STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1228

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

HEARD: Tuesday, June 9, 2020, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, June 9, 2020 at 1:00 p.m., remotely via Webex.

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, Floyd B. McKissick, Jr.

APPEARANCES:

For Duke Energy Carolinas, LLC:

Jack E. Jirak, Esq., Duke Energy Corporation, P.O. Box 1551 / NCRH 20, Raleigh, NC 27602

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolinas Industrial Group for Fair Utility Rates III (CIGFUR):

Warren K. Hicks; Bailey & Dixon, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For Carolina Utility Customers Association, Inc. (CUCA):

Robert F. Page, Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For Sierra Club:

Tirrill Moore, Esq. & Gudrun Thompson, Esq., Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association (NCSEA):

Benjamin Smith, Regulatory Counsel, 4600 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Dianna Downey, Esq., Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On February 25, 2020, Duke Energy Carolinas, LLC (DEC) filed an application pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kimberly D. McGee, Brett Phipps, Regis Repko, Steven D. Capps, and Kevin Y. Houston.

Petitions to intervene were filed by CIGFUR on March 19, 2020; by NCSEA on March 23, 2020; by the Sierra Club on April 14, 2020; and by CUCA on May 8, 2020. The Commission granted CIGFUR's petition to intervene on March 23, 2020, NCSEA's petition to intervene on March 24, 2020, the Sierra Club's petition to intervene on April 15, 2020 and CUCA's petition to intervene on May 12, 2020. The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On March 17, 2020, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice in which the Commission set this matter for hearing, established deadlines for the submission of intervention petitions, intervenor testimony, DEC rebuttal testimony, required the provision of appropriate public notice, and mandated compliance with certain discovery guidelines.

On June 5, 2020 and June 25, 2020, DEC filed affidavits of publication indicating that the public notice had been provided in accordance with the Commission's procedural order.

On May 7, 2020, DEC filed the supplemental testimony and revised exhibits and work papers of Kimberly D. McGee. Witness McGee presented revised rates reflecting the impacts related to updated numbers presented in her direct exhibits and workpapers regarding projections included in the billing period as well as the inclusion of overrecovery amounts in the EMF period related to January 2020– March 2020. These updated numbers resulted in an overall decrease in the amount requested in the original application.

On May 18, 2020, the Public Staff filed the Affidavit of Jenny X. Li and the Testimony of Dustin R. Metz. On May 18, 2020, The Sierra Club filed testimony and exhibits of John A. Rosenkranz.

On May 28, 2020, DEC filed the rebuttal testimony of Kimberly D. McGee. On May 29, 2020, DEC filed a motion to excuse all Company and Public Staff witnesses.

On June 1, 2020, the Commission granted the motion and excused all DEC and Public Staff witnesses from appearing at the evidentiary hearing.

On May 29, 2020, the Commission issued an Order Scheduling Remote Hearings for Expert Witness Testimony due to the COVID-19 pandemic. All parties subsequently filed notices consenting to remote hearings.

On June 18, 2020, DEC filed to correct exhibit titles which omitted the revised designation on several of the revised exhibits originally filed with the supplemental testimony of Kimberly D. McGee.

The case came on for hearing remotely by WebEx as scheduled on June 9, 2020. The prefiled direct and supplemental testimonies of DEC's witnesses, the prefiled affidavit and testimony of the Public Staff's witnesses were received into evidence. No other party presented witnesses or exhibits, and no public witnesses appeared at the hearing.

On June 25, 2020, the Commission issued a notice requiring that briefs and proposed orders be filed by July 24, 2020.

On July 24, 2020, DEC and the Public Staff filed a joint proposed order.

Also on July 24, 2020, the Sierra Club filed a post-hearing brief.

Based upon the Company's verified application, the testimony, affidavits, and exhibits received into evidence at the hearing and the record as a whole, the Commission makes the following findings:

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to N.C. Gen. Stat. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended December 31, 2019 (test period).

3. In its application, direct, supplemental, and rebuttal testimony including exhibits in this proceeding, DEC requested a total decrease of $144 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEC include Experience Modification Factor (EMF) riders and take into account fuel and fuel-related cost underrecoveries and overrecoveries experienced during the test period, including the update period of January 2020 – March 2020. The overall underrecovery for the test period is $57 million.

4. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

5. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

6. The test period per book system sales are 87,911,333 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 94,408,998 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	20,916,177
Natural Gas, Oil and Biomass	15,489,537
Nuclear	45,243,922
Hydro – Conventional	2,427,405
Hydro Pumped Storage	(713,520)
Solar DG	142,127
Purchased Power – subject to economic dispatch or curtailment	7,993,064
Other Purchased Power	2,613,134
Interchange Power	297,152
Total Net Generation	94,408,998

7. The appropriate nuclear capacity factor for use in this proceeding is 94.39%.

8. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 58,622,539 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	22,444,481
General Service/Lighting	23,688,550
Industrial	12,489,508
Total	58,622,539

9. The projected billing period (September 2020-August 2021) sales for use in this proceeding are 88,383,239 MWh on a system basis and 58,460,089 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	22,067,951
General Service/Lighting	23,951,115
Industrial	12,441,023
Total	58,460,089

10. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 93,353,096 MWh and is categorized as follows:

Generation Type	MWh
Coal	14,450,043
Gas Combustion Turbine (CT) and Combined Cycle (CC)	24,629,409
Nuclear	44,515,757
Hydro	4,305,885
Net Pumped Storage Hydro	(3,219,894)
Solar Distributed Generation (DG)	385,094
Purchased Power	8,286,802
Total	93,353,096

11. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

a. The coal fuel price is $27.30/MWh.

b. The gas CT and CC fuel price is $22.87/MWh.

c. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $21,603,715.

d. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.04/MWh.

e. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $272,892,569.

f. System fuel expense recovered through intersystem sales is $21,248,787.

12. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $983,087,687.

13. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $57.1 million, consisting of an underrecovery for the residential, general service/lighting, and industrial classes of $8.2 million, $15.8 million and $33.2 million respectively.

14. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1190 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

15. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.6027 cents/kilowatt-hour (kWh) for the Residential class; 1.7583 cents/kWh for the General Service/Lighting class; and 1.6652 cents/kWh for the Industrial class.

16. The appropriate EMF increments established in this proceeding, excluding the regulatory fee, are as follows: 0.0364 cents/kWh for the Residential class; 0.0666 cents/kWh for the General Service/Lighting class; and 0.2658 cents/kWh for the Industrial class.

17. The total net fuel and fuel-related costs factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.6391 cents/kWh for the Residential class; 1.8249 cents/kWh for the General Service/Lighting class; and 1.9310 cents/kWh for the Industrial class.

18. The base fuel and fuel-related costs as approved in Docket No. E-7, Sub 1146 of 1.7828 cents/kWh, 1.9163 cents/kWh, and 2.0207 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively will be adjusted by amounts equal to (0.1801) cents/kWh, (0.1580) cents/kWh, and (0.3555) cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively. The resulting approved fuel and fuel-related costs will be further adjusted by

EMF increments totaling 0.0364 cents/kWh, 0.0666 cents/kWh, and 0.2658 cents/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

N.C. Gen. Stat. § 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending December 31 as the test period for DEC. The Company's filing in this proceeding was based on the 12 months ended December 31, 2019.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Application, the direct and supplemental testimony of Company witness McGee, and the entire record in this proceeding. This finding is not contested by any party. Public Staff Witness Metz testified that the inclusion of Clemson CHP steam revenues in projected cost should be revisited once pending litigation in the DEC general rate case can be decided by the Commission. He noted that the steam revenues may need to be adjusted or removed from North Carolina retail cost of service in future fuel proceedings depending on the Commission's final decision in the general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the direct testimony of Company witnesses Capps and Repko.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and unusual events. Company witness Capps testified that the Company's seven nuclear units operated at a system average capacity factor of 97.09% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 96.19%, exceeded the five-year industry weighted average capacity factor of 91.6% for the period 2014 - 2018 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Capps testified that for the twentieth consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, which included three refueling outages. During 2019, DEC's seven nuclear units collectively achieved the highest annual net generation and annual capacity in the Company's history. Both Catawba Unit 1 and Oconee Unit 1 established new annual generation records during 2019. The Oconee station, Oconee Unit 3, and McGuire Unit 2 all recorded their second highest annual net output during 2019.

Company witness Repko testified concerning the performance of DEC's fossil, hydro, and solar assets. He stated that the primary objective of the Company's fossil, hydro, and solar generation department is to provide safe, reliable and cost-effective electricity to DEC's customers. Witness Repko further stated that DEC complies with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers.

