STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

HEARD: Wednesday, September 14, 2022, at 10:00 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Progress, LLC:

Ladawn Toon, Associate General Counsel, Duke Energy Corporation, 144 Fayetteville Street, Raleigh, North Carolina 27601

Dwight Allen, Allen Law Offices, PLLC, 4030 Wake Forest Road, Raleigh, North Carolina 27609

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

Craig D. Schauer, Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, 150 Fayetteville Street, 1700 Wells Fargo Capitol Center, Raleigh, North Carolina 27601

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

Christina Cress, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For Southern Alliance for Clean Energy (SACE):

> Gudrun Thompson and Munashe Magarira, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

> William E. H. Creech and William S. F. Freeman, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 14, 2022, Duke Energy Progress, LLC (DEP or Company), filed its application in the above-captioned docket requesting a change in its fuel charges effective for service rendered on and after December 1, 2022, along with the testimony and exhibits of witnesses Dana M. Harrington, Matthew L. Cameron, Tom Ray, John A. Verderame, Bryan P. Walsh, and David B. Johnson.

On July 8, 2022, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice (Scheduling Order).

Petitions to intervene were filed by and granted for Carolina Utility Customers Association, Inc. (CUCA), Carolina Industrial Group for Fair Utility Rates II (CIGFUR), and the Southern Alliance for Clean Energy (SACE). The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On August 12, 2022, DEP filed the supplemental testimony and revised exhibits and workpapers of Dana M. Harrington.

On August 17, 2022, the Commission issued an Order Requiring Second Public Notice.

On August 24, 2022, the Public Staff filed the affidavits of witnesses Fenge Zhang and Dustin Metz, and the direct testimony and exhibits of witness John R. Hinton.

Also on August 24, 2022, SACE filed the direct testimony and exhibits of Ronald J. Binz.

On September 1, 2022, DEP filed the rebuttal testimony of Dana M. Harrington and James J. McClay, III.

On September 8, 2022, DEP and the Public Staff filed a Joint Motion to Excuse Witnesses from Evidentiary Hearing (Joint Motion).

On September 12, 2022, DEP filed affidavits of publication of the initial public notice and second public notice.

Also on September 12, 2022, the Commission issued an Order Excusing Witnesses, Accepting Testimony, Canceling Expert Witness Hearing, and Requiring Proposed Orders.

The case came before the Commission for public witness hearing as scheduled on September 14, 2022. No public witnesses appeared to testify.

On October 14, 2022, DEP and the Public Staff each filed proposed orders.

Also on October 14, 2022, SACE filed a post-hearing brief.

Based upon the evidence presented and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. The Company is a licensed limited liability company, duly organized 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. The Company is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended March 31, 2022 (test period).

3. In its application and direct testimony in this proceeding, DEP requested a total increase of $302.3 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 DEP included Experience Modification Factor (EMF) riders accounting for fuel and fuel-related cost underrecoveries of $210.4 million experienced during the test period. This balance excludes an underrecovered balance of $38.1 million, incurred during the months of April hrough June of 2021, which was included in the EMF balance within the update period in the prior year's proceeding in Docket No. E-2, Sub 1272. This balance also includes the deferred, underrecovered balance of $4.2 million in losses on the sale of byproducts, which were approved for cost recovery through the fuel clause in the Commission's July 28, 2020, Order Allowing Recovery of Liquidated Damages and Transportation Charges issued in Docket No. E-2, Sub 1204.

4. In its direct supplemental testimony and exhibits in this proceeding, DEP updated the requested increase to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee, to $337.2 million. This request included an updated underrecovered EMF rider of $255.4 million.

