the outages in question extended outside of the test period.

Q. PLEASE COMMENT ON THESE ADDITIONAL REASONS.

A. While it is true that the Commission's cold weather investigation in Docket M-100 Sub 163 remains open, that fact in itself does not alter the fuel recovery construct in North Carolina, nor has the Commission provided any indication in Docket M-100 Sub 163 that any further investigation in that docket obviates or alters the scope of the annal fuel cost proceedings. Furthermore, while one of the outages did extend beyond the test period, the Company does not agree that this fact justifies deferral of consideration. The outage commenced in the test period, and the full replacement power cost have been determined and Public Staff has had a full opportunity to investigate the causes of that particular outage.

Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE PROVISION OF OUTAGE INFORMATION AND PUBLIC STAFF'S DISCOVERY OPPORTUNITIES.

A. The Company has been fully responsive to all data requests and has made itself available to Public Staff to answer any outstanding questions, including through in-person meetings regarding outages occurring in the test period. The fuel cost recovery construct in North Carolina establishes a timely process for the consideration of fuel costs and it is the responsibility of Public Staff and intervenors to conduct any necessary audit within the time parameters established under law as administered by this Commission. Absent any unusual circumstances or the agreement of the Company, it is not appropriate to defer consideration of outages occurring in the test period to a future case. Such a deferral is harmful to the Company and undermines the intended certainty of the process. Public Staff's vague concerns regarding information provided and meeting schedules are an insufficient basis to warrant departure from the well-established practices on these issues.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADD CONCERNING THE COMPANY'S EXECUTION AND REPORTING OF OUTAGES?

A. Yes. Public Staff's findings rely heavily on outage documentation, which by design is hindsight-based and self-critical in nature and are intended to identify every direct and contributing cause of an incident, along with all potential avenues for improvement. The reports are not designed to assess whether the actions of management were reasonable and prudent given what was known at the time, which is exactly what Public Staff is doing. As the Commission has determined, hindsight analysis is not permitted when assessing prudency. Outside of hindsight analysis, no evidence has been presented which supports Mr. Lawrence's claim that these outages were preventable-i.e., the Company's actions or inactions were imprudent. No evidence has been presented which supports leaving any test-period outages open for further scrutiny after this case is litigated. The Public Staff's hindsight conclusions are not reason enough to leave these outages, or any outages, open beyond the test period. Regarding the Company's outage reporting, we have provided all requested outage information to Public Staff, consistent with recent practice, and provided extensive documentation and detailed responses to all discovery issued in this proceeding.

Finally, overall, DEC has a long history of operating its fleet prudently to provide safe and reliable service for the benefit of DEC's customers. We continue to improve our processes and believe strongly in using lessons learned to improve our operations going forward.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1282

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
	)	
Application of Duke Energy Carolinas, LLC	)	**REVISED REBUTTAL**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**TESTIMONY OF JOHN D.**
R8-55 Relating to Fuel and Fuel-Related	)	**SWEZ FOR DUKE**
Charge Adjustments for Electric Utilities	)	**ENERGY CAROLINAS,**
	)	**LLC**

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is John D. Swez, and I am Managing Director, Trading and Dispatch, by Duke Energy Carolinas, LLC. My business address is 526 S. Tryon Street, Charlotte, North Carolina.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN SUPPORT OF DEC'S APPLICATION IN THIS DOCKET?

A. Yes, on February 28, 2023, I caused to be pre-filed with the Commission my direct testimony and 4 exhibits. On May 5, 2023, I caused to be pre-filed with the Commission supplemental testimony. On May 18, 2023, I caused to be pre-filed with the Commission rebuttal testimony, including 1 exhibit.

Q. YOUR REVISED REBUTTAL TESTIMONY INCLUDES ONE EXHIBIT. WAS THIS EXHIBIT PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes, this exhibit was prepared at my direction and under my supervision, and consists of Swez Rebuttal First Revised Exhibit 1, which shows the calculation of the average forward NYMEX Henry Hub price for the billing period as of Close of Business ("COB") January 12, 2023.

Q. WHAT IS THE PURPOSE OF YOUR REVISED REBUTTAL TESTIMONY?

A. The purpose of my revised rebuttal testimony is to redirect the Commission to the described changes for the billing period of September 1, 2023 through August 31, 2024 based on the original fuel forecast with commodity prices as of January 12, 2023 used in the Company's direct filing made February 28, 2023. This revision is due to the Company no longer proposing this option to mitigate the fuel rates for the billing period as discussed in witness Clark's revised rebuttal testimony.

Q. DOES THIS CONCLUDE YOUR REVISED REBUTTAL TESTIMONY?

A. Yes, it does.

Duke Energy Carolinas, LLC
Average Forward NYMEX Henry Hub Price
for Billing Period September 1, 2023 through August 31, 2024
As of COB January 12, 2023

	NYMEX HH COB 1/12/23
9/1/2023	$3.62
10/1/2023	$3.68
11/1/2023	$4.07
12/1/2023	$4.49
1/1/2024	$4.76
2/1/2024	$4.60
3/1/2024	$4.10
4/1/2024	$3.65
5/1/2024	$3.61
6/1/2024	$3.72
7/1/2024	$3.81
8/1/2024	$3.84
Average	**$ 3.99**

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1282

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**REVISED REBUTTAL TESTIMONY**
Pursuant to G.S. 62-133.2 and NCUC Rule	)	**OF SIGOURNEY CLARK AND**
R8-55 Relating to Fuel and Fuel-Related	)	**CHRIS BAUER FOR**
Charge Adjustments for Electric Utilities	)	**DUKE ENERGY CAROLINAS, LLC**
	)	

Q. WHAT IS THE PURPOSE OF YOUR REVISED REBUTTAL TESTIMONY?

A. The purpose of our revised rebuttal testimony is (1) to revise the proposed fuel and fuel-related costs factors related to the Company's proposed EDIT mitigation and (2) to correct a statement in our rebuttal testimony filed on May 18, 2023 related to updating the prospective component of the proposed fuel rate using the Company's latest fuel forecast with commodity prices as of April 13, 2023.

Q. YOUR REVISED REBUTTAL TESTIMONY INCLUDES THREE SECOND REVISED EXHIBITS AND THIRTEEN SUPPORTING WORKPAPERS. WERE THESE SUPPLEMENTAL EXHIBITS AND WORKPAPERS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

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

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

Clark Rebuttal Second Revised Exhibit 2:

Schedule 1: Fuel and Fuel-Related Costs Factors - reflecting a 93.52% proposed nuclear capacity factor and projected megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 93.52% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 91.87% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for pressurized water reactors and projected billing period MWh sales.

Clark Rebuttal Second Revised Exhibit 3:

Page 1: Calculation of the Proposed Composite Experience Modification Factor ("EMF") rate.

Page 2: Calculation of the EMF for residential customers.

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

Page 4: Calculation of the EMF for industrial customers.

Q. WHAT IS THE PURPOSE OF YOUR REVISED REBUTTAL TESTIMONY?

A. The purpose of our revised rebuttal testimony is (1) to revise the proposed fuel and fuel-related costs factors related to the Company's proposed EDIT mitigation and (2) to correct a statement in our rebuttal testimony filed on May 18, 2023 related to updating the prospective component of the proposed fuel rate using the Company's latest fuel forecast with commodity prices as of April 13, 2023.

Q. WHY IS THE COMPANY REVISING ITS PROPOSED FUEL AND FUEL-RELATED COST FACTORS FOR THE PROPOSED EDIT MITIGATION UPDATE?

A. After filing rebuttal testimony on May 18, 2023, the Company realized it had applied the proposed EDIT mitigant to the prospective component of the proposed fuel rate. However, in order to effectuate the desired outcome of offsetting the significant under-recovery of fuel in this proceeding, the Company has now applied the proposed EDIT mitigant against the under-recovered balance of $998 million. As such, the Company is requesting the following fuel and fuel-related cost factors for Commission approval, as shown on Clark Rebuttal Second Revised Exhibit 1:

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Total adjusted Fuel and Fuel Related Costs	2.5057	2.2927	2.0110	2.3202
EMF Increment (Decrement)	0.7654	0.7657	0.8275	0.7783
EMF Interest (Decrement)	-	-	-	-
Net Fuel and Fuel Related Costs Factors	3.2711	3.0584	2.8385	3.0985

Q. WHAT STATEMENT ARE YOU CORRECTING FROM YOUR REBUTTAL TESTIMONY?

A. In our rebuttal testimony, The Company stated that it was proposing three potential mitigants to reduce the overall increase to customer bills. The first of these means was to propose a new prospective component of the fuel rate using our latest fuel forecast dated April 13, 2023, and that the use of this forecast would reduce the equal percent increase for all customer classes from 17.98% to 17.10%.

After filing rebuttal testimony on May 18, 2023, the Company realized it had an error in its calculation. As the Company has re-calculated, the proposed fuel rates with this forecast actually would have slightly increased from the rates proposed in the Company's direct filing made on February 28, 2023. Therefore, this is no longer a potential option to mitigate the fuel increase, and the Company has revised the fuel rates to reflect the original forecast.

Q. PLEASE EXPLAIN THE IMPACT OF THE POTENTIAL EDIT MITIGANT GIVEN THAT THE COPMANY'S PROPOSED RATES ARE NOW BASED ON THE JANUARY 12, 2023 FORECAST.

A. Utilizing the January 12, 2023 forecast, the potential EDIT mitigant would reduce the equal percent rate impact for all customer classes from 17.98% to 7.47%. Additionally, the expiration of the $211,488,000 EDIT Rider Credit increases customer bill impacts by 4.07%, for a net increase from all updates to approximately 11.54%. This mitigation would lower customer impacts by a net 6.44% while lessening the negative impact on the Company's credit metrics.

The table below shows both the proposed and existing fuel and fuel-related cost factors.

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Proposed Total Fuel Factor	3.2711	3.0584	2.8385	3.0985
Existing Total Fuel Factor	2.4866	2.4471	2.4122	2.4607
Increase in Fuel Factor	0.7845	0.6113	0.4263	0.6378

Q. DOES THIS CONCLUDE YOUR REVISED REBUTTAL TESTIMONY?

A. Yes.

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, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Clark Second 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 1263)					
1	Approved Fuel and Fuel Related Costs Factors	Input	2.0003	1.8217	1.8396	1.9010
2	EMF Increment (Decrement) cents/kWh	Input	0.4863	0.6254	0.5726	0.5597
3	EMF Interest Increment (Decrement) cents/kWh	Input	-	-	-	-
4	Approved Net Fuel and Fuel Related Costs Factors	Sum	**2.4866**	**2.4471**	**2.4122**	**2.4607**
	Fuel and Fuel Related Cost Factors Required by Rule R8-55					
5	Proposed Nuclear Capacity Factor of 93.52% and Normalized Test Period Sales	Exh 2 Sch 2 pg 2	**3.2329**	**3.0056**	**2.8416**	**3.0649**
6	NERC 5 Year Average Nuclear Capacity Factor of 91.87% and Projected Period Sales	Exh 2 Sch 3 pg 2	**3.3057**	**3.0854**	**2.8573**	**3.1266**
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 93.52%					
7	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	2.4695	2.2648	1.9895	2.2905
8	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.0362	0.0279	0.0215	0.0297
9	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum	2.5057	2.2927	2.0110	2.3202
10	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.7654	0.7657	0.8275	0.7783
11	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
12	Net Fuel and Fuel Related Costs Factors cents/kWh	Sum	**3.2711**	**3.0584**	**2.8385**	**3.0985**

Note: Fuel factors exclude regulatory fee

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 93.52%
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	58,819,128	0.5613	330,162,771
2	Coal	Workpaper 3 & 4	10,320,159	3.8575	398,104,637
3	Gas CT and CC	Workpaper 3 & 4	31,212,640	3.7804	1,179,963,909
4	Reagents and Byproducts	Workpaper 9			24,944,696
5	Total Fossil	Sum	41,532,800		1,603,013,242
6	Hydro	Workpaper 3	5,600,555		
7	Net Pumped Storage	Workpaper 3	(4,083,743)		
8	Total Hydro	Sum	1,516,812		-
9	Solar Distributed Generation	Workpaper 3	358,121		-
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	102,226,860		1,933,176,012
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(878,400)		(25,697,152)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,888,880)		(83,614,236)
13	Fuel expense recovered through reimbursement	Workpaper 4			(3,687,381)
14	Net Generation	Sum Lines 10-13	86,459,580		1,820,177,243
15	Purchased Power	Workpaper 3 & 4	11,789,258	3.5185	414,804,733
16	JDA Savings Shared	Workpaper 5			(69,598,371)
17	Total Purchased Power		11,789,258		345,206,362
18	Total Generation and Purchased Power	Line 14 + Line 17	98,248,839	2.2040	2,165,383,605
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,148,043)	5.0520	(57,998,825)
20	Line losses and Company use	Line 22-Line 18-Line 19	(6,269,005)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			2,107,384,780
22	Projected System MWh Sales for Fuel Factor	Workpaper 7	90,831,791		90,831,791
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			2.3201

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 93.52%
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7	23,477,265	24,077,007	13,270,457	60,824,730
	Calculation of Renewable and Cogeneration Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 14,931,581
3	QF Purchased Power - Capacity	Workpaper 4				12,176,644
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 27,108,225
5	NC Portion - Jursidicational % based on 2021 Production Plant Allocator	Input				66.68%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 18,076,112
7	2021 Production Plant Allocation Factors	Input	47.04%	37.14%	15.81%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on 2021 Production Plant Allocator	Line 6 * Line 7	$ 8,503,847	$ 6,713,696	$ 2,858,570	$ 18,076,112
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0362	0.0279	0.0215	0.0297
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.4695	2.2648	1.9895	2.2905
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0362	0.0279	0.0215	0.0297
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.5057	2.2927	2.0110	2.3202
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.7654	0.7657	0.8275	0.7783
14	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	3.2711	3.0584	2.8385	3.0985

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 93.52%
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Rate Class	Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/(Decrease) as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1263	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	D	E	F	G
		Workpaper 7	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Clark Exhibit 1	E + F = G
1	Residential	23,477,265	$ 2,466,691,215	$ 184,183,394	7.47%	0.7845	2.4866	3.2711
2	General Service/Lighting	24,077,007	1,971,226,718	147,187,952	7.47%	0.6113	2.4471	3.0584
3	Industrial	13,270,457	757,602,036	56,568,781	7.47%	0.4263	2.4122	2.8385
4	NC Retail	60,824,730	$ 5,195,519,969	$ 387,940,127	7.47%			

Total Proposed Composite Fuel Rate:

5	Total Fuel Costs for Allocation	Workpaper 7	$ 2,111,780,996
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	27,108,225
7	System Other Fuel Costs	Line 5 - Line 6	$ 2,084,672,770
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7	91,011,082
9	NC Retail Projected Billing Period MWh Sales	Line 4	60,824,730
10	Allocation %	Line 9 / Line 8	66.83%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,393,186,813
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 1, Page 2	18,076,112
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,411,262,925
14	NC Retail Projected Billing Period MWh Sales	Line 4	60,824,730
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	2.3202
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.7783
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	3.0985

Total Current Composite Fuel Rate - Docket E-7 Sub 1263:

19	Current composite Fuel Rate cents/kWh	Clark Exhibit 1	1.9010
20	Current composite EMF Rate cents/kWh	Clark Exhibit 1	0.5597
21	Current composite EMF Interest Rate cents/kWh	Clark Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	2.4607
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.6378
24	NC Retail Projected Billing Period MWh Sales	Line 4	60,824,730
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 387,940,127

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 93.52% and Normalized Test Period Sales
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 1	58,819,128	0.5613	330,162,771
2	Coal	Calculated	8,369,573	3.8575	322,859,932
3	Gas CT and CC	Workpaper 3 & 4	31,212,640	3.7804	1,179,963,909
4	Reagents and Byproducts	Workpaper 9	-		24,944,696
5	Total Fossil	Sum	39,582,214		1,527,768,538
6	Hydro	Workpaper 3	5,600,555		
7	Net Pumped Storage	Workpaper 3	(4,083,743)		
8	Total Hydro	Sum	1,516,812		
9	Solar Distributed Generation	Workpaper 3	358,121		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	100,276,274		1,857,931,308
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(878,400)		(25,697,152)
12	Less Catawba Joint Owners	Workpaper 3 & 4	(14,888,880)		(83,614,236)
13	Fuel expense recovered through reimbursement	Workpaper 4			(3,687,381)
14	Net Generation	Sum	84,508,994		1,744,932,539
15	Purchased Power	Workpaper 3 & 4	11,789,258		414,804,733
16	JDA Savings Shared	Workpaper 5	-		(69,598,371)
17	Total Purchased Power	Sum	11,789,258		345,206,362
18	Total Generation and Purchased Power	Line 14 + Line 17	96,298,253		2,090,138,901
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,148,043)		(57,998,825)
20	Line losses and Company use	Line 22 - Line 19 - Line 18	(6,269,005)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			2,032,140,076
22	Normalized Test Period MWh Sales	Exhibit 4	88,881,205		88,881,205
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			2.2864

