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October 19, 2023

VIA ELECTRONIC FILING

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

RE: Joint Proposed Order of Duke Energy Progress, LLC and the Public Staff
Docket No. E-2, Sub 1321

Dear Ms. Dunston:

Please find enclosed for filing in the above-referenced docket the Joint Proposed Order of Duke Energy Progress, LLC and the Public Staff of the North Carolina Utilities Commission. An electronic copy of the Proposed Order is being emailed to briefs@ncuc.net.

Please contact me if you have any questions.

Sincerely,

Ladawn S. Toon

Enclosure

cc: Parties of Record

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1321

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
Application of Duke Energy Progress,	)	**DUKE ENERGY PROGRESS, LLC**
LLC Pursuant to G.S. 62-133.2 and	)	**AND PUBLIC STAFF'S JOINT**
NCUC Rule R8-55 Relating to Fuel	)	**PROPOSED ORDER APPROVING**
and Fuel-Related Charge Adjustments	)	**FUEL CHARGE ADJUSTMENT**
for Electric Utilities	)	

HEARD: Tuesday, September 19, 2023, at 9:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Progress, LLC:

Ladawn Toon, Associate General Counsel, Duke Energy Progress411 Fayetteville Street, Raleigh, North Carolina 27601

For the Carolina Industrial Group for Fair Utility Rates II:

Douglas D.C. Conant, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For the Carolina Utility Customers Association:

Amanda Hawkins, Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, Suite 1700, Wells Fargo Capitol Center, Raleigh, North Carolina 27601

For the Using and Consuming Public:

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

BY THE COMMISSION: On June 13, 2023, Duke Energy Progress, LLC ("Duke Energy Progress," "DEP," or the "Company"), 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, exhibits, and workpapers of Dana M. Harrington, the direct testimonies and exhibits of Matthew L. Cameron, Tom Simril, and John D. Swez, and the direct testimonies of Jeffrey Flanagan, David B. Johnson, and Nadene N. Wallace.

Petitions to intervene were filed by Carolina Industrial Group for Fair Utility Rates II ("CIGFUR") on June 23, 2023, and Carolina Utility Customers Association, Inc. ("CUCA") on July 3, 2023. The Commission granted CIGFUR's petition to intervene on June 27, 2023, and CUCA's petition to intervene on July 11, 2023. The intervention of the Public Staff of the North Carolina Utilities Commission (Public Staff) is recognized pursuant to N.C.G. S. § 62-15(d) and Commission Rule R1-19(e).

On June 30, 2023, the Commission entered an *Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice*. That Order provided that direct testimony of the Public Staff and intervenors should be filed on or before August 29, 2023, that DEP rebuttal testimony and exhibits should be filed on or before September 7, 2023, that DEP should publish a Public Notice in a newspaper or newspapers having general circulation in its service area once a week for two successive weeks beginning at least 45 days prior to the hearing; that DEP shall file affidavits of publication on or before the date of the hearing; and that a public hearing on this matter would be held on September 19, 2023.

On August 28, 2023, DEP filed the supplemental testimony and revised exhibits and workpapers of Dana M. Harrington.

Also, on August 28, 2023, the Public Staff filed a Motion for Extension of Time.

On August 29, 2023, the Commission entered an *Order Granting Extension of Time*.

On September 1, 2023, the Public Staff filed the testimony of Darrell Brown, and joint testimony of Evan D. Lawrence and Dustin R. Metz. The testimony addressed the relevant topics and was in accordance with N.C.G. S. § 62-133.2 and Commission Rule R8-55.

On September 1, 2023, CIGFUR filed the testimony of Brian C. Collins.

On September 8, 2023, DEP filed rebuttal testimony of Dana M. Harrington.

On September 14, 2023, DEP and Public Staff filed joint motion requesting that the Commission excuse DEP's witnesses Matthew L. Cameron, Tom Simril, John D. Swez, Jeffrey Flanagan, Nadene N. Wallace, David Johnson, and Public Staff's witness Darrell Brown from appearing at the September 19, 2023, hearing. The joint motion requested that the Commission accept the expert witnesses' testimony and exhibits into the record and represented that CUCA and CIGFUR, parties to the proceeding, had agreed to waive cross-examination of DEP's witnesses and the Public Staff's witness listed in the motion.