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

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

7. The test period per book system sales are 60,559,875 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use) and purchased power is 70,153,063 MWh and is categorized as follows:

Net Generation Type	MWh
Nuclear	29,581,602
Natural Gas, Oil, and Biogas	23,334,027
Coal	6,371,743
Hydro – Conventional	623,493
Solar	257,024
Purchased Power – subject to economic dispatch or curtailment	3,721,653
Other Purchased Power	6,263,521
Total Net Generation (may not add to sum due to rounding)	70,153,063

8. The appropriate nuclear capacity factor for use in this proceeding is 94.05%.

9. The North Carolina retail test period sales, adjusted for weather and customer growth, for use in calculating the EMF are 37,740,216 MWh. The normalized test period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Normalized Test Period MWh Sales
Residential	16,792,596
Small General Service	1,956,415
Medium General Service	10,468,785
Large General Service	8,202,098
Lighting	320,322
Total (may not add to sum due to rounding)	37,740,216

10. The projected billing period (December 2022-November 2023) sales for use in this proceeding are 61,541,989 MWh on a system basis and 38,365,559 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 Billing Period MWh Sales
Residential	16,637,596
Small General Service	1,797,603
Medium General Service	10,360,942

Large General Service	9,189,937
Lighting	379,481
Total (may not add to sum due to rounding)	38,365,559

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 69,409,824 MWh and is categorized as follows:

Generation Type	MWh
Nuclear	29,601,651
Gas Combustion Turbine (CT) and Combined Cycle (CC)	19,494,222
Coal	9,087,592
Hydro	667,442
Solar	264,499
Purchased Power	10,294,418
Total (may not add to sum due to rounding)	69,409,824

12. 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 total nuclear fuel price is $5.95/MWh.

b. The gas CT and CC fuel price is $38.00/MWh.

c. The coal fuel price is $38.66/MWh.

d. The appropriate system expense for ammonia, lime, limestone, sorbents, and catalysts consumed in reducing or treating emissions (collectively, reagents) is $21,815,046.

e. The appropriate system (gain)/loss on the sale of byproducts produced in the generation of electricity (collectively, byproducts) is $25,444,431.

f. The total system purchased power cost, including the impact of Joint Dispatch Agreement (JDA) Savings Shared and the impact of House Bill 589, N.C. Sess. L. 2017-192, is $509,875,571.

g. System fuel expense recovered through intersystem sales is $213,736,707.

13. The projected fuel and fuel-related costs for the North Carolina retail billing period are $1,010,744,631. N.C. Gen. Stat. § 62-133.2(a2) prohibits the inclusion of select purchased power fuel and fuel-related cost increases in excess of 2.5% of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding

calendar year; therefore, the Company is excluding $11,048,138 in costs from customer fuel rates in this proceeding. This brings the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding to $999,696,493. This reduction in projected costs used to set rates in this proceeding does not preclude the Company from seeking to recover the actual costs incurred on the purchased power costs described in G.S. § 62-133.2(a2) in a future proceeding as a component of the EMF.

14. The Company's appropriate North Carolina retail jurisdictional fuel and fuel-related expense undercollection for purposes of the EMF was $255,408,714, consisting of underrecoveries of $108,941,580, $8,781,456, $61,349,694, $73,664,346, and $2,671,637, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively. These amounts include the deferred underrecovered losses on the sale of byproducts from the prior year as follows: $1,800,492, $170,792, $1,075,183, $1,110,728, and $28,089, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively.

15. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1272, 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.

16. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.808¢/kilowatt-hour (kWh) for the Residential class; 3.097¢/kWh for the Small General Service class; 2.580¢/kWh for the Medium General Service class; 2.138¢/kWh for the Large General Service class; and 3.376¢/kWh for the Lighting class.

17. The appropriate EMF increments established in this proceeding, excluding the regulatory fee, are as follows: 0.649¢/kWh for the Residential class; 0.449¢/kWh for the Small General Service class; 0.586¢/kWh for the Medium General Service class; 0.898¢/kWh for the Large General Service class; and 0.834¢/kWh for the Lighting class.

18. The total net fuel and fuel-related costs factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 3.457¢/kWh for the Residential class; 3.546¢/kWh for the Small General Service class; 3.166¢/kWh for the Medium General Service class; 3.036¢/kWh for the Large General Service class; and 4.210¢/kWh for the Lighting class.

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.G.S. § 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 March 31 as the test period for DEP. The Company's filing in this proceeding was based on the 12 months ended March 31, 2022.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Application, the direct testimony of Company witness Harrington, and the entire record in this proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the supplemental direct testimony of Company witness Harrington. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is contained in the testimony of Company witnesses Ray and Walsh and the affidavit of Public Staff affiant Metz.