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 93.52% and Normalized Test Period Sales
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Normalized Test Period MWh Sales	Exhibit 4	22,892,401	24,448,017	12,219,040	59,559,458
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 14,931,581
3	QF Purchased Power - Capacity	Workpaper 4				12,176,644
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 27,108,225
5	NC Portion - Jursidicational % based on 2021 Production Plant Allocator	Input				66.68%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 18,076,112
7	2021 Production Plant Allocation Factors	Input	47.04%	37.14%	15.81%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on 2021 Production Plant Allocator	Line 6 * Line 7	$ 8,503,847	$ 6,713,696	$ 2,858,570	$ 18,076,112
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Normalized Test Period Sales	Line 8 / Line 1 / 10	0.0371	0.0275	0.0234	0.0303
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.4304	2.2124	1.9907	2.2563
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0371	0.0275	0.0234	0.0303
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.4675	2.2399	2.0141	2.2866
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.7654	0.7657	0.8275	0.7783
14	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	3.2329	3.0056	2.8416	3.0649

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 93.52% and Normalized Test Period Sales
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Rate Class	Normalized Test Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/(Decrease) as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1263	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	D	E	F	G
		Exhibit 4	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Clark Exhibit 1	E + F = G
1	Residential	22,892,401	$ 2,466,691,215	$ 170,850,882	6.93%	0.7463	2.4866	3.2329
2	General Service/Lighting	24,448,017	$ 1,971,226,718	136,533,435	6.93%	0.5585	2.4471	3.0056
3	Industrial	12,219,040	$ 757,602,036	52,473,928	6.93%	0.4294	2.4122	2.8416
4	NC Retail	59,559,458	$ 5,195,519,969	$ 359,858,245				

Total Proposed Composite Fuel Rate:

5	Total Fuel Costs for Allocation	Workpaper 7a	$ 2,036,536,291
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	27,108,225
7	System Other Fuel Costs	Line 5 - Line 6	$ 2,009,428,066
8	Normalized Test Period System MWh Sales for Fuel Factor	Workpaper 7a	89,060,496
9	NC Retail Normalized Test Period MWh Sales	Exhibit 4	59,559,458
10	Allocation %	Line 9 / Line 8	66.88%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,343,810,646
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 2, Page 2	18,076,112
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,361,886,758
14	NC Retail Normalized Test Period MWh Sales	Line 9	59,559,458
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	2.2866
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.7783
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	3.0649

Total Current Composite Fuel Rate - Docket E-7 Sub 1263:

19	Current composite Fuel Rate cents/kWh	Clark Exhibit 1	1.9010
20	Current composite EMF Rate cents/kWh	Clark Exhibit 1	0.5597
21	Current composite EMF Interest Rate cents/kWh	Clark Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	2.4607
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.6042
24	NC Retail Normalized Test Period MWh Sales	Exhibit 4	59,559,458
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 359,858,245

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 91.87% and Projected Period Sales
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Unit	Reference	Generation (MWh)	Unit Cost (cents/kWh)	Fuel Cost ($)
			D	E	D * E = F
1	Total Nuclear	Workpaper 2	57,782,460	0.5613	324,343,758
2	Coal	Calculated	11,094,415	3.8575	427,971,909
3	Gas CT and CC	Workpaper 3 & 4	31,212,640	3.7804	1,179,963,909
4	Reagents and Byproducts	Workpaper 9	-		24,944,696
5	Total Fossil	Sum	42,307,056		1,632,880,514
6	Hydro	Workpaper 3	5,600,555		
7	Net Pumped Storage	Workpaper 3	(4,083,743)		
8	Total Hydro	Sum	1,516,812		
9	Solar Distributed Generation	Workpaper 3	358,121		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	101,964,448		1,957,224,272
11	Less Lee CC Joint Owners	Workpaper 3 & 4	(878,400)		(25,697,152)
12	Less Catawba Joint Owners	Calculated	(14,626,468)		(82,140,560)
13	Fuel expense recovered through reimbursement	Workpaper 4			(3,687,381)
14	Net Generation	Sum	86,459,580		1,845,699,178
15	Purchased Power	Workpaper 3 & 4	11,789,258		414,804,733
16	JDA Savings Shared	Workpaper 5	-		(69,598,371)
17	Total Purchased Power	Sum	11,789,258		345,206,362
18	Total Generation and Purchased Power	Line 14 + Line 17	98,248,839		2,190,905,541
19	Fuel expense recovered through intersystem sales	Workpaper 3 & 4	(1,148,043)		(57,998,825)
20	Line losses and Company use	Line 22 - Line 19 - Line 18	(6,269,005)		-
21	System Fuel Expense for Fuel Factor	Lines 18 + 19 + 20			2,132,906,715
22	Projected System MWh Sales for Fuel Factor	Workpaper 7b	90,831,791		90,831,791
23	Fuel and Fuel Related Costs cents/kWh	Line 21 / Line 22 / 10			2.3482

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 91.87% and Projected Period Sales
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Description	Reference	Residential	GS/Lighting	Industrial	Total
1	NC Projected Billing Period MWh Sales	Workpaper 7b	23,477,265	24,077,007	13,270,457	60,824,730
	Calculation of Renewable Purchased Power Capacity Rate by Class					Amount
2	Purchased Power for REPS Compliance - Capacity	Workpaper 4				$ 14,931,581
3	QF Purchased Power - Capacity	Workpaper 4				12,176,644
4	Total of Renewable and QF Purchased Power Capacity	Line 2 + Line 3				$ 27,108,225
5	NC Portion - Jursidicational % based on 2021 Production Plant Allocator	Input				66.68%
6	NC Renewable and QF Purchased Power - Capacity	Line 4 * Line 5				$ 18,076,112
7	2021 Production Plant Allocation Factors	Input	47.04%	37.14%	15.81%	100.00%
8	Renewable and QF Purchased Power - Capacity allocated on 2021 Production Plant Allocator	Line 6 * Line 7	$ 8,503,847	$ 6,713,696	$ 2,858,570	$ 18,076,112
9	Renewable and QF Purchased Power - Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.0362	0.0279	0.0215	0.0297
	Summary of Total Rate by Class					
10	Fuel and Fuel Related Costs excluding Purchased Power for REPS Compliance and QF Purchased Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.5041	2.2918	2.0083	2.3186
11	REPS Compliance and QF Purchased Power - Capacity cents/kWh	Line 9	0.0362	0.0279	0.0215	0.0297
12	Total adjusted Fuel and Fuel Related Costs cents/kWh	Line 10 + Line 11	2.5403	2.3197	2.0298	2.3483
13	EMF Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	0.7654	0.7657	0.8275	0.7783
14	EMF Interest Increment (Decrement) cents/kWh	Exh 3 pg 2, 3, 4	-	-	-	-
15	Net Fuel and Fuel Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	3.3057	3.0854	2.8573	3.1266

Note: Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
NERC 5 Year Average Nuclear Capacity Factor of 91.87% and Projected Period Sales
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Rate Class	Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease)	Current Total Fuel Rate (including Capacity and EMF) E-7, Sub 1263	Proposed Total Fuel Rate (including Capacity and EMF)
		A	B	C	C / B = D	E	F	G
		Workpaper 7b	Workpaper 8	Line 25 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Clark Exhibit 1	E + F = G
1	Residential	23,477,265	$ 2,466,691,215	$ 192,298,091	7.80%	0.8191	2.4866	3.3057
2	General Service/Lighting	24,077,007	$ 1,971,226,718	$ 153,672,714	7.80%	0.6383	2.4471	3.0854
3	Industrial	13,270,457	$ 757,602,036	$ 59,061,071	7.80%	0.4451	2.4122	2.8573
4	NC Retail	60,824,730	$ 5,195,519,969	$ 405,031,876				

<u>Total Proposed Composite Fuel Rate:</u>

5	Total Fuel Costs for Allocation	Workpaper 7b	$ 2,137,302,931
6	Total of Renewable and QF Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	27,108,225
7	System Other Fuel Costs	Line 5 - Line 6	$ 2,110,194,706
8	Adjusted Projected System MWh Sales for Fuel Factor	Workpaper 7b	91,011,082
9	NC Retail Projected Billing Period MWh Sales	Line 4	60,824,730
10	Allocation %	Line 9 / Line 8	66.83%
11	NC Retail Other Fuel Costs	Line 7 * Line 10	$ 1,410,243,122
12	NC Renewable and QF Purchased Power - Capacity	Exhibit 2 Sch 3, Page 2	18,076,112
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 1,428,319,234
14	NC Retail Projected Billing Period MWh Sales	Line 4	60,824,730
15	Calculated Fuel Rate cents/kWh	Line 13 / Line 14 / 10	2.3483
16	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.7783
17	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.0000
18	Total Proposed Composite Fuel Rate	Sum	3.1266

<u>Total Current Composite Fuel Rate - Docket E-7 Sub 1263:</u>

19	Current composite Fuel Rate cents/kWh	Clark Exhibit 1	1.9010
20	Current composite EMF Rate cents/kWh	Clark Exhibit 1	0.5597
21	Current composite EMF Interest Rate cents/kWh	Clark Exhibit 1	0.0000
22	Total Current Composite Fuel Rate	Sum	2.4607
23	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 18 - Line 22	0.6659
24	NC Retail Projected Billing Period MWh Sales	Line 4	60,824,730
25	Increase/(Decrease) in Fuel Costs	Line 23 * Line 24 * 10	$ 405,031,876

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, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

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 2022				4,988,891	$ 82,008,233
2	February [1]				5,189,525	$ 61,224,070
3	March				4,642,682	$ 16,628,788
4	April				4,283,375	$ 22,131,836
5	May [1]				4,361,034	$ 82,217,312
6	June [1]				5,223,755	$ 115,761,737
7	July				5,560,704	$ 146,325,916
8	August				6,010,616	$ 185,513,643
9	September				5,369,219	$ 84,720,701
10	October				4,315,777	$ 27,143,393
11	November				4,103,701	$ 71,328,379
12	December [1]				5,009,748	$ 186,026,549
13	**Total Test Period**				**59,059,028**	**$ 1,081,030,561**
14	**Adjustment to remove (Over)/Under Recovery - January 2022 [2]**					$ 81,987,600
15	**Adjustment for Clemson CHP Steam Revenues**					$ (613,775)
16	**Adjusted (Over)/Under Recovery**					**$ 998,429,186**
17	**Potential EDIT Mitigant**					$ (534,886,169)
18	**Adjusted (Over)/Under Recovery with EDIT Mitigant**					**$ 463,543,017**
19	NC Retail Normalized Test Period MWh Sales			Exhibit 4		59,559,458
20	**Experience Modification Increment (Decrement) cents/kWh**					**0.7783**

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

[2] January 2022 filed in Docket E-7, Sub 1263 to update the EMF and included in the current EMF rate. Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 16.

Rounding differences may occur

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/ Under Recovery (d)
1	January 2022	2.6880	1.5337	2,129,408	$ 24,579,060
2	February [1]	2.2111	1.5337	2,308,671	$ 15,631,479
3	March	1.8234	1.5337	1,783,273	$ 5,165,674
4	April	2.2527	1.5337	1,441,708	$ 10,365,435
5	May [1]	3.7477	1.5337	1,441,079	$ 31,901,319
6	June [1]	3.6847	1.5337	1,916,024	$ 41,213,674
7	July	3.7644	1.5337	2,208,753	$ 49,270,398
8	August	4.1426	1.5337	2,405,836	$ 62,764,654
9	September	3.7169	1.7555	1,992,460	$ 39,079,833
10	October	3.2667	2.0003	1,373,788	$ 17,397,939
11	November	4.5684	2.0003	1,345,710	$ 34,559,470
12	December [1]	5.2540	2.0003	2,073,011	$ 73,670,397
13	**Total Test Period [3]**			**22,419,721**	**$ 405,599,334**
14	Test Period Wtd Avg. ¢/kWh	3.4346	1.6532		
15	Adjustment to remove (Over)/Under Recovery - January 2022 [2]				$ 24,571,837
16	**Adjustment for Clemson CHP Steam Revenues**				$ (217,439)
17	**Adjusted (Over)/Under Recovery**				**$ 380,810,058**
18	**Potential EDIT Mitigant**				$ (205,589,999)
19	**Adjusted (Over)/Under Recovery with EDIT Mitigant**				**$ 175,220,059**
20	NC Retail Normalized Test Period MWh Sales			Exhibit 4	22,892,401
21	**Experience Modification Increment (Decrement) cents/kWh**				**0.7654**

Notes:

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

[2] January 2022 filed in Docket E-7, Sub 1263 to update the EMF and included in the current EMF rate. Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 17.

[3] North Carolina Residential sales on Exhibit 3, Line 13 differ from North Carolina Residential sales on Wo

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, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/ Under Recovery (d)
1	January 2022	3.6550	1.6895	1,921,732	$ 37,771,442
2	February [1]	3.2504	1.6895	1,927,508	$ 30,077,232
3	March	2.2020	1.6895	1,808,909	$ 9,269,996
4	April	2.1636	1.6895	1,840,396	$ 8,725,608
5	May [1]	3.4774	1.6895	1,904,671	$ 34,049,947
6	June [1]	3.9661	1.6895	2,184,316	$ 49,730,332
7	July	4.5134	1.6895	2,260,531	$ 63,835,167
8	August	4.9415	1.6895	2,467,241	$ 80,234,867
9	September	2.9735	1.7523	2,309,221	$ 28,198,709
10	October	2.1545	1.8217	1,927,666	$ 6,414,818
11	November	3.2050	1.8217	1,777,613	$ 24,589,863
12	December [1]	5.0399	1.8217	2,007,616	$ 71,896,623
13	**Total Test Period**			**24,337,421**	**$ 444,794,604**
14	Test Period Wtd Avg. ¢/kWh	3.5242	1.7265		
15	Adjustment to remove (Over)/Under Recovery - January 2022 [2]				$ 37,762,562
16	**Adjustment for Clemson CHP Steam Revenues**				$ (263,925)
17	**Adjusted (Over)/Under Recovery**				**$ 406,768,116**
18	**Potential EDIT Mitigant**				$ (219,560,526)
19	**Adjusted (Over)/Under Recovery with EDIT Mitigant**				**$ 187,207,590**
20	NC Retail Normalized Test Period MWh Sales			Exhibit 4	24,448,017
21	**Experience Modification Increment (Decrement) cents/kWh**				**0.7657**

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

[2] January 2022 filed in Docket E-7, Sub 1263 to update the EMF and included in the current EMF rate. Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 17.

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, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Line #	Month	Fuel Cost Incurred ¢/kWh (a)	Fuel Cost Billed ¢/kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/ Under Recovery (d)
1	January 2022	3.8206	1.7243	937,751	$ 19,657,733
2	February [1]	3.3522	1.7243	953,346	$ 15,515,360
3	March	1.9331	1.7243	1,050,500	$ 2,193,118
4	April	2.0280	1.7243	1,001,271	$ 3,040,792
5	May [1]	3.3268	1.7243	1,015,284	$ 16,266,045
6	June [1]	3.9333	1.7243	1,123,416	$ 24,817,732
7	July	4.7681	1.7243	1,091,420	$ 33,220,351
8	August	5.4617	1.7243	1,137,540	$ 42,514,122
9	September	3.4130	1.7791	1,067,538	$ 17,442,158
10	October	2.1680	1.8396	1,014,322	$ 3,330,636
11	November	3.0819	1.8396	980,378	$ 12,179,045
12	December [1]	5.7913	1.8396	929,121	$ 40,459,529
13	**Total Test Period**			**12,301,885**	**$ 230,636,623**
14	Test Period Wtd Avg. ¢/kWh	3.6009	1.7565		
15	Adjustment to remove (Over)/Under Recovery - January 2022 [2]				$ 19,653,201
16	**Adjustment for Clemson CHP Steam Revenues**				$ (132,411)
17	**Adjusted (Over)/Under Recovery**				**$ 210,851,011**
18	**Potential EDIT Mitigant**				$ (109,735,643)
19	**Adjusted (Over)/Under Recovery with EDIT Mitigant**				**$ 101,115,367**
20	NC Retail Normalized Test Period MWh Sales			Exhibit 4	12,219,040
21	**Experience Modification Increment (Decrement) cents/KWh**				**0.8275**

Notes:

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

[2] January 2022 filed in Docket E-7, Sub 1263 to update the EMF and included in the current EMF rate. Included for Commission review in accordance with NC Rule R8-55(d)(3) but deducted from total (Over)/Under on Line 17.

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, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Clark Second 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) [1]	Exhibit 6 Schedule 1 (Line 4) and Workpaper 11 (NC Retail)		88,284,042		59,059,117	22,419,810	24,337,421	12,301,885
2	Customer Growth MWh Adjustment	Workpaper 13 Pg 1		160,003		162,487	130,366	103,625	(71,505)
3	Weather MWh Adjustment	Workpaper 12 Pg 1		437,160		337,854	342,225	6,970	(11,341)
4	Total Normalized MWh Sales	Sum		88,881,205		59,559,458	22,892,401	24,448,017	12,219,040
5	Test Period Fuel and Fuel Related Revenue *		$	1,606,073,846	$	1,006,893,394			
6	Test Period Fuel and Fuel Related Expense *		$	2,966,425,990	$	2,087,923,955			
7	Test Period Unadjusted (Over)/Under Recovery		$	1,360,352,144	$	1,081,030,561			

		2021 Summer Coincidental Peak (CP) kW
8	Total System Peak	17,241,828
9	NC Retail Peak	11,480,608
10	NC Residential Peak	5,400,475
11	NC General Service/Lighting Peak	4,263,819
12	NC Industrial Peak	1,816,314

* 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.