Company witness Repko testified that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned, i.e., forced outage time); (2) net capacity factor (NCF), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF is affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and (4) starting reliability (SR), which represents the percentage of successful starts.

Company witness Repko presented the following chart, which shows operation results, as well as results from the most recently published NERC Generating Availability Brochure for the period 2014 through 2018, and is categorized by generator type:

Generator Type	Measure	Review Period DEC Operational Results	2014-2018 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	76.9%	77.3%	712
	NCF	36.2%	54.8%	
	EFOR	7.4%	9.3%	
Coal-Fired Summer Peak	EAF	92.6%	n/a	n/a
Total CC Average	EAF	78.0%	84.9%	333
	NCF	71.3%	53.6%	
	EFOR	0.37%	5.1%	
Total CT Average	EAF	83.2%	87.5%	750
	SR	100.0%	98.3%	
Hydro	EAF	83.4%	80.2%	1,063

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Repko testified that, in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. During the test period, most of these units had at least one small planned outage to inspect and maintain plant equipment.

W.S. Lee Station conducted an outage in the Fall 2019. The primary purpose for the W.S. Lee Station outage was for Transmission to perform Bus Tie Breaker and 100kv Bus Junction Breakers Upgrades. In the Spring 2019, Dan River combined cycle (CC) conducted major gas turbine overhauls, as well as steam turbine valve and generator inspections. Marshall Unit 2 completed an outage in the Spring 2019. The primary purpose of this outage was to conduct stack repairs and install fly ash piping replacement. Marshall Unit 3 completed an outage in the Spring 2019. The primary purpose of this outage was to perform air preheater maintenance. Marshall Unit 4 completed an outage in the Spring 2019. The primary purpose of this outage was to conduct boiler inspections and stack inspections. W.S. Lee CC completed an outage in Spring 2019. The primary purpose of the outage was to perform inspections and balance of plant maintenance. Buck CC completed an outage in Spring 2019. The primary purpose of the outage was to perform a hot gas path inspection on the gas turbines. Lincoln CT Units 11-16 completed an outage in Spring 2019 to upgrade the turbine control systems. In Fall 2019, Belews Creek Unit 1 preformed a boiler outage. The primary purpose of the outage was to replace the horizonal reheat section of the boiler, burner installation for the natural gas co-fire conversion, and precipitator upgrades. Belews Creek Unit 2 was also in an outage to perform work on common service water pipe replacement between units, continuous emission monitoring system (CEMS) upgrade, main battery replacement, and control system power supply upgrade. Marshall Unit 2 completed an outage in Fall 2019. The primary purpose of this outage was to perform FGD inspections, repair absorber agitators, and replace check valves. Marshall Unit 1 also had an outage in the Fall 2019 to replace the generator and transformer protective relays and air preheater baskets. Cliffside Unit

5 performed work on ammonia tank inspections, catalysts replacement, and turbine valve work in the Fall 2019.

Based on a preponderance of the evidence in the record, the Commission concludes that the Company managed its baseload plants during the test period prudently and efficiently to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in December 2014, and were in effect throughout the 12 months ending December 31, 2019. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses McGee, Phipps, Repko, and Houston and the testimony of Public Staff witness Metz.

Company witness McGee testified that key factors in DEC's ability to maintain lower fuel and fuel-related rates for the benefit of customers include its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; and fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of Duke Energy Progress, LLC's (DEP) and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined companies; and the joint dispatch of DEP's and DEC's generation resources.

Company witness Phipps described DEC's fossil fuel procurement practices, set forth in Phipps Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, conducting short-term and spot purchases to supplement term natural gas supply, and obtaining natural gas transportation for the generation fleet through a mix of long-term firm transportation agreements and shorter term pipeline capacity purchases.