On September 15, 2023, the Commission issued an *Order Excusing Witnesses* (Cameron, Simril, Swez, Flanagan, Wallace, Johnson, and Brown).

On September 18, 2023, CIGFUR filed a motion to excuse witness Brian C. Collins.

On September 18, 2023, DEP and Public Staff filed joint motion to excuse remaining witnesses (consisting of DEP witness Dana M. Harrington and Public Staff witnesses Evan D.

Lawrence and Dustin R. Metz) and that the testimony and exhibits of all witnesses be received into the record.

On September 18, 2023, Commission issued an *Order Excusing Witnesses, Accepting Testimony, Canceling Expert Witness Hearing and Requiring Proposed Orders*.

On September 18, 2023, DEP filed affidavits of publication indicating that public notices had been provided in accordance with the Commission's procedural orders issued on June 30, 2023.

The matter came on for the public witness hearing as scheduled on September 19, 2023. The case was opened and no public witnesses appeared in response to a call for witnesses made during the proceeding. Nor did any party identify any public witnesses.

On October 19, 2023, DEP and the Public Staff filed a Joint Proposed Order.

Based upon the Company's verified application, direct testimony, supplemental testimony, rebuttal testimony, and exhibits received into evidence, the testimony of the Public Staff, and the testimony of CIGFUR, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Progress is a licensed limited liability company, organized and 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 Progress 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, 2023 ("test period").

3. In its application and direct testimony in this proceeding, DEP requested a total increase of $208.4 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 to take into account fuel and fuel-related cost under-recoveries of $445.1 million experienced during the test period. This balance excludes an under-recovered balance of $45.0 million, incurred during the months of April through June of 2022, which was included in the EMF balance within the update period in the prior year Docket No. E-2, Sub 1292. This balance also includes the deferred under-recovered balance of $4.1 million in losses on the sale of by-products, which were approved for cost recovery through the fuel clause in the Commission's Order Allowing Recovery of Liquidated Damages and Transportation Charges dated July 28, 2020, in Docket No. E-2, Sub 1204.

4. In its direct supplemental testimony and exhibits in this proceeding, DEP updated its requested increase in the North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee, to $208.0 million, which included an updated under-recovered EMF of $444.8 million. This updated EMF balance includes a reduction of $300,000 in North Carolina retail's share of replacement power costs associated with a Robinson Nuclear Station forced outage in December 2022.

5. The Commission finds any issues related to the operation of the Company's baseload plants were resolved through the agreement between the Company and the Public Staff as outlined in DEP witness Dana Harrington's supplemental testimony, and that in all other respects the Company's baseload plants were generally 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 60,895,867 megawatt-hours ("MWh"). The test period per book system generation (net of auxiliary use) and purchased power is 69,961,566 MWh and is categorized as follows:

Net Generation Type	MWh
Nuclear	28,995,015
Natural Gas, Oil, and Biogas	23,564,722
Coal	5,489,722
Hydro – Conventional	600,694
Solar	250,713
Purchased Power – subject to economic dispatch or curtailment	4,771,975
Other Purchased Power	6,289,249
Total Net Generation (may not add to sum due to rounding)	69,961,566

8. The appropriate nuclear capacity factor for use in this proceeding is 92.27%.

9. The North Carolina retail test period sales, adjusted for weather and customer growth, for use in calculating the EMF are 37,911,173 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	16,660,473
Small General Service	1,911,733
Medium General Service	10,553,483
Large General Service	8,443,198
Lighting	342,287
Total (may not add to sum due to rounding)	37,911,173

10. The projected billing period (December 2023-November 2024) sales for use in this proceeding are 63,231,695 MWh on a system basis and 39,238,661 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	17,326,377
Small General Service	1,816,847
Medium General Service	10,471,370
Large General Service	9,239,420
Lighting	384,646
Total (may not add to sum due to rounding)	39,238,661

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 73,018,583 MWh and is categorized as follows:

Generation Type	MWh
Nuclear	29,122,107
Gas Combustion Turbine ("CT") and Combined Cycle ("CC")	24,747,254
Coal	5,967,395
Hydro	720,836
Solar	270,472
Purchased Power	12,190,519
Total (may not add to sum due to rounding)	73,018,583

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 $6.11/MWh.

B. The gas CT and CC fuel price is $37.76/MWh.

C. The coal fuel price is $43.26/MWh.

D. The appropriate system expense for ammonia, lime, limestone, sorbents, and catalysts consumed in reducing or treating emissions (collectively, "Reagents") is $14,754,777.

E. The appropriate system gains/losses on the sale of by-products produced in the generation of electricity (collectively, "By-products") is $29,238,563.

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 $455,488,186.

G. System fuel expense recovered through intersystem sales is $204,822,948.

13. The projected fuel and fuel-related costs for the North Carolina retail billing period are $1,035,819,220.

14. The Company and the Public Staff entered into a "Stipulation Regarding the Proper Methodology for Determining the Fuel Costs Associated with Power Purchases from Power Marketers and Others" on January 5, 2023 (Fuel Proxy Agreement), Fuel Cost Proxy Percentage Calculation was increased in order to reflect a reasonable approximation of the fuel cost portion of power purchases based on current fuel commodity prices and a changing resource mix. Per the Fuel Proxy Agreement between the Company and the Public Staff, the Company will propose a composite total fuel costs to total energy ratio based upon combined short-term off-system sales for the calendar year. Such composite shall be no greater than 85%, but no less than 75%, and, to the extent that the analysis of annual composite short-term off-system sales revenue falls outside the range of 75% to 85%, the composite proxy percentage will be adjusted accordingly to reflect either the minimum or maximum of the range.

15. The Company's appropriate North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $444,779,840, consisting of under-recoveries of $198,458,092, $20,080,608, $115,027,848, $105,463,134, and $5,750,159, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively. These amounts include the $4,117,128 deferred under-recovered losses on the sale of by-products from the prior year as follows: $1,724,227, $205,451, $1,200,078,

$946,881, and $40,491, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively. The sum of class amounts may not foot to the NC retail totals due to rounding.

16. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1292 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology as approved by the Commission in that docket, but discontinued for use in the 2024 DEP fuel proceeding as instructed in the general base rates Order in Docket No. E-2, Sub 1300, which was issued on August 18, 2023.

17. 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: 2.882¢/kilowatt-hour ("kWh") for the Residential class; 3.284¢/kWh for the Small General Service class; 2.563¢/kWh for the Medium General Service class; 2.112¢/kWh for the Large General Service class; and 4.051¢/kWh for the Lighting class.

18. The appropriate EMFs established in this proceeding, excluding the regulatory fee, are as follows: 1.191¢/kWh for the Residential class; 1.050¢/kWh for the Small General Service class; 1.090¢/kWh for the Medium General Service class; 1.249¢/kWh for the Large General Service class; and 1.680¢/kWh for the Lighting class.

19. The total net fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 4.073¢/kWh for the Residential class; 4.334¢/kWh for the Small General Service class; 3.653¢/kWh for the Medium General Service class; 3.361¢/kWh for the Large General Service class; and 5.731¢/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, 2023.

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 Flanagan and Simril, the Supplemental testimony of Company Witness Harrington, and the joint testimony of Public Staff witnesses Lawrence and 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 Simril testified that DEP's nuclear fleet consists of three generating stations and a total of four units. He testified that the Company's four nuclear units operated at a system average capacity factor of 92.12% during the test period. Both this annual capacity factor, and the Company's 2-year average capacity factor of 93.06%, fell below the five-year industry average capacity factor of 93.92% for the period 2017-2021 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 three refueling outages.

Public Staff witnesses Lawrence and Metz affirm that the Company's actual system nuclear capacity factor for the test year was 92.12% and that the NERC five-year average (2017-2021) weighted for the size and type of reactors in DEP's nuclear fleet was 93.92%.

Company witness Flanagan testified concerning the performance of DEP's Traditional and Renewable (formerly called Fossil/Hydro/Solar) 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: 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 maintenance (*i.e.*, forced) outage time); 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); starting reliability ("SR"), which represents the percentage of successful starts; and 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 Flanagan 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 2017 through 2021:

DEP Comparison to NERC Five Year Average				
Generator Type	**Measure**	**Review Period* DEP Operational Results**	**2017-2021 NERC Average**	**Number of Units**
Coal Fired Test Period	EAF	63.23%	78.77%	182
	NCF	19.79%	52.30%	
	EFOF	9.22%	n/a	
*Coal Fired Summer Peak***	EAF	82.71%	n/a	n/a
Total CC Average	EAF	73.89%	84.41%	342
	NCF	65.70%	54.21%	
	EFOF	0.69%	n/a	
Total CT Average	EAF	76.22%	86.06%	680
	SR	99.15%	98.64%	
Hydro	EAF	68.95%	78.89%	909
Solar	NCF	20.31%	n/a	n/a

* Trailing 12 months ending 3/31/2023

** June, July, August

Company witness Flanagan also testified that for the review period, approximately 51% of the Company's total system generation was provided by the Traditional/Renewables fleet of which 40% was contributed from gas facilities, 9% contributed from coal-fired stations, 1% contributed by hydro sources, and 0.4% from solar facilities.