[1] North Carolina Residential sales on Exhibit 4, Line 1 differ from North Carolina Residential sales on Exhibit 3, Page 2 of 4 due to an adjustment reported on the June 2022 monthly fuel report.

Rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Nuclear Capacity Ratings
Test Period Ended December 31, 2022
Billing Period September 2023 - August 2024
Docket E-7, Sub 1282

Clark Secibd Revised Exhibit 5

Unit	Rate Case Docket E-7, Sub 1214	Fuel Docket E-7, Sub 1263	Proposed Capacity Rating MW
Oconee Unit 1	847.0	847.0	847.0
Oconee Unit 2	848.0	848.0	848.0
Oconee Unit 3	859.0	859.0	859.0
McGuire Unit 1	1,158.0	1,158.0	1,158.0
McGuire Unit 2	1,157.6	1,157.6	1,157.6
Catawba Unit 1	1,160.1	1,160.0	1,160.0
Catawba Unit 2	1,150.1	1,150.1	1,150.1
Total Company	7,179.8	7,179.7	7,179.7

Clark Second Revised Exhibit 6

DECEMBER 2022 MONTHLY FUEL FILING

Clark Second Revised
Exhibit 6 Schedule 1

DUKE ENERGY CAROLINAS
SUMMARY OF MONTHLY FUEL REPORT

Docket No. E-7, Sub 1260

Line No.		Dec 2022	12 Months Ended Dec 2022
1	Fuel and fuel-related costs	$ 400,088,306	$ 3,125,398,595
	MWH sales:		
2	Total system sales	7,795,402	89,477,757
3	Less intersystem sales	205,952	1,193,715
4	Total sales less intersystem sales	7,589,450	88,284,042
5	Total fuel and fuel-related costs (¢/KWH) (line 1/line 4)	5.2716	3.5402
6	Current fuel and fuel-related cost component (¢/KWH) (per Schedule 4, Line 7a Total)	1.8989	
	Generation Mix (MWH):		
	Fossil (by primary fuel type):		
7	Coal	1,226,989	8,102,494
8	Fuel Oil	78,865	130,190
9	Natural Gas - Combined Cycle	923,129	13,612,829
10	Natural Gas - Combined Heat and Power	7,147	91,218
11	Natural Gas - Combustion Turbine	74,091	1,686,686
12	Natural Gas - Steam	1,243,316	13,557,414
13	Biogas	2,080	18,277
14	Total fossil	3,555,617	37,199,108
15	Nuclear 100%	5,486,217	59,538,303
16	Hydro - Conventional	215,484	1,696,649
17	Hydro - Pumped storage	(34,571)	(697,976)
18	Total hydro	180,913	998,673
19	Solar Distributed Generation	15,173	320,481
20	Total MWH generation	9,237,920	98,056,565
21	Less joint owners' portion - Nuclear	1,417,939	15,313,271
22	Less joint owners' portion - Combined Cycle	(160)	592,719
23	Adjusted total MWH generation	7,820,141	82,150,575

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

Clark Second Revised
Exhibit 6 Schedule 2

DUKE ENERGY CAROLINAS
DETAILS OF FUEL AND FUEL-RELATED COSTS

Docket No. E-7, Sub 1260

Fuel and fuel-related costs:	Dec 2022	12 Months Ended Dec 2022
0501110 coal consumed - steam	$ 45,283,039	$ 270,898,099
0501222-0501223 biomass/test fuel consumed	-	
0501310 fuel oil consumed - steam	157,081	1,075,261
0501330 fuel oil light-off - steam	48,166	1,713,942
Total Steam Generation - Account 501	45,488,286	273,687,302
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	21,706,902	247,614,928
Other Generation - Account 547		
0547100, 0547124 - natural gas consumed - Combustion Turbine	11,551,223	129,502,907
0547100 - Combustion Turbine - credit for inefficient fuel cost	-	(2,857,210)
0547100 natural gas consumed - Steam	139,769,907	960,513,825
0547101 natural gas consumed - Combined Cycle	78,921,823	626,119,762
0547101 natural gas consumed - Combined Heat and Power	1,290,155	8,688,719
0547106 biogas consumed - Combined Cycle	112,306	986,012
0547200 fuel oil consumed - Combustion Turbine	13,579,427	20,076,765
Total Other Generation - Account 547	245,224,841	1,743,030,780
Reagents		
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	3,579,598	19,538,566
Total Reagents	3,579,598	19,538,566
By-products		
Net proceeds from sale of by-products	451,601	2,946,324
Total By-products	451,601	2,946,324
Total Fossil and Nuclear Fuel Expenses		
Included in Base Fuel Component	316,451,228	2,286,817,900
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (economic)	-	(215,310)
Capacity component of purchased power (renewables)	661,601	15,482,895
Capacity component of purchased power (PURPA)	414,939	9,369,817
Fuel and fuel-related component of purchased power	126,508,359	940,337,520
Total Purchased Power and Net Interchange - Account 555	127,584,899	964,974,922
Less:		
Fuel and fuel-related costs recovered through intersystem sales	43,533,664	122,923,146
Fuel in loss compensation	381,194	2,967,546
Solar Integration Charge	13,226	(4,005)
Lincoln CT marginal fuel revenue	19,737	506,640
Miscellaneous Fees Collected	-	900
Total Fuel Credits - Accounts 447 /456	43,947,821	126,394,227
Total Fuel and Fuel-related Costs	$ 400,088,306	$ 3,125,398,595

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

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

DEC 2022

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Alcoa Power Generating Inc.	-	-	-	-	-	
American Electric Power Serv Corp.	-	-	-	-	-	
Associated Electric Cooperative, Inc.	153,251	-	3,154	130,264	22,988	
Blue Ridge Electric Membership Corp.	-	-	-	-	-	
Calpine Energy Services, L.P.	-	-	-	-	-	
Cargill Power Marketers, LLC.	-	-	-	-	-	
Carolina Power Partners, LLC	$ 220,128	-	2,924	$ 187,109	$ 33,019	
Cherokee County Cogeneration Partners	-	$ -	-	-	-	
City of Kings Mountain	-	-	-	-	-	
Constellation	-	-	-	-	-	
Cube Yadkin Generation LLC	115,680	-	723	98,328	17,352	
DE Progress	-	-	-	-	-	
DE Progress - Native Load Transfer	70,200,387	-	466,390	70,248,967	2,377,140	(2,425,721)
DE Progress - Native Load Transfer (Prior Period Adjust)	-	-	-	-	-	
DE Progress - Native Load Transfer Benefit	2,350,019	-	-	2,350,019	-	
DE Progress - Fees	(25,148)	-	-	-	(25,148)	
EDF Trading North America, LLC.	-	-	-	-	-	
Exelon Generation Company, LLC.	-	-	-	-	-	
Florida Power & Light Company	-	-	-	-	-	
Haywood Electric - Economic	32,445	19,590	116	10,927	1,928	
LGE/KU	650,620	-	11,423	553,027	97,593	
Lockhart Power Co.	-	-	-	-	-	
Macquarie Energy, LLC	16,474,177	-	68,687	14,003,050	2,471,127	
Midwest Independent System Operator	-	-	-	-	-	
Morgan Stanley Capital Group	57,600	-	800	48,960	8,640	
NCEMC - Economic	30,628	3,317	611	23,215	4,097	
NCMPA - Economic	1,893,200	-	18,346	1,609,220	283,980	
NCMPA Instantaneous - Economic	7,173,244	-	48,002	4,089,467	3,083,778	
NTE Carolinas LLC	-	-	-	-	-	
Oglethorpe Power	-	-	-	-	-	
Piedmont Electric Membership Corp. - Economic	-	-	-	-	-	
Piedmont Municipal Power Agency	681,363	-	11,318	388,992	292,370	
PJM Interconnection, LLC.	498,917	-	5,150	424,080	74,838	
Rainbow Energy Marketing Corporation	-	-	-	-	-	
Rutherford Electric Membership Corp.	-	-	-	-	-	
South Carolina Electric & Gas Company / Dominion Energy	13,472	-	288	11,451	2,021	
Southern Company Services, Inc.	148,469	-	2,641	126,198	22,270	
Tennesee Valley Authority	700,625	-	12,982	595,531	105,094	
The Energy Authority	15,029	-	386	12,775	2,254	
Town of Dallas	-	-	-	-	-	
Town of Forest City	20,417	20,417	-	-	-	
Westar Energy, Inc.	-	-	-	-	-	
	$ 101,404,524	**$ 43,324**	**653,941**	**$ 94,911,581**	**$ 8,875,341**	**$ (2,425,721)**
Renewable Energy						
REPS	$ 4,896,784.45	$ 639,202	86,592	$ -	$ 4,257,583	
DERP - Purchased Power	$ 342,872.54	22,399	5,884	-	229,623	90,850
DERP - Net Metered Generation	$ 496.80	-	18			497
	$ 5,240,154	**$ 661,601**	**92,494**	**$ -**	**$ 4,487,206**	**$ 91,347**
HB589 PURPA Purchases						
CPRE - Purchased Power	$ 1,214,288.27	-	29,865			1,214,288
Qualifying Facilities	$ 3,465,792.71	414,939	66,488		2,956,940	93,914
	$ 4,680,081	**$ 414,939**	**96,353**	**$ -**	**$ 2,956,940**	**$ 1,308,203**
Non-dispatchable / Other						
Carolina Power & Light (DE Progress) (Emergency)	-	-	-	-		-
South Carolina Public Service Authority - Emergency	-	-	-	-		-
Blue Ridge Electric Membership Corp.	1,573,673	$ 803,142	24,891	654,951		115,580
Cargill Power Marketers, LLC.	-	-	-	-		-
Carolina Power Partners, LLC	-	-	-	-		-
DE Progress - As Available Capacity	-	-	-	-		-
Exelon Generation Company, LLC.	-	-	-	-		-
Haywood Electric	177,287	79,852	3,859	82,820		14,615
Macquarie Energy, LLC	15,571,770	-	35,899	13,236,005		2,335,766
Morgan Stanley Capital Group	-	-	-	-		-
NCEMC - Other	679,250	-	1,235	577,363		101,888
NCMPA	2,097,600	-	2,696	1,782,960		314,640
NTE Carolinas LLC	-	-	-	-		-
Piedmont Electric Membership Corp.	739,661	379,423	11,904	306,202		54,036
PJM Interconnection, LLC - Other	-	-	-	-		-
South Carolina Electric & Gas Company / Dominion Energy	-	-	-	-		-
Southern Company Services, Inc.	-	-	-	-		-
Tennesse Valley Authority	-	-	-	-		-
Generation Imbalance	3,118,465	-	9,905	2,559,774		558,691
Energy Imbalance - Purchases	1,435,304	-	469	1,175,506		259,798
Energy Imbalance - Sales	(4,204,965)	-	-	(3,566,988)		(637,977)
Qualifying Facilities - Pre HB589	-	-	-			-
Other Purchases	472	-	18	-		472
	$ 21,188,517	**$ 1,262,418**	**90,876**	**$ 16,808,592**	**$ -**	**$ 3,117,507**
Total Purchased Power	**$ 132,513,276**	**$ 2,382,281**	**933,664**	**$ 111,720,172**	**$ 16,319,487**	**$ 2,091,335**
Interchanges In						
Other Catawba Joint Owners	6,968,385	-	710,207	4,330,916		2,637,471
WS Lee Joint Owner	170,714		2,953	158,305		12,409
Total Interchanges In	7,139,099	-	713,160	4,489,220	-	2,649,878
Interchanges Out						
Other Catawba Joint Owners	(6,832,104)	(134,209)	(693,600)	(4,230,264)		(2,467,631)
Catawba- Net Negative Generation	-	-	-	-		-
WS Lee Joint Owner	(1,942,451)		(33,801)	(1,790,256)		(152,195)
Total Interchanges Out	(8,774,555)	(134,209)	(727,400)	(6,020,520)	-	(2,619,826)
Net Purchases and Interchange Power	**$ 130,877,820**	**$ 2,248,072**	**919,424**	**$ 110,188,872**	**$ 16,319,487**	**$ 2,121,387**

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

DEC 2022

Clark Second Revised Exhibit 6
Schedule 3 - Sales Page 2 of 5

	Total	Capacity	Non-capacity		
Sales	**$**	**$**	**mWh**	**Fuel $**	**Non-fuel $**
Utilities:					
Midwest Independent System Operator - Emergency	-	-	-	-	-
DE Progress - Emergency	-	-	-	-	-
SC Public Service Authority - Emergency	-	-	-	(155)	155
SC Electric & Gas / Dominion Energy - Emergency	508,666	-	2,763	2,270,933	(1,762,267)
Tennessee Valley Authority - Emergency	1,924,600	-	8,648	5,948,337	(4,023,737)
Market Based:					
Associated Electric Cooperative, Inc.	2,552	-	41	1,603	949
American Electric Power Services Corp.	-	-	-	-	-
Cargill-Alliant, LLC.	-	-	-	-	-
Carolina Power Partners, LLC	8,800	-	150	8,953	(153)
Central Electric Power Cooperative, Inc.	-	$ -	-	-	-
Constellation Power Sources	-	-	-	-	-
EDF Trading Company	-	-	-	-	-
Evergy Kansas Central	-	-	-	-	-
Exelon Generation Company, LLC.	-	-	-	-	-
Macquarie Energy, LLC	-	-	-	980	(980)
Midwest Independent System Operator	-	-	-	-	-
Morgan Stanley	-	-	-	-	-
NCEMC	-	-	-	-	-
NCEMC (Balancing/Generator)	-	-	-	-	-
NCMPA	127,155	87,500	213	38,688	967
Oglethorpe Power Corporation	-	-	-	-	-
PJM Interconnection, LLC.	17,071	-	200	13,976	3,095
SC Electric & Gas / Dominion Energy	20,383	-	182	4,442	15,941
South Carolina Electric & Gas - T	(4)	-	-	-	(4)
South Carolina Public Service Authority - T	(4)	-	-	-	(4)
Southern Company	90,699	-	1,058	121,282	(30,583)
Tenaska Power Service	-	-	-	-	-
Tennessee Valley Authority	5,926	-	90	3,948	1,978
The Energy Authority	18,112	-	411	10,634	7,479
Westar Energy	-	-	-	-	-
Other:					
Cargill-Alliant, LLC - Mitigation sales	-	-	-	-	-
DE Progress - Native Load Transfer Benefit	1,268,405	-	-	1,268,405	-
DE Progress - Native Load Transfer	32,571,610	-	187,066	32,362,740	208,869
Generation Imbalance	1,777,596	-	5,130	1,478,897	298,699
BPM Transmission	8,535	-			8,535
Total Intersystem Sales	**$ 38,350,103**	**$ 87,500**	**205,952**	**$ 43,533,664**	**$ (5,271,061)**

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

Twelve Months Ended
DEC 2022

Purchased Power	**Total**	**Capacity**	**Non-capacity**			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Alcoa Power Generating Inc.	-	-	-	-	-	
American Electric Power Serv Corp.	-	-	-	-	-	
Associated Electric Cooperative, Inc.	163,916	-	3,384	136,769	27,147	
Blue Ridge Electric Membership Corp. - Economic	-	-	-	-	-	
Calpine Energy Services, L.P.	-	-	-	-	-	
Cargill Power Marketers, LLC.	$ -	-	-	$ -	$ -	
Carolina Power Partners, LLC	9,667,773	$ -	128,879	5,950,172	3,717,601	
Cherokee County Cogeneration Partners	(6,400,734)	(215,310)	-	22,574	(6,207,998)	
City of Kings Mountain	-	-	-	-	-	
Constellation	489,570	-	6,659	298,638	190,932	
Cube Yadkin Generation LLC	221,550	-	2,810	162,909	58,641	
DE Progress	-	-	-	-	-	
DE Progress - Native Load Transfer	544,444,833	-	7,369,876	520,344,456	26,483,093	(2,382,715)
DE Progress - Native Load Transfer (Prior Period Adjust)	-	-	-	-	-	
DE Progress - Native Load Transfer Benefit	54,871,210	-	-	54,871,210	-	
DE Progress - Fees	(153,265)	-	-	-	(153,265)	
EDF Trading North America, LLC.	-	-	-	-	-	
Exelon Generation Company, LLC.	-	-	-	-	-	
Florida Power & Light Company	-	-	-	-	-	
Haywood Electric - Economic	958,305	242,809	6,962	439,537	275,958	
LGE/KU	785,194	-	14,077	635,117	150,077	
Lockhart Power Co.	-	-	-	-	-	
Macquarie Energy, LLC	51,250,548	-	486,963	35,216,637	16,033,911	
Midwest Independent System Operator	-	-	-	-	-	
Morgan Stanley Capital Group	72,600	-	1,100	58,110	14,490	
NCEMC	970,306	3,317	15,767	596,418	370,571	
NCMPA	14,524,190	-	220,006	9,314,124	5,210,066	
NCMPA Load Following Economic	37,141,682	-	465,009	21,929,915	15,211,767	
NTE Carolinas LLC	-	-	-	-	-	
Oglethorpe Power	-	-	-	-	-	
Piedmont Electric Membership Corp. - Economic	-	-	-	-	-	
Piedmont Municipal Power Agency	5,268,496	-	102,863	3,124,813	2,143,684	
PJM Interconnection, LLC.	14,064,189	-	192,441	8,698,896	5,365,294	
Rainbow Energy Marketing Corporation	-	-	-	-	-	
Rutherford Electric Membership Corp.	-	-	-	-	-	
South Carolina Electric & Gas Company / Dominion Energy	13,472	-	288	11,451	2,021	
Southern Company Services, Inc.	557,481	-	9,748	375,696	181,785	
Tennessee Valley Authority	5,408,020	-	84,497	3,467,042	1,940,978	
The Energy Authority	16,905	-	424	13,919	2,986	
Town of Dallas	-	-	-	-	-	
Town of Forest City	**$ 244,999**	**$ 244,999**	**-**	**$ -**	**$ -**	
Westar Energy, Inc.	$ -	$ -	-	$ -	$ -	
	734581242	275815.11	9111753	665668404.2	71019738.84	-2382715.37
Renewable Energy						
REPS	71,532,035	15,214,422	1,148,827	-	56,317,611	-
DERP - Purchased Power	4,025,008	268,474	69,800	-	2,739,889	1,016,646
DERP - Purchased Power - Pre HB589	$ -	$ -	-	$ -		$ -
DERP - Net Metered Generation	124,177.1400	0.0000	4,598.5974	0.0000		124,177.1400
	$ 75,681,220	15,482,895	1223226	$ -	$ 59,057,500	1,140,823
	ok	ok	ok		ok	
HB589 PURPA Purchases						
CPRE - Purchased Power	**$ 6,118,008**	**$ -**	**301,278**			**$ 6,118,008**