According to witness Phipps, the Company's average delivered cost of coal per ton for the test period was $82.11 per ton, compared to $78.71 per ton in the prior test period, representing an increase of approximately 4%. This includes an average transportation cost of $28.33 per ton in the test period, compared to $29.58 per ton in the prior test period, representing a decrease of approximately 4%. Witness Phipps further testified that the Company's average price of gas purchased for the test period was $3.40 per Million British Thermal Units (MMBtu), compared to $3.84 per MMBtu in the prior test period, representing a decrease of approximately 11%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

Witness Phipps stated that DEC's coal burn for the test period was 8.1 million tons, compared to a coal burn of 8.7 million tons in the prior test period, representing a decrease of approximately 7%. The Company's natural gas burn for the test period was 123.9 MMBtu, compared to a gas burn of 128.8 MMBtu in the prior test period, representing a decrease of approximately 4%. The net decrease in DEC's overall natural gas burn was primarily driven by gas to coal switching as a result of the new coal rail transportation rate that went into effect March 1, 2019.

Witness Phipps stated that coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which have lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency (EPA) regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

He also testified that with respect to natural gas, the nation's natural gas supply has grown significantly over the last several years, and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in the short term, such dynamics are influenced primarily by seasonal weather demand and overall storage inventory balances. Over the longer term planning horizon, natural gas supply is projected to continue to increase along with the needed pipeline infrastructure to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico.

Witness Phipps stated that DEC's current coal burn projection for the billing period is 5.4 million tons, compared to 8.1 million tons consumed during the test period. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $73.90 per ton for the billing period compared to $82.11 per ton in the test period. This includes an average projected total transportation cost of $28.46 per ton for the billing period, compared to $28.33 per ton in the test period.

Witness Phipps testified that this cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEC is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

Witness Phipps further testified that DEC's current natural gas burn projection for the billing period is approximately 201.9 MMBtu, which is an increase from the 123.9 MMBtu consumed during the test period. The net increase in DEC's overall natural gas burn projections for the billing period versus the test period is driven by the inclusion of natural gas generation at Belews Creek, and Marshall Units 3 and 4 as a result of the dual fuel conversions being commercially available over the course of the billing period, combined with increased generation output from Lincoln CT. The current average forward Henry Hub price for the billing period is $2.44 per MMBtu, compared to $2.63 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

According to witness Phipps, DEC continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels.

Witness Phipps also testified that the Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply that includes contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption.

According to Witness Phipps, DEC continues to maintain a short-term financial natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach.

Finally, in response to the Commission's August 7, 2019 Order Approving Fuel Charge Adjustment in Docket No. E-7, Sub 1190 (2019 Fuel Order), Witness Phipps testified to the results of the Company's review of historic price fluctuations and whether its current method of forecasting and hedging should be adjusted to mitigate the risk of significant underrecovery of fuel costs. Based on its evaluation, the Company determined that no adjustments were needed to its current method of forecasting or to its physical hedging program. However, the Company continues to refine and add modeling capabilities that will provide additional information to help with analyzing fuel forecasts and needed procurement activities, and associated ranges of potential costs. The Company also recommends extending financial hedging activities for a lower percentage in rolling years four and five to mitigate cost risks for customers as explained in more detail in Phipps Confidential Exhibit 4.

N.C. Gen. Stat. § 62-133.2(a1)(3) permits DEC to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Repko testified that the Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for nitrogen oxide (NO_x) and sulphur oxide (SO_X) emissions. The selective non-catalytic reduction technology (SCR or SNCR) that DEC currently operates on the coal-fired units uses ammonia or urea for NO_x removal. The SNCR technology employed at Allen station and Marshall Units 1, 2 and 4 injects urea into the boiler for NO_x removal. All DEC coal units have wet scrubbers installed which use crushed limestone for sulfur dioxide (SO_2) removal. Cliffside Unit 6 has a state-of-the-art SO_2 reduction system which couples a wet scrubber (e.g., limestone) and dry scrubber (e.g., quicklime). SCR equipment is also an integral part of the design of the Buck, Dan River and Lee CC stations, in which aqueous ammonia (19% solution of NH_3) is introduced for NO_x removal.

Company witness Repko further testified that overall, the type and quantity of chemicals used to reduce emissions at the Company's plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and the level of emissions reduction required. He stated that the Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. He also stated that the goal is to effectively comply with emissions regulations and provide the most efficient total-cost solution for operation of the unit.

Company witness Houston testified as to DEC's nuclear fuel procurement practices, which include computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Houston explained that for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

N.C. Gen. Stat. §§ 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Phipps testified that DEP and DEC consider the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

Based upon the fuel procurement practices report and the evidence in the record, the Commission concludes that the Company's fuel procurement and power purchasing practices were reasonable and prudent during the test period. The Commission also finds that the Company satisfactorily complied with the obligation under the 2019 Fuel Order to evaluate historic price fluctuation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee.