The joint testimony of Public Staff witnesses Lawrence and Metz elaborated on notable outages during the test period and the impact of Winter Storm Elliott. They referred to Witness Metz's testimony in the DEP general base rates case (Docket No. E-2, Sub 1300) regarding general trends in generating unit performance and staffing levels associated with plant availability and reliability.

As discussed in the Supplemental testimony of DEP witness Dana Harrington, the Company and the Public Staff agreed that a credit of $300,000 to the North Carolina Retail share of system fuel expenses is a reasonable adjustment to replacement power costs as a result of the Robinson Nuclear Station outage which occurred from December 30, 2023, to January 1, 2023.

Based upon the evidence in the record, the Commission concludes any issues with respect to the performance of DEP's nuclear plants are adequately addressed and resolved through the agreement between the Public Staff and the Company and the Company otherwise 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 Docket No. E-100, Sub 47A in 2015, and were in effect throughout the 12 months ending March 31, 2023. 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, Swez, Flanagan, and Public Staff witnesses Lawrence and Metz.

Company witness Harrington testified that key factors in DEP's ability to maintain lower fuel and fuel-related rates include its generating portfolio of diverse fuel sources, the capacity factors of its nuclear fleet, and fuel procurement strategies, which mitigate volatility in supply costs. 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 testified that DEP's nuclear fuel procurement practices involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of 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, 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, 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, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Company witness Swez described DEP's fossil fuel procurement practices, set forth in Swez Exhibit 1. Those practices include: computing near and long-term consumption forecasts using stochastic cost production modeling, developing 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 spot purchases to supplement existing natural gas supply commitments, 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 Swez, the Company's average delivered coal cost per ton increased approximately 13%, from $84.26 per ton in the prior test period to $95.13 per ton in the current test period. The Company's transportation costs decreased approximately 5%, from $35.15 per ton in the prior test period to $33.34 per ton in the current test period.

Witness Swez also testified that the Company's average price of gas purchased for the current test period was $8.15 per Million British Thermal Units ("MMBtu"), compared to $5.44 per MMBtu in the prior test period, representing an increase of approximately 50%. The cost of gas is inclusive of gas supply, transportation, storage, and financial hedging.

Witness Swez testified 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 to record levels by late 2021 and limited coal supply availability. Continued labor and resource constraints, including the threat of a rail strike in the fourth quarter of 2022, caused prices to remain elevated over the course of 2022. Going into winter 2022 (December 2022 through February 2023), coal commodity costs remained at historically high levels but began to soften in response to rapidly declining natural gas prices and an overall lack of winter weather demand. Despite current market conditions, coal producers are seeing the inflationary impacts of rising costs associated with mining operations including, but not limited to, labor and equipment costs putting additional pressure on their ability to respond to changes in market demand.

Witness Swez stated that DEP's current coal burn projection for the billing period is 2.5 million tons compared to 2.4 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 $108.60 per ton for the billing period compared to $95.13 per ton in the test period. This projected delivered cost is subject to change based on, but not limited to, the following factors: exposure to market prices and their impact on open coal positions; the amount of Central Appalachian coal DEP is able to purchase and deliver and the non-Central Appalachian coal DEP is able to consume; changes in transportation rates; performance of contract deliveries by suppliers and railroads that may not occur despite the Company's strong contract compliance monitoring process; and potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

Witness Swez further testified that DEP's current natural gas burn projection for the billing period is approximately 197.5 million MBtu, which is an increase from the 179.6 million MBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $3.34 per MMBtu, compared to $6.26 per MMBtu in the test period.

According to witness Swez, 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.