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 any unusual events. Company witness Ray stated that DEP's nuclear fleet consists of three generating stations and a total of four units. He stated that the Company's four nuclear units operated at a system average capacity factor of 93.99% during the test period. Both this annual capacity factor and the Company's 2-year average capacity factor of 93.77% met the five-year industry average capacity factor of 93.49% for the period 2016-2020 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Unit Statistical Brochure. The current test period included two refueling outages.

Public Staff affiant Metz affirms that the Company's actual system nuclear capacity factor for the test year was 93.99% and that the NERC five-year average (2016-2020) weighted for the size and type of reactors in DEP's nuclear fleet was 93.49%.

Company witness Walsh discussed the performance of DEP's fossil/hydro assets. He stated 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) starting reliability (SR), which represents the percentage of successful starts; and (4) equivalent forced outage rate (EFOR), which quantifies the number of period hours in a year during which the unit is unavailable because of forced outages and forced deratings.

Witness Walsh presented the following chart, which shows operational results, categorized by generator type, as well as results from the most recently published NERC Generating Availability Brochure for the period 2016 through 2020:

Generator Type	Measure	Review Period	2016-2020	Nbr of Units
		DEP Operational Results	NERC Average	
Coal Fired Test Period	EAF	63.1%	79.8%	183
	NCF	23.0%	53.2%	
	EFOF	8.1%	n/a	
Coal Fired Summer Peak	EAF	78.2%	n/a	n/a
Total CC Average	EAF	81.0%	84.9%	345
	NCF	67.6%	54.3%	
	EFOF	0.7%	n/a	
Total CT Average	EAF	83.8%	86.6%	709
	SR	99.2%	98.5%	
Hydro	EAF	78.5%	79.4%	1059
Solar	NCF	20.8%	n/a	n/a

Company witness Walsh also stated that for the review period, approximately 51% of the Company's total system generation was provided by the Fossil/Hydro/Solar fleet of which 38% was contributed from gas facilities, 11% contributed from coal-fired stations, 1% contributed by hydro sources, and 0.4% from solar facilities.

Based upon the evidence in the record and the absence of any testimony to the contrary, the Commission concludes that DEP generally managed its baseload plants prudently and efficiently to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

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 revised fuel procurement practices were filed with the Commission in 2015 in Docket No. E-100, Sub 47A, and were in effect throughout the 12 months ending March 31, 2022. 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 Harrington, Cameron, Verderame, and Walsh, and Public Staff affiant Metz and witness Hinton.

Company witness Harrington stated that key factors in DEP's ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio of nuclear, natural gas, coal, and hydro, the capacity factors of its nuclear fleet, and fuel procurement strategies, which mitigate volatility in supply costs. Witness Harrington also explained that other key factors include DEP's and affiliate company Duke Energy Carolina's (DEC) respective expertise in transporting, managing, and blending fuels, procuring reagents, and utilizing purchasing synergies of the combined companies, as well as the joint dispatch of DEP's and DEC's generation resources.

Company witness Cameron stated that DEP's nuclear fuel procurement practices 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 Cameron explained that for uranium concentrates, conversion, and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. 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, witness Cameron stated that DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, witness Cameron stated that DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, witness Cameron stated that DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Company witness Verderame described DEP's fossil fuel procurement practices set forth in Verderame Exhibit 1. Witness Verderame stated that those practices include computing near- and long-term consumption forecasts using stochastic cost production modeling, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the highest customer value, monitoring delivered coal volume and quality against contract commitments, conducting short-term and spot purchases to supplement term natural gas supply, obtaining natural gas transportation for the generation fleet through a mix of long-term firm transportation agreements and shorter-term pipeline capacity purchases, and managing a targeted percentage of the natural gas fuel price exposure via a rolling 60-month structured financial natural gas hedging program.

According to witness Verderame, the Company's average delivered coal cost per ton decreased approximately 9%, from $92.52 per ton in the prior test period to $84.26 per ton in the current test period. The Company's transportation costs decreased approximately 4%, from $36.75 per ton in the prior test period to $35.15 per ton in the current test period.