According to the exhibits sponsored by Company witness McGee, the test period per book system sales were 87,911,333 MWh, and test period per book system generation and purchased power amounted to 94,408,998 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (McGee Exhibit 6):

Net Generation Type	MWh
Coal	20,916,177
Natural Gas, Oil and Biomass	15,489,537
Nuclear	45,243,922
Hydro – Conventional	2,427,405
Hydro Pumped Storage	(713,520)
Solar DG	142,127
Purchased Power – subject to economic dispatch or curtailment	7,993,064
Other Purchased Power	2,613,134
Interchange In/Out	297,152
Total Net Generation	94,408,998

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness McGee's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 87,911,333 MWh and system generation and purchased power of 94,408,998 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the direct testimony and exhibits of Company witness Capps.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and unusual events. The Company proposed using a 94.39% capacity factor in this proceeding based on the operational history of the Company's nuclear units and the number of planned outage days scheduled during the billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 91.60% for the period 2014-2018 as reported in the NERC Brochure during the period of 2014 to 2018.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, and the fact that the Public Staff did not dispute the Company's proposed capacity factor, the Commission concludes that the 94.39% nuclear capacity factor, and its associated generation of 59,363,957 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 - 10

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee.

On Exhibit 4, Company witness McGee set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 58,622,539 MWh, comprised of Residential class sales of 22,444,481 MWh, General Service/Lighting class sales of 23,688,550 MWh, and Industrial class sales of 12,489,508 MWh.

Witness McGee used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Revised McGee

Exhibit 2, Schedule 1, is 88,383,239 MWh. The projected level of generation and purchased power used was 93,353,096 MWh (calculated using the 94.39% capacity factor found reasonable and appropriate above), and was broken down by witness McGee as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	14,450,043
Gas Combustion Turbine (CT) and Combined Cycle (CC)	24,629,409
Nuclear	44,515,757
Hydro	4,305,885
Net Pumped Storage Hydro	(3,219,894)
Solar Distributed Generation (DG)	385,094
Purchased Power	8,286,802
Total	**93,353,096**

As part of her Workpaper 7, Company witness McGee also presented an estimate of the projected billing period North Carolina retail Residential, General Service/Lighting, and Industrial MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	22,067,951
General Service/Lighting	23,951,115
Industrial	12,441,023
Total	**58,460,089**

These class totals were used in Revised McGee Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits (normalized for customer growth and weather), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses McGee and Phipps and the affidavit of Public Staff witness Metz.

Company witness McGee recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $27.30/MWh.
B. The gas CT and CC fuel price is $22.87/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $21,603,715.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.04/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $272,892,569.
F. System fuel expense recovered through intersystem sales is $21,248,787.

These amounts are set forth on or derived from Revised McGee Exhibit 2, Schedule 1. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his affidavit, Public Staff witness Metz stated that, based on upon his review, it appears that the projected fuel and reagent costs set forth in DEC's testimony, and the prospective components of the total fuel factor, have been calculated in accordance with the requirements of N.C. Gen. Stat. § 62-133.2. Witness Metz does however recommend to the Commission that the steam revenues included in the projected period be subject to adjustment in future fuel proceedings depending on the final Commission decision regarding the Clemson CHP unit in the general rate case pending before the Commission at the time of this filing.

No other party presented evidence on the level of DEC's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness McGee and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee and the affidavit of Public Staff witness Metz.

Consistent with N.C. Gen. Stat. § 62-133.2(a2), witness McGee testified that the annual increase in the aggregate amount of purchased power costs under the relevant sections of N.C. Gen. Stat. §62-133.2(a1) does not exceed 2.5% of DEC's total North Carolina jurisdictional gross revenues for 2019.

According to Revised McGee Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $983,087,687. Public Staff witness Metz did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $983,087,687 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-17

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee and the affidavit of Public Staff affiant Li and testimony of witness Metz.