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 Flanagan testified that the Company's Traditional/Renewables generation portfolio consists of 8,945 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. 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 Flanagan further testified 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/or 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 Swez testified that both DEP and DEC perform the same detailed daily process to determine the unit commitment plan that economically and reliably meets the Company's 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. 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 customer energy demand; the latest forecasted fuel prices that are reflective of market supply chain dynamics; variable transportation rates; planned maintenance and refueling outages; generating unit performance parameters; reliability constraints such as units run to maintain day-ahead planning reserves or units required to run for transmission or voltage support; and expected market conditions associated with power purchases and off-system sales opportunities; and projected variable renewable resource contributions (i.e. solar). 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.

No party presented testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any testimony to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

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 the exhibits sponsored by Company witness Harrington, the test period per book system sales were 60,895,867 MWh, and test period per book system generation (net of auxiliary use) and purchased power amounted to 69,961,566 MWh. The test period per book system generation and purchased power are categorized as follows (Harrington Exhibit 8):

Net Generation Type	MWh
Nuclear	28,995,015
Natural Gas, Oil and Biogas	23,564,722
Coal	5,489,198
Hydro – Conventional	600,694
Solar	250,713
Purchased Power – subject to economic dispatch or curtailment	4,771,975
Other Purchased Power	6,289,249
Total Net Generation (may not add to sum due to rounding)	69,961,566

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 exhibits setting forth per books system sales, generation by fuel type, or 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 60,895,867 MWh and system generation and purchased power of 69,961,566 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 Simril and Harrington and the testimony of Public Staff witnesses Lawrence and 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 Simril proposed using a 92.27% 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 2023-2024 billing period.

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 no party disputed the Company's proposed capacity factor, the Commission concludes that the 92.27% nuclear capacity factor and its associated generation of 29,122,107 MWh per Revised Harrington Exhibit 2A 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.

On her Revised Exhibits 3A through 3F, Company witness Harrington set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 37,911,173 MWh, comprised of Residential class sales of 16,660,473 MWh, Small General Service sales of 1,911,733 MWh, Medium General Service sales of 10,553,483 MWh, Large General Service sales 8,443,198 MWh, and Lighting class sales of 342,287 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 Revised Harrington Exhibit 2A is 63,231,695 MWh. The projected level of generation and purchased power used was 73,018,583 MWh (calculated using the 92.27% 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	29,122,107
Gas Combustion Turbine and Combined Cycle	24,747,254
Coal	5,967,395
Hydro	720,836
Solar	270,472
Purchased Power	12,190,519
Total (may not add to sum due to rounding)	73,018,583

On her Revised Exhibit 2B, 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 MWh Sales
Residential	17,326,377
Small General Service	1,816,847
Medium General Service	10,471,370
Large General Service	9,239,420
Lighting	384,646
Total (may not add to sum due to rounding)	39,238,661

These class totals were used in Revised Harrington Exhibit 2C 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 Cameron, Harrington, and Swez.

On her Revised Exhibit 2A, 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.

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 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 2C, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,035,819,220. The increase of select purchased power fuel and fuel-related costs within this amount is below the limit of 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 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 $1,035,819,200 is reasonable and complies with the requirements in accordance with 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 FINDING OF FACT NO. 14

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

Company Witness Swez stated that the most recent proxy percentage was established during the 2008 fuel proceeding and that since the 2008 proceeding, the proxy has not been updated. Witness Swez further testified that due to increasing fuel commodity prices and a changing resource mix, the Company and the Public Staff agreed that the fuel proxy established in the 2008 fuel proceeding no longer represents a reasonable approximation of the fuel cost portion of power purchases. Witness Swez testified that the Company and the Public Staff consider it reasonable to continue to use the accepted methodology of using the fuel component of the Companies' off-system sales as a reasonable basis for approximating fuel costs associated with power purchases when actual fuel costs are unavailable or unidentified as a component of the price paid for energy under a power purchase agreement.

Witness Swez testified that, per the Fuel Proxy Agreement between the Company and the Public Staff (a copy of said agreement is found as Exhibit 4 to witness Swez's testimony), starting with the Company's 2023 annual fuel rider proceeding, an annual compilation of actual total fuel and fuel-related costs as a component of total short-term off-system sales revenue is an appropriate basis for estimating fuel costs on power purchases when the actual fuel component is unavailable or unidentified as a component of the price paid for energy under a power purchase contract. Witness Swez states that for the Company's annual fuel rider proceedings filed during 2023-2027, the Company will propose a composite total fuel cost to total energy cost ratio, based on DEP's and Duke Energy Carolinas, LLC's ("DEC") combined short-term off-system sales for the calendar year. Witness Swez states that such composite shall be no greater than 85%, but no less than 75% and that to the extent that the analysis of annual composite short-term off-system sales revenue falls outside the range of 75% to 85%, the composite proxy percentage will be adjusted accordingly to reflect either the minimum or maximum of the range.