Qualifying Facilities	**$ 44,602,804 OK**	**$ 9,369,818 OK**	**747,251**		**$ 34,126,582**	**1106408.62**
	$ 50,720,812	**$ 9,369,818**	**1,048,529**	**$ -**	**$ 34,126,582**	**7224417**
Non-dispatchable / Other						
Carolina Power & Light (DE Progress) - Emergency	$ 30,606	$ -	177	$ 26,015		$ 4,591
South Carolina Public Service Authority - Emergency	-	-	-	-		-
Blue Ridge Electric Membership Corp.	12,234,125	5,929,525	293,671	5,358,911		945,690
City of Concord	-	-	-	-		-
Cargill Power Marketers, LLC.	-	-	-	-		-
Carolina Power Partners, LLC	5,412,299	-	53,596	4,600,454		811,845
DE Progress - As Available Capacity	400,501	400,501	-	-		-
Exelon Generation Company, LLC.	-	-	-	-		-
Haywood Electric	2,184,429	978,976	45,858	1,024,635		180,818
Macquarie Energy, LLC	95,814,395	-	573,508	81,442,236		14,372,159
Morgan Stanley Capital Group	-	-	-	-		-
NCEMC - Other	9,311,412	36,488	51,330	7,883,685		1,391,239
NCMPA - Reliability	6,533,220	-	39,228	5,553,237		979,983
NTE Carolinas LLC	-	-	-	-		-
Piedmont Electric Membership Corp.	5,818,999	2,826,296	140,160	2,543,798		448,905
PJM Interconnection, LLC - Other	-	-	-	-		-
South Carolina Electric & Gas Company	-	-	-	-		-
Southern Company Services, Inc.	-	-	-	-		-
Tennesse Valley Authority	-	-	-	-		-
Generation Imbalance	9,288,793		69,713	6,023,880		3,264,913
Energy Imbalance - Purchases	2,954,691		(19,820)	2,284,580		670,111
Energy Imbalance - Sales	(7,911,557)		-	(7,181,724)		(729,833)
Qualifying Facilities - Pre HB589	-	-	-	-		-
Other Purchases	6,318	-	233	-		6,318
	$ 142,078,232	**$ 10,171,786**	**1,247,654**	**$ 109,559,706**	**$ -**	**$ 22,346,739**
Total Purchased Power	**$ 1,003,061,506**	**$ 35,300,314**	**12,631,162**	**$ 775,228,110**	**$ 164,203,821**	**$ 28,329,264**
						2
Interchanges In						
Other Catawba Joint Owners	73,411,183	-	7,683,448	45,957,871		27,453,312
WS Lee Joint Owner	27,399,050	-	421,179	25,673,117		1,725,933
Total Interchanges In	100,810,232	-	8,104,626	71,630,988	-	29,179,244
Interchanges Out						
Other Catawba Joint Owners	(72,945,394)	(1,580,207)	(7,598,655)	(45,548,810)		(25,816,377)
Catawba- Net Negative Generation	(452,734)	-	(13,562)	(391,439)		(61,295)
WS Lee Joint Owner	(26,616,561)	-	(411,650)	(24,785,151)		(1,831,410)
Total Interchanges Out	(100,014,689)	(1,580,207)	(8,023,867)	(70,725,400)	-	(27,709,082)
Net Purchases and Interchange Power	**$ 1,003,857,049**	**$ 33,720,107**	**12,711,921**	**$ 776,133,698**	**$ 164,203,821**	**$ 29,799,426**

NOTES: Detail amounts may not add to totals shown due to rounding.
CPRE purchased power amounts are recovered through the CPRE Rider.

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

Twelve Months Ended DEC 2022

	Total	Capacity	Non-capacity		
Sales	$	$	mWh	Fuel $	Non-fuel $
Utilities:					
Midwest Independent System Operator - Emergency	-	-	-	-	-
DE Progress - Emergency	$ 106,271	-	1,150	$ 101,064	$ 5,207
SC Public Service Authority - Emergency	417,282	-	4,767	389,377	27,905
SC Electric & Gas / Dominion Energy - Emergency	522,805	-	3,020	2,283,300	(1,760,495)
Tennessee Valley Authority - Emergency	1,924,600	-	8,648	5,948,337	(4,023,737)
Market Based:					
Associated Electric Cooperative, Inc.	2,552	-	41	1,603	949
American Electric Power Services Corp.	-	-	-	-	-
Cargill-Alliant, LLC.	-	-	-	-	-
Carolina Power Partners, LLC	8,800	-	150	8,953	(153)
Central Electric Power Cooperative, Inc.	5,538,111	$ 5,267,000	3,450	265,640	5,471
Constellation Power Sources	-	-	-	-	-
EDF Trading Company	-	-	-	-	-
Evergy Kansas Central (BPM)	-	-	-	-	-
Exelon Generation Company, LLC.	-	-	-	-	-
Macquarie Energy, LLC	1,459,360	-	20,545	1,456,745	2,615
Midwest Independent System Operator	-	-	-	-	-
Morgan Stanley	-	-	-	-	-
NCEMC	-	-	-	-	-
NCEMC (Balancing/Generator)	-	-	-	-	-
NCMPA	1,764,061	1,050,000	6,341	686,859	27,202
Oglethorpe Power Corporation	-	-	-	-	-
PJM Interconnection, LLC.	16,952	-	200	13,976	2,976
SC Electric & Gas / Dominion Energy	209,983	-	1,382	147,017	62,966
South Carolina Electric & Gas - T	(4)	-	-	-	(4)
South Carolina Public Service Authority - T	(4)	-	-	-	(4)
Southern Company	112,627	-	1,409	136,190	(23,563)
Tenaska Power Service	-	-	-	-	-
Tennesse Valley Authority	5,926	-	90	3,948	1,978
The Energy Authority	83,368	-	1,474	62,119	21,250
Westar Energy	-	-	-	-	-
Other:					
Cargill-Alliant, LLC - Mitigation sales	-	-	-	-	-
DE Progress - Native Load Transfer Benefit	10,826,966	-	-	10,826,966	-
DE Progress - Native Load Transfer	98,082,917	17,512	1,104,079	96,983,455	1,081,950
Generation Imbalance	4,126,628	-	36,969	3,607,599	519,029
BPM Transmission	(289,990)	-	-	-	(289,990)
Total Intersystem Sales	**$ 124,919,210**	**$ 6,334,512**	**1,193,715**	**$ 122,923,146**	**$ (4,338,447)**

Duke Energy Carolinas
(Over) / Under Recovery of Fuel Costs
Dec-22

Line No.			Residential	Commercial	Industrial	Total
1	Actual System kWh sales	Input				7,589,450,642
2	DERP Net Metered kWh generation	Input				10,675,770
3	Adjusted System kWh sales	L1 + L2				7,600,126,412
4	N.C. Retail kWh sales	Input	2,073,010,864	2,007,616,467	929,120,959	5,009,748,290
5	NC kWh sales % of actual system kWh sales	L4 T / L1				66.01%
6	NC kWh sales % of adjusted system kWh sales	L4 T / L3				65.92%
7	Approved fuel and fuel related rates (¢/kWh)					
	7a Billed rates by class (¢/kWh)	L7g	2.0003	1.8217	1.8396	1.8989
	7b Billed fuel expense	L7a * L4 / 100	$41,466,436	$36,572,749	$17,092,109	$95,131,294
	Rate changes:		Agrees to CY Rate	Agrees to CY Rate	Agrees to CY Rate	ate with Annual Fuel Filings.
	7c New approved rates	Input	2.0003	1.8217	1.8396	
	7d Ratio of days to rate	Input	100.00%	100.00%	100.00%	
	7e Prior approved rates	Input	1.5337	1.6895	1.7243	
	7f Ratio of days to rate	Input	$0	$0	$0	
	7g Total prorated ¢/KWH	(L7c * L7d) + (L7e * L7f)	2.0003	1.8217	1.8396	
8	Incurred base fuel and fuel related (¢/kWh) (less renewable purchased power capacity)					
	Allocation changes:					
	8a New approved Docket E-7, Sub 1263 allocation factor	Input	41.25%	38.34%	20.40%	ate with Annual Fuel Filings.
	8b System incurred expense	Input				$399,273,363
	8c Incurred base fuel and fuel related expense	L8b * L6 * 8a	$108,577,957	$100,915,104	$53,694,541	$263,187,602
	8d Incurred base fuel rates by class (¢/kWh)	L8c / L4 * 100	5.2377	5.0266	5.7791	5.2535
9	Incurred renewable purchased power capacity rates (¢/kWh)					
	9a NC retail production plant %	Input				0.6668
	9b Production plant allocation factors	Input	$0	$0	$0	$1
	9c System incurred expense	Input				1,076,540
	9d Incurred renewable capacity expense	L9a * L9b * L9c	337,710	266,619	113,521	717,851
	9e Incurred renewable capacity rates by class (¢/kWh)	((L9a * L9c) * L9b) / L4 * 100	$0	$0	$0	$0
10	Total incurred rates by class (¢/kWh)	L8h + 9e	$5	$5	$6	$5
11	Difference in ¢/kWh (incurred - billed)	L10 - L7a	$3	$3	$4	3
12	(Over) / under recovery [See footnote]	(L4 * L11) / 100	$67,449,231	$64,608,974	$36,715,953	$168,774,159
13	Prior period adjustments	Input	$ 6,221,166	$ 7,287,649	$ 3,743,576	$ 17,252,391
14	Total (over) / under recovery	L12 + L13	$ 73,670,398	$ 71,896,623	$ 40,459,529	$ 186,026,550
15	Total system incurred expense	L8f + L9c				$ 400,349,903
16	Less: Jurisdictional allocation adjustment(s)	Input				$ 261,597
17	Total Fuel and Fuel-related Costs per Schedule 2	L15 + L16				$ 400,088,306

	Year 2022	(Over) / Under Recovery Total To Date	Residential	Commercial	Industrial	Total Company
	January	$82,008,235	$24,579,060	$37,771,442	$19,657,733	$82,008,235
	February	$143,232,306	$15,631,479	$30,077,232	$15,515,360	$61,224,071
_/1	March	$159,861,094	$5,165,674	$9,269,996	$2,193,118	$16,628,788
	April	$181,992,930	$10,365,435	$8,725,608	$3,040,792	$22,131,835
_/1	May	$264,210,240	$31,901,319	$34,049,947	$16,266,045	$82,217,311
	June	$379,971,976	$41,213,673	$49,730,332	$24,817,731	$115,761,736
	July	$526,297,892	$49,270,398	$63,835,167	$33,220,351	$146,325,916
	August	$711,811,535	$62,764,654	$80,234,867	$42,514,122	$185,513,643
	September	796,532,236	$39,079,834	$28,198,709	$17,442,158	$84,720,701
	October	823,675,629	$17,397,939	$6,414,818	$3,330,636	$27,143,393
	November	$895,004,007	34,559,470	24,589,863	12,179,045	$71,328,378
	December	$1,081,030,557	$73,670,398	$71,896,623	$40,459,529	$186,026,550
			$405,599,335	$444,794,603	$230,636,622	$1,081,030,557

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.
Includes prior period adjustments.

_/1 Reflects a prorated rate and prorated allocation factor for periods in which the approved rates changed.

Clark Second Revised Exhibit 6

DUKE ENERGY CAROLINAS
FUEL AND FUEL RELATED COST REPORT
December 2022

Description	Buck	Dan River	Lee	Clemson	Lee	Lincoln	(A) Lincoln (Unit17)	Mill Creek	Rockingham
	CC	CC	CC	CHP	Steam/CT	CT	CT	CT	CT
Cost of Fuel Purchased ($)									
Coal									
Oil	-	-	-		581,554	-	-	4,046,679	4,504,834
Gas - CC	$40,036,410	$38,694,262	$221,226						
Gas - CHP				$1,290,155					
Gas - CT					$339,173	$1,752,935	$247	$1,301,300	$8,157,569
Gas - Steam					-				
Biogas	-	379,200	-						
Total	$40,036,410	$39,073,462	$221,226	$1,290,155	$920,726	$1,752,935	$247	$5,347,979	$12,662,402
Average Cost of Fuel Purchased (¢/MBTU)									
Coal		-							
Oil					2,568.26	-	-	2,253.14	2,410.28
Gas - CC	1,210.54	1,211.01	2,080.56						
Gas - CHP				1,297.62					
Gas - CT					1,277.34	1,215.43	(1,129.41)	1,212.99	1,217.66
Gas - Steam					-				
Biogas	-	2,595.49	-						
Weighted Average	1,210.54	1,217.31	2,080.56	1,297.62	1,871.51	1,215.43	(1,129.41)	1,864.18	1,477.81
Cost of Fuel Burned ($)									
Coal		-	-		-				
Oil - CC	-	-	-						
Oil - Steam/CT					$288,821	4,242,357	-	5,012,521	4,035,727
Gas - CC	$40,036,410	$38,694,262	$221,226						
Gas - CHP				$1,290,155					
Gas - CT					339,173	$1,752,935	$247	$1,301,300	$8,157,569
Gas - Steam					-				
Biogas	-	379,200	-						
Nuclear									
Total	$40,036,410	$39,073,462	$221,226	$1,290,155	$627,994	$5,995,292	$247	$6,313,821	$12,193,296
Average Cost of Fuel Burned (¢/MBTU)									
Coal					-				
Oil - CC									
Oil - Steam/CT					1,751.81	1,517.46	-	1,952.52	1,856.01
Gas - CC	1,210.54	1,211.01	2,080.56						
Gas - CHP				1,297.62					
Gas - CT					1,277.34	1,215.43	(1,129.41)	1,212.99	1,217.66
Gas - Steam					-				
Biogas	-	2,595.49	-						
Nuclear									
Weighted Average	1,210.54	1,217.31	2,080.56	1,297.62	1,459.09	1,414.68	(1,129.41)	1,734.56	1,374.08
Average Cost of Generation (¢/kWh)									
Coal		-	-		-	-	-		
Oil - CC	-	-	-						
Oil - Steam/CT		-	-		17.56	12.13	-	23.53	20.14
Gas - CC	8.53	8.51	-						
Gas - CHP				18.05					
Gas - CT					12.54	291,185.15	-	14.61	12.95
Gas - Steam					-	-	-	-	-
Biogas	-	18.23	-						
Nuclear									
Weighted Average	8.53	8.55	-	18.05	14.44	17.14	-	20.90	14.68
Burned MBTU's									
Coal					-				
Oil - CC									
Oil - Steam/CT					16,487	279,569	-	256,721	217,441
Gas - CC	3,307,314	3,195,214	10,633						
Gas - CHP				99,425					
Gas - CT					26,553	144,223	(22)	107,280	669,936
Gas - Steam					-				
Biogas	-	14,610	-						
Nuclear									
Total	3,307,314	3,209,824	10,633	99,425	43,040	423,792	(22)	364,001	887,377
Net Generation (mWh)									
Coal									
Oil - CC									
Oil - Steam/CT		-	-		1,644	34,986	-	21,307	20,035
Gas - CC	469,549	454,840	(1,260)		-				
Gas - CHP				7,147					
Gas - CT					2,705	1	(523)	8,908	63,001
Gas - Steam					-				
Biogas	-	2,080	-						
Nuclear 100%									
Hydro (Total System)									
Solar (Total System)									
Total	469,549	456,920	(1,260)	7,147	4,349	34,987	(523)	30,215	83,036
Cost of Reagents Consumed ($)									
Ammonia	$48,324	$0	$6,766						
Limestone									
Sorbents									
Urea									
Re-emission Chemical									
Dibasic Acid									
Activated Carbon									
Lime (water emissions)									
Total	$48,324	$0	$6,766						