Witness Verderame also stated that the Company's average price of gas purchased for the current test period was $5.44 per Million British Thermal Units (MMBtu), compared to $3.76 per MMBtu in the prior test period, representing an increase of approximately 44%. He stated that the cost of gas is inclusive of gas supply, transportation, storage, and financial hedging.

Witness Verderame stated that the coal supply chain experienced increasing challenges throughout 2021 and early 2022 as historically low utility stockpiles—combined with rapidly increasing demand for coal, both domestically and internationally—made procuring additional coal supply increasingly challenging. Producers were unable to respond to this rapid rise in demand due to capacity constraints resulting from labor and resource shortages. These factors combined to drive both domestic and export coal prices in 2021 and early 2022 to record levels. Going into summer 2022, coal commodity costs remained at historically high levels as higher natural gas prices and strong domestic and foreign demand continued to put pressure on coal supplies. Witness Verderame also stated that in 2021 and early 2022, the Company experienced increased delivery delays created by rail transportation labor and resource shortages and that the Company expects rail transportation labor and resource constraints to continue into 2023.

Witness Verderame stated that DEP's current coal burn projection for the billing period is 3.5 million tons compared to 2.9 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: delivered natural gas prices versus the average delivered cost of coal, volatile power prices, and electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $100.18 per ton for the billing period compared to $84.26 per ton in the test period. This projected delivered cost 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 Central Appalachian coal DEP is able to purchase and deliver and the non-Central Appalachian coal DEP is able to consume; (3) changes in transportation rates; (4) performance of contract deliveries by suppliers and railroads that may not occur despite the Company's strong contract compliance monitoring process; 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 Verderame further stated that DEP's current natural gas burn projection for the billing period is approximately 140.5 million MBtu, which is a decrease from the 174.6 million MBtu consumed during the test period. The current average forward Henry

Hub price for the billing period is $5.51 per MMBtu, compared to $4.41 per MMBtu in the test period.

According to witness Verderame, DEP 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.

Public Staff witness Hinton explained his analysis of the Company's fuel hedging program, including stating the reasons why the Company has a hedging program in place. Witness Hinton stated that energy companies like DEP have hedging programs to protect their customers from fuel price volatility in the market by minimizing price changes and shocks. Witness Hinton further explained that volatility stems from the risks of the unknown future which may cause unforeseen substantial or frequent changes in prices at any time.

Witness Hinton stated that longer-term deals add a degree of risk where the expected benefits of stable prices are outweighed by the potential costs. He also stated that DEP's forward volatility curves indicate that the expected volatility is drastically lower beyond future year three relative to a one- or two-year future term. Witness Hinton also stated that even though long-term hedges entered into in 2017 and 2018 are currently producing net savings and reducing the cost of natural gas, he cautioned entering into longer-term deals greater than three years which have historically added costs to DEP's hedging program. Witness Hinton stated that based on his analysis of—and his previous testimony in—nine DEP annual fuel rider dockets,[1] DEP's responses to data requests, and its monthly hedge reports from April 2012 to March 2022, DEP's hedging programs are reasonable, and management of the hedging program has worked to stabilize natural gas price swings.

Witness Hinton stated that for the 2021-2022 test year, the DEP hedging program for natural gas reduced the cost of purchasing natural gas by $122.6 million, translating to an annual savings of $22.82 for the typical consumer at a system level. Witness Hinton noted that even with this recent large benefit, the balance of DEP's overall hedging program over the recent years (2012-2017) has reflected greater net costs than savings. He explained that historical hedging contracts with longer hedge horizons—meaning the length of time between the trade date and the effective date of the contract—have incurred larger net costs as hedged natural gas prices were significantly higher than actual market prices.

Witness Hinton further explained that he was not questioning DEP's ability to gauge the gas markets during these years of significantly large costs. Witness Hinton stated that during the 2008 through 2017 period, industry participants were surprised by the continued decline in natural gas prices as shale gas came into the market. Witness Hinton noted that the vast majority of the Annual Energy Outlook (AEO) Retrospective

[1] Docket No. E-2, Subs 1292, 1272, 1250, 1204, 1173, 1146, 1069, 1045, and 1031.

Review forecasted natural gas prices in 2008-2013 for 2012-2017 predicted higher future prices as compared to the actual prices. Witness Hinton also stated that natural gas price volatility has significantly increased over the last 12 months and that recent increases support the use of hedges to avoid having to purchase gas at relatively higher prices. Witness Hinton stated that he agrees with DEP's statements that it cannot predict future prices and its hedging program does not involve speculation. Finally, witness Hinton recommended that DEP utilize a short-term hedging policy with one to three years lead time from the trade date and the effective date. If DEP decides to hedge beyond three years, witness Hinton recommended that it minimize the percentage of hedges that will fall within this longer term.

In rebuttal, Company witness McClay disagreed with Witness Hinton's recommendation to shorten its hedging program from a phased financial hedging program over a rolling 60-month period to a shorter program over a rolling 36-month period. Witness McClay stated that as DEP's use of natural gas continues to increase and make up a larger component of overall fuel costs, DEP believes hedging natural gas over a rolling 60-month time horizon represents a balanced fuel price risk management approach that results in greater fuel cost certainty for a portion of forecasted natural gas burns. Witness McClay stated that the Company does not disagree that targeting a lower hedging percentage for the period beyond 36 months is a reasonable practice, given that neither DEP nor any forecaster can predict with certainty where actual natural gas prices and volatility will be in the future. However, Witness McClay stated that DEP's current approach—which targets a higher percentage of hedging for the first 12 to 36 months with a lower percentage in the 37- to 60-month period—is a reasonable approach consistent with witness Hinton's recommendation.

Witness McClay stated that prior results of the Company's hedging practices, which may or may not result in net fuel cost savings, are not an indication or expectation of future hedging results. Instead, he explains, the program's primary purpose serves to reasonably mitigate price volatility in uncertain fuel markets and DEP's current methodology—which hedges a portion for the rolling future periods beyond the front 36 months—provides the benefit of greater fuel cost certainty for more forecasted natural gas burns, given the number of risk factors that can impact price volatility. Witness McClay also stated that DEP believes continuing to hedge periods beyond the 36-month hedge horizon at lower hedging targets is reasonable and continues to be an important part of prudently managing the risk of volatility in customers' future fuel costs. He explains that DEP will continue to review its hedging program and will recommend modifications in response to changing market signals to ensure that it remains appropriately based on market conditions and the Company's strategy.

SACE witness Binz testified regarding the use of a fuel adjustment process as a regulatory tool and explained the need to introduce solar and storage considerations into the long-term planning process due to the volatility of fuel prices. Witness Binz did not, however, propose any disallowance in this fuel proceeding. Instead, he made the following recommendations to further mitigate customer exposure to fossil fuel price volatility, that: (1) the Commission consider the volatility of gas prices when making decisions about planning and resource acquisition; (2) the Company consider solar generation paired with storage; and (3) the Commission practice "risk aware" regulation in evaluating and making decisions regarding DEP's resource mix, rates, and other choices that affect customer risk.

N.C.G.S. § 62-133.2(a1)(3) permits DEP to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Walsh stated that the Company's fossil/hydro/solar generation portfolio consists of 8,868 MWs of generating capacity, 3,143 MWs of which is coal-fired generation across two generating stations and a total of five units. These units are equipped with emission control equipment, including selective catalytic reduction (SCR) equipment for removing nitrogen oxides (NOx), flue gas desulfurization (FGD or scrubber) equipment for removing sulfur dioxide (SO_2), and low NOx burners. Witness Walsh stated that this inventory of coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content, thereby providing flexibility for DEP to procure the most cost-effective options for fuel supply.

Company witness Walsh further stated that overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and the level of emissions reduction required.

N.C.G.S. §§ 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 Verderame stated that both DEP and Duke Energy Carolinas, LLC (DEC), perform the same detailed daily process to determine the unit commitment plan that economically and reliably meets the projected system needs over the next seven days. The Company utilizes a production cost model to determine an optimal unit commitment plan to economically and reliably meet system requirements. Witness Verderame stated that the model minimizes the production costs needed to serve the projected customer demand within reliability and other system constraints over a period of time using numerous factors, including: forecasted energy demand; forecasted fuel prices; variable transportation rates; planned maintenance and refueling outages; generating unit performance parameters; generating unit reliability constraints; and expected market conditions associated with power purchases. Witness Verderame stated that the production cost model output produces the optimized hourly unit commitment plan for the 7-day forecast period. This unit commitment plan also provides the starting point for dispatch, but dispatch is then also subject to real-time adjustments due to changing system conditions including management of natural gas transportation constraints. The unit commitment plan is prepared daily and adjusted, as needed, throughout any given day to respond to changing real time system conditions.

Based upon the fuel procurement practices report and the evidence in the record, the Commission concludes that these practices were reasonable and prudent during the test period. The Commission also notes the evidence presented by Public Staff witness Hinton on additional term risk associated with longer term hedge contracts and, as a result, concludes that it is prudent for the Company to periodically consult with the Public Staff to review the Company's hedging program and recommend modifications, as needed, in response to changing market signals to ensure that it remains appropriate based on market conditions. Additionally, the Commission concludes that both DEP and the Public Staff shall continue to review DEP's hedging program and shall make recommended modifications to be considered in next year's fuel charge adjustment proceeding.

The Commission also acknowledges witness Binz's testimony regarding the fuel clause as a regulatory device but concludes that it is bound by North Carolina law and, as a result, finds that a general discussion of the fuel adjustment process is not appropriate for this proceeding. The Commission agrees that renewable energy resources are important components of the continued reliability and resiliency of the electric grid. The Commission notes, however, that there are other proceedings conducted regularly that address the issues raised by witness Binz and concludes that this fuel proceeding is not the appropriate forum in which to evaluate those resources or resource planning in general.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

According to Company witness Harrington, the test period per book system sales were 60,559,875 MWh, and test period per book system generation (net of auxiliary use) and purchased power amounted to 70,153,063 MWh. The test period per book system generation and purchased power are categorized as follows (Harrington Exhibit 6):

Net Generation Type	MWh
Nuclear	29,581,602
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Hydro – Conventional	623,493
Solar	257,024
Purchased Power – subject to economic dispatch or curtailment	3,721,653
Other Purchased Power	6,263,521
Total Net Generation (may not add to sum due to rounding)	70,153,063

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. 5.

No party contested witness Harrington's testimony or 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 60,559,875 MWh and system generation and purchased power of 70,153,063 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Ray and Harrington and the affidavit of Public Staff affiant Metz.

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 any unusual events. Witness Ray proposed using a 94.05% 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 2022-2023 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 93.49% for the period 2016-2020 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Public Staff affiant Metz stated that although the Company's projected nuclear capacity factor for the billing period is slightly higher than the NERC five-year average, the Company's proposed use of a 94.05% capacity factor is not unreasonable given historic performance and no major unit outages.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEP system, and the fact that the Public Staff does not dispute the Company's proposed capacity factor, the Commission concludes that the 94.05% nuclear capacity factor, and its associated generation of 29,601,651 MWh per Harrington Exhibit 2, Schedule 1, Page 1, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

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

In her Revised Exhibit 4, Company witness Harrington set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 37,740,216 MWh, comprised of Residential class sales of 16,792,596 MWh, Small General Service sales of 1,956,415 MWh, Medium General Service sales of

10,468,785 MWh, Large General Service sales of 8,202,098 MWh, and Lighting class sales of 320,322 MWh.

Witness Harrington 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 Harrington Exhibit 2, Schedule 1, Page 1, is 61,541,989 MWh. The projected level of generation and purchased power used is 69,409,824 MWh (calculated using the 94.05% capacity factor found reasonable and appropriate above) and was broken down by witness Harrington as follows, as set forth on that same schedule:

Generation Type	MWh
Nuclear	29,601,651
Gas Combustion Turbine (CT) and Combined Cycle (CC)	19,494,222
Coal	9,087,592
Hydro	667,442
Solar	264,499
Purchased Power	10,294,418
Total (may not add to sum due to rounding)	69,409,824

In her Workpaper 8, Company witness Harrington also presented an estimate of the projected billing period North Carolina retail Residential, Small General Service, Medium General Service, Large General Service, and Lighting MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected Billing Period MWh Sales
Residential	16,637,596
Small General Service	1,797,603
Medium General Service	10,360,942
Large General Service	9,189,937
Lighting	379,481
Total (may not add to sum due to rounding)	38,365,559

These class totals were used in Revised Harrington Exhibit 2, Schedule 1, Page 3, 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 weather and customer growth), 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. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Harrington and Verderame and the affidavit of Public Staff affiant Metz.

In her Exhibit 2, Schedule 1, Page 1, Company witness Harrington recommended the fuel and fuel-related prices and expenses. 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 affiant Metz stated that based on his investigation, the projected fuel and reagent prices set forth in the testimony of Company witnesses were calculated appropriately and in accordance with the requirements of N.C.G.S. § 62-133.2. He also noted that eight months of next year's test period will have passed before the billing period in this case begins, which creates a high potential of continued underrecovery if commodity prices remain at their current elevated levels.

No other party presented evidence on the level of DEP'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 Harrington 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. 13

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

According to Revised Harrington Exhibit 2, Schedule 1, Page 3, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $999,696,493. This amount has capped the inclusion of select purchased power fuel and fuel-related cost increases at 2.5% of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year in accordance with G.S. § 62-133.2(a2).

No 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 $999,696,493 is reasonable and complies with the requirements in accordance with N.C.G.S. § 62-133.2(a2). Any deviation between the projected fuel and fuel-related costs for the North Carolina retail jurisdiction projected in this proceeding versus actual costs when incurred will be reviewed for prudency and considered for cost recovery in a future fuel proceeding according to the appropriate EMF periods.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-18

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Harrington, the affidavits of Public Staff affiants Zhang and Metz, and the testimony and exhibits of SACE witness Binz.

Company witness Harrington presented DEP's fuel and fuel-related expense undercollection and prospective fuel and fuel-related cost factors. Witness Harrington set forth the projected fuel and fuel-related costs, the amount of undercollection for purposes of the EMF, the method for allocating the increase in fuel and fuel-related costs, and the composite fuel and fuel-related cost factors. Public Staff affiant Zhang agreed that DEP's EMF increment riders for each customer class should be approved based on the following underrecoveries, which include the deferred underrecovered losses on the sale of byproducts of $4.2 million, which were approved to be included in recoverable fuel costs in Docket No. E-2, Sub 1204:

N.C. Retail Customer Class	Underrecovery
Residential	$108,941,580
Small General Service	8,781,456
Medium General Service	61,349,694
Large General Service	73,664,346
Lighting	2,671,637
Total (may not add to sum due to rounding)	$255,408,714

As a result of these amounts, Public Staff affiant Zhang recommended approval of the following EMF increment billing factors, excluding the regulatory fee:

N.C. Retail Customer Class	EMF Increment (cents/kWh)
Residential	0.649
Small General Service	0.449
Medium General Service	0.586
Large General Service	0.898
Lighting	0.834

Public Staff affiant Metz noted concern regarding the significant underrecovery that took place during the test year. He further stated that, after reviewing discovery and discussing the issue with DEP representatives and the recent trends in commodity prices, the Public Staff was satisfied the 2022 test year fuel costs were reasonable and prudently incurred.

Regarding the Company's June 30, 2022, EMF balance, SACE witness Binz stated that, as updated, the base fuel rates during the test period undercollected actual fuel costs, resulting in the $255.4 million shortfall to be added to the fuel and fuel-related costs for the billing period. Witness Binz concluded that because customers underpaid their fuel costs in the review period, they would necessarily overpay their fuel costs in the billing period.

In rebuttal, DEP witness Harrington disputed witness Binz's conclusion. She stated that Commission rules and general statutes serve to safeguard customers from paying more or less than the actual fuel costs incurred by the Company and that the Company does not earn a return (i.e., make a profit) on fuel costs incurred. She further explained that to make all parties (North Carolina retail ratepayers and the Company) whole, the (1) fuel rate approved in the most recent general rate case, (2) the annual fuel and fuel-related cost rider, and (3) the EMF rider together ensure that North Carolina retail customers pay only for the actual cost of fuel, no more, no less. She further noted that N.C.G.S. § 62-133.2 and Rule R8-55 mandate an annual fuel proceeding to reconcile all components of the fuel rate so that over a period of 32 months, DEP customers do not over or underpay the cost of fuel needed to supply their electricity.

Company witness Harrington calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the increase in fuel costs should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEP fuel cases approved by this Commission. No party opposed the use of this allocation method.

Public Staff affiant Metz recommended the approval of the total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Table 1 of his affidavit, which align with the total fuel and fuel-related cost factors proposed by the Company in the supplemental testimony of witness Harrington as shown on Revised Harrington Exhibit 1.

Based upon the testimony and exhibits in the record, the Commission concludes that DEP's projected fuel and fuel-related cost of $999,696,493 for the North Carolina retail jurisdiction for use in this proceeding is reasonable and the Public Staff's prospective fuel and fuel-related cost factors set forth in the affidavit of Public Staff witness Metz's affidavit are appropriate. The Commission also concludes that DEP's EMF underrecovery balance of $255,408,714 was prudently incurred and that the increment riders for each class set forth in the affidavits of Public Staff affiants Metz and Zhang, excluding the regulatory fee, are appropriate. Additionally, the Commission concludes that DEP's increase in fuel and fuel-related costs from the amounts approved in Docket No. E-2, Sub 1272, should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEP's past fuel cases.

The billing factors approved in this case, both excluding and including the regulatory fee, are shown as follows:

Rates in ¢/kWh excluding regulatory fee:						
	A	B	C	D	E	F
Class	Base Fuel Rate	Increment / (Decrement) to Base Fuel Rate	Prospective Rate: Columns A + B	EMF Increment / (Decrement)	EMF Interest (Decrement)	Billed Rate: Columns C+D+E
Residential	2.080	0.728	2.808	0.649	-	3.457
Small General Service	2.126	0.971	3.097	0.449	-	3.546
Medium General Service	2.228	0.352	2.580	0.586	-	3.166
Large General Service	2.204	(0.066)	2.138	0.898	-	3.036
Lighting	1.392	1.984	3.378	0.834	-	4.210

Rates in ¢/kWh including regulatory fee:						
	A	B	C	D	E	F
Class	Base Fuel Rate	Increment / (Decrement) to Base Fuel Rate	Prospective Rate: Columns A + B	EMF Increment / (Decrement)	EMF Interest (Decrement)	Billed Rate: Columns C+D+E
Residential	2.083	0.729	2.812	0.650	-	3.462
Small General Service	2.129	0.972	3.101	0.450	-	3.551
Medium General Service	2.231	0.352	2.583	0.587	-	3.170
Large General Service	2.207	(0.066)	2.141	0.899	-	3.040
Lighting	1.394	1.987	3.381	0.835	-	4.216

Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors, excluding the regulatory fee, of 3.457¢/kWh for the Residential class, 3.546¢/kWh for the Small General Service class, 3.166¢/kWh for the Medium General Service class, 3.036¢/kWh for the Large General Service class, and 4.210¢/kWh for the Lighting class, consisting of the prospective fuel and fuel-related cost factors of 2.808¢/kWh, 3.097¢/kWh, 2.580¢/kWh, 2.138¢/kWh, and 3.376¢/kWh, and EMF increments of 0.649¢, 0.449¢, 0.586¢, 0.898¢, and 0.834¢/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, all exclusive of the regulatory fee.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after December 1, 2022, DEP shall adjust the base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in Docket No. E-2, Sub 1219, amounting to 2.080¢/kWh for the Residential class, 2.126¢/kWh for the Small General Service class, 2.228¢/kWh for the Medium General Service class, 2.204¢/kWh for the Large General Service class, and 1.392¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to 0.728¢/kWh, 0.971¢/kWh, 0.352¢/kWh, (0.066¢)/kWh and 1.984¢/kWh, respectively, and further, that

DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.649¢/kWh for the Residential class, 0.449¢/kWh for the Small General Service class, 0.586¢/kWh for the Medium General Service class, 0.898¢/kWh for the Large General Service class, and 0.834¢/kWh for the Lighting class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through November 30, 2023;

2. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order; and

3. That DEP 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 No. E-2, Subs 1293, 1294, and 1295, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten days after the Commission issues orders in all four dockets.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.

This the 3rd day of November, 2022.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston

A. Shonta Dunston, Chief Clerk