The executed Fuel Proxy Agreement between the Company and the Public Staff is provided as Swez Exhibit 4.

No other party presented evidence regarding the methodology for determining fuel costs associated with power purchases from power marketers.

Based upon the evidence in the record as to the appropriate methodology, the Commission concludes that the methodology recommended by Company witness Swez and accepted by the Public Staff in the executed Fuel Proxy Agreement for purposes of determining the fuel cost portion of power purchases is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-19

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Harrington, the testimonies of Public Staff witnesses Lawrence, Metz, and Brown and CIGFUR witness Collins.

Company witness Harrington presented DEP's fuel and fuel-related expense under-collection and prospective fuel and fuel-related cost factors. Company witness Harrington's supplemental testimony sets forth the projected fuel and fuel-related costs, as well as the $444,779,840 of under-collected costs 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 witness Brown agreed that DEP's EMF increment riders for each customer class should be approved based on the following under-recoveries, which include the deferred under-recovered losses on the sale of by-products of $4.1 million that were approved to be included in recoverable fuel costs in Docket No. E-2, Sub 1204:

N.C. Retail Customer Class	Under-Recovery
Residential	$198,458,092
Small General Service	20,080,608
Medium General Service	115,027,848
Large General Service	105,463,134
Lighting	5,750,159
Total (may not add to sum due to rounding)	$444,779,840

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

N.C. Retail Customer Class	EMF Increment (cents/kWh)
Residential	1.191
Small General Service	1.050
Medium General Service	1.090
Large General Service	1.249
Lighting	1.680

Absent any evidence counter to the under-recovered fuel cost balance being requested for recovery in this proceeding of $444,779,840 as of March 31, 2023, the Commission concludes that the EMF increment billing factors as set forth in the testimony of Public Staff witness Brown are reasonable and appropriate for use in this proceeding.

Company witness Harrington calculated the Company's proposed fuel and fuel-related cost factors using a uniform percentage average bill adjustment method of cost allocation to the NC retail customer classes as approved by this Commission in DEP's 2022 annual fuel proceeding.

Public Staff witnesses Lawrence and Metz iterated that the Docket E-2, Sub 1300 Order requires that the Company move away from using the equal percentage change allocation methodology for cost allocation purposes, and instead use a direct energy allocation. They also convey that the Order stated that the change would take effect for any cases filed after the date of the Sub 1300 Order, and specifically noted that the change does not apply to this fuel case.

CIGFUR witness Collins opposed the proposed rate increase citing that it: (1) will impose a burden on DEP's industrial customers; (2) will make North Carolina a less competitive place to do business; and (3) would result in detrimental consequences for both the local economies where these industrial customers operate and the overall North Carolina economy. He referred to matters in Docket E-2, Sub 1300 and the historical evolution of "non-fuel" costs being allowed for cost recovery through the fuel rider as contributing factors to the basis for his recommendation that any increase granted should continue to be spread to classes on an equal percentage basis, consistent with past practice.

Based upon the testimony and exhibits in the record and the Commission's judgment in Docket No. E-2, Sub 1300, the equal percentage method of allocating fuel and fuel-related costs pursuant to North Carolina General Statute § 62-133.2 and Commission Rule R8-55, shall be discontinued for DEP fuel rider proceedings filed after the date of the Docket No. E-2, Sub 1300 Order, but the change shall not apply in Docket No. E-2, Sub 1321. Meaning, the billed rates approved in this proceeding and actual costs to be allocated to NC retail customer classes shall be based on the equal percentage method of allocating fuel and fuel-related costs through the current billing period of November 2023 - December 2024, after which the Company shall discontinue use of the uniform percentage average bill adjustment method of cost allocation.

The Commission concludes that DEP's projected fuel and fuel-related cost of $1,035,819,220 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 testimony of Public Staff witnesses Lawrence and Metz, excluding the regulatory fee, are appropriate.

The Commission also concludes that DEP's EMF under-recovery balance of $444,779,840 was prudently incurred and increment riders for each class set forth in the testimony of Public Staff witness Brown, 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 1292 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 test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party by way of any recommended disallowance. 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 4.073¢/kWh for the Residential class, 4.334¢/kWh for the Small General Service class, 3.653¢/kWh for the Medium General Service class, 3.361¢/kWh for the Large General Service class, and 5.731¢/kWh for the Lighting class, consisting of the prospective fuel and fuel-related cost factors of 2.882¢, 3.284¢, 2.563¢, 2.112¢, and 4.051¢/kWh, and EMF increments of 1.191¢, 1.050¢, 1.090¢, 1.249¢, and 1.680¢/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, all excluding the regulatory fee. The billing factors, both excluding and including the regulatory fee, are shown in Appendix A to this Order.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after December 1, 2023, 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 1300, amounting to 2.808¢/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 (all excluding the regulatory fee), by amounts equal to 0.073¢/kWh, 0.187¢/kWh, (0.017¢)/kWh, (0.026¢)/kWh and 0.676¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 1.192¢/kWh for the Residential class, 1.050¢/kWh for the Small General Service class, 1.090¢/kWh for the Medium General Service class, 1.249¢/kWh for the Large General Service class, and 1.679¢/kWh for the Lighting class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through November 30, 2024;

2. That the Fuel Proxy Agreement between the Company and the Public Staff be accepted and that the change in the fuel cost proxy percentage calculation be applied starting with the 2023 fuel proceeding;

3. 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

4. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustment ordered by the Commission in this Docket, as well as in Docket Nos. E-2, Subs 1320, 1323, and 1324, and file the proposed notice to customers for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of _______, 2023.

NORTH CAROLINA UTILITIES COMMISSION

____

Chief Clerk

Appendix A

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	2.808	0.073	2.881	1.192	-	4.073
Small General Service	3.097	0.187	3.284	1.050	-	4.334
Medium General Service	2.580	(0.017)	2.563	1.090	-	3.653
Large General Service	2.138	(0.026)	2.112	1.249	-	3.361
Lighting	3.376	0.676	4.052	1.679	-	5.731

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	2.812	0.073	2.885	1.194	-	4.079
Small General Service	3.102	0.187	3.289	1.052	-	4.341
Medium General Service	2.584	(0.017)	2.567	1.092	-	3.659
Large General Service	2.141	(0.026)	2.115	1.251	-	3.366
Lighting	3.381	0.677	4.058	1.681	-	5.739

Appendix B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1321

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	
Pursuant to G.S. 62-133.2 and Commission	)	NOTICE TO CUSTOMERS
Rule R8-55 Relating to Fuel and Fuel	)	OF CHANGE IN RATES
Related Cost Adjustments for Electric Utilities	)	

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order in Docket No. E-2, Sub 1321, on __________ __, 2023, after public hearing, approving net fuel and fuel-related rate increases of 1.265, 1.237, 1.073, 1.223, and 2.355 cents per kWh (excluding regulatory fee[1]) for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, or an approximate increase of $208 million on an annual basis, in the fuel and fuel-related rates and charges paid by the retail customers of Duke Energy Progress in North Carolina, effective for service rendered on and after December 1, 2023. The rate increase was ordered by the Commission after review of Duke Energy Progress' fuel and fuel-related expenses during the 12-month period ended March 31, 2023, and represents actual changes experienced by the Company with respect to its reasonable cost of fuel and fuel-related costs during the test period. The total fuel and fuel-related cost factors for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting, and Industrial customer classes are 4.073¢/kWh, 4.334¢/kWh, 3.653¢/kWh, 3.361¢/kWh, and 5.731¢/kWh respectively (excluding regulatory fee).

Overall, the changes in the approved fuel and fuel-related rates described above will result in monthly net rate increases of approximately $6.17 for each 1,000 kWh of residential usage (including regulatory fee).

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of _______, 2023.

NORTH CAROLINA UTILITIES COMMISSION

____
Chief Clerk

[1] NC reg fee multiplier of 1.00147718 will be applied to the stated net fuel and fuel-related rate increases.

CERTIFICATE OF SERVICE

I certify that a copy of the Joint Proposed Order of Duke Energy Progress, LLC and the Public Staff, in Docket No. E-2, Sub 1321, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 19th day of October, 2023.

Ladawn S. Toon
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