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
December 2022

Description	Allen	Marshall	Belews Creek	Cliffside	Catawba	McGuire	Retail	onee	Current Month
	Steam	Steam - Dual Fuel	Steam - Dual Fuel	Steam - Dual Fuel	Nuclear	Nuclear		Nuclear	
Cost of Fuel Purchased ($)									
Coal	$8,397	$22,275,183	$13,005,647	$4,159,826					39449052.41
Oil	-	-	43,134	195,355					9371554.83
Gas - CC									78951896.85
Gas - CHP									1290154.86
Gas - CT									11551223.21
Gas - Steam		23,192,605	89,015,098	27,562,204					139769906.7
Biogas									379200.4585
Total	$8,397	$45,467,788	$102,063,879	$31,917,385					280762989.3
Average Cost of Fuel Purchased (¢/MBTU)									
Coal	-	556.38	405.58	529.76					493.39
Oil	-	-	2,094.23	2,358.10					2345.876765
Gas - CC									1212.190124
Gas - CHP									1297.616153
Gas - CT									1218.467781
Gas - Steam		1,212.83	1,212.32	1,219.81					1213.873974
Biogas				.					2595.485685
Weighted Average	-	768.58	967.31	1,045.42					1021.532064
Cost of Fuel Burned ($)									
Coal	$0	$20,049,558	$15,376,945	$9,856,536					45283038.68
Oil - CC									0
Oil - Steam/CT	-	2,092	-	203,154				-	13784673.86
Gas - CC									78951896.85
Gas - CHP									1290154.86
Gas - CT								-	11551223.21
Gas - Steam		23,192,605	89,015,098	27,562,204					139769906.7
Biogas									379200.4585
Nuclear					$9,964,761	$9,371,945			29753844.93
Total	$0	$43,244,255	$104,392,043	$37,621,894	$9,964,761	$9,371,945		$0 #	320763940
Average Cost of Fuel Burned (¢/MBTU)									
Coal	-	418.68	345.25	368.79					380.0415591
Oil - CC									0
Oil - Steam/CT	-	1,442.88	-	2,545.79				-	1771.028179
Gas - CC									1212.190124
Gas - CHP									1297.616153
Gas - CT								-	1218.467781
Gas - Steam		1,212.83	1,212.32	1,219.81					1213.873974
Biogas									2595.485685
Nuclear					57.13	53.27			54.49758916
Weighted Average	-	645.32	884.95	761.55	57.13	53.27		-	371.3414283
Average Cost of Generation (¢/kWh)									
Coal	-	4.02	3.37	3.57					3.690582692
Oil - CC									-
Oil - Steam/CT	-	13.67	-	23.16				-	17.47873714
Gas - CC									8.552637244
Gas - CHP									18.05169806
Gas - CT								-	15.59056553
Gas - Steam		11.10	11.18	11.55					11.24170747
Biogas									18.2330654
Nuclear					0.57	0.53			0.542338098
Weighted Average	-	6.11	8.34	7.29	0.57	0.53			3.472252469
Burned MBTU's									
Coal	-	4,788,789	4,453,853	2,672,644					11915286
Oil - CC									0
Oil - Steam/CT	-	145	-	7,980				-	778343
Gas - CC									6513161.2
Gas - CHP									99425
Gas - CT								-	947970
Gas - Steam		1,912,266	7,342,548	2,259,553					11514367.2
Biogas									14610
Nuclear					17,441,277	17,594,902			54596626
Total	-	6,701,200	11,796,401	4,940,177	17,441,277	17,594,902		-	86379788.4
Net Generation (mWh)									
Coal	(3,652)	498,367	455,930	276,344					1226988.865
Oil - CC									0
Oil - Steam/CT	-	15	-	877				-	78865.388
Gas - CC									923129.2594
Gas - CHP									7147
Gas - CT								-	74091.111
Gas - Steam		208,863	795,860	238,593					1243315.636
Biogas									2079.740571
Nuclear 100%					1,755,875	1,777,031			5486217
Hydro (Total System)									180912.503
Solar (Total System)									15173.19
Total	(3,652)	707,245	1,251,790	515,814	1,755,875	1,777,031		-	9237921
Cost of Reagents Consumed ($)									
Ammonia			$1,573,130	$112,122					1740341.44
Limestone	$0	$463,125	669,388	417,704					1550217.58
Sorbents	-	135,320	-						135319.92
Urea	-	135,168							135167.6
Re-emission Chemical	-	-	-	-					0
Dibasic Acid	-								0
Activated Carbon	19,413	-							19413
Lime (water emissions)	-	-	-						0
Total	19,413	733,613	$2,242,518	$529,827					3580459.54

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 CONSUMPTION AND INVENTORY REPORT
December 2022

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 2022
	CC	CC	CC	CHP	Steam/CT	CT	CT	CT	CT	Steam	Steam - Dual Fuel	Steam - Dual Fuel	Steam - Dual Fuel		
Coal Data:															
Beginning balance					-					74,257	942,182	1,063,230	560,022	2,639,691	2,249,850.29
Tons received during period										-	160,876	126,317	34,519	321,712	3,321,481.00
Inventory adjustments					-					-	-	-	-	-	87,264.42
Tons burned during period					-					-	188,294	175,590	106,421	470,305	3,167,498.27
Ending balance					-					74,257	914,764	1,013,957	488,120	2,491,098	2,491,097.54
MBTUs per ton burned					-					-	25.43	25.37	25.11	25.34	25.14
Cost of ending inventory ($/ton)					-					76.97	106.48	87.57	92.62	95.19	95.19
Oil Data:															
Beginning balance	-	-	-		676,615	8,412,634	815,389	2,345,685	2,482,428	97,085	278,522	19,411	189,712	15,317,480	17,610,506
Gallons received during period	-	-	-		164,086	-	-	1,301,461	1,354,355	-	-	14,925	60,032	2,894,859	4,430,957
Miscellaneous adjustments	-	-	-		-	-	-	-	-	-	-	(12,217)	(7,796)	(18,962)	(283,590)
Gallons burned during period		-	-		119,913	2,024,251	-	1,863,711	1,584,733	-	1,055	-	57,940	5,652,654	9,217,150
Ending balance	-	-	-		720,788	6,388,383	815,389	1,783,435	2,252,050	97,085	277,467	22,119	184,008	12,540,723	12,540,723
Cost of ending inventory ($/gal)	-	-	-		2.41	2.10	2.40	2.69	2.55	3.67	1.98	2.92	3.51	2.33	2.33
Natural Gas Data:															
Beginning balance															
MCF received during period	3,201,724	3,078,374	10,314	96,396	25,719	139,785	(21)	103,973	645,289		1,854,024	7,076,232	2,186,597	18,418,406	245,725,869
MCF burned during period	3,201,724	3,078,374	10,314	96,396	25,719	139,785	(21)	103,973	645,289		1,854,024	7,076,232	2,186,597	18,418,406	245,725,869
Ending balance															
Biogas Data:															
Beginning balance															
MCF received during period	-	14,075	-											14,075	125,074
MCF burned during period	-	14,075	-											14,075	125,074
Ending balance															
Limestone Data:															
Beginning balance										17,697	69,262	39,265	31,093	157,316	158,739
Tons received during period										-	-	-	-	-	163,156
Inventory adjustments										-	-	-	-	-	(9,121)
Tons consumed during period										-	10,150	11,833	7,544	29,527	184,984
Ending balance										17,697	59,112	27,432	23,549	127,789	127,789
Cost of ending inventory ($/ton)										55.11	45.63	55.25	47.15	49.29	49.29
														Qtr Ending December 2022	Total 12 ME December 2022
Ammonia Data: (B)															
Beginning balance	3,836													3,836	2,761
Tons received during period	925													925	5,319
Tons consumed during period	1,127													1,127	4,446
Ending balance	3,634													3,634	3,634
Cost of ending inventory ($/ton)	339.09													339.09	339.09

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.
(B) Quarterly ammonia inventory amounts are revised to reflect a correction to June quantities, affecting the quarter ending September 2021 beginning balance. Revised amounts for quarter ending June 2021 are revised above.

Clark Second Revised
Exhibit 6 Schedule 7

DUKE ENERGY CAROLINAS
ANALYSIS OF COAL PURCHASED
'December 2022

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ALLEN	SPOT	-	$ -	$ -
	CONTRACT	-	7,786	-
	FUEL MANAGEMENT AGREEMENT		(7,786)	
	FIXED TRANSPORTATION / ADJUSTMENTS	-	8,397	-
	TOTAL	0	8,397	-
BELEWS CREEK	SPOT	-	-	-
	CONTRACT	126,317	11,773,259	93.20
	FUEL MANAGEMENT AGREEMENT		814,231	
	FIXED TRANSPORTATION / ADJUSTMENTS	-	418,157	-
	TOTAL	126,317	13,005,647	102.96
BUCK	SPOT	-	-	-
CLIFFSIDE	SPOT	-	-	-
	CONTRACT	34,519	3,969,974	115.01
	FUEL MANAGEMENT AGREEMENT			
	FIXED TRANSPORTATION / ADJUSTMENTS	-	189,852	-
	TOTAL	34,519	4,159,826	120.51
	TOTAL	-	-	-
MARSHALL	SPOT	60,317	11,977,372	198.57
	CONTRACT	100,559	11,121,036	110.59
	FUEL MANAGEMENT AGREEMENT		(1,413,676)	
	FUEL MANAGEMENT AGREEMENT			
	FIXED TRANSPORTATION / ADJUSTMENTS	-	-	-
	TOTAL	-	(0)	-

Clark Second Revised
Exhibit 6 Schedule 8

DUKE ENERGY CAROLINAS
ANALYSIS OF COAL QUALITY RECEIVED
December 2022

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
ALLEN	-	-	-	-
BELEWS CREEK	6.68	9.63	12,693	1.84
CLIFFSIDE	13.99	8.16	11,374	1.99
LEE	-	-	-	-
MARSHALL	7.56	9.61	12,443	1.39

DUKE ENERGY CAROLINAS
ANALYSIS OF OIL PURCHASED
DECEMBER 2022

	ALLEN	BELEWS CREEK
VENDOR	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract
SULFUR CONTENT %	-	-
GALLONS RECEIVED	-	14,925
TOTAL DELIVERED COST	$ -	$ 43,134
DELIVERED COST/GALLON	$ -	$ 2.89
BTU/GALLON	138,000	138,000

	CLIFFSIDE	MARSHALL
VENDOR	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract
SULFUR CONTENT %	-	-
GALLONS RECEIVED	60,032	-
TOTAL DELIVERED COST	$ 195,355	$ -
DELIVERED COST/GALLON	$ 3.25	$ -
BTU/GALLON	138,000	138,000

	LEE	MILL CREEK	ROCKINGHAM
VENDOR	HighTowers	HighTowers	HighTowers
SPOT/CONTRACT	Contract	Contract	Contract
SULFUR CONTENT %	-	-	-
GALLONS RECEIVED	164,086	1,301,461	1,354,355
TOTAL DELIVERED COST	$ 581,554	$ 4,046,679	$ 4,504,834
DELIVERED COST/GALLON	$ 3.54	$ 3.11	$ 3.33
BTU/GALLON	138,000	138,000	138,000

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: December 2022 - December 2022

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						

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2022

Belews Creek Station

No Outages at Baseload Units During the Month.

Buck Combined Cycle Station

No Outages at Baseload Units During the Month.

Clemson CHP

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
1	12/12/2022 8:13:00 AM To 12/21/2022 7:52:00 AM	Sch	3999	Other miscellaneous balance of plant problems	Planned outage to repair duct work damage.	
1	12/24/2022 7:59:00 AM To 12/24/2022 3:05:00 PM	Unsch	5041	Fuel piping and valves	Gas Turbine trip due to reduced gas pressure from Fort Hill.	

Dan River Combined Cycle Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
9	12/23/2022 11:51:00 PM To 12/24/2022 1:56:00 AM	Unsch	1740	Boiler drum gage glasses / level indicator	HRSG 9 LP Drum Level Transmitters froze and lost indication on the Drum level transmitters.	
9	12/24/2022 1:56:00 AM To 12/25/2022 12:08:00 AM	Unsch	5016	High pressure compressor bleed valves	Started the GT9 and unit failed to start due to a faulty Compressor Blead valve switch.	

Marshall Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
4	12/2/2022 10:55:00 PM To 12/9/2022 9:53:00 PM	Sch	8140	Reaction tanks including agitators	Maintenance outage to repair leaking reaction tank agitators "A" and "E".	
4	12/30/2022 2:56:00 PM To 12/31/2022 11:59:00 PM	Sch	0920	Other slag and ash removal problems	Clinker Removal from Bottom Ash Hopper.	

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 2022

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	11/3/2022 3:34:00 AM To 12/11/2022 3:07:00 AM	Sch	4640	Seal oil system and seals	Generator inspection.	
WS Lee CC ST 10	12/11/2022 3:07:00 AM To 12/31/2022 11:59:00 PM	Unsch	4410	Turning gear and motor	Fire damage discovered in the ST compartment.	
WS Lee CC GT 11	11/3/2022 3:48:00 AM To 12/10/2022 8:44:00 AM	Sch	5272	Boroscope inspection	Gas turbine 11 borscope inspection.	
WS Lee CC GT 11	12/10/2022 8:56:00 AM To 12/10/2022 7:19:00 PM	Sch	1740	Boiler drum gage glasses / level indicator	Test fired unit coming out of PO. (HRSG drum levels)	
WS Lee CC GT 11	12/11/2022 3:07:00 AM To 12/31/2022 11:59:00 PM	Unsch	4410	Turning gear and motor	Fire damage in the ST compartment.	
WS Lee CC GT 12	11/3/2022 3:47:00 AM To 12/10/2022 3:55:00 PM	Sch	5260	Major overhaul (use for non-specific overhaul only; see page B-CCGT-2)	GT12 HGP overhaul.	
WS Lee CC GT 12	12/10/2022 5:05:00 PM To 12/11/2022 3:07:00 AM	Sch	5048	Gas fuel system including controls and instrumentation	Unit testing coming out of outage - (ACDMS not available for tuning).	
WS Lee CC GT 12	12/11/2022 3:07:00 AM To 12/31/2022 11:59:00 PM	Unsch	4410	Turning gear and motor	Fire damage located in the ST compartment.	

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 Second Revised Exhibit 6
Schedule 10

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: December 2022

	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)	647,998	651,793	653,520	889,246	887,785	880,020	875,855
(C2) Capacity Factor (%)	102.83	103.31	102.26	103.21	103.04	101.97	102.37
(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	0
(E2) % Net MWH Not Gen. Due to Partial Scheduled Outages	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(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	-17,830	-20,881	-14,424	-27,694	-26,233	-16,980	-20,255
(G2) % Net MWH Not Gen Due to Partial Forced Outages	-2.83	-3.31	-2.26	-3.21	-3.04	-1.97	-2.37
(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	100	100	100	100	100	100
(L) Output Factor (%)	102.83	103.31	102.26	103.21	103.04	101.97	102.37
(M) Heat Rate (BTU/Net KWH)	10,060	10,004	9,978	9,893	9,909	9,993	9,873

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
December 2022
Belews Creek Station

	Unit 1	Unit 2
(A) MDC (mW)	1,110	1,110
(B) Period Hrs	744	744
(C) Net Generation (mWh)	595,517	656,273
(D) Capacity Factor (%)	72.11	79.47
(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	61,727	44,766
(H) Scheduled Derates: percent of Period Hrs	7.47	5.42
(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	38,639	0
(L) Forced Derates: percent of Period Hrs	4.68	0.00
(M) Net mWh Not Generated due to Economic Dispatch	129,957	124,801
(N) Economic Dispatch: percent of Period Hrs	15.74	15.11
(O) Net mWh Possible in Period	825,840	825,840
(P) Equivalent Availability (%)	87.85	94.58
(Q) Output Factor (%)	72.11	79.47
(R) Heat Rate (BTU/NkWh)	9,723	9,803

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2022
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)	135,615	135,779	198,155	469,549
(D) Capacity Factor (%)	88.48	88.59	87.04	87.90
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	636	636
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	0.28	0.12
(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	152	152	3,216	3,521
(L) Forced Derates: percent of Period Hrs	0.10	0.10	1.41	0.66
(M) Net mWh Not Generated due to Economic Dispatch	17,497	17,333	25,656	60,486
(N) Economic Dispatch: percent of Period Hrs	11.42	11.31	11.27	11.32
(O) Net mWh Possible in Period	153,264	153,264	227,664	534,192
(P) Equivalent Availability (%)	99.90	99.90	98.31	99.22
(Q) Output Factor (%)	88.48	88.59	87.04	87.90
(R) Heat Rate (BTU/NkWh)	10,371	10,176	2,649	7,056

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2022
Clemson CHP

	Clemson CHP1
(A) MDC (mW)	16
(B) Period Hrs	744
(C) Net Generation (mWh)	7,147
(D) Capacity Factor (%)	61.98
(E) Net mWh Not Generated due to Full Scheduled Outages	3,343
(F) Scheduled Outages: percent of Period Hrs	28.99
(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	110
(J) Forced Outages: percent of Period Hrs	0.95
(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	932
(N) Economic Dispatch: percent of Period Hrs	8.09
(O) Net mWh Possible in Period	11,532
(P) Equivalent Availability (%)	70.06
(Q) Output Factor (%)	88.46
(R) Heat Rate (BTU/NkWh)	13,906

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2022
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)	131,290	127,576	198,054	456,920
(D) Capacity Factor (%)	85.66	83.24	86.43	85.30
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	0	0	0	0
(H) Scheduled Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	5,002	0	5,002
(J) Forced Outages: percent of Period Hrs	0.00	3.26	0.00	0.93
(K) Net mWh Not Generated due to Partial Forced Outages	457	457	5,331	6,246
(L) Forced Derates: percent of Period Hrs	0.30	0.30	2.33	1.17
(M) Net mWh Not Generated due to Economic Dispatch	21,517	20,229	25,767	67,512
(N) Economic Dispatch: percent of Period Hrs	14.04	13.20	11.24	12.60
(O) Net mWh Possible in Period	153,264	153,264	229,152	535,680
(P) Equivalent Availability (%)	99.70	96.44	97.67	97.90
(Q) Output Factor (%)	85.66	86.05	86.43	86.10
(R) Heat Rate (BTU/NkWh)	10,567	10,487	2,708	7,138

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2022
Marshall Station

	Unit 3	Unit 4
(A) MDC (mW)	658	660
(B) Period Hrs	744	744
(C) Net Generation (mWh)	358,385	297,208
(D) Capacity Factor (%)	73.21	60.53
(E) Net mWh Not Generated due to Full Scheduled Outages	0	132,020
(F) Scheduled Outages: percent of Period Hrs	0.00	26.89
(G) Net mWh Not Generated due to Partial Scheduled Outages	6,231	0
(H) Scheduled Derates: percent of Period Hrs	1.27	0.00
(I) Net mWh Not Generated due to Full Forced Outages	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	5,409	0
(L) Forced Derates: percent of Period Hrs	1.10	0.00
(M) Net mWh Not Generated due to Economic Dispatch	119,527	61,812
(N) Economic Dispatch: percent of Period Hrs	24.42	12.59
(O) Net mWh Possible in Period	489,552	491,040
(P) Equivalent Availability (%)	97.62	73.11
(Q) Output Factor (%)	73.21	82.78
(R) Heat Rate (BTU/NkWh)	9,494	9,365

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Carolinas
Baseload Steam and CHP Units
Performance Review Plan
December 2022
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)	-376	-884	0	-1,260
(D) Capacity Factor (%)	0.00	0.00	0.00	-0.21
(E) Net mWh Not Generated due to Full Scheduled Outages	58,307	60,004	76,097	194,407
(F) Scheduled Outages: percent of Period Hrs	31.60	32.52	32.68	32.30
(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	124,218	124,218	156,775	405,212
(J) Forced Outages: percent of Period Hrs	67.32	67.32	67.32	67.32
(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	0	1,174	0	1,174
(N) Economic Dispatch: percent of Period Hrs	0.00	0.64	0.00	0.20
(O) Net mWh Possible in Period	184,512	184,512	232,872	601,896
(P) Equivalent Availability (%)	0.00	0.00	0.00	0.38
(Q) Output Factor (%)	0.00	0.00	0.00	-55.41
(R) Heat Rate (BTU/NkWh)	0	0	0	-14,135

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Carolinas
Intermediate Power Plant Performance Review Plan
December 2022

		Cliffside Station
		Cliffside 6
(A)	**MDC (mW)**	849
(B)	**Period Hrs**	744
(C)	**Net Generation (mWh)**	427,074
(D)	**Net mWh Possible in Period**	631,656
(E)	**Equivalent Availability (%)**	79.65
(F)	**Output Factor (%)**	84.32
(G)	**Capacity Factor (%)**	67.61

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 2022

		Cliffside Station
		Unit 5
(A)	MDC (mW)	546
(B)	Period Hrs	744
(C)	Net Generation (mWh)	88,740
(D)	Net mWh Possible in Period	406,224
(E)	Equivalent Availability (%)	95.43
(F)	Output Factor (%)	68.09
(G)	Capacity Factor (%)	21.85

Notes:

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

Duke Energy Carolinas Base Load Power Plant Performance Review Plan
Report Period: January 2022 - December 2022

	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)	6,988,171	7,123,871	7,013,087	9,221,671	10,228,639	10,277,595	8,685,269
(C2) Capacity Factor (%)	94.18	95.9	93.2	90.91	100.83	101.14	86.21
(D1) Net MWH Not Gen. Due to Full Schedule Outages	544,917	0	486,752	805,968	0	0	1,159,200
(D2) % Net MWH Not Gen. Due to Full Schedule Outages	7.34	0.00	6.47	7.95	0.00	0.00	11.51
(E1) Net MWH Not Gen. Due to Partial Scheduled Outages	20,893	2,936	98,689	51,931	0	1,094	42,417
(E2) % Net MWH Not Gen. Due to Partial Scheduled Outages	0.28	0.04	1.31	0.51	0.00	0.01	0.42
(F1) Net MWH Not Gen Due to Full Forced Outages	0	443,928	0	227,682	111,593	0	259,478
(F2) % Net MWH Not Gen Due to Full Forced Outages	0.00	5.98	0.00	2.24	1.10	0.00	2.58
(G1) Net MWH Not Gen due to Partial Forced Outages	-134,261	-142,255	-73,688	-163,172	-196,152	-117,089	-72,364
(G2) % Net MWH Not Gen Due to Partial Forced Outages	-1.80	-1.92	-0.98	-1.61	-1.93	-1.15	-0.72
(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 (%)	92.38	93.81	92.16	89.24	98.76	99.99	85.38
(L) Output Factor (%)	101.65	101.99	99.64	101.22	101.96	101.14	100.25
(M) Heat Rate (BTU/Net KWH)	10,148	10,114	10,091	10,005	10,003	10,073	10,033

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, 2022 through December, 2022
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)	5,464,278	3,779,808
(D) Capacity Factor (%)	56.20	38.87
(E) Net mWh Not Generated due to Full Scheduled Outages	682,961	1,672,770
(F) Scheduled Outages: percent of Period Hrs	7.02	17.20
(G) Net mWh Not Generated due to Partial Scheduled Outages	82,895	84,005
(H) Scheduled Derates: percent of Period Hrs	0.85	0.86
(I) Net mWh Not Generated due to Full Forced Outages	687,179	2,163,967
(J) Forced Outages: percent of Period Hrs	7.07	22.25
(K) Net mWh Not Generated due to Partial Forced Outages	251,493	60,684
(L) Forced Derates: percent of Period Hrs	2.59	0.62
(M) Net mWh Not Generated due to Economic Dispatch	2,554,795	1,962,366
(N) Economic Dispatch: percent of Period Hrs	26.27	20.18
(O) Net mWh Possible in Period	9,723,600	9,723,600
(P) Equivalent Availability (%)	82.47	59.05
(Q) Output Factor (%)	65.99	65.86
(R) Heat Rate (BTU/NkWh)	9,021	9,783

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, 2022 through December, 2022
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)	1,406,294	1,403,629	2,056,915	4,866,838
(D) Capacity Factor (%)	77.93	77.78	76.73	77.38
(E) Net mWh Not Generated due to Full Scheduled Outages	127,024	132,116	189,644	448,783
(F) Scheduled Outages: percent of Period Hrs	7.04	7.32	7.07	7.14
(G) Net mWh Not Generated due to Partial Scheduled Outages	115,863	114,594	18,320	248,777
(H) Scheduled Derates: percent of Period Hrs	6.42	6.35	0.68	3.96
(I) Net mWh Not Generated due to Full Forced Outages	0	6,355	0	6,355
(J) Forced Outages: percent of Period Hrs	0.00	0.35	0.00	0.10
(K) Net mWh Not Generated due to Partial Forced Outages	152	152	13,415	13,720
(L) Forced Derates: percent of Period Hrs	0.01	0.01	0.50	0.22
(M) Net mWh Not Generated due to Economic Dispatch	155,227	147,714	402,266	705,207
(N) Economic Dispatch: percent of Period Hrs	8.60	8.19	15.01	11.21
(O) Net mWh Possible in Period	1,804,560	1,804,560	2,680,560	6,289,680
(P) Equivalent Availability (%)	86.53	85.97	91.74	88.59
(Q) Output Factor (%)	83.83	84.35	82.58	83.44
(R) Heat Rate (BTU/NkWh)	10,472	10,245	2,388	6,990

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, 2022 through December, 2022
Clemson CHP

	Clemson CHP1
(A) MDC (mW)	15
(B) Period Hrs	8,760
(C) Net Generation (mWh)	91,218
(D) Capacity Factor (%)	67.66
(E) Net mWh Not Generated due to Full Scheduled Outages	7,454
(F) Scheduled Outages: percent of Period Hrs	5.53
(G) Net mWh Not Generated due to Partial Scheduled Outages	14,157
(H) Scheduled Derates: percent of Period Hrs	10.50
(I) Net mWh Not Generated due to Full Forced Outages	10,738
(J) Forced Outages: percent of Period Hrs	7.97
(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	11,246
(N) Economic Dispatch: percent of Period Hrs	8.34
(O) Net mWh Possible in Period	134,813
(P) Equivalent Availability (%)	76.08
(Q) Output Factor (%)	78.22
(R) Heat Rate (BTU/NkWh)	12,264

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, 2022 through December, 2022
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)	1,158,153	1,172,815	1,779,047	4,110,015
(D) Capacity Factor (%)	64.18	64.99	65.94	65.16
(E) Net mWh Not Generated due to Full Scheduled Outages	362,259	372,530	559,938	1,294,727
(F) Scheduled Outages: percent of Period Hrs	20.07	20.64	20.75	20.53
(G) Net mWh Not Generated due to Partial Scheduled Outages	107,474	107,353	9,098	223,925
(H) Scheduled Derates: percent of Period Hrs	5.96	5.95	0.34	3.55
(I) Net mWh Not Generated due to Full Forced Outages	25,190	20,771	24,126	70,086
(J) Forced Outages: percent of Period Hrs	1.40	1.15	0.89	1.11
(K) Net mWh Not Generated due to Partial Forced Outages	457	457	5,686	6,600
(L) Forced Derates: percent of Period Hrs	0.03	0.03	0.21	0.10
(M) Net mWh Not Generated due to Economic Dispatch	151,026	130,634	320,186	601,845
(N) Economic Dispatch: percent of Period Hrs	8.37	7.24	11.87	9.54
(O) Net mWh Possible in Period	1,804,560	1,804,560	2,698,080	6,307,200
(P) Equivalent Availability (%)	72.55	72.23	77.80	74.71
(Q) Output Factor (%)	82.36	83.10	84.15	83.34
(R) Heat Rate (BTU/NkWh)	10,691	10,619	2,489	7,120

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, 2022 through December, 2022
Marshall Station

	Unit 3	Unit 4
(A) MDC (mW)	658	660
(B) Period Hrs	8,760	8,760
(C) Net Generation (mWh)	3,101,170	2,712,398
(D) Capacity Factor (%)	53.80	46.91
(E) Net mWh Not Generated due to Full Scheduled Outages	586,574	1,467,292
(F) Scheduled Outages: percent of Period Hrs	10.18	25.38
(G) Net mWh Not Generated due to Partial Scheduled Outages	10,850	0
(H) Scheduled Derates: percent of Period Hrs	0.19	0.00
(I) Net mWh Not Generated due to Full Forced Outages	101,148	149,140
(J) Forced Outages: percent of Period Hrs	1.75	2.58
(K) Net mWh Not Generated due to Partial Forced Outages	235,834	146,348
(L) Forced Derates: percent of Period Hrs	4.09	2.53
(M) Net mWh Not Generated due to Economic Dispatch	1,728,504	1,306,421
(N) Economic Dispatch: percent of Period Hrs	29.99	22.60
(O) Net mWh Possible in Period	5,764,080	5,781,600
(P) Equivalent Availability (%)	83.79	69.51
(Q) Output Factor (%)	61.49	65.12
(R) Heat Rate (BTU/NkWh)	10,369	9,782

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, 2022 through December, 2022
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)	1,172,874	1,533,260	1,948,119	4,654,253
(D) Capacity Factor (%)	53.99	70.58	71.05	65.67
(E) Net mWh Not Generated due to Full Scheduled Outages	306,173	307,959	392,464	1,006,597
(F) Scheduled Outages: percent of Period Hrs	14.09	14.18	14.31	14.20
(G) Net mWh Not Generated due to Partial Scheduled Outages	38,348	53,273	0	91,621
(H) Scheduled Derates: percent of Period Hrs	1.77	2.45	0.00	1.29
(I) Net mWh Not Generated due to Full Forced Outages	537,604	152,289	194,999	884,893
(J) Forced Outages: percent of Period Hrs	24.75	7.01	7.11	12.49
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	147,623	147,623
(L) Forced Derates: percent of Period Hrs	0.00	0.00	5.38	2.08
(M) Net mWh Not Generated due to Economic Dispatch	117,480	125,699	58,674	301,853
(N) Economic Dispatch: percent of Period Hrs	5.41	5.79	2.14	4.26
(O) Net mWh Possible in Period	2,172,480	2,172,480	2,741,880	7,086,840
(P) Equivalent Availability (%)	59.40	76.36	73.19	69.93
(Q) Output Factor (%)	88.31	90.01	90.42	89.75
(R) Heat Rate (BTU/NkWh)	10,787	10,488	2,522	7,229

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, 2022 through December, 2022

Cliffside Station

Units	Unit 6
(A) MDC (mW)	849
(B) Period Hrs	8,760
(C) Net Generation (mWh)	4,410,848
(D) Net mWh Possible in Period	7,437,240
(E) Equivalent Availability (%)	71.91
(F) Output Factor (%)	82.25
(G) Capacity Factor (%)	59.31

Notes:

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

Duke Energy Carolinas
Peaking Power Plant
Performance Review Plan
January, 2022 through December, 2022

Cliffside Station

Units		Unit 5
(A)	**MDC (mW)**	546
(B)	**Period Hrs**	8,760
(C)	**Net Generation (mWh)**	600,803
(D)	**Net mWh Possible in Period**	4,782,960
(E)	**Equivalent Availability (%)**	57.36
(F)	**Output Factor (%)**	38.11
(G)	**Capacity Factor (%)**	12.56

Notes:

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

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Clark Second Revised Workpaper 1

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs	10,026,652	9,119,788	8,799,414	9,938,344	7,338,135	6,713,739	6,883,057	58,819,128
Cost (Gross of Joint Owners)	$ 62,355,885	$ 50,162,610	$ 46,520,487	$ 54,060,516	$ 41,917,165	$ 34,438,133	$ 40,707,973	$ 330,162,771
$/MWh	6.2190	5.5004	5.2868	5.4396	5.7122	5.1295	5.9142	
Avg $/MWh		**5.6132**						
Cents per kWh		**0.5613**						

			Sept 2023 - August 2024
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	10,027
CATA_UN02	Catawba	GWh	9,120
MCGU_UN01	McGuire	GWh	8,799
MCGU_UN02	McGuire	GWh	9,938
OCON_UN01	Oconee	GWh	7,338
OCON_UN02	Oconee	GWh	6,714
OCON_UN03	Oconee	GWh	6,883
			58,819
	Proposed Nuclear Capacity Factor		93.52%

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 2023 through August 2024
Docket E-7, Sub 1282

Clark Second Revised Workpaper 2

	Catawba 1	Catawba 2	McGuire 1	McGuire 2	Oconee 1	Oconee 2	Oconee 3	Total
MWhs with NERC applied	9,272,460	9,193,324	9,256,473	9,253,276	6,900,340	6,908,486	6,998,101	57,782,460
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	91.25%	91.25%	91.25%	91.25%	93.00%	93.00%	93.00%	91.87%
Cost	$ 52,048,053	$ 51,603,849	$ 51,958,314	$ 51,940,367	$ 38,732,897	$ 38,778,626	$ 39,281,651	$ 324,343,758

Avg $/MWh	**5.6132**
Cents per kWh	**0.5613**

2017-2021	Capacity Rating	NCF Rating	Weighted Average	
Oconee 1	847.0	93.00	10.97%	
Oconee 2	848.0	93.00	10.98%	
Oconee 3	859.0	93.00	11.13%	
McGuire 1	1,158.0	91.25	14.72%	
McGuire 2	1,157.6	91.25	14.71%	
Catawba 1	1,160.0	91.25	14.74%	
Catawba 2	1,150.1	91.25	14.62%	
	7,179.7		**91.87%**	Wtd Avg on Capacity Rating

rounding differences may occur

Duke Energy Carolinas, LLC **Clark Second Revised Workpaper 3**
North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation and Purchased Power in MWhs
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Resource Type	**Sept 2023 - August 2024**	
NUC Total (Gross)	58,819,128	
COAL Total	10,320,159	
Gas CT and CC total (Gross)	31,212,640	
Run of River	5,600,555	
Net pumped Storage	(4,083,743)	
Total Hydro	1,516,812	
Catawba Joint Owners	(14,888,880)	
Lee CC Joint Owners	(878,400)	
DEC owned solar	358,121	
Total Generation		86,459,580
Purchases for REPS Compliance	1,438,042	
Qualifying Facility Purchases - Non-REPS compliance	2,389,958	
Other Purchases	164,878	
Allocated Economic Purchases	1,329,474	
Joint Dispatch Purchases	6,466,906	
	11,789,258	
Total Generation and Purchased Power		98,248,839
Fuel Recovered Through Intersystem Sales	(1,148,043)	

rounding differences may occur

Duke Energy Carolinas, LLC **Clark Second Revised Workpaper 4**
North Carolina Annual Fuel and Fuel Related Expense
Projected Fuel and Fuel Related Costs
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Resource Type	Sept 2023 - August 2024	
Nuclear Total (Gross)	$ 330,162,771	
COAL Total	398,104,637	
Gas CT and CC total (Gross)	1,179,963,909	
Catawba Joint Owner costs	(83,614,236)	
CC Joint Owner costs	(25,697,152)	
Non-Economic Fuel Expense Recovered through Reimbursement	(3,687,381)	*use the average of th
Reagents and gain/loss on sale of By-Products	24,944,696	Workpaper 9
Purchases for REPS Compliance - Energy	68,790,240	
Purchases for REPS Compliance - Capacity	14,931,581	
Purchases of Qualifying Facilities - Energy	59,039,401	
Purchases of Qualifying Facilities - Capacity	12,176,644	
Other Purchases	397,088	
JDA Savings Shared	(69,598,371)	Workpaper 5
Allocated Economic Purchase cost	52,870,968	Workpaper 5
Joint Dispatch purchases	206,598,811	Workpaper 6
Total Purchases	345,206,362	
Fuel Expense recovered through intersystem sales	(57,998,825)	Workpaper 5
Total System Fuel and Fuel Related Costs	**$ 2,107,384,780**	

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Joint Dispatch Fuel Impacts
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Clark Second Revised 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
9/1/2023	$ 4,976,440	$ 7,317,885	$ (674,018)	$ (305,418)	$ (23,724,256)	$ 23,724,256	$ 6,910,581	$ (6,910,581)
10/1/2023	$ 5,904,520	$ 6,517,440	$ (69,203)	$ (114,170)	$ (15,802,316)	$ 15,802,316	$ 11,215,995	$ (11,215,995)
11/1/2023	$ 2,503,327	$ 3,105,057	$ (1,223,486)	$ (674,629)	$ (18,519,025)	$ 18,519,025	$ 10,008,333	$ (10,008,333)
12/1/2023	$ 762,505	$ 1,041,966	$ (5,872,462)	$ (1,890,081)	$ (15,722,366)	$ 15,722,366	$ 4,518,477	$ (4,518,477)
1/1/2024	$ 2,893,193	$ 2,042,582	$ (10,525,081)	$ (11,843,518)	$ (13,602,107)	$ 13,602,107	$ 4,544,884	$ (4,544,884)
2/1/2024	$ 315,449	$ 384,533	$ (10,078,466)	$ (13,200,189)	$ (6,837,056)	$ 6,837,056	$ 2,614,179	$ (2,614,179)
3/1/2024	$ 1,955,226	$ 2,816,591	$ (622,625)	$ (648,265)	$ (10,251,414)	$ 10,251,414	$ 1,341,892	$ (1,341,892)
4/1/2024	$ 3,952,712	$ 6,000,661	$ (639,409)	$ (211,299)	$ (12,097,213)	$ 12,097,213	$ 1,413,004	$ (1,413,004)
5/1/2024	$ 654,154	$ 713,694	$ (1,763,746)	$ (237,095)	$ (14,639,411)	$ 14,639,411	$ 6,435,252	$ (6,435,252)
6/1/2024	$ 4,153,979	$ 5,991,152	$ (1,260,436)	$ (644,515)	$ (21,582,339)	$ 21,582,339	$ 3,725,538	$ (3,725,538)
7/1/2024	$ 3,609,443	$ 5,189,561	$ (2,532,634)	$ (1,768,613)	$ (17,455,853)	$ 17,455,853	$ 14,114,687	$ (14,114,687)
8/1/2024	$ 8,014,976	$ 11,749,845	$ (1,306,118)	$ (1,592,378)	$ (11,496,801)	$ 11,496,801	$ 2,755,548	$ (2,755,548)
Sept 23 - Aug 24		$ 52,870,968		$ (33,130,170)		$ 181,730,155		$ (69,598,371)

$ 206,598,811	Workpaper 6 - Transfer - Purchases
$ (24,868,655)	Workpaper 6 - Transfer - Sales
$ 181,730,155	Sept 22-Aug 23 Net Fuel Transfer Payment
$ (24,868,655)	Workpaper 6 - Transfer - Sales
$ (33,130,170)	Sept 23-Aug 24 Economic Sales Cost
$ (57,998,825)	**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 2023 through August 2024
Docket E-7, Sub 1282

Clark Second Revised Workpaper 6

	Transfer Projection		Purchase Allocation Delta		Purchase Adjusted Transfer	Sale Adjusted Transfer	Fossil Gen Cost		Sale Pre-Net Payments	Purchase Pre-Net Payments
	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC	PEC	DEC	PECtoDEC	DECtoPEC
9/1/2023	606,726	20,805	50,315	(50,315)	657,041	20,805	36.94	26.37	548,621	24,272,877
10/1/2023	619,535	32,076	95,370	(95,370)	714,904	32,076	28.43	141.02	4,523,430	20,325,746
11/1/2023	744,209	8,765	33,471	(33,471)	777,680	8,765	25.47	147.32	1,291,176	19,810,201
12/1/2023	558,288	34,315	(6,026)	6,026	558,288	40,342	33.48	73.65	2,971,155	18,693,520
1/1/2024	364,075	36,080	10,140	(10,140)	374,215	36,080	40.82	46.37	1,673,120	15,275,228
2/1/2024	261,473	47,009	(1,221)	1,221	261,473	48,231	36.72	57.30	2,763,603	9,600,659
3/1/2024	395,731	100,349	(4,372)	4,372	395,731	104,721	34.26	31.57	3,306,397	13,557,811
4/1/2024	400,208	82,708	30,753	(30,753)	430,962	82,708	33.12	26.32	2,176,582	14,273,794
5/1/2024	682,741	36,797	7,545	(7,545)	690,286	36,797	22.54	25.00	919,824	15,559,236
6/1/2024	551,409	42,848	67,925	(67,925)	619,334	42,848	36.79	28.05	1,201,775	22,784,114
7/1/2024	501,238	41,647	55,203	(55,203)	556,441	41,647	33.71	31.28	1,302,736	18,758,589
8/1/2024	328,372	64,562	102,180	(102,180)	430,552	64,562	31.79	33.92	2,190,235	13,687,036
Sept 23 - Aug 24	6,014,005	547,961	441,282	(441,282)	6,466,906	559,580			$ 24,868,655	$ 206,598,811
									Net Pre-Net Payments	$ 181,730,155

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 93.52%
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Fall 2022 Forecast
Billed Sales Forecast
Sales Forecast - MWhs (000)

		Projected sales for the Billing Period	Remove impact of SC DERP Net Metered Generation	Adjusted Sales
North Carolina:				
	Residential	23,477,265		23,477,265
	General	23,838,527		23,838,527
	Industrial	13,270,457		13,270,457
	Lighting	238,480		238,480
	NC RETAIL	60,824,730	-	60,824,729
South Carolina:				
	Residential	7,223,610	136,278	7,359,888
	General	5,371,691	42,584	5,414,275
	Industrial	9,133,136	429	9,133,565
	Lighting	51,014	-	51,014
	SC RETAIL	21,779,451	179,291	21,958,742
Total Retail Sales				
	Residential	30,700,876	136,278	30,837,153
	General	29,210,218	42,584	29,252,802
	Industrial	22,403,593	429	22,404,022
	Lighting	289,494	-	289,494
	Retail Sales	82,604,181	179,291	82,783,471
	Wholesale	8,227,610	-	8,227,610
	Projected System MWH Sales for Fuel Factor	90,831,791	179,291	91,011,082
	NC as a percentage of total	**66.96%**		**66.83%**
	SC as a percentage of total	23.98%		24.13%
	Wholesale as a percentage of total	9.06%		9.04%
		100.00%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs		179,291
Marginal fuel rate per MWh for SC NEM	$	24.52
Fuel benefit to be directly assigned to SC Retail	$	4,396,215

System Fuel Expense	$	2,107,384,780	Clark Exhibit 2 Schedule 1 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$	4,396,215	
Total Fuel Costs for Allocation	$	2,111,780,996	Clark Exhibit 2 Schedule 1 Page 3 of 3, L5

Reconciliation	System	NC Retail Customers	Wholesale	South Carolina Retail	
Total system fuel expense from Clark Exhibit 2 Schedule 1 Page 1	$ 2,107,384,780				
QF and REPS Compliance Purchased Power - Capacity	$ 27,108,225				
Other fuel costs	$ 2,080,276,555				
SC Net Metering Fuel Allocation adjustment	$ 4,396,215				
Jurisdictional fuel costs after adj.	$ 2,084,672,770				
Allocation to states/classes		66.83%	9.04%	24.13%	
Jurisdictional fuel costs	$ 2,084,672,770	$ 1,393,186,813	$ 188,454,418	$ 503,031,540	66.68%
Direct Assignment of Fuel benefit to SC Retail	$ (4,396,215)		$ -	$ (4,396,215)	
Total system actual fuel costs	$ 2,080,276,555	$ 1,393,186,813	$ 188,454,418	$ 498,635,324	
QF and REPS Compliance Purchased Power - Capacity	27,108,225	18,076,112			
Total system fuel expense from Clark Exhibit 2 Schedule 1 Page 1	$ 2,107,384,780	**$ 1,411,262,925**			
		Exh.2, Sch. 1 page 3, Line 13			

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
Proposed Nuclear Capacity Factor of 93.52% and Normalized Test Period Sales
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Clark Second Revised Workpaper 7a

Fall 2022 Forecast
Billed Sales Forecast - Normalized Test Period Sales
Sales Forecast - MWhs (000)

	Test Period Sales	Customer Growth Adjustment	Weather Adjustment	Remove impact of SC DERP Net Metered generation	Normalized Test Period Sales
NC RETAIL	59,059,117	162,487	337,854	-	59,559,458
SC RETAIL	20,955,111	(8,320)	99,613	179,291	21,225,695
Wholesale	8,269,814	5,836	(306)	-	8,275,343
Normalized System MWH Sales for Fuel Factor	88,284,042	160,003	437,160	179,291	89,060,496
NC as a percentage of total	**66.90%**				**66.88%**
SC as a percentage of total	23.74%				23.83%
Wholesale as a percentage of total	9.37%				9.29%
	100.00%				100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	179,291
Marginal fuel rate per MWh for SC NEM	$ 24.52
Fuel benefit to be directly assigned to SC Retail	$ 4,396,215

System Fuel Expense	$ 2,032,140,076	Clark Exhibit 2 Schedule 2 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,396,215	
Total Fuel Costs for Allocation	$ 2,036,536,291	Clark Exhibit 2 Schedule 2 Page 3 of 3, L5

Reconciliation	**System**	**NC Retail Customers**	**Wholesale**	**South Carolina Retail**
Total system fuel expense from Clark Exhibit 2 Schedule 2 Page 1	$ 2,032,140,076			
QF and REPS Compliance Purchased Power - Capacity	$ 27,108,225			
Other fuel costs	$ 2,005,031,851			
SC Net Metering Fuel Allocation adjustment	$ 4,396,215			
Jurisdictional fuel costs after adj.	$ 2,009,428,066			
Allocation to states/classes		66.88%	9.29%	23.83%
Jurisdictional fuel costs	$ 2,009,428,055	$ 1,343,810,646	$ 186,712,496	$ 478,904,904
Direct Assignment of Fuel benefit to SC Retail	$ (4,396,215)		$ -	$ (4,396,215)
Total system actual fuel costs	$ 2,005,031,840	$ 1,343,810,646	$ 186,712,496	$ 474,508,689
QF and REPS Compliance Purchased Power - Capacity	27,108,225	18,076,112		
Total system fuel expense from Clark Exhibit 2 Schedule 2 Page 1	$ 2,032,140,065	**$ 1,361,886,758**		
		Exh. 2, Sch 2 page 3, Line 13		

rounding differences may occur

Duke Energy Carolinas, LLC **Clark Second Revised Workpaper 7b**
North Carolina Annual Fuel and Fuel Related Expense
Projected and Adjusted Projected Sales and Costs
NERC 5 Year Average Nuclear Capacity Factor of 91.87% and Projected Period Sales
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Fall 2022 Forecast
Billed Sales Forecast
Sales Forecast - MWhs (000)

		Projected sales for the Billing Period	Remove impact of SC DERP Net Metered generation	Adjusted Sales
North Carolina:				
	Residential	23,477,265		23,477,265
	General	23,838,527		23,838,527
	Industrial	13,270,457		13,270,457
	Lighting	238,480		238,480
	NC RETAIL	60,824,730	-	60,824,730
South Carolina:				
	Residential	7,223,610	136,278	7,359,888
	General	5,371,691	42,584	5,414,275
	Industrial	9,133,136	429	9,133,565
	Lighting	51,014	0	51,014
	SC RETAIL	21,779,451	179,291	21,958,742
Total Retail Sales				
	Residential	30,700,876	136,278	30,837,154
	General	29,210,218	42,584	29,252,802
	Industrial	22,403,593	429	22,404,022
	Lighting	289,494	-	289,494
	Retail Sales	82,604,181	179,291	82,783,472
	Wholesale	8,227,610	-	8,227,610
	Projected System MWh Sales for Fuel Factor	90,831,791	179,291	91,011,082
	NC as a percentage of total	**66.96%**		**66.83%**
	SC as a percentage of total	23.98%		24.13%
	Wholesale as a percentage of total	9.06%		9.04%
		100.00%		100.00%

SC Net Metering allocation adjustment

Total projected SC NEM MWhs	179,291	
Marginal fuel rate per MWh for SC NEM	$ 24.52	
Fuel benefit to be directly assigned to SC Retail	$ 4,396,215	
System Fuel Expense	$ 2,132,906,715	Clark Exhibit 2 Schedule 3 Page 1 of 3
Fuel benefit to be directly assigned to SC Retail	$ 4,396,215	
Total Fuel Costs for Allocation	$ 2,137,302,931	Clark Exhibit 2 Schedule 3 Page 3 of 3, Line 5

Reconciliation	**System**	**NC Retail Customers**	**Wholesale**	**South Carolina Retail**
Total system fuel expense from Clark Exhibit 2 Schedule 3 Page 1	$ 2,132,906,715			
QF and REPS Compliance Purchased Power - Capacity	$ 27,108,225			
Other fuel costs	$ 2,105,798,490			
SC Net Metering Fuel Allocation adjustment	$ 4,396,215			
Jurisdictional fuel costs after adj.	$ 2,110,194,706			
Allocation to states/classes		66.83%	9.04%	24.13%
Jurisdictional fuel costs	$ 2,110,194,706	$ 1,410,243,122	$ 190,761,601	$ 509,189,982
Direct Assignment of Fuel benefit to SC Retail	$ (4,396,215)		$ -	$ (4,396,215)
Total system actual fuel costs	$ 2,105,798,490	$ 1,410,243,122	$ 190,761,601	$ 504,793,767
QF and REPS Compliance Purchased Power - Capacity	27,108,225	18,076,112		
Total system fuel expense from Clark Exhibit 2 Schedule 3 Page 1	$ 2,132,906,715	**$ 1,428,319,234**		
		Exh. 2, Sch.3 page 3, Line 13		

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Annualized Revenue
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Clark Second Revised Workpaper 8

	January 2023 Actuals			Normalized Sales	
	Revenue	**kWh Sales**	**Cents/ kWh**	**Clark Exhibit 4**	**Total Annualized Revenues**
	(a)	(b)	(a)/(b) *100 = (c)	(d)	(c) * (d) * 10
Residential	$ 259,112,943	2,404,726,417	10.7752	22,892,401	$ 2,466,691,215
General	$ 161,395,026	2,001,691,757	8.0629	24,448,017	$ 1,971,226,718
Industrial	$ 55,270,705	891,437,613	6.2002	12,219,040	$ 757,602,036
Total	$ 475,778,674	5,297,855,787		59,559,458	$ 5,195,519,969

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Reagents and ByProducts
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Clark Second Revised Workpaper 9

Reagent and ByProduct projections

Date	Ammonia	Urea	Limestone	Magnesium Hydroxide	Calcium Carbonate	Lime	**Reagent Cost**	**Gypsum (Gain)/ Loss**	**Ash (Gain)/Loss**	**Steam (Gain)/Loss**	**Sale of By-Products (Gain)/Loss**
9/1/2022	$ 215,268	$ 20,510	$ 258,314	$ 37,104	$ 22,496	$ 13,158	**$ 566,851**	$ 72,900	$ (11,374)	$ (249,752)	**$ (188,226)**
10/1/2022	$ 126,192	$ 12,023	$ 151,427	$ 20,990	$ 12,726	$ 13,158	**$ 336,516**	$ 42,578	$ (7,798)	$ (249,752)	**$ (214,972)**
11/1/2022	$ 175,908	$ 16,760	$ 211,084	$ 22,395	$ 13,578	$ 13,158	**$ 452,884**	$ 52,334	$ (12,578)	$ (249,752)	**$ (209,995)**
12/1/2022	$ 1,809,326	$ 172,388	$ 2,171,130	$ 139,582	$ 84,629	$ 13,158	**$ 4,390,213**	$ 702,173	$ (219,291)	$ (249,752)	**$ 233,130**
1/1/2023	$ 2,582,989	$ 246,100	$ 3,099,500	$ 205,790	$ 124,770	$ 13,158	**$ 6,272,308**	$ 1,096,545	$ (268,116)	$ (249,752)	**$ 578,677**
2/1/2023	$ 2,113,676	$ 201,385	$ 2,536,340	$ 167,519	$ 101,567	$ 13,158	**$ 5,133,645**	$ 816,993	$ (238,439)	$ (249,752)	**$ 328,803**
3/1/2023	$ 447,777	$ 42,663	$ 537,317	$ 56,469	$ 34,237	$ 13,158	**$ 1,131,622**	$ 144,210	$ (32,598)	$ (249,752)	**$ (138,140)**
4/1/2023	$ 245,737	$ 23,413	$ 294,876	$ 33,856	$ 20,527	$ 13,158	**$ 631,567**	$ 69,849	$ (12,590)	$ (249,752)	**$ (192,493)**
5/1/2023	$ 183,122	$ 17,447	$ 219,740	$ 34,191	$ 20,730	$ 13,158	**$ 488,388**	$ 52,063	$ (3,750)	$ (249,752)	**$ (201,439)**
6/1/2023	$ 544,468	$ 51,875	$ 653,343	$ 56,548	$ 34,285	$ 13,158	**$ 1,353,677**	$ 163,414	$ (51,742)	$ (249,752)	**$ (138,080)**
7/1/2023	$ 916,015	$ 87,275	$ 1,099,187	$ 78,871	$ 47,819	$ 13,158	**$ 2,242,325**	$ 283,833	$ (91,686)	$ (260,498)	**$ (68,352)**
8/1/2023	$ 896,206	$ 85,388	$ 1,075,417	$ 92,289	$ 55,955	$ 13,158	**$ 2,218,412**	$ 292,195	$ (94,322)	$ (260,498)	**$ (62,626)**
	$ 10,256,683	$ 977,229	$ 12,307,675	$ 945,605	$ 573,319	$ 157,896	**$ 25,218,407**	$ 3,789,087	$ (1,044,284)	$ (3,018,514)	**$ (273,711)**

Total Reagent cost and Sale of By-products **$ 24,944,696**

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
Billing Period September 2023 through August 2024
Docket E-7, Sub 1282

Clark Second Revised Workpaper 10

Line No.	Description	Forecast $	(Over)/Under Collection $	Total $
1	Amount in current docket	139,103,703	70,794,129	209,897,832
2	Amount in Sub 1263, prior year docket	100,735,755	13,526,437	114,262,192
3	Increase/(Decrease)	38,367,948	57,267,693	95,635,640
4	2.5% of 2022 NC retail revenue of $4,944,339,147			123,608,479
	Excess of purchased power growth over 2.5% of revenue			0

	E-7, Sub 1282			
WP 4	Purchases for REPS Compliance - Energy	68,790,240	66.83%	45,972,517
WP 4	Purchases for REPS Compliance - Capacity	14,931,581	66.68%	9,956,570
WP 4	Purchases	397,088	66.83%	265,374
WP 4	QF Energy	59,039,401	66.83%	39,456,032
WP 4	QF Capacity	12,176,644	66.68%	8,119,542
WP 4	Allocated Economic Purchase cost	52,870,968	66.83%	35,333,668
		208,205,922		139,103,703
	E-7, Sub 1263			
	Purchases for REPS Compliance	66,782,210	66.08%	44,126,819
	Purchases for REPS Compliance Capacity	14,610,064	66.68%	9,742,178
	Purchases	7,489,994	66.08%	4,949,066
	QF Energy	40,652,503	66.08%	26,861,429
	QF Capacity	8,445,498	66.68%	5,631,567
	Allocated Economic Purchase cost	14,263,480	66.08%	9,424,695
		152,243,749		100,735,755

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 1282

Clark Second Revised Workpaper 10a

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, 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 plant %	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	$ 717,851	$ 16,428,537
Billed rate (¢/kWh):	0.0279	0.0279	0.0279	0.0279	0.0279	0.0279	0.0279	0.0279	0.0284	0.0279	0.0279	0.0279	
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	$ (678,751)	$ (64,394)
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**	**$ 16,332,605**	**$ 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.
(1) January - May NC actual capacity shown herein is adjusted to reflect use of 2021 production plant allocation factor. Actual true-up related to allocator was made as prior period adjustment in May 2022 of Schedule 4.

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1282

Clark Second Revised Workpaper 10b

2021	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**12 ME**
System KWH Sales - Sch 4, Adjusted	8,623,321,816	7,033,781,083	6,170,273,584	6,357,924,869	5,750,592,351	7,218,972,840	8,473,666,049	8,688,276,000	8,107,525,420	6,609,883,548	6,537,708,709	7,191,590,664	86,763,516,933
NC Retail KWH Sales - Sch 4	5,785,766,552	4,705,197,397	4,216,101,608	4,307,482,408	3,784,759,966	4,813,117,777	5,540,576,171	5,890,178,638	5,517,650,819	4,297,619,492	4,396,624,370	4,888,703,073	58,143,778,271
NC Retail % of Sales, Adjusted (Calc)	67.09%	66.89%	68.33%	67.75%	65.82%	66.67%	65.39%	67.79%	68.06%	65.02%	67.25%	67.98%	67.01%
NC retail production plant %	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%	66.98%
Fuel and Fuel related component of purchased power													
System Actual $ - Sch 3 Fuel$:	$ 14,110,987	$ 21,997,962	$ 7,288,155	$ 1,159,999	$ 6,909,766	$ 19,650,947	$ 27,256,372	$ 22,941,922	$ 20,301,410	$ 27,877,777	$ 27,842,536	$ 26,295,173	$ 223,633,006
System Actual $ - Sch 3 Fuel-related$; Economic Purchases	1,908,455	2,653,190	897,843	1,159,946	1,043,015	1,716,177	3,233,998	2,658,287	1,580,193	2,101,644	2,163,509	2,417,594	$ 23,533,851
System Actual $ - Sch 3 Fuel-related$; Purchased Power for REPS Compliance	3,836,471	3,851,010	3,578,469	1,634,328	5,557,142	6,244,501	5,777,306	6,144,771	5,617,037	5,684,750	4,972,836	4,406,882	$ 57,305,503
System Actual$ - Sch 3 Fuel-related$; SC DERP	148,221	63,773	117,353	217,851	155,453	263,492	427,484	260,031	242,117	236,248	246,176	205,494	$ 2,583,692
System Acutal $ - Sch 3 Fuel-related$; HB589 purpa Purchases	2,756,782	2,455,383	2,198,548	2,656,105	2,051,181	3,609,263	3,393,224	3,761,968	2,668,737	2,679,082	2,593,637	2,343,504	$ 33,167,413
Total System Economic & QF$	22,760,916	31,021,318	14,080,368	6,828,229	15,716,557	31,484,380	40,088,384	35,766,979	30,409,494	38,579,500	37,818,693	35,668,647	340,223,465
Less:													
Native Load Transfers, Native Load Transfer Benefit & DE - Progress fees	$ 13,085,320	$ 20,311,355	$ 6,186,575	$ 12,225	$ 6,203,819	$ 19,379,239	$ 26,072,774	$ 21,770,863	$ 19,434,801	$ 26,816,502	$ 23,378,784	$ 23,491,467	$ 206,143,723
Total System Economic $ without Native Load Transfers	$ 9,675,596	$ 10,709,964	$ 7,893,793	$ 6,816,004	$ 7,306,104	$ 8,232,386	$ 14,015,610	$ 13,996,116	$ 10,974,693	$ 11,762,998	$ 14,439,909	$ 12,177,179	$ 128,000,354
NC Actual $ (Calc)	$ 6,491,783	$ 7,164,353	$ 5,393,769	$ 4,617,830	$ 4,808,522	$ 5,488,793	$ 9,164,222	$ 9,488,606	$ 7,468,928	$ 7,648,076	$ 9,710,873	$ 8,277,809	$ 85,723,565
Billed rate (¢/kWh):	0.1367	0.1367	0.1367	0.1367	0.1367	0.1367	0.1367	0.1367	0.1363	0.1357	0.1357	0.1357	
Billed $:	$ 7,911,008	$ 6,433,522	$ 5,764,770	$ 5,889,717	$ 5,174,987	$ 6,581,084	$ 7,575,754	$ 8,053,773	$ 7,518,618	$ 5,832,583	$ 5,966,949	$ 6,634,781	$ 79,337,545
(Over)/ Under $:	$ (1,419,225)	$ 730,832	$ (371,001)	$ (1,271,887)	$ (366,465)	$ (1,092,291)	$ 1,588,468	$ 1,434,833	$ (49,690)	$ 1,815,493	$ 3,743,924	$ 1,643,028	$ 6,386,020
Capacity component of purchased power													
System Actual $ - Capacity component of Cherokee County Cogen Purchases	$ 430,619	$ 430,619	$ 215,311	$ 215,310	$ 322,964	$ 1,399,512	$ 3,229,644	$ 3,229,644	$ 645,929	$ 215,310	$ 215,310	$ 215,310	$ 10,765,481
System Actual $ - Capacity component of Purchased Power for REPS Compliance	679,198	657,904	611,495	370,864	1,021,112	874,770	880,403	2,930,150	2,610,093	2,651,828	2,162,592	642,188	$ 16,092,597
System Actual $ - Capacity component of HB589 Purpa QF purchases	401,588	376,607	536,828	347,396	110,548	427,589	1,222,705	1,697,840	1,371,802	1,324,805	834,474	281,956	$ 8,934,138
System Actual $ - Capacity component of SC DERP	14,999	7,491	12,697	15,442	14,837	24,880	38,885	24,278	22,766	22,049	24,646	19,907	$ 242,878
System Actual $ - Sch 2 pg 1 ANNUAL VIEW	$ 1,526,405	$ 1,472,621	$ 1,376,331	$ 949,012	$ 1,469,461	$ 2,726,751	$ 5,371,637	$ 7,881,912	$ 4,650,590	$ 4,213,992	$ 3,237,022	$ 1,159,361	$ 36,035,094
NC Actual $ (Calc) (1)	$ 1,022,340	$ 986,317	$ 921,825	$ 635,619	$ 984,201	$ 1,826,295	$ 3,597,760	$ 5,279,066	$ 3,114,825	$ 2,822,404	$ 2,168,059	$ 776,504	$ 24,135,214
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 $:	$ 1,698,557	$ 1,381,329	$ 1,237,743	$ 1,264,570	$ 1,111,112	$ 1,413,012	$ 1,626,576	$ 1,729,210	$ 1,608,069	$ 1,241,743	$ 1,270,349	$ 1,412,529	$ 16,994,798
(Over)/Under $:	$ (676,218)	$ (395,012)	$ (315,918)	$ (628,950)	$ (126,911)	$ 413,283	$ 1,971,184	$ 3,549,856	$ 1,506,756	$ 1,580,661	$ 897,710	$ (636,025)	$ 7,140,416
TOTAL (Over)/ Under $:	**$ (2,095,442)**	**$ 335,820**	**$ (686,918)**	**$ (1,900,837)**	**$ (493,375)**	**$ (679,008)**	**$ 3,559,653**	**$ 4,984,689**	**$ 1,457,065**	**$ 3,396,154**	**$ 4,641,634**	**$ 1,007,003**	**$ 13,526,437**

Note: The billed rate for September and October are pro-rated based on number of billing days in cycle on new rate schedules.
(1) January - May NC actual capacity shown herein is adjusted to reflect use of 2019 production plant allocation factor. Actual true-up related to allocator was made as prior period adjustment in June 2020 of Schedule 4.

rounding differences may occur

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Actual Sales by Jursidiction - Subject to Weather
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1282

Clark Second Revised Workpaper 11

Line #	Description	Reference	MWhs NORTH CAROLINA	SOUTH CAROLINA	TOTAL COMPANY	% NC	% SC
1	Residential	Company Records	22,419,810	6,932,595	29,352,406	76.38	23.62
2	Total General Service	Company Records	24,337,421	5,555,439	29,892,860		
3	less Lighting and Traffic Signals		326,292	83,069	409,361		
4	General Service subject to weather		24,011,129	5,472,369	29,483,499	81.44	18.56
5	Industrial	Company Records	12,301,885	8,467,077	20,768,963	59.23	40.77
6	Total Retail Sales	1+2+5	59,059,117	20,955,111	80,014,228		
7	Total Retail Sales subject to weather	1+4+5	58,732,825	20,872,042	79,604,867	73.78	26.22

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, 2021
Docket E-7, Sub 1282

Line #	Description	REFERENCE	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Total Residential		448,056	76.38	342,225	23.62	105,831
	General Service						
2	Total General Service		8,558	81.44	6,970	18.56	1,588
	Industrial						
3	Total Industrial		(19,147)	59.23	(11,341)	40.77	(7,806)
4	Total Retail	L1+ L2+ L3	437,466		337,854		99,613
5	Wholesale		(306)				
6	Total Company	L4 + L5	437,160		337,854		99,613

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, 2021
Docket E-7, Sub 1282

	Residential	Commercial	Industrial	
2022	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	**TOTAL MWH ADJUSTMENT**	
JAN	430,826	41,682	(6,770)	
FEB	26,706	3,498	334	
MAR	196,589	16,797	229	
APR	57,319	1,598	(581)	
MAY	(79,111)	(16,277)	(3,799)	
JUN	(157,659)	(57,717)	(13,625)	
JUL	(87,489)	(31,423)	(6,855)	
AUG	7,117	4,384	604	
SEP	9,348	5,285	898	
OCT	-	26,141	6,943	
NOV	23,449	17,862	5,321	
DEC	20,961	(3,272)	(1,847)	
Total	**448,056**	**8,558**	**(19,147)**	**437,466**

Wholesale

2022	**TOTAL MWH ADJUSTMENT**	Note:	**The Resale customers include:**
JAN	(2,917)	1	Concord[1]
FEB	8,132	2	Dallas
MAR	12,387	3	Forest City
APR	7	4	Kings Mountain[1]
MAY	(4,538)	5	Due West
JUN	(8,323)	6	Prosperity[2]
JUL	(3,594)	7	Lockhart
AUG	2,515	8	Western Carolina University
SEP	1,554	9	City of Highlands
OCT	(8,702)	10	Haywood
NOV	11,971	11	Piedmont
DEC	(8,800)	12	Rutherford
		13	Blue Ridge
Total	**(306)**	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, 2021
Docket E-7, Sub 1282

Line	Estimation Method [1]	Rate Schedule	NC Proposed kWh [1] Adjustment	SC Proposed kWh Adjustment	Wholesale Proposed kWh Adjustment	Total Company
1	*Regression*	Residential	130,366,123	72,505,791		
2						
3		**General Service (Excluding Lighting):**				
4	*Customer*	General Service Small and Large	109,009,655	1,179,199		
5	*Regression*	Miscellaneous	(2,444,761)	(1,131,149)		
6		Total General	106,564,894	48,050		
7						
8		**Lighting:**				
9	*Regression*	T & T2 (GL/FL/PL/OL)[2]	(2,957,804)	(1,879,960)		
10	*Regression*	TS	18,088	(14,903)		
11		Total Lighting	(2,939,716)	(1,894,862)		
12						
13		**Industrial:**				
14	*Customer*	I - Textile	(28,808,158)	(776,997)		
15	*Customer*	I - Nontextile	(42,696,403)	(78,201,535)		
16		Total Industrial	(71,504,561)	(78,978,532)		
17						
18						
19		Total	162,486,740	(8,319,553)	5,835,657	160,002,845
					WP 13-2	

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

Duke Energy Carolinas, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment to kWh Sales-Wholesale
Twelve Months Ended December 31, 2021
Docket E-7, Sub 1282

Calculation of Customer Growth Adjustment to kWh Sales - Wholesale

Line No.		Reference	
1	Total System Resale (kWh Sales)	Company Records	9,637,002,447
2	Less Intersystem Sales	Exhibit 6, Sch 1	1,193,715,448
3	Total kWh Sales Excluding Intersystem Sales	L1 - L2	8,443,286,999
4	Residential Growth Factor	Line 8	0.6912
5	Adjustment to kWhs - Wholesale	L3 * L4 / 100	5,835,657
6	Total System Retail Residential kWh Sales	Company Records	29,352,405,508
7	2022 Proposed Adjustment kWh - Residential (NC+SC)	WP 13-1	202,871,914
8	Percent Adjustment	L7 / L6 * 100	0.6912

rounding differences may occur