Company witness McGee presented DEC's original fuel and fuel-related expense under-collection and prospective fuel and fuel-related cost factors. Company witness McGee's supplemental testimony and revised exhibits set forth the projected fuel and fuel-related costs, the amount of under-collection for purposes of the EMF, the method for allocating the decrease in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with exhibits and workpapers reflecting the following adjustments: (1) correction to the Company's reagent and by-product projection to incorporate additional revenue associated with the sale of steam by-products produced from the generation of electricity by the Clemson CHP unit, and (2) inclusion of the overcollection balances for the update period January 2020 – March 2020 in the (over-)/undercalculation.

Public Staff affiant Li testified that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost underrecoveries of $8,172,161, $15,770,030, and $33,198,354 for the Residential, General Service/Lighting, and Industrial classes, respectively. Li recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost underrecovery amounts and on the Company's proposed normalized North Carolina retail sales of 22,444,481 MWh for the residential class, 23,688,550 MWh for the general service/lighting class, and 12,489,508 MWh for the industrial class, as proposed by the Company. Li stated that these amounts produce EMF increment riders for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	0.0364 cents per kWh
General Service/Lighting	0.0666 cents per kWh
Industrial	0.2658 cents per kWh

Company witness McGee calculated the Company's proposed fuel and fuel-related cost factors for which there is no specific guidance in N.C. Gen. Stat.

§ 62-133.2(a2) using a uniform bill adjustment method. She stated that DEC proposes to use the same uniform percentage average bill adjustment methodology to adjust its fuel rates to reflect a proposed increase in fuel and fuel-related costs as it did in its 2019 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1190. No party opposed the use of this allocation method. Public Staff witness Metz recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Company witness McGee's second supplemental testimony and revised exhibits.

Based upon the testimony and exhibits in the record, the Commission concludes that DEC's projected fuel and fuel-related cost of $983,087,687 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that (1) DEC's EMFs proposed in this proceeding, excluding the regulatory fee and (2) DEC's prospective fuel and fuel-related cost factors proposed in this proceeding for each of DEC's rate classes are appropriate. Additionally, the Commission concludes that DEC's increase in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1190, other than those costs allocated pursuant to N.C. Gen. Stat. § 62-133.2(a2), should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEC's past fuel cases.

The following tables summarize the impact of the rates approved in this case and the rates approved in Docket No. E-7, Sub 1190 (excluding regulatory fee).

E-7 Sub 1228			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	(0.1801)	(0.1580)	(0.3555)
EMF Component	0.0364	0.0666	0.2658
Total Fuel Factor	1.6391	1.8249	1.9310

E-7 Sub 1190			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	0.0298	0.0398	(0.1273)
EMF Component	0.1375	0.0927	0.2089
Total Fuel Factor	1.9501	2.0488	2.1023

Summary of Differences Sub 1228 — 1190 (excluding regulatory fee):

Change in Fuel Rates			
Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Base Fuel	-	-	-
Prospective Component	(0.2099)	(0.1978)	(0.2282)
EMF Component	(0.1011)	(0.0261)	0.0569
Total Fuel Factor	(0.3110)	(0.2239)	(0.1713)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding of fact is contained in the testimony of Company witness McGee and in the affidavits of Public Staff affiant Li and witness Metz and is discussed in more detail in Evidence and Conclusions for Finding of Fact No. 5.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculations, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 1.6391 cents/kWh for the Residential class, 1.8249 cents/ kWh for the General Service/Lighting class, and 1.9310 cents/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.6027 cents/kWh, 1.7583 cents/kWh, and 1.6652 cents/kWh, EMF increments of 0.0364 cents/kWh, 0.0666 cents/kWh, and 0.2658 cents/kWh, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after September 1, 2020, DEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 1.7828 cents/kWh, 1.9163 cents/kWh, and 2.0207 cents/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively as approved in Docket No. E-7, Sub 1146, by amounts equal to (0.1801) cents/kWh, (0.1580) cents/kWh, and (0.3555) cents/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively, and further, that DEC shall adjust the resulting approved fuel and fuel-related costs by EMF increments of 0.0364 cents/kWh for the Residential class, 0.0666 cents/kWh for the General Service/Lighting class, and 0.2658 cents/kWh for the Industrial class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through August 31, 2021.

2. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments as soon as practicable.

3. That DEC shall work with the Public Staff to prepare a notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket Nos. E-7, Sub 1229 and E-7, Sub 1231, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in all three dockets.

ISSUED BY ORDER OF THE COMMISSION.

This the 19th day of August, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk