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PLACE: Via Videoconference
DATE: Tuesday, June 1, 2021
DOCKET NO.: E-7, Sub 1250
TIME: 1:00 P.M. TO 2:38 P.M.
BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Application of Duke Energy Carolinas, LLC, Pursuant to N.C.G.S. 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities

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A P P E A R A N C E S:

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FOR FAIR UTILITY RATES III:
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Jun 17 2021

A P P E A R A N C E S (Cont'd.):

FOR THE USING AND CONSUMING PUBLIC:

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Jun 17 2021

TABLE OF CONTENTS

EXAMINATIONS

PAGE

PANEL

STEVE IMMEL, JOHN A. VERDERAME (Direct)

Direct Examination by Mr. Kaylor........................14

Cross Examination by Ms. Thompson......................44

Cross Examination by Mr. Moore.........................64

Redirect Examination by Mr. Kaylor.....................66

DEVI GLICK

Direct Examination by..................................69

Cross Examination by..................................123

JOHN A. VERDERAME (Rebuttal)

Direct Examination by Mr. Kaylor......................125

Cross Examination by Mr. Moore........................127

Redirect Examination by Mr. Kaylor....................153

***See Reporter's Note on page 175 regarding testimony of excused witnesses.

BRYAN L. SYKES

Testimony...175

OFFICIAL COPY

Jun 17 2021

TABLE OF CONTENTS

EXAMINATIONS (Cont'd.)

PAGE

KEVIN Y. HOUSTON

Testimony..197

STEVEN D. CAPPS

Testimony..207

JUNE CHIU

Affidavit..222

DUSTIN R. METZ

Testimony..230

TABLE OF CONTENTS

EXHIBITS

IDENTIFIED/ADMITTED

Verderame Exhibits 1-3.......................31/68

(Confidential Verderame Exhibit 3 was filed under seal.)

Duke Energy Carolinas, LLC's Application.....--/68

(Confidential version filed under seal.)

OFFICIAL COPY Jun 17 2021

TABLE OF CONTENTS

EXHIBITS (Cont'd.)

IDENTIFIED/ADMITTED
Exhibits DG-1 and DG-2........................74/125
(Confidential Exhibit DG-2 was
filed under seal.)
Sierra Club Cross Examination
Exhibit Number 1.............................133/152
Sierra Club Cross Examination
Exhibit Number 2.............................137/152
Sierra Club Cross Examination
Exhibit Number 3.............................140/152
Sierra Club Cross Examination
Exhibit Number 4.............................148/152
Sierra Club Cross Examination
Exhibit Number 5.............................152/152
Sykes Exhibits 1-6 (Direct)..................175/175
Sykes Revised Exhibits 1-4 (Supplemental)....175/175
Sykes Exhibits 5-6 (Supplemental)............175/175
Houston Exhibits 1-2.........................197/197
Capps Confidential Exhibit 1.................207/207
(Filed under seal.)
Metz Exhibit 1...............................230/230

OFFICIAL COPY
Jun 17 2021

P R O C E E D I N G S

CHAIR MITCHELL: All right. Good afternoon, everyone. Let's come to order and go on the record, please.

I'm Charlotte Mitchell, Chair of the North Carolina Utilities Commission, and with me this afternoon are the following Commissioners -- when I announce your name, please indicate your presence -- Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I'm here.

CHAIR MITCHELL: Commissioner Gray.

COMMISSIONER GRAY: Present.

CHAIR MITCHELL: Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Yes. Good afternoon.

CHAIR MITCHELL: Commissioner Duffley.

COMMISSIONER DUFFLEY: Good afternoon.

CHAIR MITCHELL: Commissioner Hughes.

COMMISSIONER HUGHES: Good afternoon.

CHAIR MITCHELL: And Commissioner McKissick.

COMMISSIONER McKISSICK: Good afternoon. Present.

CHAIR MITCHELL: I now call for hearing Docket Number E-7, Sub 1250. On February 23rd, 2021, Duke Energy Carolinas, LLC, to which I will refer to hereafter

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Jun 17 2021

as D-E-C, or DEC, filed confidential and public versions of its Application to address the fuel and fuel-related cost components of its electric utility rates, together with the testimony and exhibits of Bryan Sykes, Kevin Houston, John Verderame, Steve Immel, and Steven Capps. The proceeding was assigned Docket Number E-7, Sub 1250.

On March 18th, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice which, among other things, scheduled a public witness hearing and an expert witness hearing for June 1st, to be held remotely -- both of which were to be held remotely due to the COVID-19 pandemic.

The Carolina Utility Customer Assoc--- Carolina Utility Customers Association, Inc., the North Carolina Sustainable Energy Association, the Sierra Club, and the Carolina Industrial Group for Fair Utility Rates III petitioned for and were granted the right to intervene in this proceeding. The Public Staff is also a party to the proceeding by operation of North Carolina General Statute 62-15(d).

On March 29th, 2021, DEC filed supplemental testimony and exhibits of Bryan Sykes.

On May 10th, 2021, the Public Staff filed a

OFFICIAL COPY

Jun 17 2021

Notice of Affidavit, the Affidavit of June Chiu, and the direct testimony of Dustin Metz.

On May 17th, 2021, the Sierra Club filed confidential and public versions of the direct testimony and exhibits of Devi Glick.

On May 24th, 2021, DEC and the Public Staff filed a Joint Motion to request that Company witnesses Sykes, Houston, and Capps, and Public Staff witnesses Chiu and Metz be excused from appearing at the expert witness hearing, and that the prefiled testimony, exhibits, and affidavits of the respective witnesses be received into evidence and made a part of the record in this matter. This motion was allowed by Order of the Commission dated May 28, 2021.

On May 27th, 2021, DEC filed a motion requesting that the public witness hearing scheduled for this proceeding be canceled due to the fact that no public witnesses had registered to testify, which motion was allowed by Order of the Commission dated May 28th, 2021. Also on May 27th, 2021, DEC filed the rebuttal testimony of John Verderame.

On May 25th and on May 27th, DEC filed Affidavits of Publication for the initial public notice and second public notice, as required by the Commission's

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Jun 17 2021

Scheduling Order in this matter.

All right. That brings us to today. Each of the parties to the proceeding filed in this docket consent to hold the evidentiary by -- the evidentiary hearing by remote means.

Let me remind you, as we're conducting the hearing remotely, please be mindful of not causing or creating interference with my ability or with the court reporter's ability to hear the witnesses or counsel. Please do not unmute your microphone if you are not speaking. If you must speak during the proceeding, please indicate your name first so that the court reporter and I can be certain as to who is speaking.

Okay. Let's get started. Pursuant to the State Ethics Act, I remind all members of the Commission of their duty to avoid conflicts of interest, and inquire at this time as to whether any Commissioner has a known conflict of interest with respect to the matters coming before us this afternoon?

(No response.)

CHAIR MITCHELL: All right. The record will reflect that no conflicts have been identified, so we'll go ahead and proceed. I'll call upon the parties to announce their appearances, beginning with DEC.

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Jun 17 2021

MR. KAYLOR: Chair Mitchell, Robert Kaylor appearing on behalf of Duke Energy Carolinas.

CHAIR MITCHELL: All right. Good afternoon, Mr. Kaylor. All right. Intervenors?

MS. THOMPSON: Good afternoon, Chair Mitchell, members of the Commission. This is Gudrun Thompson appearing on behalf of the Sierra Club, and with me is my co-counsel Tirrill Moore, also appearing on behalf of the Sierra Club.

CHAIR MITCHELL: Good afternoon, Ms. Thompson.

MR. CREECH: Good afternoon, Chair Mitchell, and other members of the Commission. I'm William Zeke Creech with the Public Staff, and joining me is John Little, all on behalf of the Using and Consuming Public.

CHAIR MITCHELL: All right. Good afternoon, Mr. Creech.

MR. GRAY: Madam Chairman, this is Jeff Gray with the law firm of Bailey & Dixon, appearing on behalf of the Intervenor Carolina Industrial Group for Fair Utility Rates III, or CIGFUR III.

CHAIR MITCHELL: Good afternoon, Mr. Gray. Any other counsel making an appearance today?

(No response.)

CHAIR MITCHELL: All right. Before we begin,

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Jun 17 2021

then, any preliminary matters that the Commission needs to take up before we move into the hearing?

MR. KAYLOR: Chair Mitchell, Robert Kaylor on behalf of Duke Energy. We would like to offer as a panel for their direct testimony our witness Immel and Verderame, and then -- because the parties indicate there would be cross of both of them, and then we would like for them to step down, and after Sierra witness Glick testifies, we'd like to bring Mr. Verderame back for his rebuttal testimony.

CHAIR MITCHELL: All right. Thank you, Mr. Kaylor. Any objections to order of witnesses as proposed by Mr. Kaylor? Ms. Thompson?

(No response.)

CHAIR MITCHELL: All right. I'm hearing no objection, so Mr. Kaylor -- Ms. Thompson, there you are. Any objection? Ms. Thompson, your video is going in and out.

MS. THOMPSON: Sorry. I turned it on and then turned it off again, Chair Mitchell. We have no objection to that. Just one thing to note, we had conferred with Duke counsel about having two attorneys cross the panel, one for Mr. Immel and one for Verderame, and counsel for Duke had indicated no objection to that,

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Jun 17 2021

and so with that, no objection to them being presented as a panel.

CHAIR MITCHELL: Okay. Thank you, Ms. Thompson.

MR. CREECH: No objection from the Public Staff.

CHAIR MITCHELL: All right. Thank you, Mr. Creech.

MR. GRAY: And no objection from CIGFUR.

CHAIR MITCHELL: All right. With that, we will proceed. Mr. Kaylor, the case is with you.

MR. KAYLOR: Yes. We would call Steve Immel. Mr. Immel?

MR. IMMEL: I'm here, Robert, yes.

CHAIR MITCHELL: All right. Mr. Kaylor, do you want to call both of your witnesses? That way we can affirm them at the same -- get them --

MR. KAYLOR: Yes. I will call Mr. Verderame, also.

CHAIR MITCHELL: Okay. All right. Mr. Verderame, let me make sure I -- there you are. Mr. Immel, where are you on my screen? All right. There you are, Mr. Immel.

JOHN A. VERDERAME and

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Jun 17 2021

STEVE IMMEL; Having first been duly affirmed,
Testified as follows:

CHAIR MITCHELL: All right, Mr. Kaylor.

MR. KAYLOR: Thank you.

DIRECT EXAMINATION BY MR. KAYLOR:

Q Mr. Immel, state your name and address for the record, please.

A (Immel) Steve Immel. I work at Duke Energy at -- located at 526 South Church Street in Charlotte, North Carolina.

Q And in what capacity do you work for Duke Energy?

A I am the Vice President of the Fleet Transition Strategy.

Q And did you prefile testimony, direct testimony, in this proceeding?

A Yes, sir. I did.

Q Do you have any additions or corrections to that prefiled testimony?

A No, sir.

Q At this time, would you proceed to -- I believe you made a summary of that. Would you proceed --

MR. KAYLOR: Well, first, I would ask the Chair that that testimony be copied into the record as if given

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Jun 17 2021

orally.

CHAIR MITCHELL: All right, Mr. Kaylor. Hearing no objection to your motion, the 12 pages of direct testimony filed on February 23rd, 2021 by witness Steve Immel shall be copied into the record as if given orally from the stand.

MR. KAYLOR: Thank you.

(Whereupon, the prefiled direct testimony of Steve Immel was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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

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Jun 17 2021

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steve Immel and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy and am the Vice President ("VP") of Fleet Transition Strategy.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of Kentucky with a Bachelor of Science degree in Civil Engineering and a Masters of Business Administration from Queens College. My career began with Duke Energy (d/b/a Duke Power) in 1980 as an Associate Design Engineer. Since that time, I have held various roles of increasing responsibility in corporate facilities, investment recovery, supply chain, and operations areas, including the role of Hydro Manager; Station Manager at Duke Energy Carolinas, LLC's ("DEC" or the "Company") Allen Steam Station and then Marshall Steam Station. I was named VP of Duke Energy Indiana's Midwest Regulated Operations in 2012 and VP of Outage and Project Services in 2014. In 2016, I was named to VP of Carolinas Coal Generation for the Company and Duke Energy Progress, LLC. I assumed my current role in 2020.

Q. WHAT ARE YOUR CURRENT DUTIES AS VP OF FLEET TRANSITION STRATEGY?

A. In this role, I am responsible for developing strategies to address various integrated resource plan ("IRP") scenarios and related plans for the Fossil/Hydro/Solar workforce.

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Jun 17 2021

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified before the North Carolina Utilities Commission on behalf of the Company in its most recent general rate case in Docket No E-7, Sub 1214.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (1) describe DEC's Fossil/Hydro/Solar generation portfolio and changes made since the 2020 fuel and fuel-related cost recovery proceeding, as well as those expected in the near term, (2) discuss the performance of DEC's Fossil/Hydro/Solar facilities during the test period of January 1, 2020 through December 31, 2020 (the "test period"), (3) provide information on significant Fossil/Hydro/Solar outages that occurred during the test period, and (4) provide information concerning environmental compliance efforts.

Q. PLEASE DESCRIBE DEC'S FOSSIL/HYDRO/SOLAR GENERATION PORTFOLIO.

A. The Company's Fossil/Hydro/Solar generation portfolio consists of approximately 15,043 megawatts ("MWs") of generating capacity, made up as follows:

Coal-fired -	6,764 MWs
Steam Natural Gas -	170 MWs
Hydro -	3,277 MWs
Combustion Turbines ("CT") -	2,633 MWs
Combined Cycle Turbines ("CC")-	2,116 MWs

Solar - 71 MWs

Combined Heat and Power ("CHP") - 13 MWs

The coal-fired assets consist of four generating stations with a total of 13 units. These units are equipped with emissions control equipment, including selective catalytic or selective non-catalytic reduction ("SCR" or "SNCR") equipment for removing nitrogen oxides ("NO_x"), and flue gas desulfurization ("FGD" or "scrubber") equipment for removing sulfur dioxide ("SO_2"). In addition, all 13 coal-fired units are equipped with low NO_x burners. The steam natural gas unit – Lee Station ("Lee") Unit 3 – is considered to be a peaking unit.

The Company has a total of 31 simple cycle CT units, of which 29 are considered the larger group providing approximately 2,549 MWs of capacity. These 29 units are located at Lincoln, Mill Creek, and Rockingham Stations, and are equipped with water injection systems that reduce NO_x and/or have low NO_x burner equipment in use. The Lee CT facility includes two units with a total capacity of 84 MWs equipped with fast-start ability in support of DEC's Oconee Nuclear Station. The Company has 2,116 MWs of CC turbines, comprised of the Buck CC, Dan River CC and W.S. Lee CC facilities. These facilities are equipped with technology for emissions control, including SCRs, low NO_x burners, and carbon monoxide/volatile organic compounds catalysts. The Company's hydro fleet includes two pumped storage facilities with four units each that provide a total capacity of 2,220 MWs, along with conventional hydro assets consisting of 59 units providing approximately 1,057 MWs of capacity. The 71 MWs of solar capacity are made up of 17 roof top solar sites providing 3 MWs of relative summer dependable capacity, the Mocksville solar facility providing 6 MWs of

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Jun 17 2021

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relative summer dependable capacity, the Monroe solar facility providing 22 MWs of relative summer dependable capacity, Woodleaf solar facility providing 2 MWs of relative summer dependable capacity, Gaston solar facility providing 10 MW of relative summer dependable capacity and Maiden Creek solar facility providing 28 MW of relative summer dependable capacity. Finally, the Company has the Clemson CHP that provides 12.5 MW of capacity.

Q. WHAT CHANGES HAVE OCCURRED WITHIN THE FOSSIL/HYDRO/SOLAR PORTFOLIO SINCE DEC'S 2019 FUEL AND FUEL-RELATED COST RECOVERY PROCEEDING?

A. Marshall Unit 3 was upgraded in November 2020 to allow for co-fired operation, allowing utilization of coal and natural gas. Gaston solar facility went into service in December 2020 and will provide the DEC territory with 10 MW of capacity. Maiden Creek solar facility went into service in January 2021 and will provide the DEC territory with 28 MW of capacity. Bad Creek Unit 2 was upgraded in October 2020, increasing the unit's capacity by 80 MWs.

Q. WHAT ARE DEC'S OBJECTIVES IN THE OPERATION OF ITS FOSSIL/HYDRO/SOLAR FACILITIES?

A. The primary objective of DEC's Fossil/Hydro/Solar generation department is to provide safe, reliable and cost-effective electricity to DEC's customers. Operations personnel and other station employees are well-trained and execute their responsibilities to the highest standards in accordance with procedures, guidelines, and a standard operating model.

The Company complies with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure

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Jun 17 2021

reliability for customers. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power options for DEC's customers. Equipment inspection and maintenance outages are generally scheduled during the spring and fall months when customer demand is reduced due to milder temperatures. These outages are well-planned and executed in order to prepare the unit for reliable operation until the next planned outage in order to maximize value for customers.

Q. WHAT IS HEAT RATE?

A. Heat rate is a measure of the amount of thermal energy needed to generate a given amount of electric energy and is expressed as British thermal units ("Btu") per kilowatt-hour ("kWh"). A low heat rate indicates an efficient fleet that uses less heat energy from fuel to generate electrical energy.

Q. WHAT HAS BEEN THE HEAT RATE OF DEC'S COAL UNITS DURING THE TEST PERIOD?

A. Over the test period, the average heat rate for DEC's coal fleet was 9,865 Btu/kWh. DEC's Rogers Energy Complex ("Cliffside"), Belews Creek Steam Station ("Belews Creek"), and Marshall Steam Station ("Marshall") have typically ranked as some of the most efficient coal-fired generating stations in the nation, with heat rates of 9,519, Btu/kWh, 9,871 Btu/kWh, and 9,941 Btu/kWh, respectively. For the test period, the Marshall units provided 35% of coal-fired generation for DEC, with the Belews Creek units providing 31% and Cliffside providing 31%.

Q. HOW MUCH GENERATION DID EACH TYPE OF FOSSIL/HYDRO/SOLAR GENERATING FACILITY PROVIDE FOR THE TEST PERIOD AND HOW DOES DEC UTILIZE EACH TYPE OF GENERATING FACILITY TO SERVE CUSTOMERS?

A. The Company's system generation totaled 95 million MW hours ("MWhs") for the test period. The Fossil/Hydro/Solar fleet provided 35 million MWhs, or approximately 37% of the total generation. As a percentage of the total generation, 16% was produced from coal-fired stations and approximately 15% from CC operations, 1% from CTs, 2.5% from hydro facilities, and 0.16% from solar.

The Company's portfolio includes a diverse mix of units that, along with additional nuclear capacity, allows DEC to meet the dynamics of customer load requirements in a cost-effective manner. Additionally, DEC has utilized the Joint Dispatch Agreement, which allows generating resources for DEC and DEP to be dispatched as a single system to enhance dispatching by allowing DEC customers to benefit from the lowest cost resources available. The cost and operational characteristics of each unit generally determine the type of customer load situation (*e.g.*, base and peak load requirements) that a unit would be called upon, or dispatched, to support.

Q. HOW DID DEC COST EFFECTIVELY DISPATCH ITS DIVERSE MIX OF GENERATING UNITS DURING THE TEST PERIOD?

A. The Company, like other utilities across the U.S., has experienced a change in the dispatch order for each type of generating facility due to continued favorable economics resulting from low pricing of natural gas. Further, the addition of new

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Jun 17 2021

CC units within the Carolinas' portfolio in recent years has provided DEC with additional natural gas resources that feature state-of-the-art technology for increased efficiency and significantly reduced emissions. These factors promote the use of natural gas and provide real benefits in cost of fuel and reduced emissions for customers.

Q. PLEASE DISCUSS THE OPERATIONAL RESULTS FOR DEC'S FOSSIL/HYDRO/SOLAR FLEET DURING THE TEST PERIOD.

A. The Company's generating units operated efficiently and reliably during the test period. The following key measures are used to evaluate the operational performance depending on the generator type: (1) equivalent availability factor ("EAF"), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (*i.e.*, forced) outage time); (2) net capacity factor ("NCF"), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF *is* affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate ("EFOR"), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated[1] hours); a low EFOR represents fewer unplanned outages and derated hours, which equates to a higher reliability measure; and (4) starting reliability ("SR"), which represents the percentage of successful starts. For 2021,

[1] Derated hours are hours the unit operation was less than full capacity.

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the Company is including another measure to assess plant reliability—equivalent forced outage factor ("EFOF")—which quantifies the number of period hours in a year during which the unit is unavailable because of forced outages and forced deratings.

The following chart provides operation results, as well as results from the most recently published North American Electric Reliability Council ("NERC") Generating Availability Brochure ("NERC Brochure") representing the period 2015 through 2019 and is categorized by generator type. The NERC data reported represents an average of comparable units based on capacity rating. The data in the chart reflects DEC results compared to the NERC five-year averages.

Generator Type	Measure	Review Period	2015 - 2019	Nbr of Units
		DEC Operational Results	NERC Average	
Coal-Fired Test Period	EAF	72.3%	76.5%	705
	EFOR	15.1%	9.6%	
	EFOF	7.0%	n/a	
Coal-Fired Summer Peak	EAF	78.7%	n/a	n/a
Total CC Average	EAF	86.1%	84.9%	350
	NCF	73.1%	54.8%	
	EFOR	0.55%	4.9%	
	EFOF	0.48%	n/a	
Total CT Average	EAF	83.5%	86.9%	746
	SR	99.0%	98.4%	
Hydro	EAF	77.4%	79.9%	1,060

Q. PLEASE DISCUSS SIGNIFICANT OUTAGES OCCURRING AT DEC'S FOSSIL/HYDRO/SOLAR FACILITIES DURING THE TEST PERIOD.

A. In general, planned maintenance outages for all fossil and larger hydro units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. Most of these units had at least one small planned outage during this test period to inspect and maintain plant equipment.

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Jun 17 2021

In the Spring 2020, Cliffside Unit 5 performed a boiler outage. The primary purpose of the outage was to perform Mercury and Air Toxics Standards ("MATS") boiler repairs, absorber recycle pump upgrade, turbine bearing inspection and repairs, motor transformer replacement, and safety relief valves inspection and repairs. Cliffside Unit 6 also performed a boiler outage. The primary purpose of the outage was to perform MATS boiler repairs, turbine valve inspections and repairs, and recirculating pump replacement. Marshall Unit 3 performed an outage to change out the burners for the Dual Fuel Optionality ("DFO") conversion project. The outage was stopped for the COVID-19 pandemic. The work re-commenced with updated health and safety measures in place. Belews Creek Unit 1 performed an outage to repair the High Pressure and Low-Pressure hydrogen coolers. Rockingham CT Unit 3 and Unit 4 performed an outage to install new exhaust stack silencers. Lincoln CT Unit 1 through Unit 8 had an outage to perform switchyard work to tie in Unit 17. Lincoln CT Unit 13 and Unit 14 had an outage to upgrade generator breaker relay for NERC compliance.

In the Fall 2020, Rockingham CT Unit 5 performed an outage to conduct a hot gas path inspection. Buck CC had an outage to perform steam turbine inspections, valve upgrades, gas turbine generator inspections, and high energy piping inspections. Marshall Unit 3 had an outage to install the remaining gas piping for the DFO project, install flame monitoring equipment, and install gas igniters. Marshall Unit 4 had an outage to install gas burners for DFO project, control upgrades, and inspection of high energy piping. Allen Unit 1 had an outage to inspect and repair turbine oil coolers.

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Jun 17 2021

Q. HOW DOES DEC ENSURE EMISSIONS REDUCTIONS FOR ENVIRONMENTAL COMPLIANCE?

A. The Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for NO_x and SO_2 emissions. The SCR technology that DEC currently operates on the coal-fired units uses ammonia or urea for NO_x removal. The SNCR technology employed at Allen Station and Marshall Units 1, 2 and 4 injects urea into the boiler for NO_x removal. All DEC coal units have wet scrubbers installed that use crushed limestone for SO_2 removal. Cliffside Unit 6 has a state-of-the-art SO_2 reduction system that couples a wet scrubber (*e.g.*, limestone) and dry scrubber (*e.g.*, quicklime). SCR equipment is also an integral part of the design of the Buck, Dan River and Lee CC Stations in which aqueous ammonia is introduced for NO_x removal.

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. The Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. Overall, the goal is to effectively comply with emissions regulations and provide the optimal total-cost solution for the operation of the unit. The Company will continue to leverage new technologies and chemicals to meet both present and future state and federal emission requirements including the MATS rule. MATS chemicals that DEC uses when required to reduce emissions include, but may not be limited to, activated carbon, mercury oxidation chemicals, and mercury re-emission prevention chemicals. Company witness Sykes provides the cost information for DEC's chemical use and forecast.

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

A. Yes, it does.

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Feb 17 2021

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Jun 17 2021

Q Mr. Immel, would you proceed with a summary of your direct testimony?

A Yes, sir. The purpose of my testimony is to describe DEC's fossil/hydro generation portfolio, discuss the performance of DEC's fossil/hydro facilities during the review period of January 1st, 2020 through December 31st, 2020, provide information on significant fossil/hydro outages that occurred during the review period, and discuss DEC's environmental compliance efforts.

DEC's fossil/hydro generation portfolio consists of approximately 15,043 MW of generating capacity. This includes 6,764 MW of coal-fired generation, 3,277 MW of hydroelectric generation, 2,633 MW of natural gas combustion turbine generation, 2,116 MW of natural gas combined cycle generation, 170 MW of steam natural gas, 71 MW of solar, and 13 MW of combined heat and power.

The Company's fossil/hydro generating units operated efficiently and reliably during the review period. DEC's total system generation was 95 million MWh, of which approximately 37 percent was provided by the fossil/hydro fleet. The breakdown includes 16 percent contribution from coal-fired stations,

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Jun 17 2021

approximately 15 percent contribution from combined cycle operations, 1 percent contribution from the CTs, the combustion turbines, and 2.5 percent contribution from the hydro facilities, and 0.2 of a percent from the solar facilities. This concludes my direct testimony summary.

MR. KAYLOR: Thank you, Mr. Immel.

Q Mr. Verderame, would you please state your name and address for the record, please?

A (Verderame) Good afternoon. My name is John Verderame. I work for Duke Energy at 526 South Church Street, Charlotte, North Carolina.

Q And in what capacity are you employed by the Company?

A I'm the Vice President of the Fuels and Systems Optimization Group.

Q And did you cause to have prefiled testimony direct -- in this proceeding direct testimony consisting of 11 pages?

A I did.

Q Do you have any additions or corrections to that testimony?

A No, I don't.

Q And did you also have, I believe, three direct exhibits; is that correct?

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Jun 17 2021

A That's correct.
Q And I believe one of those was confidential; is that correct?
A That's correct.
MR. KAYLOR: Madam Chair, at this time I would ask that the direct testimony of Mr. Verderame be copied into the record as if given orally on the stand today.
CHAIR MITCHELL: All right, Mr. Kaylor. Hearing no objection to that motion, the direct testimony of Mr. Verderame, filed on February 23rd, 2021, consisting of 11 pages, will be copied into the record as if delivered orally from the stand.
MR. KAYLOR: And that his exhibits be identified as they are marked.
CHAIR MITCHELL: And the three exhibits attached to that testimony will be identified as marked when prefiled, noting that one of them is confidential.
MR. KAYLOR: Thank you.

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(Whereupon, the prefiled direct testimony of John A. Verderame was copied into the record as if given orally from the stand.)

(Verderame Exhibits 1-2 and Confidential Verderame Exhibit 3 were identified as premarked.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John A. Verderame. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Vice President, Fuels & Systems Optimization for Duke Energy Corporation ("Duke Energy"). In that capacity, I lead the organization responsible for the purchase and delivery of coal, natural gas, fuel oil, and reagents to Duke Energy's regulated generation fleet, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas," "DEC," or the "Company") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"). In addition, I manage the fleet's power trading, system optimization, energy supply analytics, and contract administration functions.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics from the University of Rochester in 1983, and a Master's in Business Administration in Finance from Rutgers University in 1985. I have worked in the energy industry for 19 years. Prior to that, from 1986 to 2001, I was a Vice President in the United States (US) Government Bond Trading Groups at the Chase Manhattan Bank and Cantor Fitzgerald. My responsibilities as a US Government Securities Trader included acting as the Firm's market maker in US Government Treasury securities. I joined Progress Energy, in 2001, as a Real-Time Energy Trader. My responsibilities as a Real-Time Energy Trader included managing the real-time energy position of the Progress Energy regulated utilities. In 2005, I was

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Jun 17 2021

promoted to Manager of the Power Trading group. My role as manager included responsibility for the short-term capacity and energy position of the Progress Energy regulated utilities in the Carolinas and Florida.

In 2012, upon consummation of the merger between Duke Energy Corp. and Progress Energy, Progress Energy became Duke Energy Progress and I was named Managing Director, Trading and Dispatch. As Managing Director, Trading and Dispatch I was responsible for Power and Natural Gas Trading and Generation Dispatch on behalf of Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I assumed my current position in November 2019.

Q. HAVE YOU TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDING?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe DEC's fossil fuel purchasing practices, provide actual fossil fuel costs for the period January 1, 2020 through December 31, 2020 ("test period") versus the period January 1, 2019 through December 31, 2019 ("prior test period"), and describe changes projected for the billing period of September 1, 2021 through August, 31 2022 ("billing period").

Q. YOUR TESTIMONY INCLUDES THREE EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Verderame Exhibit 1, which summarizes the Company's Fossil Fuel Procurement Practices, Verderame Exhibit 2, which summarizes total monthly natural gas purchases and monthly contract and spot coal purchases for the test period and prior test period, and Verderame Confidential Exhibit 3, which summarizes the annual fuels related transactional activity between DEC and Piedmont Natural Gas Company, Inc. ("Piedmont") for spot commodity transactions during the test period, as required by the Merger Agreement between Duke Energy and Piedmont.

Q. PLEASE PROVIDE A SUMMARY OF DEC'S FOSSIL FUEL PROCUREMENT PRACTICES.

A. A summary of DEC's fossil fuel procurement practices is set out in Verderame Exhibit 1.

Q. HOW DOES DEC OPERATE ITS PORTFOLIO OF GENERATION ASSETS TO RELIABLY AND ECONOMICALLY SERVE ITS CUSTOMERS?

A. Both DEC and DEP utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider factors that include, but are not limited to, the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their respective customers.

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Q. PLEASE DESCRIBE THE COMPANY'S DELIVERED COST OF COAL AND NATURAL GAS DURING THE TEST PERIOD.

A. The Company's average delivered cost of coal per ton for the test period was $90.53 per ton, compared to $82.11 per ton in the prior test period, representing an increase of approximately 10%. The cost of delivered coal includes an average transportation cost of $35.07 per ton in the test period, compared to $28.33 per ton in the prior test period, representing an increase of approximately 24% and also includes $24.8 million in costs associated with the mitigation of coal contract obligations related to COVID-19 load losses, as is described in more detail below. The Company's average price of gas purchased for the test period was $2.94 per Million British Thermal Units ("MMBtu"), compared to $3.40 per MMBtu in the prior test period, representing a decrease of approximately 14%. The cost of gas is inclusive of gas supply, transportation, storage and financial hedging.

DEC's coal burn for the test period was 5.9 million tons, compared to a coal burn of 8.1 million tons in the prior test period, representing a decrease of 28%. The Company's natural gas burn for the test period was 135.4 MMBtu, compared to a gas burn of 123.9 MMBtu in the prior test period, representing an increase of approximately 9%.

As a result of load reduction from the COVID-19 pandemic, extremely low natural gas prices, and mild winter weather, the Company experienced a significant shift in generation from coal to natural gas. The COVID-19 pandemic had an unprecedented and unanticipated impact on forecasted load in 2020, which in turn reduced coal demand and required inventory mitigation beyond the Company's typical no-cost mitigation measures. Influenced by the

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Mar 17 2021

operational realities from the pandemic, DEC burned significantly less coal than anticipated, and customers benefited from greater utilization of lower-cost natural gas.

Given the reduction in actual and forecasted coal usage for the balance of 2020, the Company was required to evaluate alternatives to reduce its coal contract obligations for 2020 that exceeded its consumption and storage capabilities. The Company exercised and exhausted its rights to flex down contractual obligations, defer tons, and optimize off-site storage opportunities at no additional cost to the customer in order to address the excess coal due to significant declines in demand related to COVID-19 related shut-downs. After exhausting all of its no-cost contract mitigation options, it was necessary to determine whether to force run coal generation or continue to maximize customers savings by burning natural gas while negotiating to buy out for the remaining balance of its excess 2020 coal obligations. The Company determined through its production cost analysis that pursuing contractual buyouts would result in projected customer savings of approximately $22 million as compared with force running coal generation.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN COAL AND NATURAL GAS MARKET CONDITIONS.

A. Coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers due to declining demand for coal stemming from accelerated coal retirements and overall declines in coal generation demand resulting from the impacts of COVID-19 economic shutdowns in 2020; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency ("EPA") regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening access to investor financing coupled with deteriorating credit quality is increasing the overall costs of financing for coal producers; and, (7) corrections in production levels in an attempt to bring coal supply in balance with demand.

With respect to natural gas, the nation's natural gas supply has grown significantly over the last several years and producers continue to enhance production techniques, enhance efficiencies, and lower production costs. Natural gas prices are reflective of the dynamics between supply and demand factors, and in the short term, such dynamics are influenced primarily by seasonal weather demand and overall storage inventory balances. While there continues to be adequate natural gas production capacity to serve increased market demand, pipeline infrastructure permitting and regulatory process approval efforts are challenged due to increased reviews and interventions, which can delay and change planned pipeline construction and commissioning timing. Specifically, cancellation of the Atlantic Coast Pipeline which was terminated July 5, 2020 will limit the Company's access to low cost natural gas resources.

Over the longer term planning horizon, natural gas supply is projected to continue to increase while the pipeline infrastructure needed to move the growing supply to meet demand related to power generation, liquefied natural gas exports and pipeline exports to Mexico is highly uncertain.

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Q. WHAT ARE THE PROJECTED COAL AND NATURAL GAS CONSUMPTIONS AND COSTS FOR THE BILLING PERIOD?

A. DEC's current coal burn projection for the billing period is 6.9 million tons, compared to 5.9 million tons consumed during the test period. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. While coal burns are projected to increase, they remain well below historic coal burns due to coal to gas switching resulting from changes in the coal rail transportation rate structure forecasted to go into effect April 1, 2021. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $63.95 per ton for the billing period compared to $90.53 per ton in the test period. This includes an average projected total transportation cost of $26.67 per ton for the billing period, compared to $35.07 per ton in the test period. This projected delivered cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEC is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

DEC's current natural gas burn projection for the billing period is approximately 169.6 MMBtu, which is an increase from the 135.4 MMBtu

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consumed during the test period. The net increase in DEC's overall natural gas burn projections for the billing period versus the test period is primarily driven by coal to gas switching as a result of the change in coal rail transportation rates that are forecasted to go into effect April 1, 2021. While coal burns are projected to increase, they remain well below historic coal burns. Increased gas burns are also impacted by the inclusion of natural gas generation at Belews Creek Unit 2, and Marshall Units 3 & 4 as a result of the dual fuel conversions being commercially available over the course of the billing period, combined with lower forecasted natural gas prices in the back half of the billing period. The current average forward Henry Hub price for the billing period is $2.86 per MMBtu, compared to $2.08 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

Q. WHAT STEPS IS DEC TAKING TO MANAGE PORTFOLIO FUEL COSTS?

A. The Company 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. With respect to coal procurement, the Company's procurement strategy includes: (1) having an appropriate mix of term contract and spot purchases for coal; (2) staggering coal contract expirations in order to limit exposure to forward market price changes; and (3) diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The

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Company conducts spot market solicitations throughout the year to supplement term contract purchases, taking into account changes in projected coal burns and existing coal inventory levels.

The Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply. These procurement practices include contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasted fuel consumption. Lastly, DEC continues to maintain a short-term financial natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach.

Lastly, DEC procures long-term firm interstate and intrastate transportation to provide natural gas to their generating facilities. Given the Company's limited amount of contracted firm interstate transportation, the Company purchases shorter term firm interstate pipeline capacity as available from the capacity release market. The Company's firm transportation ("FT") provides the underlying framework for the Company to manage the natural gas supply needed for reliable cost-effective generation. First, it allows the Company access to lower cost natural gas supply from Transco Zone 3 and Zone 4 and the ability to transport gas to Zone 5 for delivery to the Carolinas' generation fleet. Second, the Company's FT allows it to manage intraday supply adjustments on the pipeline through injections or withdrawals of natural gas supply from storage, including on weekends and holidays when the gas markets are closed. Third, it allows the Company to mitigate imbalance penalties associated with Transco pipeline restrictions, which can be significant. The Company's customers receive the benefit of each of these aspects of the Company's FT: access to lower cost gas supply, intraday supply adjustments at minimal cost, and mitigation of punitive pipeline imbalance penalties.

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

A. Yes, it does.

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Q Mr. Verderame, do you have a summary of your direct testimony?

A I do.

Q Please proceed.

A In my direct testimony, I describe DEC's fossil fuel purchasing practices, provided actual fossil fuel cost for the period January 1, 2020 through December 31, 2020, the test period, versus the period January 1, 2019 through December 31, 2019, the prior test period, and describe changes projected for the billing period of September 1, '21 through August 31, 2022, the billing period.

No party to this proceeding has filed testimony recommending a disallowance of any cost incurred by DEC.

Q Does that conclude your summary?

A It does.

MR. KAYLOR: Chair Mitchell, at this time the panel is available for cross examination.

CHAIR MITCHELL: All right, Mr. Kaylor. Ms. Thompson, you all are up.

MS. THOMPSON: Thank you, Chair Mitchell. Good afternoon, gentlemen. Gudrun Thompson representing the Sierra Club in this proceeding.

MR. VERDERAME: Good afternoon.

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MS. THOMPSON: All my questions are going to be for you, Mr. Immel.

CROSS EXAMINATION BY MS. THOMPSON:

Q Mr. Immel, you are now -- your title is Vice President of Fleet Transition Strategy for Duke Energy; is that correct?

A (Immel) Yes, ma'am, uh-huh.

Q And you've held that position since 2020?

A Yes, ma'am.

Q Just prior to taking your current position, you were Vice President of Carolinas Coal Generation for DEC and DEP; is that right?

A That is correct. Yes, ma'am.

Q Now, is the Vice President of Fleet Transition Strategy, your current position, was that a newly created position at the time that you assumed that position?

A Yes. It was roughly in the April time frame of 2020. Yes, ma'am.

Q And was your old position eliminated or did somebody else move into that position?

A Somebody else has moved into that position. Yes, ma'am.

Q And who is that?

A That is Julie Turner.

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Q Thank you. Mr. Immel, generation -- you testified in your direct that generation from the Company's coal-fired power plants accounted for about 16 percent of the Company's total coal generation in the calendar year 2020 test period. Does that sound right?
A Yes, it does, uh-huh.
Q And then generation from Belews Creek, Cliffside, and Marshall added up to about 97 percent of coal-fired generation during that same test period?
A Subject to check, but yes, ma'am.
Q So does that mean -- just using lawyer arithmetic, given that Allen is the only other plant on system, does that -- would I be right in inferring that the Allen units accounted for about three percent of coal-fired generation during that period?
A That would be correct.
Q Okay. Now, you also testified that Belews, Cliffside, and Marshall have typically ranked as some of the most efficient coal-fired generating stations in the nation. Do you recall that?
A I do, yes.
Q Now, when you say "typically," what time period are you referring to?
A As recent as the past couple years, yes --

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Q Okay. So that's --
A -- historically, yes.
Q Sorry. I didn't mean to cut you off.
A And also historically. They have -- they have won efficiency awards for quite some time.
Q And so that -- when you say recently as the past couple years, does that include the test period?
A I -- it would be subject to check, ma'am. I'm not sure if the test period is in there.
Q Okay. So subject to check, so you're not basing that -- when you say they typically ranked as some of the most efficient coal-fired generating stations in the nation, you're not basing that on specific performance during the test period, that particular statement?
A I'd have to go back and check it, yes.
Q Fair enough. Now, when the Company is making decisions to commit and dispatch its coal plants, you're not comparing your coal plants to other coal plants around the country; you're comparing them with other resources on the Company's system; isn't that right?
A Yes. We dispatch internally to the -- internally to the DEC/DEP system, correct.
Q Okay. And you just -- you had testified that

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Belews, Cliffside, and Marshall were some of the most efficient plants in the nation. When you say more efficient or most efficient, does that mean in terms of how much fuel the plant is burning?
A Yes. Efficiency would be measured by heat rate, which is the amount of energy, thermal energy it takes to convert to a kWh, so the efficiency or the heat rate of those three facilities is extremely efficient compared to the industry, yes.
Q So just in a layperson's term, if you have a lower heat rate, you're burning less fuel, if you produced --
A Less fuel, same amount of energy, yes.
Q Okay.
A Miles per --
Q Yes. That's a good analogy. Thank you. So given that DEC has some of the most efficient coal units in the country, you would expect to have some of the lowest fuel cost per unit of generation among all coal plants in the country, wouldn't you?
A I would -- I would think so, but I'm not -- I'm not familiar with cost in comparison to the industry.
Q Now, you specifically call out Belews, Cliffside, and Marshall as some of the most efficient

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coal plants. I notice you omitted Allen. How do the Allen units compare with the Company's other coal plants in terms of efficiency?

A Allen is a -- is certainly an older facility. Its heat rate is not as efficient as the plants you just mentioned, so in terms of comparison, its heat rate is not as good as -- it's not as efficient, much older facility.

Q Now, you also discuss some of the key measures that are used to evaluate the operational performance of the Company's generating units. Do you recall that?

A Yes, ma'am. I do.

Q I'm going to ask you about just a couple of those. One of those key measures is something called net capacity factor; is that right?

A Yes. There is a measurement called net capacity factor, yes.

Q And that fac--- that measure, abbreviated NCF, measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period. Does that sound right?

A It does, uh-huh.

Q And that is -- so that's one -- just again,

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that's one of the key measures that you identified in your direct testimony for evaluating the operating -- operational performance of the Company's coal plants?

A No. I don't believe so.

Q Oh.

A The net capacity factor is not the measure of performance. What I have said in testimony was the measure of performance for things like equipment availability factor, equivalent forced outage rate, equivalent forced outage factor. Net capacity factor is not a measurement of performance. It's a measurement of how much the plant ran.

Q All right. Well, then, let's turn to page 8 of your testimony, and maybe you can just clear this up for me. If you could turn to page 8 of your prefiled direct testimony, and there's a question at lines 6 and 7 of that page.

A Yes. I'm on page 8. Yes. I see the question, uh-huh.

Q Okay. So do you see where the question says "Please discuss the operational results for DEC's fossil/hydro/solar fleet during the test period"?

A Yes.

Q And then on lines 9 and 10, just below that,

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there's a sentence that starts "The following key measures are used to evaluate the operational performance, depending on the generator type," and then if you scroll down a little bit or read down a little bit on line 14, net capacity factor is one of the measures that are listed in that sentence. Do you see that?

A It does, and if I could -- if I could read a couple sentences after where it mentions that, it says "Net capacity factor, 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. Net capacity factor is affected by the dispatch of the unit to serve customer needs." So it is a measure of how much it ran; it's not a measure of the performance.

Q Okay.

A It's how it was economically dispatched, which would tell you the capacity factor.

Q All right. I think I understand. What is the -- well, just can you explain a little bit, then, what that net capacity factor metric tells you, other than just how much it ran? What's the significance of that?

A Well, it would -- it would have an impact on

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things like our maintenance strategies around that unit. And since it's not being called upon as frequently for economic dispatch since it is not as efficient a unit as others that were dispatched before it, it would change our maintenance practices. We would perform less frequent maintenance. It would be performed on run time of equipment versus period time of equipment, so it would impact our maintenance strategy for sure.

Q All right. Another one of the key measures that you called out in that sentence that starts with "The following key measures are used to evaluate the operational performance" is the equivalent forced outage rate, or EFOR. Does that sound right?

A Yes, it does.

Q And with the EFOR, am I correct that a lower EFOR is better, in layperson's term?

A Yes. It is better, yes.

Q There's a table on -- if I could refer you to page 9 of your testimony, there's a table on page 9 -- let me know when you're there.

A I'm there, uh-huh.

Q Okay. At the top, it's the third column from the left, top row where it says Review Period, can you just -- is the review period the test period, or what is

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that review period?
A It would be the test period.
Q Okay. So that table on page 9 shows the EFOR for the Company's coal fleet was higher than the NERC -- was higher during the test period, at 72.3 -- or sorry -- was -- hang on. Let me -- I think I'm getting tangled up. EFOR. Yeah. There we go. Sorry. Wrong -- I had the wrong percentage.
The EFOR there under Review Period for the Company's coal fleet, 15.1 percent; is that right?
A That's correct.
Q And that EFOR was actually higher during the test period than the number you're comparing it to, which was the NERC average over the 2015 to 2019 period; is that right?
A Yes, ma'am. That's correct.
Q Why was that?
A So, again, if I go back to a little bit of a definition on equivalent forced outage rate, that is the time a generator is forced out of availability due to some type of mechanical issue, divided by the amount of hours that the unit is available during the year. And so we had two fairly significant events at two of our generators that makes up probably 75 percent of that 15

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percent forced outage number there. Both of them happened at Marshall Station. Marshall Unit 3, we had a spring planned outage. Planned outage -- a planned generator outage means you're planning maintenance, it doesn't impact this forced outage rate. It's planned. However, if you -- if the outage runs longer than the planned outage, then it's considered forced out, which would have an impact on this.

So in the spring outage on Marshall 3, where we were installing some of our dual fuel equipment, as you recall, that's when the pandemic started, spring of last year. And so when the pandemic started, there was an attempt to work through that. Most of these were contract resources. They were impacted by the pandemic. It extended that outage period by some 45 days due to availability of resources, due to -- due to the efficiency of the workers not being able to work closely together, so that had a dramatic impact -- that probably had a 30 percent impact on that 15 percent number, just that one outage.

And in the second significant outage, which probably would make up for the other 40 -- another 40 percent of that 15 percent number, would be Marshall Unit 4, we had a short in the generator rotor which was fairly

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Jun 17 2021

catastrophic -- it melted copper and some other things -- and it ended up in an extended forced outage of approximately 70 days.

So those two events alone would account for 75 percent of the 15 percent.

Q All right. Thank you. That's helpful. Let's move on to another point you made in your direct testimony. You mentioned the Joint Dispatch Agreement between the Company and Duke Energy Progress, and you note that the J-- the Joint Dispatch Agreement, or JDA, allows generating resources for DEC and DEP to be dispatched as a single system. The DEC customers benefit from the lowest cost resources available. That was on page 7 of your testimony. Does that sound right to you? And I can refer you to the specific part, if you would like. Page 7, lines 14 through 16. Mr. Immel, I believe you're on mute.

A I'm sorry. Yes, ma'am. I see that.

Q Okay. Are you aware that the Company and Duke Energy Progress filed reply comments with the Commission this past Friday in the Integrated Resource Planning docket, which is Docket E-100, Sub 165?

A I'm not aware of that, no.

Q Okay. Well, I will represent to you that they

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did, and in those comments the Companies said that the Commission's approval of the merger -- that would be the merger between Duke Energy and Progress Energy -- was conditioned upon the Joint Dispatch Agreement not being interpreted as providing for or requiring a single integrated electric system.

MR. KAYLOR: Objection. Not relevant to this proceeding.

MS. THOMPSON: Chair Mitchell, may I be heard?

CHAIR MITCHELL: Yeah. Please do so, Ms. Thompson.

MS. THOMPSON: Well, I was -- I had just asked Mr. Immel about a point in his testimony where he says the Joint Dispatch Agreement allows generating resources for DEC and DEP to be dispatched as a single system, which was a quote from his testimony, and so I believe it is relevant that the Company, in a separate filing, said that essentially the JDA cannot be interpreted to provide for a single integrated electric system.

CHAIR MITCHELL: All right. Mr. Kaylor, did you want to say something else?

MR. KAYLOR: Well, he just said he wasn't familiar with that filing.

CHAIR MITCHELL: All right. I'm going to

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Jun 17 2021

overrule the objection. I'll allow the witness to answer the question, to the best of his ability, and we'll give the response the weight that it's due. So please proceed to answer the question, assuming you remember it, Mr. Immel.

A So could I ask you to repeat the question, please?

Q I actually hadn't quite gotten to my question, Mr. Immel. I was sort of setting it up. So you recall I referred to the reply comments in the IRP docket. I'll just repeat that quote and then I'll ask you my question, if that's okay.

A That would be good.

Q Okay. So in those reply comments in the IRP docket, the Company said that the Commission's approval of the merger was conditioned upon the Joint Dispatch Agreement not being interpreted as providing for or requiring a single integrated electric system. So I'll just ask you to accept that filing was made, subject to check, and included that statement.

MR. KAYLOR: And I will continue with my objection, Madam Chair.

CHAIR MITCHELL: All right. And I'll overrule the objection again. Mr. Immel, please --

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Jun 17 2021

A Okay. So the question?
Q And so Mr. Immel, my question is, is it your testimony that the Joint Dispatch Agreement allows the generating resources for DEC and DEP to be dispatched as a single system?
A So my response would be -- the best of my ability, the response is unit commitment and dispatch is determined per DEC and DEP jurisdictions. And so the day-ahead planning, the amount of reserve margin that's required is looked at in the individual jurisdictions. It's not looked at in total. It's looked at in individual DEC and DEP jurisdictions, and the units are dispatched in those individual jurisdictions. This comment about the Joint Dispatch Agreement, when we have those opportunities and we have enough transmission capabilities to share energy back and forth is when we do that, so that would be the way I would respond.
Q So you've actually anticipated, and I think answered, all my other questions I was going to ask you, but let me just make sure -- let me just confirm a couple things. So the Company and DEP do not have a reserve sharing agreement, correct?
A The what? Pardon?
Q DE Carolinas and DE Progress do not have any

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Jun 17 2021

kind of reserve sharing agreement, correct?
A Not that I'm aware of.
Q And they also do not share firm capacity, right?
A Not that I'm aware of.
Q So I think I just understood you to say, when you were explaining, that under the Joint Dispatch Agreement, what's happening there is really energy only is being exchanged between the two Companies?
A That is my understanding. That would be a very good question to ask the next witness, Mr. Verderame --
Q Okay. And then --
A -- yes.
Q Thank you. And then I think you also answered, but I want to make sure that I understood you, that the Company conducts its realtime dispatch on its own system, not -- it does not do that based on the entire or a combined DE Carolinas and DEP system, correct?
A Again, that would be my response because there are transmission constraints between the two jurisdictions, but yes, ma'am.
Q Okay. And then same answer for the commitment of units, that would be based on the DE Carolinas system and not for the entire -- for a combined system?

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Jun 17 2021

A Again, my understanding, that is correct.
Q Okay. Now, you also testify about a change in the dispatch order for each type of generating facility. This is on page 7 of your testimony, lines 22 to 23. Just let me know when you're there.
A Yes. I'm there, uh-huh.
Q And you say that due to essentially low natural gas prices, right?
A That's correct. Again, we -- the dispatch, the incremental dispatch is based on the variable cost which is, well, for the most part fuel and reagent. That's correct.
Q Now, so during the test period, calendar year 2020, what did that change in the dispatch order look like, just in kind of layperson's terms or directionally?
A Well, and I don't know how many years -- when you say "change," are you talking about change from 2019 to '20 or 2015 to 2020? It's been a gradual change, but as gas prices have continued to fall, and as we have added newer technologies to the DEC fleet, for example, W.S. Lee combined cycle, between the efficiency of the new technology and the gas price it will start impacting how we dispatch coal. Thus, Allen Station, which used to be baseload with a high capacity factor, as you mentioned

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earlier, the capacity factors have dropped because it's a lower -- a less efficient unit.

Q So would you just -- I think I'm understanding you to say that there's been a change underway for some time in how units are dispatched due to changing economics of natural gas, and would you say that trend just continued during the test period or, you know, accelerated? Was there any change in that trendline?

A Well, I think rather than guess, we could probably get you the data. I think John Verderame would be a good witness to have that data, you know, more readily available, but, yeah, I would say certainly over time gas prices have -- over a period of time have continued to decline, and we've added higher efficient technology generation through our fleet which changes, as I mentioned before, the dispatch, of how we dispatch.

Q And essentially you're dispatching coal units less?

A It all depends on that fuel price, you know. A good example is where we have added the capability to burn gas at a couple of our coal facilities. In fact, we burn gas if that fuel is less costly than coal at a period of time. So it depends a lot on the cost of the fuel. It depends a considerable amount on the cost of

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the fuel, yes.

Q And just one other point on this, related to this. You mention -- let me see, where is it? It's on page -- towards the top of page 7 -- sorry -- page 8 of your direct, line 4 and 5. You mention benefits, fuel benefits in cost of fuel and reduced emissions for customers. Do those benefits come from primarily dispatching coal units less and so you have lower emissions, lower fuel cost and less emissions as a result?

A Yes. If you dispatch more of the combined cycle fleet, less CO2 emissions and certainly less cost for the -- to the customer.

Q All right. Just one last couple of questions -- or a few more questions for you on another statement that you made in your direct. This is on page 11 of your direct testimony. Starting on line 17 -- I'll let you get there. Let me know when you're there.

A Okay. I am there.

Q So you say "The Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. Overall, the goal is to effectively comply with emissions

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regulations and provide the optimal total-cost solution for the operation of the unit." I would just like to unpack that a little bit. When you say changes to fuel mix and favorable or unfavorable impacts, what are you talking about there?

A Well, I would go back up to the top of that page at the question that reads "How does DEC ensure emissions reductions for environmental compliance?" So favorable would mean if we were burning gas vers--- in a combined cycle versus coal. Certainly, there would be less CO2 emissions. That's favorable. Unfavorable would be if we were burning more coal based on prices in terms of CO2 emissions, but at the same time we continue to be compliant with -- whatever fuel we're burning, we're going to comply with the regulations.

Q Okay. Similar question for changes in the coal burn. You talk a little bit about the impacts, favorable or unfavorable, due to changes in the coal burn?

A Again, the favorable and unfavorable, it would relate to the -- to the emissions question, so favorable being less CO2 emissions versus unfavorable would be more CO2 emissions, but --

Q And --

A -- the customer -- you know, again, we're going

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to burn the most efficient and less cost fuel. Customers benefit.

Q That actually anticipates what I think might be my last question or maybe last couple questions. You use the term "optimal total-cost solution." What do you mean by that?

A Point me to the line.

Q Oh, sorry. It's on line -- line 20 on page 11, "the optimal total-cost solution for the operation of the unit."

A So the optimal solution today is around cost and compliance, and so when we burn coal, it takes different reagents to ensure our air permits are met, as well as burning, you know, that type fuel. When we burn a different fuel, there's different reagents that are required, so it's the total optimal use of fuel and reagents to comply and reduce emissions.

Q Okay. I think I understand. So the total -- your use of the word "total" there is intended to embrace both the fuel and the fuel-related costs --

A Yes, ma'am.

Q -- correct? And you have -- and that's -- you mention that in your testimony because of the Company's obligation to operate its units to minimize the fuel and

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fuel-related cost for the benefit of customers?

A Yes, ma'am.

Q All right. Okay.

MS. THOMPSON: Thank you. Thank you, Mr. Immel. That's all I have for you today, or all I have for you in this proceeding.

THE WITNESS: Thank you.

MS. THOMPSON: Thank you, Chair Mitchell. I will turn it over to my colleague Mr. Moore.

CHAIR MITCHELL: All right. Mr. Moore, you may proceed.

MR. MOORE: Thank you, Chair Mitchell. Good afternoon, Mr. Verderame. I just have a couple questions for you. I think the majority of mine are going to be looking at your rebuttal testimony.

CROSS EXAMINATION BY MR. MOORE:

Q Has the Company looked at ways to replace the transportation service that would have been provided by the Atlantic Coast Pipeline?

MR. KAYLOR: Madam -- Chair Mitchell, I thought we were going to do the rebuttal later.

MR. MOORE: Yes. I'm sorry, Mr. Kaylor. This is concerning his direct testimony. The remainder of my questions will be later.

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MR. KAYLOR: Okay.

CHAIR MITCHELL: All right. Mr. Moore, you may proceed.

Q Do you want me to repeat that, Mr. Verderame?

A (Verderame) No. That's fine, Mr. Moore. So yes. I think the Company recognizes that it has an incremental need for interstate, upstream firm transportation capacity and, you know, we are in discussions with several counterparties. We've made no decisions or have come to no definitive conclusions or agreements.

Q Has the Company looked at acquired capacity on the Mountain Valley Pipeline?

A So Mountain Valley Pipeline is certainly one of the counterparties that we are having discussions with.

Q In your testimony on page 10, you stated that firm transportation capacity is important, as it allows the Company to avoid imbalance penalties on the Transco Pipeline; is that correct?

A That's correct.

Q Has the Company incurred any imbalance penalties during the test year?

A No, and we work very hard to not incur penalties.

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Q Did the Company experience any service disruptions during the test period due to inadequate natural gas supply?

A No, we did not, not during the test period, no.

Q Okay.

MR. MOORE: That's all my questions for Mr. Verderame's direct.

CHAIR MITCHELL: All right. Redirect, Mr. Kaylor?

MR. KAYLOR: Thank you. Just one or two questions for Mr. Immel.

REDIRECT EXAMINATION BY MR. KAYLOR:

Q If you could, turn to page 9 again to the chart where you were asked some questions on, Mr. Immel.

A (Immel) Yes, sir. I'm there.

Q So you were asked some questions about the NERC average for the time period 2015 to 2019. Now, that 2019 obviously does not include the pandemic year that we started in in 2020; is that correct?

A That is correct. Yes, sir.

Q And you did indicate that COVID and the pandemic did have some impact on your ability to bring in outside contractors and to perform work at the same level as you would have but for that experience; is that

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correct?

A That is correct. Yes, sir.

Q And I believe you mentioned with regard to the review period for the coal-fired EFOR, which was the forced outage rates, that the 15 percent on the DEC system would have been probably 5 percent had it not been for the outages at Marshall 3 and 4; is that correct?

A That is correct. Yes, sir.

Q Thank you.

MR. KAYLOR: No other questions for our panel.

CHAIR MITCHELL: All right. Questions for the panel from Commissioners?

(No response.)

CHAIR MITCHELL: All right. I'm hearing no questions for the panel, so gentlemen, you are relieved for the time being. You may step down. And I'll entertain a motion, Mr. Kaylor.

MR. KAYLOR: Yeah. I would move that Mr. Immel be excused from the hearing since he did not have any rebuttal testimony, so the rebuttal will just be Mr. Verderame, and I would also move that the exhibits that were marked for identification be admitted into the record at this time.

CHAIR MITCHELL: All right, Mr. Kaylor.

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Hearing no objection to your motion, as to the exhibits to Mr. Verderame's testimony, those exhibits will be admitted into the record.

(Whereupon, Verderame Exhibits 1 through 3 were admitted into evidence. Confidential Verderame Exhibit 3 was filed under seal.)

CHAIR MITCHELL: All right. Also, your motion that the witness be allowed to step down is granted.

(Witness Immel excused.)

CHAIR MITCHELL: Anything else, Mr. Kaylor?

MR. KAYLOR: Thank you. I would ask also that the Company's Application which we filed in this be admitted into the record, also.

CHAIR MITCHELL: All right. Hearing no objection to that motion, Mr. Kaylor, it is allowed. I'll note for purposes of the record that the Company filed both confidential and redacted versions of that application, so we need to take care that confidential information is redacted from the transcript, as appropriate.

(Whereupon, Duke Energy Carolinas, LLC's Application was admitted into evidence. The confidential version

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Jun 17 2021

was filed under seal.)

MR. KAYLOR: Thank you, Chair Mitchell. And that would conclude the Company's direct case.

CHAIR MITCHELL: All right. With that, I will turn to Ms. Thompson, Mr. Moore.

MS. THOMPSON: Yes, Chair Mitchell. The Sierra Club calls Ms. Devi Glick to the stand.

CHAIR MITCHELL: All right. Ms. Glick, let's go ahead and get you under oath.

DEVI GLICK; Having first been duly affirmed, Testified as follows:

CHAIR MITCHELL: All right. Thank you. Ms. Thompson, you may proceed.

DIRECT EXAMINATION BY MS. THOMPSON:

Q Ms. Glick, could you please state your name and business address for the record?

A My name is Devi Glick. I work at Synapse Energy Economics, 485 Massachusetts Ave., Cambridge, Massachusetts.

Q And did you cause to be prefiled in this docket on May 17th, 2021, confidential and public versions of your direct testimony consisting of 43 pages?

A I did.

MS. THOMPSON; And Chair Mitchell, I am just

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going to -- before I move on, I'm going to just -- I should have probably raised this during preliminary matters, but we just -- the Sierra Club just today filed corrected versions of -- in both confidential and public versions of corrections to Ms. Glick's testimony. Rather than have her walk us through those from the witness stand, I -- they have been served upon the parties, and then I emailed a copy to Ms. Fennell as well, so just want to inquire whether the Commission has received those.

CHAIR MITCHELL: All right. Thank you, Ms. Thompson. I have seen them in the docket, and so we will treat them at this point as having been filed.

MS. THOMPSON: Okay.

Q Ms. Glick, did you also cause to be prefiled in this docket today a corrected version of your direct testimony in both confidential and public versions?

A I did, yes.

Q Along with redlined versions showing the corrections?

A Yes.

Q And without going -- without going into anything confidential, could you just very briefly explain the reason for and just the nature of the

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corrections?

A Yes. I updated my analysis that calculates the cost, the fuel cost incurred during the test period to reflect the average cost of both coal and natural gas.

Q All right. And why did you do that?

A The testimony originally used just the average cost of coal.

Q Okay. Ms. --

MS. THOMPSON: Oh. Mr. Kaylor.

MR. KAYLOR: Chair Mitchell, I would point out at this time that we did receive this about, I guess, 45 minutes before the hearing so we haven't had time to review it. It may not be anything that we would take issue with, but I just would like to point out that we haven't had the ability to go in and follow up with any discovery on what, in essence, is new testimony. It may be that it's being filed as a result of errors that we pointed out in our rebuttal, but that being the case, I assume we'll move forward from there.

MS. THOMPSON: Chair Mitchell, may I be heard?

CHAIR MITCHELL: You may.

MS. THOMPSON: I think it's fairly common for witnesses to make corrections to their testimony that have been -- they they've either discovered upon further

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Jun 17 2021

review or that have been brought to light for some reason, so this is not any -- any different from that, except that for the convenience of the parties and for the Commission, we elected to file those, you know, as errata rather than having Ms. Glick go through all the corrected numbers from the stand.

CHAIR MITCHELL: All right. Thank you, Ms. Thompson. Mr. Kaylor, I recognize that you've just received this only minutes ago, so you obviously have the opportunity to explore this with the witness on cross examination, and we'll recognize your right to do so when we get there.

MR. KAYLOR: Thank you.

CHAIR MITCHELL: Uh-huh.

MS. THOMPSON: So I lost track of where I was.

Q Okay. If the questions to you -- if the questions put to you in your corrected prefiled direct testimony were asked at the hearing today, would your answers be the same?

A Yes, they would.

Q Great.

MS. THOMPSON: Chair Mitchell, I would move to have Ms. Glick's corrected prefiled direct testimony entered into the record as though given orally from the

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Jun 17 2021

stand, and to have the confidential version thereof remain under seal.

CHAIR MITCHELL: All right. Hearing no objection to that motion, it's allowed, Ms. Thompson.

Q MS. THOMPSON: And Ms. Glick, did you also cause to be prefiled two exhibits marked as DG-1 and Confidential DG-2, the latter of which was filed under seal?

A Yes.

Q And were those exhibits prepared by you or under your direction?

A Yes, they were.

Q Okay.

MS. THOMPSON: Chair Mitchell, I would move to have the exhibits attached to Ms. Glick's prefiled direct testimony identified as premarked, and to have them moved into evidence with Confidential Exhibit DG-2 being entered into evidence under seal.

CHAIR MITCHELL: All right, Ms. Thompson. We'll hold off on admitting them into the record for the time being, but we will identify them as they were when they were prefiled, as they were marked when prefiled.

MS. THOMPSON: Thank you.

(Whereupon, the corrected direct testimony of Devi Glick was copied into the record as if given orally from the stand. The confidential version was filed under seal.)

(Whereupon, Exhibit DG-1 and Confidential Exhibit DG-2 were identified as premarked.)

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BEFORE THE NORTH CAROLINA UTILITES COMMISSION

DOCKET NO. E-7, SUB 1250

IN THE MATTER OF	)	
APPLICATION OF DUKE ENERGY	)	
CAROLINAS, LLC PURSUANT TO	)	**DIRECT TESTIMONY OF**
N.C.G.S. § 62-133.2 AND	)	**DEVI GLICK ON BEHALF OF**
COMMISSION RULE R8-5	)	**THE SIERRA CLUB**
RELATING TO FUEL AND FUEL-	)	
RELATED CHARGE ADJUSTMENTS	)	
FOR ELECTRIC UTILITIES	)	

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Jun 07 2021

TABLE OF CONTENTS

LIST OF TABLES 2

1. Introduction and purpose of testimony 3
2. Findings and recommendations 8
3. DEC controls and coordinates the commitment and dispatch of its coal-fired generating units. 12
4. DEC's coal fleet operated at an average cost that exceeded the marginal system cost for nearly all of 2020. 18
5. DEC excluded over 40 percent of the fuel and variable costs incurred at its coal units from its unit commitment and dispatch decision-making process 24
6. DEC incurred $8.5 million in avoidable unit costs at its coal plants as a result of uneconomic unit commitment decisions. 30
7. Recommendations for the Commission 40

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Jun 07 2021

LIST OF TABLES

Table 1: 2020 Annual Capacity Factors for DEC Coal Units 19

Table 2: CONFIDENTIAL Average Cost of Generation relative to Average System Lambda ($/MWh) 21

Table 3: DEC's coal unit costs relative to other solid-fuel plants in the U.S. in 2020 24

Table 4: Total Production Costs incurred by DEC's Coal Fleet in 2020 ($Million) 26

Table 5: Operational costs in excess of system lambda ($Million) 38

OFFICIAL COPY
Jun 07 2021

1. Introduction and Purpose of Testimony

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit-commitment practices, plant

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Jun 07 2021

economics, utility resource needs, and solar valuation before state utility regulators in North Carolina, Arizona, Connecticut, Florida, Indiana, Michigan, New Mexico, South Carolina, Texas, Wisconsin, and Virginia. In the course of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than eight years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Sierra Club.

Q Have you testified previously before the North Carolina Utilities Commission ("Commission")?

Yes, I submitted testimony in Docket No. E-100, Sub 158, the 2018 biennial proceeding regarding avoided cost rates.

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Jun 07 2021

Q What is the purpose of your testimony in this proceeding?

My testimony addresses the analysis and decision-making processes Duke Energy Carolinas' ("DEC" or the "Company") uses to commit (turn on, keep on, or turn off) and dispatch (turn up or down once a unit is committed) its coal-fired power plants. In particular, I evaluate the production costs that DEC reported and used to make its unit commitment decisions in 2020 (the marginal production cost) and compare those to the fuel costs the Company seeks to recover from ratepayers in this docket (the average or full cost of production). I explain how the significant discrepancy between the marginal and average cost of production is driving DEC's uneconomic commitment of its coal plants and evaluate the impact DEC's underrepresentation of unit costs had on ratepayers in 2020. Finally, I outline recommendations for improving the transparency and functioning of the Company's unit commitment process to better serve ratepayers.

Q Why is the issue of unit commitment relevant to this fuel clause adjustment proceeding?

North Carolina law says that the utility can recover the "reasonable costs of fuel and fuel-related costs prudently incurred during the test period."[1] DEC's incurred fuel costs are directly tied to the operation of each of its units, and thus its unit-

[1] N.C. Gen. Stat.§ 133-2(d).

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Jun 07 2021

commitment decisions and practices inform the Commission's determination whether those costs were reasonable and prudently incurred.

While in the past utilities operated their coal-fired plants as baseload resources with little thought given to whether the plants should be turned on or off, in recent years low gas prices and nearly zero-variable cost renewables have pushed coal generation to become marginal and uncompetitive during many hours of the year. The practice of committing coal plants to run when it is not economic to do so saddles ratepayers with avoidable fuel costs, recovered in this docket, and thereby allows utilities to continue operating aging and costly coal plants when there are lower cost alternatives that can meet customers' needs.

Q You've addressed the full 'production' cost of DEC's generating units, which includes variable operations and maintenance costs. Why is the full production cost relevant to a proceeding that only seeks recovery of fuel costs?

The operation of the Company's generation units is governed by the full production cost of those units, which includes both fuel and non-fuel variable costs. While the Company only seeks recovery of its incurred fuel costs in this docket, whether or not the Company prudently incurred those fuel costs can only be assessed by evaluating how the Company operated its generating units.

Q How is the remainder of your testimony structured?

In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I define the terms "unit commitment" and "dispatch" and describe how electric utilities make daily operational decisions at coal-fired power plants.

In Section 4, I evaluate the fuel and other production costs incurred by DEC (which, if determined to be reasonable and prudently incurred, would normally be passed on to ratepayers) to operate its coal-fired power plants in the 2020 test year. I compare the production cost of DEC units to those of other coal units around the country.

In Section 5, I review the marginal production costs the Company uses to make its unit commitment decisions at its coal units and evaluate the significant deviation between the average production cost incurred at each unit over the course of the test year, and the marginal cost of production used for the purposes of making unit commitment and dispatch decisions.

In Section 6, I explain the practice of uneconomic unit commitment, outline reasons why utilities may utilize this practice, and discuss the impacts this practice has on DEC's ratepayers. I evaluate the economic performance of DEC's coal units during the 2020 test year. I discuss the costs that uneconomic commitment practices will impose on ratepayers if approved for recovery in this proceeding. I quantify the customer net revenue losses resulting from the Company's decisions to "must-run" each of its coal plants during the test year.

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In Section 7, I outline recommended reporting requirements for future fuel charge adjustment dockets that will allow the Commission to evaluate whether the Company's unit-commitment practices are causing the Company to incur fuel costs unreasonably or imprudently.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. During the 2020 test year, DEC's coal units had some of the highest fuel costs among all coal units in the country, yet DEC continued to incur costs in operating and maintaining the units. As explained in Section 4, Allen, Marshall, Cliffside and Belews Creek ranked in the top 75^{th} – 90^{th} percentile for most expensive fuel costs in 2020 among all United States coal-fired power plants.
2. During the 2020 test year, DEC's reported average cost of generation at each of its four coal plants exceeded the system lambda (marginal cost of energy) during nearly every month, with only two exceptions – Allen and Cliffside in the month of December 2020. Other than these two instances, the average cost of generation exceeded the system lambda for all plants in all months, as explained in Section 4. In total, DEC's units incurred $233 million in variable costs above system lambda. This means that during the

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test year, many of DECs coal plants failed to pass the lowest bar of economic performance a large portion of the time.

3. DEC omitted from its unit commitment decisions approximately $263 million worth of fuel and variable costs (approximately $250 million of which is fuel costs), representing over 40 percent of those costs at its coal units, thus allowing the units to commit and dispatch significantly more than they would if the units' full variable production cost was reflected.
4. DEC regularly committed its coal units at times when its marginal production costs exceeded the system lambda, even when it would have been less costly to serve captive retail customer load with other resources. This means that those unit commitments were uneconomic, yet DEC seeks to pass those excess costs on to ratepayers in this docket.
5. During the 2020 test year, DEC's unit-commitment practices at its coal plants caused the Company to incur avoidable excess costs of $8.5 million at Allen, Marshall, Cliffside, and Belews Creek based on the Company's reported marginal variable production costs for those units.
6. DEC did not adequately report and describe its fuel cost accounting and unit-commitment practices in its fuel charge adjustment application. The Company should have included documentation of its daily decision-making process and its reasoning for frequent uneconomic commitment.

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Q Please summarize your recommendations.

A Based on my findings, I offer the following chief recommendations:

1. I recommend that the Commission examine DEC's production cost accounting, its unit commitment process that relies on its production costs, and the operational decisions and incurred costs that result, and scrutinize such costs carefully for potential disallowance in future proceedings.
2. DEC's should be required to provide full transparency into the Company's marginal and average production costs. Specifically, DEC should provide a full breakdown of the following, accompanied by a detailed explanation of each and full work papers that show how each component was calculated:
   a. Full production cost of each unit that will be passed on to ratepayers in this docket, broken down by the following categories:
      i. Fixed costs
      ii. Variable costs
         1. Fuel
         2. Reagents/ by products
         3. Emissions
         4. Variable O&M
   b. Marginal production cost of each unit used for making unit commitment and dispatch decisions, broken down by the same

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components listed directly above. For any production costs Excluded from DEC marginal production costs, the Company should provide a detailed justification for why these costs are not relevant for making unit commitment decisions.

3. The Commission should require DEC to provide a detailed report describing its daily unit-commitment decisions and practices as part of future fuel charge adjustment proceedings. DEC should provide the following information as part of each fuel charge adjustment filing, to inform the Commission's review of its unit-commitment practices and determination whether DEC's fuel- and fuel-related costs for those units were reasonably and prudently incurred:

    a. All 7-day forecast sheets used to develop the Company's daily unit-commitment decisions and marginal cost.

    b. The reason for any deviation between the commitment decision suggested by the Company's forward-looking price-based analysis and the Company's actual commitment decision (e.g., where the Company's analysis suggests that a unit has a production cost above the marginal system cost during a given day, and the Company self-commits the unit anyway).

    c. Hourly data sufficient for the Commission to calculate the net revenues that each plant actually incurred in each test year period, including total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable operations and maintenance ("O&M") cost, system lambdas, day-ahead commitment status, and actual outages.

4. Given the low capacity factor at which DEC's coal fleet operated in 2020—extremely low, in the case of some units—the Company should evaluate moving some of its plants to seasonal operation and retiring some of its units.

3. DEC CONTROLS AND COORDINATES THE COMMITMENT AND DISPATCH OF ITS COAL-FIRED GENERATING UNITS.

Q Please summarize this section.

A In this section, I define the concepts of unit commitment and dispatch and explain how dispatchable power plants operate in DEC's system. I define the practice of uneconomic unit commitment by regulated, vertically integrated utilities like DEC and discuss the impacts this practice can have on ratepayers, if utilities are permitted to pass along the avoidable excess costs that result.

Q Please explain the terms "unit commitment" and "dispatch."

A Unit commitment is the process by which a utility decides if a long-lead time generating unit, generally steam boilers, should be operational for the following day. Commitment is the decision to either keep the unit online, bring a unit online that is not currently generating, or bring offline ("de-commit") a unit that is

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currently online. Unit commitment decisions are distinct from "dispatch" decisions, which are the decisions to incrementally increase or decrease a unit's generation. Fast-start units like combustion turbines or battery storage can generally be dispatched from idle (or "blackstart") and do not need to be committed ahead of time. However, large steam boilers require a clear commitment, and once committed to operate, must run at a minimum level of output.

Q How does the process of unit-commitment occur?

A The process of unit commitment requires that the operator look forward to determine if a long-lead time unit is likely to operate economically over the next few days. To make this determination, the operator will compare the costs of starting and operating a particular unit with the costs of all other units on its system to determine whether that unit should be online the next day. When a unit is committed economically, the unit is reasonably expected to be lower cost than the marginal cost of energy, called "system lambda," over the next day or days. When a unit is committed uneconomically, the operator has decided to operate that unit at its economic minimum, which is the lowest MW output that a unit can safely and efficiently maintain, even though that unit's marginal costs of production are projected to be higher than the system lambda.

Q In this testimony, you refer to "average costs" of production and DEC's reported "marginal cost" of production. Can you briefly explain what you

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mean by these two terms, which variable costs are included in each, and why they are relevant to this proceeding?

A Each of DEC's coal-fired power plants has a specific set of costs incurred to operate the unit. The cost of production is composed of fixed costs, which are incurred regardless of whether and how a unit is operated, and variable costs, which are incurred based on usage. Variable costs include fuel, reagents/byproducts emissions, and variable O&M.

When making a unit commitment decision, DEC utilizes the marginal cost of production. The marginal cost of production is calculated based on the replacement cost of fuel, which is the "market price of fuel plus variable transportation costs,"[2] and the cost of reagents/byproducts, emission, and variable O&M. This cost represents the incremental cost of operating the unit.

But the marginal cost of production does not represent the actual production costs passed on to ratepayers. The average production cost represents the cost to operate each unit (that is actually passed on to ratepayers) spread out over the unit's MW output. This includes the cost of the fuel that was actually burned (or paid out) and all associated transportation costs, regardless of contract structure. Reagent / byproduct, emissions, and variable O&M costs are also included.

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[2] Duke Energy Carolinas Response to Sierra Club Request 1-8.

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Q Please describe how dispatchable power plants are generally committed and operated by electric utilities like DEC that operate outside of organized wholesale markets.

A In a non-centralized market, the unit commitment process is completely dictated by the utility. The utility is responsible for internally committing and dispatching its units, and procuring energy through bilateral trades when needed, and generally does so on a variable cost basis within operational constraints. These utilities generally use internal systems that project the marginal production cost to operate each unit and calculates the cost of the marginal unit in the system, called "system lambda." Resources are committed based on cost, with the lowest-cost resources coming online first, and progressively more expensive units being turned on until system load is met. Both the unit-commitment and dispatch processes should be based on economics and should generally ensure customers are served by the lowest-cost resources while maintaining reliability.

Q In practice, are all power plants actually committed by electric utilities in that way?

A No. Utilities may ignore marginal cost when making operational decisions or simply consider only a portion of the unit's actual cost in making commitment and dispatch decisions. The result is that utilities keep units online and operating when it otherwise would not operate. Some utilities do adhere closely to efficient dispatch and commitment, but others do not, and can exhibit a wide discrepancy between the cost of operation and operational decision, as is seen with DEC.

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There are a variety of reasons why utilities ignore or underrepresent unit costs, and the practice varies widely

First, for inflexible units with long start-up and shut-down times, such as coal-fired power plants, utilities regularly force units to stay online in order to avoid unit cycling costs. Utilities have historically tried to avoid cycling of coal plants because it can result in wear-and-tear that increases maintenance costs.[3] But, while continuous operation of coal units can reduce cycling costs, it generally results in the incursion of unnecessary operational costs well in excess of the cycling costs being avoided. Cycling times and costs can be incorporated into multi-day unit commitment decision-making processes.

Second, in order to address fuel over-supply issues, utilities sometimes explicitly adjust how fuel costs are accounted for in their dispatch. Specifically, they may lower the marginal cost of a unit for the purposes of keeping a unit online to burn excess fuel. This is generally done when it is cheaper to burn the coal at a loss than to store the coal or cancel a fuel contract. Duke Energy Indiana refers to this process as a 'coal price decrement.'[4]

Third, there are structural and company decisions relating to fuel contracts, transportation contracts, and operations and maintenance ("O&M") that

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[3] *See* Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices. NARUC, January 2020. Accessible at https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45.

[4] Direct Testimony of John Swez, IURC Cause No. 38707-FAC 125.

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drive the utility's categorization of costs. Specifically, utilities that sign coal contracts with fixed tonnage requirements or must-take provisions of fuel contracts often categorize some of their fuel costs as fixed, and therefore exclude them from unit dispatch and commitment decisions. This practice effectively locks ratepayers into paying a portion of fuel costs, often without any formal approval from the regulatory commission. Utility treatment of O&M costs– specifically, utility judgement of what costs are truly variable and predictable based on unit operations, and which are truly fixed—also varies widely.

Q Are there any reasons why a utility might be incentivized to operate a unit more often than it should be from a cost perspective?

A Yes. A utility that receives a return of and on assets in the rate base may have an incentive to show that aging units are still "used and useful" despite the substantial capital and fixed expense required to keep them online. A unit that is neither economic over the long-run (i.e. relative to replacement options) and does not provide economic service on a short-term basis may be perceived as not used or useful and at risk for disallowance. As noted by the Energy Information administration, coal units that move to very low utilizations are often retired shortly thereafter,[5] because the justification for their operational costs evaporates.

[5] As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation. September 1, 2020. Accessible at https://www.eia.gov/todayinenergy/detail.php?id=44976

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4. DEC'S COAL FLEET OPERATED AT AN AVERAGE PRODUCTION COST THAT EXCEEDED THE MARGINAL SYSTEM COST FOR NEARLY ALL OF 2020.

Q Please summarize this section.

A In this section, I review the actual generation costs that were passed on to ratepayers as a result of DEC's operation of its coal-fired units in the test year 2020. I find that the Company's four coal-fired power plants all operated at an average production cost that exceeded the marginal system cost during nearly every month in 2020 (the exception was one month at each Allen and Cliffside).

Q Describe DECs coal-fired power stations.

A The Company has four coal-fired power stations: Allen, Marshall, Cliffside, and Belews Creek. Allen consists of five units (Units 1-5) and has a total capacity rating of 1,130 MW. Marshall consists of four units and has a total capacity rating of 2,078 MW. Cliffside consists of two units, Units 5 and 6, which have capacity ratings of 546 and 849 MW respectively. Belews Creek consists of two units, Units 1 and 2, which each have a capacity rating of 1,100 MW.[6]

[6] Duke Energy Carolinas, Application in the Fuel Charge Adjustment Proceeding. Exhibit 6, Schedule 10.

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Q Describe Duke's utilization of its coal-fired fleet in 2020.

A In 2020, each of Duke's coal-fired power plants was minimally utilized. Specifically, every unit with the exception of Cliffside 6 (56.6 percent) had an annual capacity factor below 39 percent, as shown in Table 1. The five Allen units had the worst performance, operating at between a 1.1 percent and 10.8 percent capacity factor.[7]

Table 1: 2020 Annual Capacity Factors for DEC Coal Units

Unit	2020 Capacity Factor (%)
Allen 1	1.1%
Allen 2	1.2%
Allen 3	2.8%
Allen 4	10.8%
Allen 5	9.4%
Belews Creek 1	28.1%
Belews Creek 2	27.5%
Cliffside 5	22.8%
Cliffside 6	56.6%
Marshall 1	25.9%
Marshall 2	28.9%
Marshall 3	36.1%
Marshall 4	38.2%

Source: DEC Response to Sierra Club Request 1-3(a), CONFIDENTIAL Attachment; DEC Application in the Fuel Charge Adjustment Proceeding (Exhibit 6, Schedule 10)

[7] Duke Energy Carolinas Response to Sierra Club 1-3a, CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; Duke Energy Carolinas, Application in the Fuel Charge Adjustment Proceeding. Exhibit 6, Schedule 10. Disclosed publicly with agreement of DEC counsel.

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Q Please summarize your analysis of the economic performance of DEC's units in 2020 based on the Company's actual cost data.

A I reviewed data reported by DEC on the average cost of generation for each plant by month and the hourly system lambdas. I compared the monthly average system lambda[8] to the monthly average cost of generation at each plant.[9] As shown in Table 2, I found that during the test year of 2020 the average cost of generation at each coal station was higher than the average system lambda, with the exception of one month each at Allen and Cliffside. That means that in every month of 2020, nearly all of DEC's coal-fired power plants were operating at an average cost above the marginal cost of electricity on its system, when there were lower cost resources available to serve load. DEC did this by underrepresenting the marginal production cost used for the purposes of making unit commitment decision. In total, DEC total production costs were $233 million more than the cost of serving load met by the coal units at the system lambda (as discussed in section 5).

[8] Duke Energy Carolinas Response to Sierra Club 1-3b, CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC.

[9] Duke Energy Carolinas Response to Sierra Club 1-3 1-3f&j, CONFIDENTIAL Attachment.

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Table 2: CONFIDENTIAL Average Cost of Generation relative to Average System Lambda ($/MWh)

[redacted]	[redacted]	[redacted]				
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: Duke Energy Carolinas Response to Sierra Club 1-3b, CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC; Duke Energy Carolinas Response to Sierra Club 1-3 1-3f&j, CONFIDENTIAL Attachment.

Q Why do you compare the average cost of generation to the marginal system cost when DEC makes unit commitment decisions based on marginal unit costs?

A It is reasonable to expect there will be a small difference between marginal unit costs and average unit costs based on (1) the delta between fuel and market prices at the time contracts were signed and the present, as well as truly unavoidable fixed/ sunk production costs. But a responsible utility manager should seek to minimize the portion of average costs that falls into these categories and are therefore omitted from the unit commitment process. Specifically, this can be done by (1) securing fuel and transportation contracts that are flexible and have

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minimal locked-in or must-take provisions; (2) carefully reviewing the costs of fuel contracts relative to alternatives, including reduced operation and retirement of the plant, prior to signing any new fuel contracts; and (3) carefully reviewing O&M costs to break-out the variable costs associated with predictive and preventative maintenance from those that are truly fixed.

Q Does the analysis reflected in Table 2 represent the total costs incurred by ratepayers as a result of DEC operating and maintaining its coal plants?

A No. The monthly Average Cost of Generation displayed in Table 2 was provided by the Company and is composed of actual fuel and variable operating expenses, and excludes from consideration any of the large fixed costs of maintaining those units which are passed on to customers. These costs are not the same as those used by the Company for the purpose of making unit commitment decisions. As I will discuss in depth in section 5, there is a significant and unexplained discrepancy between the average production costs DEC seeks to pass on to ratepayers in this docket and the marginal production costs DEC uses to make unit commitment and dispatch decisions.

The data in Table 2 simply show whether the units pass the lowest bar of providing value to ratepayers on an hourly basis. It says nothing about whether the plant is the lowest-cost resource available to serve customer load (relative to alternatives) based on the full forward-going costs (both fixed and variable)

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required to keep the plant operational. A full unit economic analysis of this type was presented by my colleague Rachel Wilson in Docket No. E-7, Sub 1214.

Q Do the coal units "pass the lowest bar of providing value to ratepayers on an hourly basis"?

A According to the values reported by the Company, no.

Q How do the fuel costs at DEC's coal units compare to those of other coal plants across the country?

A Allen, Marshall, Cliffside and Belews Creek have some of the highest fuel costs among coal plants in the country.[10] Specifically, as shown in Table 3, the coal used at Allen, Belews Creek, Marshall and Cliffside cost between $2.38/MMBtu and $2.81/MMBtu during the 2020. This puts these plants in the 75th to 90th percentile of most expensive solid fuel in the country. Allen, for example, has a fuel cost higher than 90 percent of comparable coal plants nationwide. Even the DEC coal plant with the lowest fuel cost in this analysis, Cliffside, is more expensive than 75 percent of comparable plants nationwide.[11]

[10] Author's calculation from EIA Form 923, 2020.

[11] EIA Form 923, 2020.

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Table 3: DEC's coal unit costs relative to other solid-fuel plants in the U.S. in 2020

Plant	Fuel Cost ($/MMBtu)	Percentile of most expensive solid-fuel plants
Allen	$2.81	90%
Belews Creek	$2.68	86%
Marshall	$2.52	81%
Cliffside	$2.38	75%

Source: EIA Form 923 for 2020.

5. DEC EXCLUDED OVER 40 PERCENT OF THE PRODUCTION COSTS INCURRED AT ITS COAL UNITS FROM ITS UNIT COMMITMENT AND DISPATCH DECISION-MAKING PROCESS

Q Please summarize this section.

A In this section I review the production costs that DEC seeks to pass on to ratepayers, the marginal production costs DEC models in making its daily unit commitment and dispatch decisions, and DEC's marginal system cost. I find that DEC excluded a significant portion of its production costs from its unit commitment decisions, and the justifications provided by the Company only explain a small portion of the omitted costs.

Q Do you have any concerns with the unit-commitment data DEC has provided?

A Yes, DEC appears to be excluding a significant portion of its actual fuel and variable operating costs from the marginal cost of production that it uses to make its unit-commitment decisions. Specifically, the Company's reported marginal

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cost of production omits over 40 percent of actual production costs incurred at its coal plants.[12]

The Company’s marginal fuel costs represent the cost DEC would pay today to replace the fuel that it burns. DEC calculates the replacement cost of coal based on “[redacted][13] Actual fuel costs, however, represent the cost of the fuel that DEC actually uses for generation at each plant. The Company seeks to recover actual fuel expenses from ratepayers in this docket.

As shown in Table 4 below, in 2020 DEC incurred $597 million in fuel and other production costs operating its coal fleet. But only $333 million in variable fuel and other operating costs were included in the Company’s unit commitment and dispatch modeling. This means that a full 40 percent of the Company’s production costs, equaling $263 million, were excluded from DEC’s unit commitment and dispatch decision-making processes. As a result, Duke’s unit commitment modeling showed that its fleet provided a value of almost $31

[12] Analysis based on data from Duke Energy Carolinas Response to Sierra Club Request 1-3(a) CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; Duke Energy Carolinas Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices; and Duke Energy Carolinas Response to Sierra Club Request 1-3(f) CONFIDENTIAL 2021 SCDR 1.3f_j.

[13] Duke Energy Carolinas Response to Sierra Club Request CONFIDENTIAL 1-17.

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million in production costs to its ratepayers in 2020, but in fact the Company actually incurred $233 million in excess production costs relative to system lambda in 2020. Of that total, approximately 95 percent, or $221 million, represents fuel costs.

Table 4: Total Production Costs incurred by DEC's Coal Fleet in 2020 ($Million)

Cost Description	($Million)	Source
a. Production costs passed on to ratepayers	$597	Average Cost of Generation from DEC in SC 1.3(f)&(j)
b. Unit variable costs used by DEC for the purpose of making unit commitment and dispatch decisions	$333	Modeled unit variable costs from DEC in SC 1.3(a)
c. Total cost of serving load met by coal units at System Lambda	$364	System lambda from DEC in SC 1.3(b) x generation from SC 1.3(a)
e. Cost of generation omitted from DEC's unit commitment and dispatch decision-making process	($263)	(b) - (a)
d. Difference between system lambda and DEC's incomplete modeled unit production costs	$31	(c) - (b)
f. Actual operational losses incurred by DEC and passed on to ratepayers from operating its coal fleet in 2020	($233)	(c) - (a)

Source: DEC Response to Sierra Club Request 1-3(a), CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices; DEC Response to Sierra Club Request 1-3(f) CONFIDENTIAL 2021 SCDR 1.3f_j. Disclosed publicly with agreement of DEC counsel.

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Q How does this discrepancy in reported fuel costs impact the Company's unit-commitment decision-making?

A As discussed above, DEC makes unit commitment decisions based on each unit's marginal production cost, also known as the incremental operating costs. Lower operating costs therefore put the unit lower on the supply curve and make it more likely that a unit will be committed. If the marginal production costs used for making unit-commitment decisions and market offer curves represent only a portion of the actual cost of fuel, then a unit will appear more economic than it actually is, and the unit will be over-committed and over-dispatched as a result.

Full (actual) fuel costs are still typically passed on to ratepayers either through the fuel charge adjustment process or through base rates (for the non-fuel variable component), regardless of what cost is used to make unit-commitment decisions. But these costs will be higher than if the plant was committed and operated based on its actual fuel cost. For this reason, the Commission should be concerned about which fuel costs the Company is using for different purposes and how those costs are calculated.

Q What accounts for the difference between DEC marginal and actual fuel costs at its coal plants?

A DEC provided several explanations for why certain of its operational costs are considered fixed and therefore excluded from its unit commitment decision-making process. But none of the Company's explanations account for the sheer

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magnitude of costs $225 million in costs excluded from its commitment modeling.

First, DEC indicated that its current rail transportation contracts include both fixed and variable costs. The fixed cost component is considered by DEC to be sunk and therefore excluded from its unit commitment decisions.[14] But, fixed transportation costs accounted for only 0.2 percent of total fuel costs incurred in December 2020, according to the Company's December 2020 fuel report.[15] The Company indicated that in the contract it is about to sign, these rail costs will instead be fully variable. While in theory, accounting for these rail costs as variable will increase the marginal production cost of DECs units slightly, closing the gap between the units marginal and actual production costs, and making alternatives even more attractive, in reality these costs have only a small impact on total production cost.

Second, the incremental cost of fuel DEC models represents the replacement cost of fuel, not the cost the Company has paid for its current fuel supply. But, because DEC utilized a fuel procurement strategy that relied on relatively flexible and short-term coal purchases this delta should be minimized.

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[14] Duke Energy Carolinas Response to Sierra Club Request 1-22.

[15] Exhibit 6, Schedule 7 to Duke Energy Carolinas Application in Docket No. E-7, Sub 1250.

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Indeed, in 2020, just over [redacted] of DEC's coal supply came from contracts of two years or fewer.[16] With short-term and spot contracts, the coal price in the contract and the replacement price the Company would pay on the spot market should not differ significantly. Additionally, with short-term and spot contracts, the Company has more flexibility to adjust its purchase based on need (compared with long-term contracts that tend to contain a minimum annual take). Short-term contracts should not lock ratepayers into significant fixed costs.

Third, DEC selected a buy-out option for some of its coal contracts instead of accepting delivery of the fuel and running the units for the purpose of burning off the coal. The Company's own analysis indicated that this option was projected to save ratepayers $22 million in 2020.[17] The $24.8 million in costs associated with this buy-out are also included in the fuel costs passed on to ratepayers.[18,19]

Q How would DEC's system be impacted if the Company updated its marginal production costs to include underrepresented costs?

A If DEC updated its marginal costs to represent a larger portion of the production cost of each unit, its coal units would shift higher on the supply stack. This would make alternative resources more cost-competitive on an operational basis. As a

[16] Duke Energy Carolinas Response to Sierra Club Request 1-18, CONFIDENTIAL Coal Supply Summary attachment.
[17] Direct Testimony of J, Verderame, Page 6.
[18] Duke Energy Carolinas Response to Sierra Club Request 1-21, 2021 DEC PSDR 3-1d CONFIDENTIAL Carolinas Decrement Analysis Documents.
[19] Direct Testimony of J. Verderame, Page 5.

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Jun 07 2021

result, the output of DEC's coal-fired units would be expected to decrease substantially. System lambdas would also likely increase, to more accurately reflect the true system lambda. This increase in system lambdas may lead to an increase in the valuation of alternative new resources.

6. DEC INCURRED $8.5 MILLION IN AVOIDABLE UNIT COSTS AT ITS COAL PLANTS AS A RESULT OF UNECONOMIC UNIT COMMITMENT DECISIONS.

Q Please summarize this section.

A In this section I review the marginal cost of production that DEC uses for the purposes of making unit commitment and dispatch decisions. I find that, even with DEC modeling marginal costs that omit over 40 percent of its actual variable production costs, DEC still incurred nearly $8.5 million in avoidable operational costs at its coal plants during these months as a result of these uneconomic unit commitment practices.

Q How does the analysis in this section differ from the analysis presented in section 4 above?

A In Section 4, I present analysis on how DEC's units *actually* performed during the test year period using data available after the fact (*i.e.,* the average cost of generation[20] that DEC incurred by operating its coal units uneconomically rather than turning them off). I show the total excess costs that DEC seeks to pass on to ratepayers during the months where the units average production costs exceeded the average system lambda.[21]

In contrast, in this section, I evaluate the hourly data, projections, and analysis that DEC modeled to inform its unit commitment decisions.[22] I identify the periods of time when the Company projected it would incur operational costs in excess of the system marginal cost[23] by operating its units, but yet still opted to operate its coal units and then predictably incurred significant net losses. I then calculate the excess costs that DEC seeks to pass on to ratepayers.

In this section I am relying on DEC's characterization of its marginal cost of production at its coal plants, which as I note above are far lower than—its average costs of production. Even relying on the company's characterization of

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[20] This number is slightly higher than the [redacted] million contract-buy out cost calculated by DEC on Duke Energy Carolinas Response to Sierra Club 1-3 1-3f&j CONFIDENTIAL Attachment.

[21] Duke Energy Carolinas Response to Sierra Club 1-3b, CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC.

[22] DEC Response to Sierra Club Request 1-3(a), CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices.

[23] DEC Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices.

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marginal costs of production, I still find that the Company self-commits its coal units out of merit on a regular basis.

Q What does it mean to operate a unit "out of merit" or "uneconomically"?

A When a utility operates a unit without regard for the unit's marginal cost, the unit is said to be committed "out of merit" order. This is generally done by the utility applying a "must-run" status to the unit, thereby forcing the unit to operate with a power output no less than its minimum operating level—no matter how the unit's operating economics compare to that of other units on the utility's system. Ratepayers incur the fuel and variable costs to operate the unit, regardless of whether there were lower cost resource options available to meet system needs.

This practice is common among investor-owned utilities, such as DEC, that are able to pass fuel costs directly on to ratepayers. It is much less common among merchant plants / independent power producers that operate within organized wholesale markets.[24] These operators rely entirely on market revenues to cover their units' operating and fixed costs. This provides a strong incentive to

[24] *See, for example,* Playing with Other People's Money. Sierra Club, October 2019. Accessible at https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.

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them to only commit their units when the market will cover the unit's operating costs.

Q How does DEC operate its system?

A DEC operates its system with Duke Energy Progress based on the terms of a Joint Dispatch Agreement.[25] The Fuels and Systems Optimization Portfolio Management group (Unit Commitment) is responsible for developing a unit commitment plan (that is deciding which units to turn on or keep online). The Energy Control Center (ECC) is responsible for operating and economically dispatching the Company's generation resources.[26] In deciding which units to commit and dispatch, the Company calculates the marginal production cost for each unit based on the market replacement cost of fuel, reagents/byproduct costs, emissions, and other variable O&M costs incurred at that particular unit.[27]

Q What tools does DEC have to inform its unit-commitment decisions?

A DEC conducts cost-based forward-looking analysis everyday using a unit commitment modeling software called GenTrader.[28] Forecasted customer demand, fuel and emission market prices, contractual obligations, unit costs and parameters, and planned unit outage information are all input into the model. The

[25] Duke Energy Carolinas Response to Sierra Club Request 1-28, Attachment SC 1.28.
[26] Duke Energy Carolinas Response to Sierra Club Request 1-5.
[27] Duke Energy Carolinas Response to Sierra Club Request 1-8.
[28] *Id*.

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model outputs “a unit commitment plan that is utilized to dispatch the generation fleet to minimize production costs while ensuring reliability over the 7-day forecast period.”[29] The Company adjusts the analysis throughout the day as needed. I will refer to this analysis as the “7-day forecast.”[30]

Q How should DEC be using the results of its cost-based analysis to inform unit-commitment decisions?

A Except in the case of unit testing or other extenuating circumstances, DEC should elect to commit its units only if it expects the unit to operate at below system lambda over a reasonable near-term time period (the Company’s 7-day forecast period would be a reasonable time-period), incorporating consideration of reliability, start-up and shut-down costs and times. Conversely, the Company should take a unit offline if the Company projects it will operate at a cost that exceeds system lambda. Operating the units otherwise would predictably result in higher costs that could have been avoided. Therefore, the Company should document any deviations between its final commitment decision and the decision based on its 7-day forecast.

[29] Duke Energy Carolinas Response to Sierra Club Request 1-9.

[30] In Indiana, Duke Energy produces a 7-day forecast known as the P&L or Profit and Loss Analysis.

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Q Should a utility always commit its units to minimize costs to ratepayers based purely on the basis of marginal costs?

A Not necessarily. There are certainly circumstances, although limited, in which a unit needs to be operated out of merit. For example, units sometimes need to be brought or kept online for testing purposes or in anticipation of a reliability need. These decisions may be made regardless of costs. Aside from these exceptions, utilities are expected to use accurate cost information and robust processes to make commitment decisions, but they are not expected to never operate a unit uneconomically or to always be right based on perfect hindsight.

First, given the inflexibility of coal units, it can sometimes make sense to leave a unit online for short periods of time, even when there are lower cost resources available, in order to be available to provide electricity during hours of high demand. But even so, the unit must be projected to be economic overall across a multi-day or week period of time.

Second, if system demand or the availability (or cost) of alternative energy opportunities differs significantly from what the utility projected, the utility's commitment decisions may not minimize costs to ratepayers during a multi-day period. If the utility's own contemporaneous analysis indicated that operating the unit would minimize costs, it is not necessarily an imprudent decision. But, if the high costs are part of a pattern in which the utility is consistently and systematically wrong and has neglected to modify its decision-making process,

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the entire process may not be robust or prudent. The accuracy of the utility's daily unit-commitment decision-making process should itself be a feedback into its decision-making process, with modifications incorporated when the current process is falling short.

Q Why is it concerning that DEC is self-committing its coal units out of merit order so frequently?

A Operating units out of merit order incurs unnecessary fuel and variable operational costs that are passed on to ratepayers. These costs are likely avoidable if the units were instead committed and dispatched based on economics.

In addition, when a unit is committed out of merit, it shows up on the supply curve as a zero- or low-cost resource, but ratepayers still incur the full cost to operate the resources. By artificially cutting the line, and showing up as a zero- or low-cost resource, these out of merit coal units displace lower cost resources that were previously below the margin. This has a price suppressive effect, and results in a system lambda that is below the marginal cost of energy on DEC's system. The coal unit is still operating above system lambda and those full unit costs are being passed on to ratepayers. Beyond the direct ratepayer impact, this has important implications for how avoided costs are calculated.

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Q Why is it notable that DEC incurred costs in excess of system lambda at many of its units over many months during the test year period?

A As discussed above, it is understandable that DEC may incur operational costs in excess of system marginal costs on a daily or even weekly basis as a result of the longer start-up and shut-down costs associated with coal units. These units may accept a “loss” in a few hours of the day or week in order to be online during peak hours. But it is not reasonable or prudent for DEC to operate a unit at a cost that exceeds the system marginal cost over a sustained period of time. Excess costs incurred as a result of this operational decision are avoidable through better unit-commitment decisions and indicate that DEC is either (1) not using robust and complete input data to inform its unit-commitment decisions, or (2) ignoring the results of its unit-commitment analysis.

Q Did you identify avoidable losses based on your analysis?

A Yes, as shown in Table 5, I find that in 2020, DEC could have avoided at least $8.5 million in operational costs at its coal plants if the Company had made better unit-commitment decisions. Specifically, these are the costs that are avoidable if DEC had turned its coal units off in the months when each unit’s production costs exceeded the system’s marginal cost and instead used its lower cost resources to meet system needs.

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Table 5: Operational costs in excess of system lambda ($Million)

Plant	Avoidable Operational Costs ($000)
Allen 1	[redacted]
Allen 2	[redacted]
Allen 3	[redacted]
Allen 4	[redacted]
Allen 5	[redacted]
Belews Creek 1	[redacted]
Belews Creek 2	[redacted]
Cliffside 5	[redacted]
Cliffside 6	[redacted]
Marshall 1	[redacted]
Marshall 2	[redacted]
Marshall 3	[redacted]
Marshall 4	[redacted]
Total	**$(8,463)**

Source: DEC Response to Sierra Club Request 1-3(a), CONFIDENTIAL 2021 SCDR 1.3a_d_e_j DEC Coal Unit Fuel Detail; DEC Response to Sierra Club request 1-3(b), CONFIDENTIAL 2021 SCDR 1.3b DEC INCDEC Prices.

Confidential Exhibit DG-2 shows the monthly break-down, by unit, of monthly production costs relative to system lambda. In the months where the values are positive, the unit on net has a lower production cost then the marginal system cost. In months where the values are negative, the unit on net has a higher production cost than the system marginal cost.

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Q What evidence do you have that the costs incurred during the months in 2020 when unit costs exceeded system marginal costs are avoidable?

A DEC provided hourly data with "modeled" unit costs and load and actual system lambdas. Although the modeling occurs after the fact,[31] the modeled costs represent the cost information that the Company had at the time it made its units commitment and dispatch decisions. Any time the unit costs were projected to exceed system lambda (inclusive of start-up cost considerations) over a multi-day stretch, a responsible utility manager would reduce costs to ratepayers if the units were shut down.

We asked multiple times for the contemporaneous documentation that DEC produced at the time that they made their daily unit commitment decisions, but they only provided the loading reports, not their 7-day forecast sheets.[32] Without the contemporaneous documentation, the Commission will lack critical information to assess the reasonableness and prudence of the Company's daily unit commitment decisions.

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[31] Duke Energy Carolinas Response to Sierra Club Request 3-2.

[32] Duke Energy Carolinas Response to Sierra Club 1-9(b); Duke Energy Carolinas Response to Sierra Club Request 3-1.

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7. Recommendations for the Commission

Q Please summarize your recommendations.

A I recommend that the Commission examine closely DEC's production cost accounting, its unit commitment process that relies on its production costs, and the operational decisions and incurred costs that result, and carefully scrutinize these costs for potential disallowance in future proceedings.

Q What do you recommend to address the discrepancy in production costs used to make unit commitment decision and the actual costs passed on to ratepayers?

A DEC's should be required to provide full transparency into the Company's marginal and average production costs. Specifically, DEC should provide a full breakdown of the following, accompanied by a detailed explanation of each and full work papers that show how each component was calculated:

1. Full production cost of each unit that will be passed on to ratepayers in this docket, broken down by the following categories:
    a. Fixed costs
    b. Variable costs
        i. Fuel
        ii. Reagents/ by products
        iii. Emissions
        iv. Variable O&M.

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2. Marginal production cost of each unit used for making unit commitment and dispatch decisions, broken down by the same components listed directly above. For any items not included in DEC marginal production costs, the Company should provide a detailed justification for why these costs are not relevant for making unit commitment decisions.

Q What information do you specifically recommend that DEC provide in each fuel cost adjustment filing to allow a review of the prudence of its unit-commitment practices?

A The utility filings in this docket are insufficient and do not meet the filing requirements for this proceeding outlined in Commission Rule R8-55(e).[33] I recommend that DEC compile and file as workpapers with its annual fuel cost adjustment application a detailed report describing its daily unit-commitment decisions and practices as part of future fuel charge adjustment proceedings. DEC should provide the following information as part of each annual fuel charge adjustment application, to inform the Commission's review of its unit-commitment practices and determination whether DEC's fuel- and fuel-related costs for those units were reasonably and prudently incurred:

a. All 7-day forecast sheets used to develop the Company's daily unit-commitment decisions and marginal cost.

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[33] NCUC Rule R8-55(e).

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b. The reason for any deviation between the commitment decision suggested by the Company's forward-looking price-based analysis and the Company's actual commitment decision (e.g., where the Company's analysis suggests that a unit has a production cost above the marginal system cost during a given day, and the Company self-commits the unit anyway).

c. Hourly data sufficient for the Commission to calculate the net value or excess costs that each plant actually incurred in each test year period, including total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable operations and maintenance ("O&M") cost, system lambdas, day-ahead commitment status, and actual outages.

Q What other recommendations do you have for the Commission?

A I recommend that the Commission direct DEC to conduct a new retirement study of each unit in the Company's fleet. I acknowledge that the Company conducted retirement analyses for its 2020 Integrated Resource Plans at the direction of the Commission. However, DEC should be required to evaluate the continued operation of each of its coal units based on economics, from both a short-term operational, and long-term planning perspective.

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Q **Are you recommending a disallowance in this docket relating to DEC's uneconomic commitment practices at any of its coal units?**

A Not at this time. As discussed in Section 6, $8.5 million represents the net operational losses that DEC incurred at its coal units as a result of sustained uneconomic operations during specific months. These losses could have been avoided, had the Company economically committed its coal units. While I am not recommending a disallowance at this time, I do recommend that the Commission direct DEC to evaluate the economics of continuing to maintain and operate the units relative to alternative resources to meet system capacity and energy needs while maintaining reliability.

Q **Does this conclude your testimony?**

A Yes.

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CERTIFICATE OF SERVICE

I certify that the parties of record on the service list who have signed a confidentiality agreement have been served with the *Corrected* Direct Testimony of Devi Glick –*Public Version* on behalf of the Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 1st day of June, 2021.

s/ Gudrun Thompson

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Q Ms. Glick, did you prepare a summary of your testimony?
A Yes, I did.
Q And would you please provide that to the Commission?
A Sure. My name is Devi Glick. I am a Senior Associate at Synapse Energy Economics, and I am testifying today on behalf of the Sierra Club. Thank you for the opportunity to testify today.
My testimony addresses the analysis and decision making processes that Duke Energy Carolinas uses to commit and dispatch its coal-fired power plants. The term commitment refers to the Company's decision to turn on, keep on, or turn off a coal-fired power plant, while the term dispatch refers to the Company's decision to turn up or down a unit between its operational minimum and maximum levels.
I show in my testimony that the cost DEC uses to make its unit commitment decisions vary substantially from the fuel cost that the Company now seeks to recover from ratepayers in this docket. I discuss how this discrepancy is driving DEC's uneconomic commitment of its coal fleet, and I calculate the excess cost passed on to ratepayers as a result.

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Finally, I outline recommendations for improving transparency and functioning of the Company's unit commitment process. In the past, utilities operated their coal-fired power plants as baseload resources, with little thought given to whether the plants should be turned on or off, but in recent years low gas prices and nearly zero variable cost renewables have pushed coal generation to become marginal and uncompetitive during many hours of the year. Failing to adequately reflect this fact in its fleet operation has caused DEC to run coal plants when it is not economic to do so, saddling ratepayers with excess avoidable fuel cost.

Based on my review, I find that DEC's coal units had some of the highest fuel costs among all coal units in the country during the 2020 test year, yet DEC continued to operate and maintain the units. As a result, DEC's units incurred 233 million in variable cost above system lambda, what I will refer to as excess cost, during the test year. The system lambda represents the marginal cost of energy on the system.

In an economically efficient system, units are committed based on variable cost, with the lowest cost resources coming online first and progressively more expensive units being turned on until system load is met,

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but when units are committed using a marginal cost, that represents only a small portion of the unit's full variable cost, excess costs are incurred. These excess costs are a direct result of DEC's inadequate unit commitment process. I find that DEC's commitment process omitted approximately 263 million worth of fuel and variable costs, representing over 40 percent of those costs at its coal units, thus allowing the units to commit and dispatch significantly more than they would if the unit's full variable cost was reflected. Of that, 263 million in fuel costs accounted for approximately 250 million.

My testimony identifies several potential explanations for the discrepancies between DEC's marginal and actual fuel costs, but none adequately explains the sheer volume of costs excluded from its commitment modeling. I find that even using DEC's incomplete marginal cost accounting, the Company can still be found to have incurred excess marginal cost of eight and a half million dollars. My testimony recommends that the Commission examine DEC's production cost accounting, unit commitment process, and operational decisions.

Finally, I discuss how DEC did not adequately report and describe its fuel costs, accounting and unit

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commitment practices in its fuel charge adjustment application. I recommend that the Commission require the Company to provide transparent accounting of its variable cost allocation and documentation of its daily decision making process and its reasoning for any uneconomic commitment decision. My testimony outlines several pieces of information that would be helpful to the Commission. This concludes my summary.

Q Thank you.

MS. THOMPSON: Chair Mitchell, Ms. Glick is available for cross examination and questions from the Commission.

CHAIR MITCHELL: All right. Thank you, Ms. Thompson. Mr. Kaylor?

CROSS EXAMINATION BY MR. KAYLOR:

Q Ms. Glick, did you have a chance to review the rebuttal testimony of Mr. Verderame?

A I did, yes.

Q Based on that rebuttal testimony, did you have any reason to alter any of your testimony?

A I updated some of the values. The -- some of the corrections I made were I looked at -- I added in the natural gas cost as well. That did contribute to some of the corrections that I made in one of the tables, two of

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the tables, I believe.

MR. KAYLOR: No further questions.

CHAIR MITCHELL: All right. Before we move to questions from the Commission, just pause here to see if any other Intervenors have questions for this witness?

MR. GRAY: None from CIGFUR.

CHAIR MITCHELL: All right.

MR. CREECH: No questions, Madam Chair.

CHAIR MITCHELL: All right. Thank you, Mr. Creech. All right. Questions for the witness from Commissioners?

(No response.)

CHAIR MITCHELL: All right. Ms. Glick, it looks like you are off the hook for the afternoon. Thank you, ma'am. You may step down.

THE WITNESS: Thank you, Chair.

(Witness excused.)

CHAIR MITCHELL: Ms. Thompson, I'll take a motion from you.

MS. THOMPSON: Yes. Thank you, Chair Mitchell, for the reminder. I'd like to move Ms. exhibits -- Ms. exhibits -- Ms. Glick's prefiled exhibits into the record, with Confidential Exhibit DG-2 being kept under seal.

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CHAIR MITCHELL: All right. Hearing no objection to that motion, Ms. Thompson, it will be allowed, and the exhibits to Ms. Glick's testimony will be admitted into evidence.

MS. THOMPSON: Thank you.

(Whereupon, Exhibit DG-1 and Confidential Exhibit DG-2 were admitted into evidence.)

CHAIR MITCHELL: All right. With that, we will turn back to you, Mr. Kaylor.

MR. KAYLOR: Thank you, Chair Mitchell. We will recall our witness John Verderame to appear for his rebuttal testimony.

CHAIR MITCHELL: All right. Mr. Verderame, I will remind you that you are under oath, sir.

THE WITNESS: Yes, ma'am.

DIRECT EXAMINATION BY MR. KAYLOR:

Q Would you proceed with a summary of your rebuttal testimony?

A Thank you. In my rebuttal testimony I take issue with, and provide detailed objection to, Sierra Club witness Glick's testimony and recommendations with respect to DEC's unit commitment and dispatch process. I also disagree with witness Glick's characterization of

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the performance of DEC's coal units and hers assertions -- her assertions that DEC has omitted fuel and variable costs representing 40 percent of the actual production costs.

I categorically reject witness Glick's assertion that DEC has operated its plants "with little thought given to whether the plants should be turned on or off." Witness Glick also made generalized recommendations concerning DEC's coal and transportation contracting strategies, but when asked in discovery, witness Glick failed to identify a single instance of a fuel or transportation contracting issue in this proceeding.

The purpose of this proceeding is to establish fuel rates for DEC. Witness Glick has not recommended any changes to the fuel rate proposed by DEC, but instead has sought to leverage this proceeding into an opportunity to opine on a number of topics that are either properly addressed in other proceedings, such as general rate case or IRP proceeding, or have previously been rejected by the Commission with respect to other Sierra Club witnesses. The Sierra Club, like other parties to this proceeding, has not recommended disallowance of any costs incurred by DEC in the test

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period in this proceeding, and accordingly, the Commission should disregard the bulk of Sierra Club testimony provided by witness Glick as being not relevant to a fuel proceeding under the fuel statute and the Commission rules.

This concludes my direct -- my rebuttal testimony summary.

Q Thank you.

MR. KAYLOR: Chair Mitchell, the witness is available for cross.

CHAIR MITCHELL: All right. Mr. Moore, I believe you're up?

MR. MOORE: Yes. Thank you, Chair Mitchell. Mr. Verderame, my name is Tirrill Moore, again, representing the Sierra Club.

CROSS EXAMINATION BY MR. MOORE:

Q In your role as the Vice President of Fuel and Systems Operation for Duke Energy, you're responsible for the purchasing and delivery of fuel, but also system optimization, correct?

A That's correct.

Q So you would be the correct person to ask a question about how the Company structures its fuel contracts?

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A That's correct.
Q Are you the right person to ask about the Company's commitment and dispatch decision making process?
A Yes. I lead those teams.
Q I think it would be helpful, before we get started, to define a few terms. I'm going to give you a couple definitions, and will you just let me know if --
A Yes.
Q -- at a high level, they are definitions? Unit commitment is the decision to turn on or turn off a generating unit or keep online a unit that is already online?
A I agree with that.
Q And dispatch is, then, to increase or decrease a unit's generation level once it's already been placed online?
A Agree.
Q And so marginal production cost is the incremental cost of operating a unit based on only the sys-- or the unit's variable costs; is that right?
A Okay. Yes.
Q And is that the costs that are used for Duke's commitment and dispatch decision making?

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A No.
Q Can you explain?
A So we use all variable costs for commitment. Any cost that is incurred because a unit is either committed or dispatched is used for commitment purposes. For dispatch purposes we only use those costs that are related to the actual change in generation, the dispatch cost, so we don't include start-up costs and no-load costs, so costs that are incurred just to keep the unit online. So I think that's the difference there between categorizing commitment and dispatch as one.
Q Okay. Thank you. And then cost of generation or production costs includes all fuel, fixed and variable, variable operations and maintenance costs, commissions and reagent costs; is that right?
A So that is the cost that goes through rates, right, that we will recover in this proceeding, but the cost we use for dispatch, the fuel costs for dispatch are different costs.
Q Okay. Great. Thank you. And so system marginal cost or system lambda is the cost to produce an additional or incremental megawatt of generation on the DEC system in a given hour?
A Again, only -- only fuel and variable O&M

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components of those costs, yes.
Q Okay. Great. Thank you. So I believe Mr. Immel was asked this question, but I'll ask it to you. Would you agree that the Company has an obligation to minimize all costs, including its fuel cost, while reliably serving load?
A Yes. I'd agree.
Q And the fuel costs incurred by the Company are directly tied to which plants are operated?
A So the fuel costs we recover are tied to not only the fuel cost, but also the fixed and variable -- the fixed transportation costs.
Q Well, so if the Company runs more fuel generation, they will incur more cost to buy coal; is that correct?
A If the Company runs more coal generation, then we will incur more cost to burn coal, yes.
Q Great. Thank you. And then the decision which power plants are operated, that's the Company's commitment decision; is that right?
A That's right.
Q Okay. And so the Company's fuel costs are also impacted by the extent to which a power plant is run; is that correct?

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A Yes.
Q And that's the dispatch decision --
A Right.
Q -- correct?
A Yes.
Q So in your rebuttal testimony you discuss the production cost modeling that the Company uses to formulate its unit commitment plan and it notes GenTrader; is that right?
A That's right.
Q And that model creates a seven-day forecast that shows the marginal cost to operate a unit; is that right?
A So, yes, one of the outputs is the marginal cost.
Q And so using that forecast, the Company then decides its commitment decision, so which units to turn on or off be online?
A That's right.
Q So it's fair to say that the inputs into that model have a large impact on the Company's commitments; is that right?
A They're fundamental to the -- to the outputs, yes.

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Q I'd like to take a look at what has been premarked as Sierra Club's Exhibit 6. And this is marked as a confidential exhibit, but I have discussed with the Company's counsel, and in the form that it was produced, it does not need to be marked as confidential. We're not going to look at any of the attachments that were provided as well.

CHAIR MITCHELL: All right.

Q Let me know when you have a chance to pull that up.

CHAIR MITCHELL: All right. Mr. Moore, because we are operating remotely, I want to make sure that we're all looking at the same document, so describe the document -- describe the header of the document for me.

MR. MOORE: Okay.

Q Well, Mr. Verderame, do you have it pulled up?

A I do.

Q Do you want to describe it to the Chair?

A Sure. Chair Mitchell, it's -- the header is Sierra Club Exhibit 5, Duke Energy Carolinas, LLC, Docket No. E-7, Sub 1250, Fuel and Fuel-Related Cost Proceeding, Test Year Ended December 31, 2020. Sierra Club Data Request No. 1-8.

CHAIR MITCHELL: Okay. Thank you, Mr.

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Verderame. And just again, for purposes of the record, the document that has been provided is marked confidential, but Mr. Moore, what I am hearing you say is the document is not, in fact, confidential. And I'd like Mr. Kaylor to confirm that, please.

MR. KAYLOR: That is correct, Chair Mitchell.

CHAIR MITCHELL: Okay. Thank you, Mr. Kaylor. Let's go ahead and mark that exhibit, Mr. Moore.

MR. MOORE: Yes. So at this time I would like to mark what has been premarked as Sierra Club Exhibit 6 as Sierra Club Cross Examination Exhibit 1.

CHAIR MITCHELL: Okay. The document will be marked as Sierra Club Cross Examination Exhibit Number 1.

(Whereupon, Sierra Club Cross Examination Exhibit Number 1 was marked for identification.)

Q Mr. Verderame, do you recognize this document?

A I do.

Q So in this data request, the Company responded that one of the inputs used to make its unit commitments is the price of fuel; is that correct?

A That's correct.

Q And for the purposes -- this is under the Company's response to question (a). And for the purposes

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of the model, the price of fuel is defined as the market price of fuel plus variable transportation costs?

A Correct.

Q But just to confirm, the market price of fuel means the price the day of the unit commitment decision on the model was run; is that right?

A So coal -- coal prices, the curves are updated weekly, so it may not be the exact day, but, you know, there's a different time scale to coal markets than there are the gas markets. So gas prices we update daily; coal prices are only updated weekly.

Q And the market price is not what the Company is asking to recover in this proceeding, correct?

A No. That is correct.

Q Okay. Thank you. Returning to the data request, the Company stated that fixed transportation costs are considered fixed and are not included in the unit commitment decision; is that right?

A That's correct.

Q But you are asking to recover fixed transportation cost for fuel in this proceeding; is that right?

A That's right.

Q Does the Company consider the cost associated

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with fixed tonnage requirements or must-take provisions in their coal contracts as fixed costs?

A So we don't have any must -- must-take provisions in our coal contracts, per se, so I would say no.

Q Okay. On pages -- on page 10 of your rebuttal testimony, lines 16 to 17 -- let me know when you're there. I'm going to read you a bit of that.

A Hold on just one second, please. Okay.

Q It states "...the fact that certain units are not required to operate at times does not equate to poor performance or mean that the units are not necessary to ensure reliability." Did I read that right?

A The second half of the sentence, yeah.

Q What do you mean by "required to operate" in that sentence?

A So by "required to operate," we mean to meet a reliability condition to meet -- serve native load.

Q Now, is that referring to a commitment decision or a dispatch decision?

A So that's -- that would be a commitment decision and a dispatch decision.

Q So a unit is dispatched in realtime when its marginal production costs are below system lambda; is

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that correct?
A That -- no, not necessarily.
Q Okay. Can you explain?
A So a unit will be dispatched -- it might be dispatched above system lambda because it's either -- it could be required for reliability, to be online for a transmission constraint, or just a load requirement.
Q Okay. Thank you. I'm going to take a look at another exhibit. This has been be premarked as Sierra Club Exhibit 2. Let me know when you have that pulled up.
A Okay. I'm there.
Q Can you describe what this document is?
A So this is a data request.
Q Is it Data Request 1-4?
A Oh, I'm sorry. Yes. Sierra Club Data Request 1-4.
Q And do you recognize this document?
A I do.
MR. MOORE: Chair, at this time I would like to mark this exhibit, what has been premarked as Sierra Club Exhibit 2, as Sierra Club Cross Exhibit 2.
CHAIR MITCHELL: All right. The document will be marked Sierra Club Cross Examination Exhibit Number 2.

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(Whereupon, Sierra Club Cross Examination Exhibit Number 2 was marked for identification.)

Q So looking at this document, it asks for hourly data for when units are committed for reliability reasons, correct?

A Yes.

Q And did the Company object to this request?

A So we reject--- we did object to a portion of this request.

Q Okay. Thank you. I don't have any more questions on that exhibit, so you can put it away if you like. If you looked back and saw that a unit had not been required to operate for months at a time, would that be a sign to you that the unit was not necessary to ensure reliability?

A No, it would not.

Q Can you explain that?

A So -- and this is somewhat part of the IRP planning process, but we plan the system to meet peak load requirements, and there are certainly periods during the year where the unit would not be required, whether it's an anomalous weather year or whether it's just, you know, just a shoulder month period where load

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Jun 17 2021

requirements don't require us to -- us to dispatch or commit a unit. It doesn't mean the unit isn't important to providing reliability. Otherwise, we would be, you know, forced into relying on the market to go out and purchase to meet those loads. So we plan to meet the load as a reliability strategy and commitment.

Q We're not going to look at any of the numbers in this exhibit, but in formulating your rebuttal testimony, did you review Ms. Glick's Confidential Exhibit D (sic)?

A Let me find what D was. Okay. I reviewed the whole -- I didn't review all of the workpapers, but I did review exhibits that were in the workpapers. Exhibit DG-2, is that it, at the end?

Q Correct. I believe that is right. Let me -- give me one minute. Yes. That's correct.

A Yes, I did.

Q Obviously, you disagree with Ms. Glick's conclusions, but do you dispute any of the calculations that are in that exhibit?

A So I didn't validate the calculations, but I will -- I will say that I fundamentally disagree with the methodology of the loss in terms of being compared to system lambda in any way. I just -- I just don't think

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that's an appropriate -- I know that's not an appropriate way to assess whether a unit, you know, makes -- is valuable to a system or not. And I think -- when I first started reading this, I tried to get my arms around what the witness was trying to, I don't know, trying to get across other than working backwards from a conclusion, but really what it came to is I think there's a conflation here between market methodologies and non-market methodologies.

I notice in her -- in her testimony she uses words like "price suppressive effect" and "revenues" and "losses." I think these are -- these are terms used in structured markets, and I think the idea of using system lambda as some type of a proxy for an LMP in a structured market, which is maybe a more force--- a fulsome kind of representation of cost is really just fundamentally wrong. It doesn't make any sense and -- to me and my team.

Q Okay.

A I will say I can't -- I can't agree with these numbers.

Q Okay. On page 14 of your rebuttal testimony, you said that the Company provided every seven-day ahead unit commitment forecast in its supplemental response to

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a Sierra Club data request. Do you recall that?

A Yes.

Q I'd like to take a look at that. This was premarked as Sierra Club Exhibit 5.

A I'll have to go back to my exhibits.

MR. MOORE: And, again, Chair, this is marked as confidential, but I have talked to the Company counsel, and in its current form, it does not need to be marked as such. We're not going to look at any attachments to that document.

MR. KAYLOR: Correct, Chair Mitchell.

A Okay.

Q Do you recognize this document?

A I do.

MR. MOORE: Chair, at this time I would like to mark what was premarked as Sierra Club Exhibit 5 as Sierra Club Cross Examination Exhibit 3.

CHAIR MITCHELL: All right. The document will be marked as Sierra Club Cross Examination Exhibit Number 3, and counsel for DEC has confirmed that the document is not confidential.

(Whereupon, Sierra Club Cross Examination Exhibit Number 3 was marked for identification.)

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Q So, again, on page 14 of your rebuttal testimony, where you're talking about the Company providing the seven-day-ahead unit commitment forecast, this is the document you're talking about?

A Well, the seven-day for--- well, yes. Okay. The seven-day forecast was, I believe, part of this exhibit, right, so in this document.

Q Correct. I believe it was to question (b), which I'm going to read it and you let me know if I read it correctly, "Indicate whether the Company performs economic analysis to inform its unit commitment decisions for its coal units," and then (b)(2) says "If so, provide all analysis conducted during the test year 2020 in native machine readable format." Is that correct?

A Right. Correct.

Q And so in your supplemental response to that request, the Company did provide its unit loading forecast; is that right?

A That's right.

Q And are you familiar with those?

A Yes.

Q And so on page 6 of your rebuttal, you discuss the inputs into your daily analysis to determine your unit commitment plan. And let me know if these sound

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like the input to that plan. You mentioned forecasted customer energy demand, fuel commodity and emissions allowance market prices, contractual obligations including power market purchases and sales, generating unit parameters, and planned unit outages; is that correct?

A That's correct.

Q So the unit loading reports that were produced in response to Data Request 1-9(b), do they indicate the forecasted energy demand?

A Yes, they do. I believe it's one of the top lines.

Q Do they contain the fuel commodity and emissions allowance market prices?

A So the market prices are embedded in the GenTrader model. This seven-day is a forecast of the output of that model. It doesn't -- it doesn't have those -- it doesn't display those market prices.

Q So do they contain the Company's contractual obligations?

A I don't believe the contractual obligations would be part of a fuel input because we use replacement cost of fuel.

Q Well, I'm referring to the documents that you

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Jun 17 2021

produced, the unit loading reports produced in response to 1-9(b). Did they contain the Company's contractual obligations, what was given to the Sierra Club?

A I'm sorry, Mr. Moore. I'm not tracking the question.

Q Okay. We'll move on. Do you know if the unit loading reports contain the unit generating parameters?

A So I actually don't have it open. I don't know whether it has the -- has the min's and max's. I do know it recognizes when a unit is at its forecasted min or max or somewhere in between.

Q So the GenTrader model recognizes that?

A The GenTrader -- that's one of the inputs to the GenTrader.

Q But it is not necessarily defined in the output of that model?

A I think it's displayed in that output as the color -- the color of the number. You may have a black-and-white version of it, though.

Q But I guess the key question is all of the pieces of information we just discussed are a key part of the decision making process that the Company undergoes, correct?

A That's right. And they're all in the GenTrader

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Jun 17 2021

model as inputs to the model.

Q But what was provided was the outputs to the model; is that correct?

A That's right. We really did our best to try and provide what you were looking for here, given, you know, what is machine readable and what's -- you know, what cannot be condensed into something that can be emailed.

Q Correct. So, but as we said earlier, the inputs to the model are important in getting to the output, correct?

A Yes.

Q On page 7 of your rebuttal, you discuss -- and we talked about this a little bit -- why you believe system lambda is not an appropriate measure for unit commitment decisions?

A That's right.

Q And your argument is that system lambda is the measure of the instantaneous system incremental cost, while unit commitment decisions are based on total cost over a multi-day period; is that right?

A That's right. Well, total variable cost.

Q Right. How do you measure whether a unit is projected to provide benefits over a multi-day period?

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A So that is the, I think, the output of the GenTrader model. That optimization model looks at all those parameters and determines what unit should be on and when they should be cycled off or kept on through to the next period when they would be needed as the least cost solution.

Q And Ms. Glick did actually acknowledge in her testimony that there were times where a unit might operate, even though its operational cost exceeded system lambda; isn't that right?

A I believe there was one nod to that, but the majority of the testimony is fundamentally based in this idea of averaged system lambda cost as a metric of either unit efficiency or dispatch efficiency.

Q Right. If the Company's forward-looking analysis ends up being wrong in hindsight, it's not necessarily an imprudent decision. Is that what you're saying, basically?

A You know, I'm saying that we make decisions with all the information we have available to us in terms of unit availability, projected load, weather. And the weather is -- we have a saying, the forecast is always wrong, it's never going to be right, but we do our best to get it as -- you know, as close as we can and, you

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know, run the system in the least -- you know, the least cost and most effective way we can for customers to minimize cost.

Q So if the Company looked back on their analysis and found that their analysis was consistently wrong, would you agree that that would be something the Company should look into?

A So we do look back at that analysis. We look back at it every week and we trend it. And, yes, absolutely, if we saw that it was deviating from -- significantly from planned perimeters, then certainly we would go back and look at it. We have metrics around load forecasting, weather forecasting, solar forecasting. These are all things we, you know, we watch very closely because they'll inform how good the load forecast is and, ultimately, how good the plan is for what generation needs to be dispatched or committed.

Q Would you agree that if a unit consistently committed at a marginal production cost in excess of system lambda, that should prompt the Company to take another look at its decision making process?

A No. Again, the commitment decision is inclusive of all the variable cost, the start cost, the start fuel, and these no-load costs, right? They are, by

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Jun 17 2021

definition, more expensive than the instantaneous cost to move one megawatt above another. It's just a form metric. No one uses the metric. RTOs don't use a metric like that. Honestly, if that was a boundary for how we dispatch plants, that we could never dispatch or commit a unit that had a higher than the system average lambda for the day, we'd curtail load most every day.

Q Just one minute. I want to take a look now at what was premarked as Sierra Club Exhibit 7.

A Seven (7).

MR. MOORE: And, again, Chair, this was also marked as confidential, but I've talked to Company's counsel, and in its current form, it does not need to be marked such. We're not going to look at any of the attachments.

A Okay. I'm there.

MR. KAYLOR: That's correct, Chair Mitchell.

Q And Mr. Verderame, do you recognize this?

A I do. I'm there.

Q Does this appear to be DEC's response to Sierra Club Data Request 1-3?

A 1-3 it is, yes.

MR. MOORE: Chair Mitchell, at this time I would like to mark what was premarked as Sierra Club

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Jun 17 2021

Exhibit 7 as Sierra Club Cross Examination Exhibit 4.

CHAIR MITCHELL: All right. The document will be marked as Sierra Club Cross Examination Exhibit Number 4, and counsel for DEC has confirmed that the document is not confidential.

(Whereupon, Sierra Club Cross Examination Exhibit Number 4 was marked for identification.)

Q And I'm going to read a portion of that data request, and you let me know if I read it correctly. On the second line of the request itself, it says "Please provide the following hourly information for the year 2019 and the test year," and then it says "If not available at an hourly scale, please explain why and provide the most temporally granular scale available." Is that right?

A That's correct.

Q So then request (f) is asking for the accounting fuel cost; is that right?

A That's correct.

Q And the Company -- can you read the Company's response?

A "This request seeks an analysis calculation, a compilation which" -- we have -- "which has not already

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Jun 17 2021

been formed. Instead, please see attached confidential monthly average cost of generation in dollar per mWh of the Company's coal-fired generation units for the test period January 2020 through December 2021." Now, we simply don't have that data broken down on an hourly basis. We provided it the way we calculate it and the way we recover it. And I'll just mention that also includes (g) below it as a part of that number.

Q Right. And so (g) was asking for the accounting variable cost of production and the Company, similarly, objected to that request; is that right?

A Yeah. We just didn't have it and really couldn't figure out a way to put it together for you. I believe we file--- we provided everything else on an hourly granularity.

Q One second. I think we're going to take a look now at what was premarked as Sierra Club Exhibit 3.

A And I have these stored in order.

Q Okay. And do you recognize that request?

A Yes.

Q Can you read Request (a)?

A "Provide the hourly production cost used for purposes of unit commitment and dispatch for each DEC and DEP unit dispatched under the Joint Dispatch Agreement

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Jun 17 2021

for the year 2019 and the 2020 test year."

Q And the Company objected to that request as well?

A Well, I believe we partially objected to it. We objected because 2019 was outside of the test period. And we did provide all that information for DEC, but this is a DEC case, and we didn't feel that the DEP data was appropriate or relevant to this case.

Q On page 3 of your rebuttal testimony, you state "The content and structure of the Company's application in this proceeding conforms to all applicable legal requirements." Is that right?

A As I understand them, yes.

Q Are you an attorney, sir?

A No.

Q So you're not offering a legal conclusion there?

A I am not.

Q Would you agree that it's up to the Commission to decide whether the application meets all legal requirements?

A Yes. And it's my understanding that we have or else I believe we would have been met with some -- something from the Staff or the Commission itself. And

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Jun 17 2021

we certainly would provide anything that the Commission asks for, but I believe we have met that standard and what we --

MR. MOORE: No further questions. Thank you, Mr. Verderame.

THE WITNESS: Thank you.

MR. MOORE: Madam Chair, at this time I would like to move all the exhibits into the record.

CHAIR MITCHELL: All right. Mr. Moore, just for purposes of clarity, would you identify those cross examination exhibits individually?

MR. MOORE: I'll go through them. We have what was premarked as Sierra Club Exhibit 6 is now Sierra Club Cross Exhibit 1; what was marked as Sierra Club Exhibit 2 is now marked as Sierra Club Cross Exhibit 2; what was marked as Sierra Club Exhibit 5 is now Sierra Club Cross Examination Exhibit 3; what was marked as Sierra Club Exhibit 7 is now marked as Sierra Club Cross Examination Exhibit 4; and then what was marked as Sierra Club Exhibit 3 is now marked as Sierra Club Cross Exhibit 5.

CHAIR MITCHELL: All right. Mr. Moore, you did not -- we did not mark Cross Exhibit Number 5, so let's do that now. We will mark for identification what was Sierra Club Cross -- or Sierra Club Exhibit Number 3 as

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Jun 17 2021

Sierra Club Cross Examination Exhibit Number 5.

(Whereupon, Sierra Club Cross Examination Exhibit Number 5 was marked for identification.)

CHAIR MITCHELL: And why don't you make your motion again, Mr. Moore.

MR. MOORE: Thank you. Chair, I would like to move the cross examination exhibits into the record as marked.

CHAIR MITCHELL: All right. Hearing no objection to your motion, it will be allowed.

(Whereupon, Sierra Club Cross Examination Exhibit Numbers 1-5 were admitted into evidence.)

CHAIR MITCHELL: All right. At this point I want to check in with our court reporter. We've been going for about an hour and a half. Linda, how are you doing? Do you need a break?

COURT REPORTER: I'm doing well. I don't need a break.

CHAIR MITCHELL: All right. Well, let's proceed, then. Mr. Kaylor, any redirect for your witness?

MR. KAYLOR: Thank you, Chair Mitchell. Just a

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Jun 17 2021

few questions.

REDIRECT EXAMINATION BY MR. KAYLOR:

Q Mr. Verderame, you -- you've been involved in this case. Are you involved in other cases that the Company files with the Commission, rate cases, IRP proceedings, those type proceedings?

A So no, not in North Carolina, I have not been.

Q And you did have occasion to review the testimony filed by the Sierra Club witness Glick, did you not?

A I did.

Q Is it fair to say that you take -- you disagree with virtually everything that this witness has included in her testimony; would that be correct?

A I'd say other than our agreement on what commitment and dispatch is, yes. I can't find a lot of common ground in anything in her testimony.

Q And you compare what she's testifying to on our system to maybe what happens on an RTO, a regional transmission organization?

A I do believe that's the language she was viewing this through.

Q And are you aware that the Sierra Club has had other witnesses that have testified in recent DEC cases

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Jun 17 2021

that have brought up these same issues?

A I am.

MR. MOORE: Your Honor, I would object to this line of questioning. I believe this is relevant to Mr. Verderame's direct and is not relevant to his rebuttal testimony.

CHAIR MITCHELL: All right. Mr. Kaylor?

MR. KAYLOR: I believe it is relevant, and I think --

CHAIR MITCHELL: All right. I'll allow the question to go forward, Mr. Kaylor. Just limit your redirect to matters pertaining to cross examination on this witness's rebuttal testimony, please, sir.

MR. KAYLOR: Okay. I believe he answered that already.

Q Mr. Verderame, I believe that you have indicated that the Company did all it could to respond to the data requests and -- the numerous data requests requiring a tremendous amount of work on behalf of Company personnel; is that correct?

A That is absolutely correct.

Q Were you aware that -- if the Sierra Club propounded any follow-up questions to the responses that we provided in these particular data requests?

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Jun 17 2021

A I'm sorry. Can you repeat that?
Q Are you aware that the Sierra Club objected to --
A Oh.
Q -- or had any follow-up data requests to these responses that have been provided?
A Yes.
Q And do you know whether or not they filed a Motion to Compel to compel the Company to respond more fully to any of the ones that we objected to?
A I was not aware of any Motion to Compel.
MR. KAYLOR: Thank you. That's all I have, Madam Chair.
CHAIR MITCHELL: All right. Questions for the witness from Commissioners?
(No response.)
CHAIR MITCHELL: Okay. I am seeing no questions for the witness from Commissioners, so at this point in time, Mr. Immel (sic), you may step down and be excused, sir.
MR. KAYLOR: Verderame.
CHAIR MITCHELL: I'm sorry. Mr. Verderame. I'm sorry.
THE WITNESS: I knew.

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Jun 17 2021

CHAIR MITCHELL: Mr. Verderame, we appreciate your testimony here today. You may be excused.

(Witness excused.)

CHAIR MITCHELL: Mr. Kaylor, abundance of caution --

MR. KAYLOR: Yes.

CHAIR MITCHELL: -- I'd like for you to move the witness's test--- rebuttal testimony --

MR. KAYLOR: Yes.

CHAIR MITCHELL: -- into the record, please, sir.

MR. KAYLOR: Exactly. I would move that the rebuttal testimony of Mr. Verderame be accepted into the record as if given on the stand today.

CHAIR MITCHELL: All right, Mr. Kaylor. Hearing no objection to your motion, the 17 pages of rebuttal testimony filed by Mr. Verderame will be copied into the record as if delivered orally from the stand.

(Whereupon, the prefiled rebuttal testimony of John A. Verderame was copied into the record as if given orally from the stand.)

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May 17 2021

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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

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May 17 2021

I. INTRODUCTION AND PURPOSE

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

A. My name is John A. Verderame. My business address is 526 South Church Street, Charlotte, North Carolina 28202. I am employed as Vice President, Fuels & Systems Optimization for Duke Energy Corporation ("Duke Energy"). In that capacity, I lead the organization responsible for the purchase and delivery of coal, natural gas, fuel oil, and reagents to Duke Energy's regulated generation fleet, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas," "DEC," or the "Company") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"). In addition, I manage the fleet's power trading, system optimization, energy supply analytics, and contract administration functions.

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

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of Ms. Devi Glick filed on behalf of Sierra Club as it relates to DEC's unit commitment and dispatch processes of its coal generation stations.

Q. WHAT IS THE PURPOSE OF THIS PROCEEDING?

A. The purpose of this proceeding is to obtain Commission approval of the Company's proposed fuel rates pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55.

Q. HAS ANY PARTY RECOMMENDED AN ADJUSTMENT TO THE FUEL RATES PROPOSED BY THE COMPANY?

A. No.

Q. PLEASE PROVIDE YOUR GENERAL RESPONSE TO THE TESTIMONY OF SIERRA CLUB WITNESS DEVI GLICK.

A. Consistent with the testimony of Sierra Club's witness from the 2019 fuel case proceedings for the Company and for DEP, witness Glick submits extensive testimony concerning a range of issues—some of which are not relevant to this proceeding and others of which have been addressed in other proceedings—but does not make any recommendation that is germane to the purpose of this proceeding.

Q. HAS THE COMPANY PROVIDED SUFFICIENT INFORMATION IN THIS PROCEEDING TO ESTABLISH ITS TEST PERIOD FUEL AND FUEL-RELATED COSTS WERE REASONABLE AND PRUDENTLY INCURRED, INCLUDING THAT INFORMATION THAT IS REQUIRED UNDER APPLICABLE LAW?

A. Yes. The content and structure of the Company's application in this proceeding conforms to all applicable legal requirements and is substantially identical to that of all recent fuel rider applications, and the Company has responded to extensive discovery requests, including those of Sierra Club. Furthermore, no party has alleged that the Company's fuel application failed to conform to applicable law. Specifically, the Company's application conformed in all respects with the requirements outlined in Commission Rule R8-55, including the specific information required to be included in a fuel rider application under

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May 17 2021

Rule R8-55(e). Compliance with the Commission's clear and objective information requirements is the appropriate standard for evaluating the sufficiency of the Company's application.

Q. DID SIERRA CLUB'S WITNESS IN THE 2020 FUEL PROCEEDINGS FOR DEC AND DEP ALSO CRITICIZE THE AMOUNT OF INFORMATION PROVIDED BY DEC AND DEP, RESPECTIVELY?

A. Yes. In the 2020 fuel proceedings, the Sierra Club witness similarly ignored the applicable legal requirements and, instead, sought to impose his subjective judgement regarding the necessary contents of the Company's fuel application.

Q. WHAT WAS THE COMMISSION'S CONCLUSIONS ON THESE ISSUES IN THE 2020 DEC AND DEP FUEL PROCEEDINGS?

A. The Commission rejected the recommendation of the Sierra Club witness in the 2020 fuel proceedings for DEC and DEP. Specifically, in the DEP fuel order, the Commission confirmed "that the sufficiency of the Company's fuel application should be evaluated based on the requirements of applicable law."[1] The Commission further noted that it had previously rejected similar recommendations from the Sierra Club witness and observed that "the scope and level of detail contained in the Company's application, testimony, exhibits, and workpapers as filed in this proceeding conforms with applicable law and is consistent with prior applications."[2] The Commission has rejected similar recommendations from a Sierra Club witness in the two most recent fuel

[1] Order Approving Fuel Charge Adjustment, Docket No. E-2, Sub 1250 (November 30, 2020), at 12-13.
[2] *Id.* at 13.

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May 17 2021

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May 17 2021

proceedings and should, for the same reasons, reject the recommendation of the Sierra Club witness in this proceeding.

Q. PLEASE RESPOND TO WITNESS GLICK'S RECOMMENDATION THAT "THE COMMISSION DIRECT DEC TO CONDUCT A NEW RETIREMENT STUDY OF EACH UNIT IN THE COMPANY'S FLEET."[3]

A. There is simply no basis under applicable law to suggest that a fuel rider proceeding is the appropriate forum in which to consider a retirement analysis of Company generating units. In fact, Witness Glick acknowledges that a retirement analyses has been conducted in the 2020 Integrated Resource Plan ("IRP") but, inexplicably and without alleging any infirmity in the retirement analyses in the IRP, insists that the same analyses be performed in this proceeding. This recommendation should be completely disregarded.

II. UNIT COMMITMENT AND DISPATCH

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE CONCEPTS OF UNIT COMMITMENT AND DISPATCH?

A. "Unit Commitment" or "Commitment" is the process of modeling the optimal mix of generation units to be placed online to economically and reliably meet projected system needs. "Generation Dispatch" or "Dispatch" is the process of economically optimizing the MW output of individual generators once they have been placed online (through the unit commitment process) by evaluating the instantaneous balancing of load and generation. In lay terms, the

[3] Glick Direct, at 42.

commitment process determines which generating units should be placed online and dispatch determines how those units are operated once they are online.

Q. PLEASE DESCRIBE GENERALLY THE COMPANY'S APPROACH TO COMMITMENT AND DISPATCH?

A. The Company performs a detailed daily process to determine the unit commitment plan that is necessary to economically and reliably meet projected system needs over the next seven days. The Company utilizes a production cost model called GenTrader to determine an optimal unit commitment plan to economically and reliably meet system requirements. Inputs to the model include, but are not limited to, the following: 1) forecasted customer energy demand; 2) fuel commodity and emission allowance market prices; 3) contractual obligations including power market purchases and sales; 4) generating unit parameters such as, but not limited to, minimum load, maximum load, heat rate, ramp rate, variable O&M, start-up costs and shut-down costs; and 5) planned unit outages and unit de-rates. 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. The unit commitment plan is prepared daily and adjusted, as needed, throughout any given day to respond to changing real time system conditions.

Only variable costs are utilized in the unit commitment model. Fixed costs—which are those costs that will be incurred regardless of whether a unit is committed—are not considered in the development of the unit commitment plan.

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Q. WHAT IS WITNESS GLICK'S BENCHMARK FOR ECONOMIC UNIT COMMITMENT AND DISPATCH?

A. Witness Glick states in her testimony that "[w]hen a unit is committed economically, the unit is reasonably expected to be lower cost than the marginal cost of energy, called 'system lambda' over the next day or days."[4]

Q. DO YOU AGREE THAT SYSTEM LAMBDA IS AN APPROPRIATE MEASURE OF WHETHER A UNIT COMMITMENT DECISION IS ECONOMIC?

A. No. System lambda is a calculation of *instantaneous* system *incremental* cost, whereas unit commitment decisions are appropriately made based on the *total* variable cost of generation over a *multi-day* period. If a unit is projected to provide benefit to customers over a multi-day period based on the total variable cost of generation, then the unit is placed online. Once online, the unit is dispatched based on the instantaneous system incremental cost. In other words, system lambda is the appropriate price signal for dispatch decisions but not for unit commitment decisions. Witness Glick fundamentally misunderstands the Company's unit commitment methodology.

Q. WITNESS GLICK OFFERS A COMPARISON OF CERTAIN UNITS' MONTHLY AVERAGE COST OF GENERATION TO A MONTHLY AVERAGE SYSTEM LAMBDA.[5] IS THIS AN APPROPRIATE COMPARISON?

[4] Glick Direct Testimony, at 13.
[5] Glick Direct, at 21.

A. No. This comparison is not meaningful and provides no useful information. First, system lambda is the instantaneous marginal cost on the system and varies, sometimes substantially, over the course of day and certainly over the course of a month. To average all of these instantaneous values ignores the actually experienced variability. Averaging these values over a month has even less value, as it is ignoring the fact that delivering energy to a customer is a 24 hour a day, 7 days a week, 365 days a year obligation. Averaging instantaneous data into a monthly comparison ignores the fact that the unit may have been critical to supplying customer demand at certain critical periods of time. Stated simply, a unit with a higher average cost is still often critical in ensuring reliability during a high price period on the system even where the average system lambda is lower than the average cost of the unit. Witness Glick paints with a broad brush with no appreciation for the actual minute by minute dispatch decisions made by the Company to ensure reliable and economic service.

Second, the average cost of generation cited by Witness Glick is also misleading because average costs are not the prices on which the Company makes dispatch decisions. A generating unit's marginal cost on which dispatch decisions are made is lower than its average cost of generation because average cost of generation includes fixed fuel transportation costs, start-up fuel costs and no-load cost (which is the cost of fuel needed to produce steam pressure sufficient to synchronize the generator to the grid), all of which are sunk costs.

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May 17 2021

Q. IS THE PRACTICE OF UNIT COMMITMENT PLANNING AND DISPATCHING UNITS BASED ON VARIABLE COSTS CONSISTENT WITH GOOD UTILITY PRACTICE?

A. Yes. Fixed fuel-related costs are "sunk," meaning that the cost will be incurred whether or not a unit is committed and dispatched. It is therefore entirely reasonable, and consistent with industry practice, to only utilize variable costs when making commitment and dispatch decisions.

Q. WHAT OTHER ASPECTS OF THE COMMITMENT AND DISPATCH PROCESS DOES WITNESS GLICK OVERSIMPLIFY OR IGNORE?

A. Witness Glick presents an oversimplified view of unit commitment and dispatch decisions but ignores the real world decisions made by the Company to ensure reliable service—that is, the necessity of maintaining day-ahead planning reserves, operating reserves, and regulating reserves in order to maintain system reliability. The Company's unit commitment plans include 1,770 MW of capacity above and beyond DEC's expected peak load. Capacity must be online (or available) within a short period of time. A coal unit will provide energy and capacity during the peak. The Company recognizes that the capacity factors of its coal fleet are declining. For example, Allen Station's operation strategy has shifted from a baseload to a cycling resource. However, the Company requires cycling resources, which operate at lower capacity factors, to provide reliable service to customers in periods of high demand. If a needed coal unit were not online then the Company would have to start more expensive additional CTs and/or purchase more expensive energy and capacity from the market (assuming that capacity was even available in the market during such a time).

Q. PLEASE RESPOND TO WITNESS GLICK'S ASSERTIONS REGARDING THE "PERFORMANCE" OF THE COMPANY'S COAL UNITS.

A. Witness Glick repeatedly refers to the "performance" of the Company's coal units when assessing the capacity factors of the units. As an initial matter, assessing the capacity factors of units and their value to the system is not relevant to a fuel proceeding, and witness Glick's testimony in this respect should be ignored.

Nevertheless, it is worth noting that witness Glick's description of a unit's "performance" is misleading. There is certainly no dispute that certain of the Company's coal units have low capacity factors. But this does not equate to poor performance. The Company maintains required capacity resources to meet its system requirements and obligations, and the fact that certain units are not required to operate at times does not equate to poor performance or mean that the units are not necessary to ensure reliability. Witness Glick's characterization and comparisons ignore the Company's capacity reserve requirements and obligations and the fact the annualized capacity factors of certain coal units are lower because the Company committed and dispatched other more cost effective units or, if available purchased energy and capacity from the bi-lateral power market before committing and dispatching such units.

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May 17 2021

However, a low capacity factor in a particular year does not, by itself, eliminate the need for these units.

Q. WHAT IS YOUR RESPONSE TO WITNESS GLICK'S SUGGESTION THAT THE COMPANY COULD HAVE PROVIDED LESS COSTLY CUSTOMER SERVICE BY NOT COMMITTING ITS COAL UNITS BUT INSTEAD SERVING RETAIL LOAD WITH "OTHER RESOURCES"?[6]

A. Witness Glick does not attempt to offer a credible or specific explanation of how the Company could have replaced the approximately 6,934 MW of reliable generation energy and capacity provided by the Company's coal units nor does she identify which specific "other resources" she believes should have been dispatched to serve customers.

III. COAL UNIT COSTS

Q. PLEASE RESPOND TO WITNESS GLICK'S ASSERTIONS CONCERNING THE COMPANY'S CLASSIFICATION OF FIXED AND VARIABLE COSTS?

A. Sierra Club witness Glick refers to "underrepresented costs" (a term that she never explains) and then states "[i]f DEC updated its marginal costs to represent a larger portion of the production cost of each unit, its coal units would shift higher on the supply stack."[7] While it is common sense that shifting more costs from fixed to variable will cause a resource to move higher in the stack, witness

[6] Glick Direct, at 9.
[7] Glick Direct, at 29.

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May 17 2021

Glick utterly fails to identify any specific cost that DEC is allegedly mis-categorizing.

When making unit commitment and dispatch decisions, the Company evaluates all generation cost types and appropriately categorizes them as fixed or variable. Witness Glick has provided no specific examples of costs categorized as fixed that she believes should be categorized as variable. It would be inappropriate and potentially result in a less economic commitment and dispatch outcome to assign fixed costs as variable for inclusion into unit commitment and dispatch prices just to achieve witness Glick's apparently desired result of seeing coal units shift higher on the supply stack.

Q. DOES WITNESS GLICK, IN HER TESTIMONY, EVER DISCUSS OR ACKNOWLEDGE THE ABILITY OF THE COMPANY'S COAL FLEET TO OPERATE ON NATURAL GAS?

A. No, despite being provided cost of generation for natural gas, natural gas burns and natural gas production costs related to dual fuel operations at Cliffside Units 5&6, Belews Creek Unit 1, and Marshall Units 3&4, witness Glick never discusses the dual fuel operation of these units.

Q. HOW DOES THE COMPANY RESPOND TO WITNESS GLICK'S ASSERTION THAT THE COMPANY OMITTED FUEL AND VARIABLE COSTS REPRESENTING 40% OF THE COMPANY'S ACTUAL PRODUCTION COSTS?

A. Based on the working sheet providing by Sierra Club in response to the Company's data request, it appears that witness Glick took the Average Coal

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May 17 2021

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May 17 2021

Cost of Generation ($/MWh) and multiplied that by the total daily Net Generation (MWh) aggregated by month including dual fuel natural gas generation. This calculation produced witness Glick's production costs of $558M. However, witness Glick's calculation excludes the Average Natural Gas Cost of Generation ($/MWh) for the dual fuel units of Belews Creek, Cliffside and Marshall which were provided to Sierra Club as part of Data 1-3f&j. In other words, it appears that witness Glick's calculations in this respect were fundamentally flawed by ignoring the gas operation of these units.

Beyond this exclusion, it is not entirely clear what costs witness Glick is referring to that are being omitted. If witness Glick is referring to the omission of variable costs in the unit commitment and dispatch process, the Company vigorously disagrees with the assertion. As previously outlined, the Company includes all variable costs in its unit commitment and dispatch process and excludes fixed costs that would be incurred regardless of whether a unit ran or not.

Q. WITNESS GLICK ALLEGES THAT THE COMPANY INCURRED $8.5 MILLION IN AVOIDABLE OPERATIONAL BASED ON A COMPARISON OF "MONTHLY PRODUCTION COSTS RELATIVE TO SYSTEM LAMBDA."[8] PLEASE RESPOND.

A. I fundamentally disagree with this allegation. Witness Glick's testimony in this instance once again utilizes average monthly numbers (average production costs and average system lambda) in a completely inappropriate manner that

[8] Glick Rebuttal, at 38.

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May 17 2021

ignores the way in which a utility actually operates its system on an hourly basis to ensure reliable and economic service. The average system lambda does not provide the real picture concerning the hours in which the units in question were called up on to operate when needed.

Q. HOW DOES THE COMPANY RESPOND TO WITNESS GLICK'S ASSERTION THAT THE COMPANY DID NOT PROVIDE THE 7 DAY AHEAD UNIT COMMITMENT FORECAST?[9]

A. Witness Glick's assertion in this respect is simply incorrect, as in fact the Company provided every 7 day ahead unit commitment forecast published in the year 2020 (1,078 individual forecasts) to Sierra Club in the supplemental response to discovery request Sierra Club DR1-9b. These forecasts were delivered to Sierra Club on May 7, 2021. These files are the output of the GenTrader model and indicated the hourly optimized unit commitment and dispatch plan for the next seven days.

Q. IN WHAT WAYS IS SIERRA CLUB TESTIMONY IN THIS PROCEEDING SIMILAR TO ITS TESTIMONY IN THE RECENT DEC RATE CASE IN DOCKET NO. E-7, SUB 1214?

A. In the DEC rate case in Docket No. E-7, Sub 1214, Sierra Club's witness made a number of outlandish recommendations concerning the Company's coal units, all of which were rejected by the Commission. In rejecting the Sierra Club's witnesses recommendations, the Commission observed, in part, that the Sierra Club witness had, by her own admission, failed to "evaluate what replacement alternatives the Company should have chosen instead of making the

[9] Glick Direct, at 39.

investments, and did not identify any particular investment DEC should not have made." The Commission also noted that the Sierra Club witness had acknowledged that "she did not analyze whether shutting the units down was a feasible path DEC could have chosen and still have been able to meet its service obligations."

While in this proceeding the Sierra Club witness has not made an actual disallowance recommendation, there are substantial similarities with the Sierra Club positions from the DEC rate case, in that the Sierra Club witness in this proceeding has failed to identify any specific examples of ways in which the Company should have operated its system differently during the test period or identified any specific decision that is imprudent. The Sierra Club's witness does not undertake a meaningful assessment of reliability and has utterly failed to identify a single decision by the Company during the test period that should have been different.

Q. WHAT OTHER GENERAL OBSERVATIONS DO YOU HAVE CONCERNING WITNESS GLICK'S TESTIMONY?

A. Sierra Club witness Glick also makes general conclusory assertions with little to no hard evidence to support such assertions. For instance, Witness Glick asserts that "in the past utilities operated their coal-fired plants as baseload resources with little thought given to whether the plants should be turned on or off." I categorically reject this assertion as it relates to DEC's operation of its generating facilities—there has been no period of time in which DEC operated its plants "with little thought given to whether the plants should be turned on or

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May 17 2021

off." When asked in discovery to produce "all analysis, workpapers, documents and supporting data" for such statement, Sierra Club asserted that "[t]his statement is supported by Ms. Glick's experience reviewing the changes in the operation and performance of coal-fired power plants across historical and current data." In other words, witness Glick has made a sweeping assertion of a general lack of prudence across all utilities and yet is not able to offer a single concrete piece of evidence to support this assertion.

Witness Glick also makes generalized recommendations concerning the Company's coal and transportation contracting strategies. For instance, witness Glick asserts that a "…responsible utility manager should seek to minimize the portion of average costs that falls into these categories and are therefore omitted from the unit commitment process. Specifically, this can be done by (1) securing fuel and transportation contracts that are flexible and have minimal locked-in or must-take provisions; (2) carefully reviewing the costs of fuel contracts relative to alternatives, including reduced operation and retirement of the plant, prior to signing any new fuel contracts…" Yet, when asked in discovery, witness Glick failed to identify a single instance of a fuel or transportation contract at issue in this proceeding that DEC should not have entered. Furthermore, witness Glick acknowledged in discovery response that she has never been "responsible for the negotiation of a fuel or transportation contract in connection with the operation of coal-fired generating facility." In other words, witness Glick seeks to opine on technical topics regarding which

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May 17 2021

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May 17 2021

she has no personal experience and for which she is unable to even attempt to identify an alleged imprudent decision.

Q. PLEASE COMMENT GENERALLY ON THE PURPOSE OF THIS PROCEEDING AS IT RELATES TO THE TESTIMONY OF SIERRA CLUB WITNESS GLICK.

A. Once again, the purpose of this proceeding is to establish fuel rates for DEC. Witness Glick has not recommended any changes to the fuel rates proposed by DEC. Instead, witness Glick has sought to leverage this proceeding into an opportunity to opine on a number of topics that are either properly addressed in other proceedings or have previously been rejected by the Commission. In the Company's view, such efforts are not an efficient use of regulatory resources.

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

A. Yes, it does.

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Jun 17 2021

CHAIR MITCHELL: All right. At this point I believe we have come to the end of at least the -- the cross examination times that were identified by the Commission. I will check in with counsel to see if there are any other matters that need to be addressed before we move towards adjournment?

MR. KAYLOR: Chair Mitchell, I'm not aware of any. I think we've moved that all our exhibits be entered into the record, I believe we asked that the Application be entered into the record, and I think this would conclude the Company's case.

CHAIR MITCHELL: All right. Thank you, Mr. Kaylor. Ms. Thompson, I see that you are appearing. Do you have anything for the Commission's attention?

MS. THOMPSON: No. Thank you, Chair Mitchell. Nothing for the Sierra Club.

CHAIR MITCHELL: Okay. Well, as is the case, we will entertain post-hearing filings, briefs, proposed orders 30 days from the notice of the mailing of the transcript. Of course, you're absolutely welcome and encouraged to file those sooner than that. And with that, I thank you all for your preparation and participation in this hearing today. And unless there's anything else for my attention, we will be adjourned.

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Jun 17 2021

(The hearing was adjourned.)

***Reporter's Note: Per Commission Order issued on May 28, 2021, the introduction of the prefiled testimony, exhibits, and affidavits of the following witnesses is ordered, and they were excused from testifying at the expert witness hearing: Bryan L. Sykes, Kevin Y. Houston, Steven D. Capps, June Chiu, and Dustin R. Metz.

(Whereupon, the prefiled direct and supplemental testimonies of Bryan L. Sykes were copied into the record as if given orally from the stand.)

(Sykes Exhibits 1-6 filed with direct testimony, and Sykes Revised Exhibits 1-4 and Sykes Exhibits 5 and 6 filed with supplemental testimony were identified as premarked and admitted into evidence.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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

DIRECT TESTIMONY OF BRYAN L. SYKES FOR DUKE ENERGY CAROLINAS, LLC

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Jun 17 2021

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bryan L. Sykes. My business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Rates Manager for Duke Energy Carolinas, LLC ("DEC" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received my Bachelor of Science and Master of Science Degrees in Accounting from East Carolina University. I am a certified public accountant licensed in the State of North Carolina. I began my career in 2001 with Arthur Andersen, LLP as a staff auditor. From 2001 until 2006 I held various roles in public accounting firms, including Grant Thornton, LLP (successor to Arthur Andersen, LLP) and subsequently PricewaterhouseCoopers, LLP. In 2006, I started at Progress Energy, Inc. as a financial auditor and subsequently held a variety of positions in the accounting organization before and after the merger with Duke Energy Corporation in 2012. I joined the Rates Department in 2019 as Manager, Rates and Regulatory Filings.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES MANAGER FOR DEC.

A. I am responsible for providing regulatory support for retail rates, providing guidance on DEC's fuel and fuel-related cost recovery application in North Carolina, and its fuel cost recovery application in South Carolina.

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Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I provided testimony in Docket Nos. E-7, Sub 1231 and E-2, Sub 1254 regarding Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's compliance reports and applications for approval of their respective CPRE cost recovery riders in 2020.

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DEC?

A. Yes. DEC's books of account follow the uniform classification of accounts prescribed by the Federal Energy Regulatory Commission ("FERC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the information and data required by North Carolina General Statutes ("N.C. Gen. Stat.") § 62-133.2(c) and (d) and Commission Rule R8-55, as set forth in Sykes Exhibits 1 through 6, along with supporting work papers. The test period used in supplying this information and data is the twelve months ended December 31, 2020 ("test period"), and the billing period is September 1, 2021 through August 31, 2022 ("billing period").

Q. WHAT IS THE SOURCE OF THE ACTUAL INFORMATION AND DATA FOR THE TEST PERIOD?

A. Actual test period kilowatt hour ("kWh") generation, kWh sales, fuel-related revenues, and fuel-related expenses were taken from DEC's books and records. These books, records, and reports of DEC are subject to review by the appropriate regulatory agencies in the three jurisdictions that regulate DEC's electric rates. In addition, independent auditors perform an annual audit to provide assurance that, in all material respects, internal accounting controls are operating effectively and DEC's financial statements are accurate.

Q. WERE SYKES EXHIBITS 1 THROUGH 6 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes, these exhibits were either prepared by me or at my direction and under my supervision, and consist of the following:

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

Exhibit 2:

Schedule 1: Fuel and Fuel-Related Costs Factors - reflecting a 93.21% proposed nuclear capacity factor and projected megawatt hour ("MWh") sales.

Schedule 2: Fuel and Fuel-Related Costs Factors - reflecting a 93.21% nuclear capacity factor and normalized test period sales.

Schedule 3: Fuel and Fuel-Related Costs Factors - reflecting a 91.95% North American Electric Reliability Corporation ("NERC") five-year national weighted average nuclear capacity factor for pressurized water reactors and projected billing period MWh sales.

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Exhibit 3:

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

Page 2: Calculation of the EMF for residential customers.

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

Page 4: Calculation of the EMF for industrial customers.

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

Exhibit 5: Nuclear Capacity Ratings.

Exhibit 6: December 2020 Monthly Fuel Reports.

1) December 2020 Monthly Fuel Report required by NCUC Rule R8-52.

2) December 2020 Monthly Base Load Power Plant Performance Report required by NCUC Rule R8-53.

Q. PLEASE EXPLAIN SYKES EXHIBIT 1.

A. Sykes Exhibit 1 presents a summary of fuel and fuel-related cost factors, including the current fuel and fuel-related cost factors, the fuel and fuel-related cost factor calculations as required under Rule R8-55, and the proposed fuel and fuel-related cost factors.

Q. WHAT FUEL AND FUEL-RELATED COSTS FACTORS DOES DEC PROPOSE FOR INCLUSION IN RATES FOR THE BILLING PERIOD?

A. DEC proposes fuel and fuel-related costs factors for residential, general service/lighting, and industrial customers of 1.4456¢, 1.7015¢, and 1.8359¢ per kWh, respectively, to be reflected in rates during the billing period. The factors DEC proposes in this proceeding incorporate a 93.21% nuclear capacity factor as testified to by Company witness Capps, projected fossil fuel costs as testified to by Company witness Verderame, projected nuclear fuel costs as testified to by Company witness Houston, and projected reagents costs as testified to by Company witness Immel. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Sykes Exhibit 1, are as follows:

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Total adjusted Fuel and Fuel Related Costs	1.4755	1.7254	1.7589	1.6414
EMF Increment (Decrement)	(0.0259)	(0.0207)	0.0770	(0.0033)
EMF Interest (Decrement)	(0.0040)	(0.0032)	-	(0.0029)
Net Fuel and Fuel Related Costs Factors	1.4456	1.7015	1.8359	1.6352

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

A. The proposed fuel and fuel-related costs factors will result in a 1.89% decrease on customers' bills. The table below shows both the proposed and existing fuel and fuel-related costs factors.

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Proposed Total Fuel Factor	1.4456	1.7015	1.8359	1.6352
Existing Total Fuel Factor	1.6391	1.8249	1.9310	1.7791
Decrease in Fuel Factor	(0.1935)	(0.1234)	(0.0951)	

Q. WHAT ARE THE KEY DRIVERS IMPACTING THE PROPOSED FUEL

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AND FUEL-RELATED COSTS FACTORS?

A. The decrease in the proposed net fuel and fuel-related costs factors is primarily driven by a $2 million over-recovery in the current test period compared to a $57 million under-recovery included in current rates. In addition, estimated system fuel costs in the billing period are lower due to lower kilowatt-hour sales and lower commodity prices.

Q. HOW DOES DEC DEVELOP THE FUEL FORECASTS FOR ITS GENERATING UNITS?

A. For this filing, DEC used an hourly dispatch model in order to generate its fuel forecasts. This hourly dispatch model considers the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities. In addition, the model dispatches DEC's and DEP's generation resources via joint dispatch, which optimizes the generation fleets of DEC and DEP for the benefit of customers.

Q. PLEASE EXPLAIN WHAT IS SHOWN ON SYKES EXHIBIT 2, SCHEDULES 1, 2, AND 3, INCLUDING THE NUCLEAR CAPACITY FACTORS.

A. Exhibit 2 is divided into three schedules. Schedule 1 sets forth system fuel costs used in the determination of the prospective fuel and fuel-related costs. The calculation uses the nuclear capacity factor of 93.21% and provides the forecasted MWh sales for the billing period on which system generation and costs are based.

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Forecasted generation and purchased power associated with the Company's CPRE Program, established by N.C. Gen. Stat § 62-110.8 and approved by this Commission in Docket No. E-7, Sub 1156, used to supply the Company's native load has been included in Exhibit 2. The purchased and generated power costs associated with this generation are included in the Company's Rider CPRE filing in Docket No. E-7, Sub 1247.

Schedule 2 also uses the proposed capacity factor of 93.21% along with normalized test period kWh generation, as prescribed by NCUC Rule R8-55 (e)(3), which requires the use of the methodology adopted by the Commission in DEC's last general rate case.

The capacity factor shown on Schedule 3 is prescribed in NCUC Rule R8-55(d)(1). The normalized five-year national weighted average NERC nuclear capacity factor is 91.95%. This capacity factor is based on the 2015 through 2019 data reported in the NERC Generating Unit Statistical Brochure for pressurized water reactors rated at and above 800 MWs. Projected billing period kWh generation was also used for Schedule 3 per NCUC Rule R8-55 (d)(1).

Page 2 of Exhibit 2, Schedules 1, 2, and 3 presents the calculation of the proposed fuel and fuel-related costs factors by customer class resulting from the allocation of renewable and cogeneration power capacity costs by customer class on the basis of peak demand, a proxy for the production plant allocator since the annual cost of service study is not available at the timing of filing.

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Jun 17 2021

Page 3 of Exhibit 2, Schedules 1, 2, and 3 shows the allocation of system fuel costs to the North Carolina retail jurisdiction, and the calculation of DEC's proposed fuel and fuel-related costs factors for the residential, general service/lighting and industrial classes, exclusive of regulatory fee, using the uniform percentage average bill adjustment method.

Q. PLEASE SUMMARIZE THE METHOD USED TO ADJUST TEST PERIOD KWH GENERATION IN SYKES EXHIBIT 2, SCHEDULES 2 AND 3.

A. The methodology used by DEC in its most recent general rate case for determining generation mix is based upon generation dispatch modeling as used on Sykes Exhibit 2, Schedule 1. For purposes of this filing, as a proxy for generation dispatch modeling, Sykes Exhibit 2, Schedules 2 and 3 adjust the coal generation produced by the dispatch model. For example, on Exhibit 2, Schedule 2, which is based on the proposed capacity factor and normalized test period sales, DEC decreased the level of coal generation to account for the difference between forecasted generation and normalized test period generation. On Exhibit 2, Schedule 3, which is based on the NERC capacity factor, DEC increased the level of coal generation to account for the decrease in nuclear generation. The decrease in nuclear generation results from assuming a 91.95% NERC nuclear capacity factor compared to the proposed 93.21% nuclear capacity factor.

Q. SYKES EXHIBIT 3 SHOWS THE CALCULATION OF THE TEST PERIOD OVER/(UNDER) RECOVERY BALANCE AND THE EMF RATE. HOW DID FUEL EXPENSES COMPARE WITH FUEL

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REVENUE DURING THE TEST PERIOD?

A. Sykes Exhibit 3, Pages 1 through 4, demonstrates that for the test period, DEC experienced an over-recovery for the residential and general service/lighting customer classes of $6.0 million and $4.8 million, respectively, and an under-recovery for the industrial customer class of $8.9 million. There are two adjustments included in the calculation of the over-recovery balance at December 31, 2020. The first adjustment relates to the months of January 2020 through March 2020, which were included in the fuel rate approved in the last fuel and fuel-related cost recovery proceeding and are included for Commission review in the current proceeding. The Company has excluded the amount of over-recovery for the months of January 2020 through March 2020 that was included in the EMF approved in Docket E-7, Sub 1228 when computing the proposed EMF factors. For purposes of computing interest on amounts to be refunded to residential and general service customers in this proceeding, a second adjustment is being made. The Company has adjusted the over-recovery amount to exclude customer credits for payments the Company received related to purchased power contract terms. Such amounts are not considered a refund of amounts advanced by customers and accordingly are not included in the computation of interest on over-recovery.

The over/(under) recovery amount was determined each month by comparing the amount of fuel revenue collected for each class to actual fuel and fuel-related costs incurred by class. The revenue collected is based on actual monthly sales for each class. Actual fuel and fuel-related costs incurred were first allocated to the NC retail jurisdiction based on jurisdictional sales, with consideration given to any fuel and fuel-related costs or benefits that should be directly assigned. The North Carolina retail amount is further allocated among customer classes as follows: (1) capacity-related purchased power costs were allocated among customer classes based on production plant allocators from DEC's cost of service study and (2) all other fuel and fuel-related costs were allocated among customer classes based on fixed allocation percentages established in DEC's previous fuel and fuel-related cost recovery proceeding based on the uniform percentage average bill adjustment method.

Q. PLEASE EXPLAIN SYKES EXHIBIT 4.

A. As required by NCUC Rule R8-55(e)(1) and (e)(2), Sykes Exhibit 4 sets forth test period actual MWh sales, the customer growth MWh adjustment, and the weather MWh adjustment. Test period MWh sales were normalized for weather using a 30-year period and adjusted for projected customer growth. Both of these adjustments were determined using the methods approved for use in DEC's last general rate case (Docket No. E-7, Sub 1146) and used in its last fuel proceeding. Sykes Exhibit 4 also sets forth actual test period fuel-related revenue and fuel expense on a total DEC basis and for North Carolina retail. Finally, Sykes Exhibit 4 shows the test period peak demand for the system and for North Carolina retail customer classes.

Q. PLEASE EXPLAIN SYKES EXHIBIT 5.

A. Sykes Exhibit 5 sets forth the capacity ratings for each of DEC's nuclear units, in compliance with Rule R8-55(e)(12).

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Q. DO YOU BELIEVE DEC'S FUEL AND FUEL-RELATED COSTS INCURRED IN THE TEST YEAR ARE REASONABLE?

A. Yes. As shown on Sykes Exhibit 6, DEC's test year actual fuel and fuel-related costs were 1.7305¢ per kWh. Key factors in DEC's ability to maintain lower fuel and fuel-related rates for the benefit of customers include (1) its diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; (2) lower natural gas prices; (3) the high capacity factors of its nuclear fleet; and (4) fuel procurement strategies that mitigate volatility in supply costs. Other key factors include the combination of DEC's and DEP's respective skills in procuring, transporting, managing, and blending fuels, procuring reagents and the increased and broader purchasing ability of Duke Energy Corporation after its merger with Progress Energy, Inc., as well as the joint dispatch of DEC's and DEP's generation resources. Company witness Capps discusses the performance of DEC's nuclear generation fleet, and Company witness Immel discusses the performance of the fossil and hydro fleet, as well as the use of chemicals for reducing emissions. Company witness Verderame discusses fossil fuel procurement strategies, and Company witness Houston discusses DEC's nuclear fuel costs and procurement strategies.

Q. IN DEVELOPING THE PROPOSED FUEL AND FUEL-RELATED COSTS FACTORS, WERE THE FUEL COSTS ALLOCATED IN ACCORDANCE WITH N.C. GEN. STAT. § 62-133.2(A2)?

A. Yes, the costs for which statutory guidance is provided are allocated in compliance with N.C. Gen. Stat. § 62-133.2(a2). These costs are described in subdivisions (4), (5), (6), (10) and (11) of N.C. Gen. Stat. § 62-133.2(a1). Subdivisions (4), (6), (10) and (11) address purchased power non-capacity costs. Subdivisions (5), (6), (10) and (11) address purchased power capacity costs. The allocation methods for these costs are as follows:

(a) Capacity-related purchased power costs in Subdivisions (5), (6), (10) and (11) are allocated based upon peak demand, a proxy for the production plant allocator since the annual cost of service study is not available at the timing of filing from the latest annual cost of service study.

(b) Non-capacity related purchased power costs in Subdivisions (4), (6), (10) and (11) are allocated in the same manner as all other fuel and fuel-related costs, using a uniform percentage average bill adjustment method.

Q. HOW ARE THE OTHER FUEL AND FUEL-RELATED COSTS ALLOCATED FOR WHICH THERE IS NO SPECIFIC GUIDANCE IN N.C. GEN. STAT. § 62-133.2(A2)?

A. System costs are allocated to the NC retail jurisdiction based on jurisdictional sales, with consideration given to any fuel and fuel-related costs or benefits that should be directly assigned. Costs are further allocated among customer classes using the uniform percentage average bill adjustment methodology in setting fuel rates in this fuel proceeding. DEC proposes to use the same uniform percentage average bill adjustment methodology to adjust its fuel rates to reflect a proposed decrease in fuel and fuel-related costs as it did in its 2020 fuel and fuel-related cost recovery proceeding in Docket No. E-7, Sub 1228.

Q. PLEASE EXPLAIN THE CALCULATION OF THE UNIFORM PERCENTAGE AVERAGE BILL ADJUSTMENT METHOD SHOWN

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ON SYKES EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3.

A. Sykes Exhibit 2, Page 3 of Schedule 1, shows DEC's proposed fuel and fuel-related cost factors for the residential, general service/lighting and industrial classes, exclusive of regulatory fee. The uniform bill percentage change of (1.89%) was calculated by dividing the fuel and fuel-related cost decrease of $83,415,574 for North Carolina retail by the normalized annual North Carolina retail revenues at current rates of $4,419,603,081. The cost decrease of $83,415,574 was determined by comparing the total proposed fuel rate per kWh to the total fuel rate per kWh currently being collected from customers and multiplying the resulting decrease in fuel rate per kWh by projected North Carolina retail kWh sales for the billing period. The proposed fuel rate per kWh represents the rate necessary to recover projected period fuel costs for the billing period (as computed on Sykes Exhibit 2, Schedule 1) and the proposed composite EMF decrement rate (as computed on Sykes Exhibit 3, page 1). This results in a uniform bill percentage change of (1.89)%. Sykes Exhibit 2, Page 3 of Schedules 2 and 3 uses the same calculation, but with the methodology as prescribed by NCUC Rule R8-55(e)(3) and NCUC Rule R8-55(d)(1), respectively.

Q. HOW ARE SPECIFIC FUEL AND FUEL-RELATED COSTS FACTORS FOR EACH CUSTOMER CLASS DERIVED FROM THE UNIFORM PERCENT ADJUSTMENT COMPUTED ON SYKES EXHIBIT 2, PAGE 3 OF SCHEDULES 1, 2, AND 3?

A. Sykes Exhibit 2, Page 3 of Schedules 1, 2, and 3 uses the same calculation, but with the methodology as prescribed by NCUC Rule R8-55(e)(3) and NCUC Rule

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Jun 17 2021

R8-55 (d)(1), respectively, with the breakdown shown on Sykes Exhibit 2, Page 2 of Schedules 2 and 3. The equal percent increase or decrease for each customer class is applied to current annual revenues by customer class to determine a dollar amount of increase or decrease for each customer class. The dollar increase or decrease is divided by the period sales for each class (either projected billing period or adjusted test period) to derive a cents per kWh increase or decrease. The current total fuel and fuel-related cost factors for each class are increased or decreased by the proposed cents per kWh increases or decreases to get the proposed total fuel and fuel-related cost factors. The proposed total factors are then separated into the prospective and EMF components by subtracting the EMF components for each customer class (as computed on Sykes Exhibit 3, Page 2, 3, and 4) to derive the prospective component for each customer class. This breakdown is shown on Sykes Exhibit 2, Page 2 of Schedules 1, 2, and 3.

Q. HAS DEC'S ANNUAL INCREASE IN THE AGGREGATE AMOUNT OF THE COSTS IDENTIFIED IN SUBDIVISIONS (4), (5), (6), (10) AND (11) OF N.C. GEN. STAT. § 62-133.2(a1) EXCEEDED 2.5% OF ITS NORTH CAROLINA RETAIL GROSS REVENUES FOR THE TEST PERIOD?

A. No. N.C. Gen. Stat. § 62-133.2(a2) limits the amount of annual increase in certain purchased power costs identified in § 62-133.2(a1) that DEC can recover to 2.5% of its North Carolina retail gross revenues for the preceding calendar year. The amount recoverable in DEC's proposed rates for purchased power under the relevant sections of N.C. Gen. Stat. § 62-133.2(a1) does not increase by more than 2.5% of DEC's gross revenues for its North Carolina retail jurisdiction for the test

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period.

Q. HAS DEC FILED WORKPAPERS SUPPORTING THE CALCULATIONS, ADJUSTMENTS, AND NORMALIZATIONS AS REQUIRED BY NCUC RULE R8-55(E)(11)?

A. Yes. The work papers supporting the calculations, adjustments and normalizations are included with the filing in this proceeding**.**

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

A. Yes, it does.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1250

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bryan L. Sykes. My business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes, on February 23, 2021, I caused to be pre-filed with the Commission my direct testimony and 6 exhibits and 13 supporting workpapers.

Q. YOUR SUPPLEMENTAL TESTIMONY INCLUDES FOUR (4) REVISED EXHIBITS AND TWO (2) REVISED SUPPORTING WORKPAPERS. WERE THESE SUPPLEMENTAL EXHIBITS AND WORKPAPERS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

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

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

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

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

Sykes Revised Exhibit 4: Sales, Fuel Revenue, Fuel Expense and System Peak

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Jun 17 2021

Sykes Revised Workpaper 7a: Calculation of Allocation Percentages Based on Normalized Test Period Sales

Sykes Revised Workpaper 12: Weather Normalization Adjustment

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present revised rates reflecting the impacts related to three updates to numbers presented in my direct exhibits.

The first update relates to the proposed EMF increment (decrement) for the experienced under-recovery of fuel and fuel-related costs, pursuant to NCUC Rule R8-55(d)(3), which allows the Company to incorporate the fuel and fuel-related cost recovery balance up to thirty (30) days prior to the hearing. The Company elects this option and supplements the direct testimony and exhibits to include the fuel and fuel-related cost recovery balance as of the 11 months ended February 28, 2021.

The second update corrects the over/under-recovery amounts originally reported in monthly fuel reports and incorporated into the EMF in this proceeding. The Company recently discovered that the cost of power purchased from Duke Energy Progress, LLC under the Joint Dispatch Agreement was inadvertently overstated from September 2020 through March 2021. Regarding the recent discovery of the inadvertent overstatement of power purchased from DEP and the timing of this supplemental filing, the Company and the Public Staff have agreed that it would be difficult for the Public Staff to audit the adjustment prior to the filing of testimony by the Public Staff. Accordingly, the Company proposes that the

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Jun 17 2021

Public Staff should be entitled to present the results of its audit on this issue in DEC's 2022 fuel adjustment proceeding. An adjustment to correct the over/under-collection amounts for the months included in the EMF period in this proceeding is shown on Revised Exhibit 3.

The third update revises one of the fuel rate scenarios presented in my direct filing. The scenario based on the proposed nuclear capacity factor and normalized test period sales is updated to reflect a revision to the weather adjustment related to test period kWh sales for the wholesale jurisdiction. The revised total Company normalized test period sales are shown on Revised Exhibit 4. There are no revisions to proposed rates as a result of this update.

Q. HOW DID THE FUEL AND FUEL-RELATED COST RECOVERY BALANCE CHANGE IN THE TWO (2) MONTHS BEING INCORPORATED?

A. The Company experienced an under-collection of $24,376,967 during the months January through February 2021, after considering the second update described above. As shown on Sykes Revised Exhibit 3, the incorporation of the update period under-collection balance resulted in an under-recovered balance of $20,494,879. Incorporating the under-collections experienced during January and February 2021 will increase the EMF decrement rate charged to residential customers, change the EMF rate from a decrement to an increment charged to general service/lighting customers and increase the EMF increment rate charged to industrial customers.

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

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Jun 17 2021

A. The NC Retail Total Fuel Costs were increased by $24,056,611 from the amounts filed in my direct Exhibit 2, Schedule 1, page 3. The components of the proposed fuel and fuel-related cost factors by customer class, as shown on Sykes Revised Exhibit 1, are as follows:

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh	Composite cents/kWh
Total adjusted Fuel and Fuel Related Costs	1.5337	1.6895	1.7243	1.6414
EMF Increment (Decrement)	(0.0282)	0.0476	0.1391	0.0353
EMF Interest (Decrement)	(0.0041)	-	-	-
Net Fuel and Fuel Related Costs Factors	1.5014	1.7371	1.8634	1.6767

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

A. The revised proposed fuel and fuel-related costs factors will result in a 1.34% decrease on customers' bills, as compared to the previously filed decrease of 1.89%.

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

A. Yes, it does.

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(Whereupon, the prefiled direct testimony of Kevin Y. Houston was copied into the record as if given orally from the stand.)

(Whereupon, Houston Exhibits 1 and 2 were identified as premarked and admitted into evidence.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin Y. Houston and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Manager of Nuclear Fuel Supply for Duke Energy Carolinas, LLC ("DEC" or the "Company") and Duke Energy Progress, LLC ("DEP").

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DEC?

A. I am responsible for nuclear fuel procurement for the nuclear units owned and operated by DEC and DEP.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Florida with a Bachelor of Science degree in Nuclear Engineering, and from North Carolina State University with a Master's degree in Nuclear Engineering. I began my career with the Company in 1992 as an engineer and worked in Duke Energy's nuclear design group where I performed nuclear physics roles. I assumed my current role having commercial responsibility for purchasing uranium, conversion services, enrichment services, and fuel fabrication services in 2012.

I have served as Chairman of the Nuclear Energy Institute's Utility Fuel Committee, an association aimed at improving the economics and reliability of nuclear fuel supply and use. I became a registered professional engineer in the state of North Carolina in 2003.

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Q. HAVE YOU FILED TESTIMONY OR TESTIFIED BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDING?

A. Yes. I filed testimony in the DEC fuel and fuel-related cost recovery proceedings in Docket E-7, Sub 1228.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (1) provide information regarding DEC's nuclear fuel purchasing practices, (2) provide costs for the January 1, 2020 through December 31, 2020 test period ("test period"), and (3) describe changes forthcoming for the September 1, 2021 through August 31, 2022 billing period ("billing period").

Q. YOUR TESTIMONY INCLUDES TWO EXHIBITS. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared at my direction and under my supervision, and consist of Houston Exhibit 1, which is a Graphical Representation of the Nuclear Fuel Cycle, and Houston Exhibit 2, which sets forth the Company's Nuclear Fuel Procurement Practices.

Q. PLEASE DESCRIBE THE COMPONENTS THAT MAKE UP NUCLEAR FUEL.

A. In order to prepare uranium for use in a nuclear reactor, it must be processed from an ore to a ceramic fuel pellet. This process is commonly broken into four distinct

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Jun 17 2021

industrial stages: (1) mining and milling; (2) conversion; (3) enrichment; and (4) fabrication. This process is illustrated graphically in Houston Exhibit 1.

Uranium is often mined by either surface (*i.e.*, open cut) or underground mining techniques, depending on the depth of the ore deposit. The ore is then sent to a mill where it is crushed and ground-up before the uranium is extracted by leaching, the process in which either a strong acid or alkaline solution is used to dissolve the uranium. Once dried, the uranium oxide ("U_3O_8") concentrate – often referred to as yellowcake – is packed in drums for transport to a conversion facility. Alternatively, uranium may be mined by in situ leach ("ISL") in which oxygenated groundwater is circulated through a very porous ore body to dissolve the uranium and bring it to the surface. ISL may also use slightly acidic or alkaline solutions to keep the uranium in solution. The uranium is then recovered from the solution in a mill to produce U_3O_8.

After milling, the U_3O_8 must be chemically converted into uranium hexafluoride ("UF_6"). This intermediate stage is known as conversion and produces the feedstock required in the isotopic separation process.

Naturally occurring uranium primarily consists of two isotopes, 0.7% Uranium-235 ("U-235") and 99.3% Uranium-238. Most of this country's nuclear reactors (including those of the Company) require U-235 concentrations in the 3-5% range to operate a complete cycle of 18 to 24 months between refueling outages. The process of increasing the concentration of U-235 is known as enrichment. Gas centrifuge is the primary technology used by the commercial enrichment suppliers. This process first applies heat to the UF_6 to create a gas.

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Feb 17 2021

Then, using the mass differences between the uranium isotopes, the natural uranium is separated into two gas streams, one being enriched to the desired level of U-235, known as low enriched uranium, and the other being depleted in U-235, known as tails.

Once the UF_6 is enriched to the desired level, it is converted to uranium dioxide powder and formed into pellets. This process and subsequent steps of inserting the fuel pellets into fuel rods and bundling the rods into fuel assemblies for use in nuclear reactors is referred to as fabrication.

Q. PLEASE PROVIDE A SUMMARY OF DEC'S NUCLEAR FUEL PROCUREMENT PRACTICES.

A. As set forth in Houston Exhibit 2, DEC'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.

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. Throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEC's exposure to price volatility. Diversifying fuel suppliers reduces DEC's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Q. PLEASE DESCRIBE DEC'S DELIVERED COST OF NUCLEAR FUEL DURING THE TEST PERIOD.

A. Staggering long-term contracts over time for each of the components of the nuclear fuel cycle means DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets. DEC mitigates the impact of market volatility on the portfolio of supply contracts by using a mixture of pricing mechanisms. Consistent with its portfolio approach to contracting, DEC entered into several long-term contracts during the test period.

DEC's portfolio of diversified contract pricing yielded an average unit cost of $47.06 per pound for uranium concentrates during the test period, representing a 4.6% increase from the prior test period.

A majority of DEC's enrichment purchases during the test period were delivered under long-term contracts negotiated prior to the test period. The staggered portfolio approach has the effect of smoothing out DEC's exposure to price volatility. The average unit cost of DEC's purchases of enrichment services during the test period decreased 9.6% to $104.04 per Separative Work Unit.

Delivered costs for fabrication and conversion services have a limited

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Jun 17 2021

impact on the overall fuel expense rate given that the dollar amounts for these purchases represent a substantially smaller percentage – 16% and 4%, respectively, for the fuel batches recently loaded into DEC's reactors – of DEC's total direct fuel cost relative to uranium concentrates or enrichment, which are 46% and 34%, respectively.

Q. PLEASE DESCRIBE THE LATEST TRENDS IN NUCLEAR FUEL MARKET CONDITIONS.

A. Prices in the uranium concentrate markets have recently increased due to production cutbacks; however, prices remain relatively low. Industry consultants believe that production cutbacks have been warranted due to the previously existing oversupply conditions and that market prices need to further increase in the longer term to provide the economic incentive for the exploration, mine construction, and production necessary to support future industry uranium requirements.

Market prices for enrichment and conversion services have recently increased primarily due to a reduction in available inventory supplies.

Fabrication is not a service for which prices are published; however, industry consultants expect fabrication prices will continue to generally trend upward.

Q. WHAT CHANGES DO YOU SEE IN DEC'S NUCLEAR FUEL COST IN THE BILLING PERIOD?

A. Because fuel is typically expensed over two to three operating cycles (roughly three to six years), DEC's nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period, as well as prior periods. The fuel residing in the reactors during the billing period will have been obtained under historical contracts negotiated in various market conditions. Each of these contracts contributes to a portion of the uranium, conversion, enrichment, and fabrication costs reflected in the total fuel expense.

The average fuel expense is expected to increase from 0.5814 cents per kWh incurred in the test period, to approximately 0.6057 cents per kWh in the billing period.

Q. WHAT STEPS IS DEC TAKING TO PROVIDE STABILITY IN ITS NUCLEAR FUEL COSTS AND TO MITIGATE PRICE INCREASES IN THE VARIOUS COMPONENTS OF NUCLEAR FUEL?

A. As I discussed earlier and as described in Houston Exhibit 2, for uranium concentrates, conversion, and enrichment services, DEC relies extensively on staggered long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time and incorporating a range of pricing mechanisms, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEC's exposure to price volatility.

Although costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a cents per kWh basis will likely continue to be a fraction of the cents per kWh cost of fossil fuel. Therefore, customers will continue to benefit from DEC's diverse generation mix and the

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Jun 17 2021

strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

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

A. Yes, it does.

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Jun 17 2021

(Whereupon, the prefiled direct testimony of Steven D. Capps was copied into the record as if given orally from the stand.)

(Capps Confidential Exhibit 1 was identified as premarked and admitted into evidence and was filed under seal.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

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

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven D. Capps and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy") with direct executive accountability for Duke Energy's South Carolina nuclear plants, including Duke Energy Carolinas, LLC's ("DEC" or the "Company") Catawba Nuclear Station ("Catawba") in York County, South Carolina, the Oconee Nuclear Station ("Oconee") in Oconee County, South Carolina, and Duke Energy Progress, LLC's ("DEP") Robinson Nuclear Plant, located in Darlington County, South Carolina.

Q. WHAT ARE YOUR PRESENT RESPONSIBILITIES AS SENIOR VICE PRESIDENT OF NUCLEAR OPERATIONS?

A. As Senior Vice President of Nuclear Operations, I am responsible for providing executive oversight for the safe and reliable operation of Duke Energy's three South Carolina operating nuclear stations. I am also involved in the operations of Duke Energy's other nuclear stations, including DEC's McGuire Nuclear Station ("McGuire") located in Mecklenburg County, North Carolina.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a B.S. in Mechanical Engineering from Clemson University and have over 33 years of experience in the nuclear field in various roles with increasing responsibilities. I joined Duke Energy in 1987 as a field engineer at Oconee. During my time at Oconee, I served in a variety of leadership positions at the station, including Senior Reactor Operator, Shift Technical Advisor, and Mechanical and Civil Engineering Manager. In 2008, I transitioned to McGuire as the Engineering Manager. I later became plant manager and was named Vice President of McGuire in 2012. In December 2017, I was named Senior Vice President of Nuclear Corporate for Duke with direct executive accountability for Duke Energy's nuclear corporate functions, including nuclear corporate engineering, nuclear major projects, corporate governance and operation support and organizational effectiveness. I assumed my current role in October 2018.

Q. HAVE YOU TESTIFIED OR SUBMITTED TESTIMONY BEFORE THIS COMMISSION IN ANY PRIOR PROCEEDINGS?

A. Yes. I provided testimony and appeared before the Commission in DEC's fuel and fuel related cost recovery proceeding in Docket No. E-7, Sub 1163 and provided testimony in DEC's fuel and fuel related cost recovery proceedings in Docket No. E-7, Sub 1190 and Docket No. E-7, Sub 1228.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe and discuss the performance of DEC's nuclear fleet during the period of January 1, 2020 through December 31, 2020 ("test period"). I provide information about refueling outages completed during the period and also discuss the nuclear capacity factor being proposed by DEC for use in this proceeding in determining the fuel factor to be reflected in rates during the billing period of September 1, 2021 through August 31, 2022 ("billing period").

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Q. PLEASE DESCRIBE EXHIBIT 1 INCLUDED WITH YOUR TESTIMONY.

A. Exhibit 1 is a confidential exhibit outlining the planned schedule for refueling outages for DEC's nuclear units through the billing period. This exhibit represents DEC's current plan, which is subject to adjustment due to changes in operational and maintenance requirements.

Q. PLEASE DESCRIBE DEC'S NUCLEAR GENERATION PORTFOLIO.

A. The Company's nuclear generation portfolio consists of approximately 5,389 megawatts ("MWs") of generating capacity, made up as follows:

Oconee -	2,554 MWs
McGuire -	2,316 MWs
Catawba -	519 MWs [1]

The three generating stations summarized above are comprised of a total of seven units. Oconee began commercial operation in 1973 and was the first nuclear station designed, built, and operated by DEC. It has the distinction of being the second nuclear station in the country to have its license, originally issued for 40 years, renewed for up to an additional 20 years by the NRC. The license renewal, which was obtained in 2000, extends operations to 2033, 2033, and 2034 for Oconee Units 1, 2, and 3, respectively.

McGuire began commercial operation in 1981, and Catawba began commercial operation in 1985. In 2003, the NRC renewed the licenses for McGuire and Catawba for up to an additional 20 years each. This renewal extends operations until 2041 for McGuire Unit 1, and 2043 for McGuire Unit 2 and

[1] Reflects DEC's ownership of Catawba Nuclear Station.

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Catawba Units 1 and 2. The Company jointly owns Catawba with North Carolina Municipal Power Agency Number One, North Carolina Electric Membership Corporation, and Piedmont Municipal Power Agency.

Q. WHAT ARE DEC'S OBJECTIVES IN THE OPERATION OF ITS NUCLEAR GENERATION ASSETS?

A. The primary objective of DEC's nuclear generation department is to safely provide reliable and cost-effective electricity to DEC's customers in North and South Carolina. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees receive extensive, comprehensive training and execute their responsibilities to the highest standards in accordance with detailed procedures that are continually updated to ensure best practices. The Company maintains station equipment and systems reliably, and ensures timely implementation of work plans and projects that enhance the performance of systems, equipment, and personnel. Station refueling and maintenance outages are conducted through the execution of well-planned, well-executed, and high-quality work activities, which ensure that the plant is prepared for operation until the next planned outage.

Q. PLEASE DISCUSS THE PERFORMANCE OF DEC'S NUCLEAR FLEET DURING THE TEST PERIOD.

A. The Company operated its nuclear stations in a reasonable and prudent manner during the test period, providing approximately 63% of the total power generated by DEC. During 2020, DEC's seven nuclear units collectively achieved a fleet capacity factor of 95.05%, marking the 21st consecutive year in which DEC's nuclear fleet exceeded a system capacity factor of 90%. With comprehensive and

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successful Covid-19 mitigation protocols, the Company successfully executed five refueling outages with no impact to schedule or planned scope. All refueling outages were completed within budget and four of the five refueling outages completed under the scheduled allocation. McGuire Unit 2 entered its 2020 refueling outage after completing a breaker-to-breaker continuous cycle run, and Oconee Unit 2 established a new annual net generation record during 2020.

Q. HOW DOES DEC'S NUCLEAR FLEET COMPARE TO INDUSTRY AVERAGES?

A. The Company's nuclear fleet has a history of performance that consistently exceeds industry averages. The most recently published North American Electric Reliability Council's ("NERC") Generating Unit Statistical Brochure ("NERC Brochure") indicates an average capacity factor of 91.95% for the period 2015 through 2019 for comparable units. The Company's 2020 capacity factor of 95.05% and 2-year average[2] of 96.07% both exceed the NERC average of 91.95%.

Industry benchmarking efforts are a principal technique used by the Company to ensure best practices, and Duke Energy's nuclear fleet continues to rank among the top performers when compared to the seven-other large domestic nuclear fleets using Key Performance Indicators ("KPIs") in the areas of personal safety, radiological dose, capacity factor, forced loss rate, industry performance index, and total operating cost. On a larger industry basis using early release data for 2020 from the Electric Utility Cost Group, all three of DEC's nuclear plants rank in the top quartile in total operating cost among the 56 U.S. operating nuclear

[2] This represents the simple average for the current and prior 12-month test periods.

plants. By continually assessing the Company's performance as compared with industry benchmarks, the Company continues to ensure the overall safety, reliability and cost-effectiveness of DEC's nuclear units.

The superior performance of DEC's nuclear fleet has resulted in substantial benefits to customers. DEC's nuclear fleet has produced approximately 47.1 million MWhs of additional, emissions-free generation over the past 21 years (as compared with production at a capacity factor of 90%), which is equivalent to an additional 9.8 months of output from DEC's nuclear fleet (based on DEC's average annual generation for the same 21-year period). These performance results demonstrate DEC's continuing success in achieving high performance without compromising safety and reliability.

Q. WHAT IMPACTS A UNIT'S AVAILABILITY AND WHAT IS DEC'S PHILOSOPHY FOR SCHEDULING REFUELING AND MAINTENANCE OUTAGES?

A. In general, refueling, maintenance, and NRC required testing and inspections impact the availability of DEC's nuclear system.

Prior to a planned outage, DEC develops a detailed schedule for the outage and for major tasks to be performed, including sub-schedules for particular activities. The Company's scheduling philosophy is to strive for the best possible outcome for each outage activity within the outage plan. For example, if the "best ever" time an outage task was performed is 12 hours, then 12 hours becomes the goal for that task in each subsequent outage. Those individual aspirational goals are incorporated into an overall outage schedule. The Company then aggressively works to meet, and measures itself against, that aspirational schedule. To

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minimize potential impacts to outage schedules due to unforeseen maintenance requirements, "discovery activities" (walk-downs, inspections, etc.) are scheduled at the earliest opportunities so that any maintenance or repairs identified through those activities can be promptly incorporated into the outage plan.

As noted, the schedule is utilized for measuring outage preparation and execution and driving continuous improvement efforts. However, for planning purposes, particularly with the dispatch and system operating center functions, DEC also develops an allocation of outage time that incorporates reasonable schedule losses. The development of each outage allocation is dependent on maintenance and repair activities included in the outage, as well as major projects to be implemented during the outage. Both schedule and allocation are set aggressively to drive continuous improvement in outage planning and execution.

Q. HOW DOES DEC HANDLE OUTAGE EXTENSIONS AND FORCED OUTAGES?

A. If an unanticipated issue that has the potential to become an on-line reliability challenge is discovered while a unit is off-line for a scheduled outage and repair cannot be completed within the planned work window, the outage is extended when in the best interest of customers to perform necessary maintenance or repairs prior to returning the unit to service. The decision to extend an outage is based on numerous factors, including reliability risk assessments, system power demands, and the availability of resources to address the emergent challenge. In general, if an issue poses a credible risk to reliable operations until the next scheduled outage, the issue is repaired prior to returning the unit to service. This approach enhances reliability and results in longer continuous run times and fewer forced outages,

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Jun 17 2021

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Feb 17 2021

thereby reducing fuel costs for customers in the long run. In the event that a unit is forced off-line, every effort is made to safely perform the repair and return the unit to service as quickly as possible.

Q. DOES DEC PERFORM POST OUTAGE CRITIQUES AND CAUSE ANALYSES FOR INTERNAL IMPROVEMENT EFFORTS?

A. Yes. DEC applies self-critical analysis to each outage and, using the benefit of hindsight, identifies every potential cause of an outage delay or event resulting in a forced or extended outage, and applies lessons learned to drive continuous improvement. The Company also evaluates the performance of each function and discipline involved in outage planning and execution to identify areas in which it can utilize self-critical observation for improvement efforts.

Q. IS SUCH ANALYSES INTENDED TO ASSESS OR MAKE A DETERMINATION REGARDING THE PRUDENCE OR REASONABLENESS OF A PARTICULAR ACTION OR DECISION?

A. No. Given this focus on identifying opportunities for improvement, these critiques and cause analyses are not intended to document the broader context of the outage nor do they make any attempt to assess whether the actions taken were reasonable in light of what was known at the time of the events in question. Instead, the reports utilize hindsight (*e.g.*, subsequent developments or information not known at the time) to identify every potential cause of the incident in question. However, such a review is quite different from evaluating whether the actions or decisions in question were reasonable given the circumstances that existed at that time.

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Q. WHAT OUTAGES WERE REQUIRED FOR REFUELING AT DEC'S NUCLEAR FACILITIES DURING THE TEST PERIOD?

A. There were five refueling outages completed during the test period: McGuire Unit 2, Oconee Unit 3, and Catawba Unit 1 in the spring of 2020, followed by McGuire Unit 1 and Oconee Unit 1 in the fall. All five outages were completed within budget, and all outage scope completion goals were met. The combined O&M outage costs for the five refueling outages totaled $132.9 million compared to the combined budget for the five outages of $136.4 million. Total days offline for refueling during the test period totaled 146.9 days compared to a total scheduled allocation of 151.5 days. Four of the five refueling outages were completed under allocation. The McGuire Unit 1 refueling outage extended 4 days beyond allocation.

After completing a continuous cycle run of 524.5 days, McGuire Unit 2 entered a spring refueling outage on March 21, 2020. In addition to refueling, safety and reliability enhancing maintenance, inspections and testing were completed. Maintenance work included the replacement of the 2D reactor coolant pump seal, and preventive maintenance on the 2A nuclear service work pump, 2A chemical and volume control motor, and 2A containment spray motor. Both the 2A and 2B component cooling heat exchangers were cleaned. Inspections on the reactor vessel head, 2B low pressure turbine, and thrust bearings were completed. After refueling, maintenance, and inspections and testing were completed, the unit returned to service on April 13, 2020, for a total duration of 23.4 days compared to a 25-day schedule allocation. The outage was accomplished with the lowest dose in the station's history.

Oconee Unit 3 shut down for refueling on April 10, 2020. During the outage, the unit's low-pressure turbines were replaced. Safety enhancements included the replacement of the standby shutdown letdown line. Reliability enhancements included the replacements of the 3A high pressure injection motor, 3B reactor building cooling unit motor, 3D1 heater drain pump and motor, 3B1 reactor coolant pump seal, and 20 air operated valve positioners. Preventive maintenance was completed on the 3A and 3B feedwater pumps, main transformer, 3TB switchgear and breaker, and the 3X8 load center. Inspections and testing completed included radiography tests on the high-pressure injection nozzle thermal sleeve and valves, condenser waterbox and discharge piping inspections, and 3TC switchgear inspections. After refueling, maintenance, testing and inspections completed, the unit returned to service on May 9, 2020. The outage duration was 28.97 days compared to a schedule allocation of 34.5 days.

Catawba Unit 1 shut down on May 2, 2020 for refueling. In addition to refueling activities, safety and reliability enhancements, testing and inspections were completed. Replacement of the unit's low-pressure turbines were completed. Other maintenance activities included replacement of the 1C reactor coolant pump motor, replacement of the 1A, 1C, and 1D reactor coolant pump seal packages, and replacement of the 1B reactor coolant charging pump motor. The 1B component cooling water heat exchanger tubes were replaced with new stainless-steel tubes. Volumetric inspection of the reactor vessel head and all head welds, and inspections and testing of seven motor-control centers were completed. After refueling, maintenance, inspections, and testing completed, the unit returned

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Jun 17 2021

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Jun 17 2021

to service on June 1, 2020, for a total duration of 30.2 days compared to a 31-day schedule allocation.

McGuire Unit 1 was removed from the grid on September 19, 2020 to begin refueling. Along with routine refueling activities, safety and reliability enhancements and inspections were completed. Reliability enhancements completed during the refueling outage included replacement of the 1A reactor coolant pump seal and the 1B1 component cooling pump motor. Valve work and modifications completed included valve and valve actuator replacements in the heater drain, safety injection, nuclear service water and station air systems. Inspections completed included the reactor vessel 10-year in-service inspection, material reliability program upper and lower internals inspection, and inspection of the reactor coolant hot and cold leg nozzles. An 8-year reactor coolant pump switchgear inspection and testing of the 1A engineered safety features was also completed. The unit's turbine driven auxiliary feedpump turbine and 1C low pressure turbine were also inspected. With the exception of duration, all outage goals were met. The outage extended four days beyond the scheduled allocation due to challenges with reactor vessel inspection equipment performance and an emergent repair on a cold leg accumulator outlet check valve. Once work activities, testing and inspections were completed, the unit returned to service on October 21, 2020. The total outage duration was 32.1 days compared to a 28-day scheduled allocation.

The fifth and final refueling outage executed during the test period began on October 16, 2020 when Oconee Unit 1 shutdown for refueling. In addition to refueling, safety and reliability enhancements, testing and inspections were

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Mar 17 2021

completed. Significant outage scope included the replacement of the unit's low-pressure turbine rotors, completing a multi-year project to replace the aging low-pressure turbines on all three Oconee units. The replacement of the low-pressure turbine rotors improves reliability, and reduces maintenance expense and inspection requirements during future refueling outages. Other reliability enhancements included replacement of the 1B1 reactor coolant pump motor, 1A1 and 1B2 reactor coolant pump seals, 1D2 heater drain pump and 1A high pressure injection pump motor. Replacement of the unit 1 standby shutdown facility reactor coolant letdown line also completed a multi-year station project; with this work now completed on all three Oconee units. Electrical work completed included main power relaying upgrade and preventive maintenance on the Unit 1 main transformer and various switchgear and breakers. Inspection activities included steam generator Eddy Current and reactor vessel materials reliability program inspections. After refueling, maintenance, inspections and testing completed, the unit returned to service on November 18, 2020, for a total duration of 32.2 days compared to a 33-day schedule allocation.

Q. WHAT CAPACITY FACTOR DOES DEC PROPOSE TO USE IN DETERMINING THE FUEL FACTOR FOR THE BILLING PERIOD?

A. The Company proposes to use a 93.21% capacity factor, which is a reasonable value for use in this proceeding based upon the operational history of DEC's nuclear units and the number of planned outage days scheduled during the billing period. This proposed percentage is reflected in the testimony and exhibits of Company witness Sykes and exceeds the five-year industry weighted average capacity factor of 91.95% for comparable units as reported in the NERC Brochure during the period of 2015 to 2019.

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

A. Yes, it does.

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(Whereupon, the Affidavit of June Chiu and Appendix A were copied into the record as if given orally from the stand.)

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May 10 2021
Jun 17 2021

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1250

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	AFFIDAVIT OF JUNE CHIU

STATE OF NORTH CAROLINA

COUNTY OF WAKE

I, June Chiu, first being duly sworn, do depose and say:

I am a Staff Accountant with the Accounting Division of the Public Staff - North Carolina Utilities Commission. A summary of my duties, education, and experience is attached to this affidavit as Appendix A.

The purpose of my affidavit is to present the results of the Public Staff's investigation of the Experience Modification Factor (EMF) riders proposed by Duke Energy Carolinas, LLC (DEC or the Company) in this proceeding. The EMF riders are utilized to "true-up," by customer class, the recovery of fuel and fuel-related costs incurred during the test year. DEC's test year in this fuel proceeding is the twelve months ended December 31, 2020.

In its application, filed on February 23, 2021, DEC proposed EMF increment/(decrement) riders in cents per kilowatt-hour (kWh), excluding the

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May 17 2021

North Carolina regulatory fee, for each North Carolina retail customer class, as follows:

Residential	(0.0259) cents per kWh
General Service/Lighting	(0.0207) cents per kWh
Industrial	0.0770 cents per kWh

DEC also proposed EMF interest decrement riders for two of three North Carolina retail customer classes, as follows:

Residential	(0.0040) cents per kWh
General Service/Lighting	(0.0032) cents per kWh
Industrial	0.0000 cents per kWh

On April 29, 2021, DEC filed the Supplemental Testimony of Bryan L. Sykes with Revised Sykes Exhibits and supporting workpapers. Witness Sykes' supplemental testimony and revised exhibits reflect the impact of three updates to numbers presented in witness Sykes' direct exhibits and workpapers. They are as follows:

(1) An update to the EMF increments and decrements to incorporate the fuel and fuel-related cost recovery balances for January through February 2021, pursuant to Commission Rule R8-55(d)(3). The reported under-recovery included in the update, although included in this proceeding, would be reviewed as part of next year's fuel and fuel-related cost proceeding;

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May 17 2021

(2) A correction to the over/under-collection amounts for the months included in the EMF period. The cost of power purchased from Duke Energy Progress, LLC under the Joint Dispatch Agreement was inadvertently overstated from September 2020 through March 2021. The Company proposes that the Public Staff should be entitled to present the results of its audit on this adjustment in DEC's 2022 fuel adjustment proceeding; and

(3) A revision to the weather adjustment related to test period kWh sales for the wholesale jurisdiction. There are no revisions to proposed rates as a result of this update.

Revised Sykes Exhibit 1 included in witness Sykes' supplemental testimony sets forth the Company's revised proposed EMF increment/(decrement) riders in cents per kilowatt-hour (kWh), excluding the North Carolina regulatory fee, for each North Carolina retail customer class, as follows:

Residential	(0.0282) cents per kWh
General Service/Lighting	0.0476 cents per kWh
Industrial	0.1391 cents per kWh

DEC also now proposes an EMF interest decrement rider for one of three North Carolina retail customer classes, as follows:

Residential	(0.0041) cents per kWh
General Service/Lighting	0.0000 cents per kWh

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May 17 2021

Industrial	0.0000 cents per kWh

In witness Sykes' Revised Exhibits filed on April 29, 2021, DEC's proposed revised (over)/under-recovery of fuel for each of the North Carolina retail customer classes is as follows:

Residential	$(6,587,808)
General Service/Lighting	$10,990,202
Industrial	$16,092,490

The revised riders were calculated by dividing the fuel cost under-recoveries by DEC's normalized test year N.C. retail sales of 23,329,575 megawatt-hours (MWh) for the residential class, 23,102,975 MWh for the general service/lighting class, and 11,570,060 MWh for the industrial class.

The Public Staff's investigation included procedures intended to evaluate whether the Company properly determined its per books fuel and fuel-related costs and revenues during the test period. These procedures included a review of the Company's filing, prior Commission orders, the Monthly Fuel Reports filed by the Company with the Commission, and other Company data provided to the Public Staff. The Public Staff also reviewed certain specific types of expenditures impacting the Company's test year fuel and fuel-related costs, including reagents (limestone, ammonia, urea, etc.), renewable energy, and purchased power, as well as reviews of source documentation of fuel and fuel-related costs for certain selected Company generation resources. Performing the Public Staff's investigation required the review of numerous responses to written and verbal

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May 17 2021

data requests, and several telephone conferences with Company representatives.

As a result of the Public Staff's investigation, I am recommending that DEC's EMF riders for each customer class be based on net fuel and fuel-related cost (over)/under-recoveries of $(6,587,808) for the residential class, $10,990,202 for the general service/lighting class, and $16,092,490 for the industrial class, and normalized North Carolina retail sales of 23,329,575 MWh for the residential class, 23,102,975 MWh for the general service/lighting class, and 11,570,060 MWh for the industrial class, as proposed by the Company. These amounts produce EMF increment/(decrement) riders for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	(0.0282) cents per kWh
General Service/Lighting	0.0476 cents per kWh
Industrial	0.1391 cents per kWh

I also recommend an EMF interest decrement rider for each North Carolina retail customer class as follows, excluding the regulatory fee, resulting from the over-recovered fuel amounts from each class:

Residential	(0.0041) cents per kWh
General Service/Lighting	0.0000 cents per kWh
Industrial	0.0000 cents per kWh

I have provided these amounts to Public Staff witness Dustin Metz for incorporation into his recommended final fuel factor. The Public Staff also

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May 17 2021

reserves its rights to review and audit the January and February 2021 fuel and fuel-related costs and the Joint Dispatch adjustment between DEC and Duke Energy Progress, LLC, included by the Company in its supplemental filing in DEC's 2022 fuel rider proceeding.

This completes my affidavit.

June Chiu

June Chiu

Sworn to and subscribed before me
this the 10th day of May, 2021.

Cleo L. Ackerman

Cleo L. Ackerman
Notary Public

Cleo L Ackerman
NOTARY PUBLIC
WAKE COUNTY, N.C.
My Commission Expires 01-08-2023

My Commission Expires: 1-08-2023

APPENDIX A

JUNE CHIU

Qualifications and Experience

I graduated from Drake University with a Masters degree in Business Administration. Prior to joining the Public Staff, I worked in the state government and corporate areas. My duties varied from performing audit engagements to supervision of accounting and internal controls and preparing SEC filings.

I joined the Public Staff in October 2017. I am responsible for (1) examining and analyzing testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings, and (2) preparing and presenting testimony, exhibits, and other documents for presentation to the Commission.

I have performed audits and/or presented testimony and exhibits before the Commission for water cases involving Ridgecrest, Water Resources, Aqua, Lake Junaluska, Carolina Water Service Inc. of NC, JAARS, etc. I have participated in electric cases such as the Dominion Energy North Carolina 2019 general rate case, Duke Energy Carolinas, LLC's 2019 general rate case, and Duke Energy Progress, LLC's 2020 REPS proceeding.

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(Whereupon, the testimony of Dustin R. Metz and Appendix A was copied into the record as if given orally from the stand.)

(Whereupon, Metz Exhibit 1 was identified as premarked and admitted into evidence.)

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May 17 2021

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

In the Matter of		
Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	TESTIMONY OF DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1250

Testimony of Dustin R. Metz

On Behalf of the Public Staff

North Carolina Utilities Commission

May 10, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Energy Division of the Public Staff representing the using and consuming public.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are outlined in detail in Appendix A of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

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A. The purpose of my testimony is to present the results of the Public Staff's investigation and recommendations regarding the proposed fuel and fuel-related cost factors for the residential, general service/lighting, and industrial customers of Duke Energy Carolinas, LLC (DEC or the Company), as set forth in the Company's February 23, 2021 application and testimony and April 29, 2021 supplemental testimony.

Q. WHAT ARE THE TEST AND BILLING PERIODS FOR THIS PROCEEDING?

A. For this proceeding, the test period is January 1, 2020, through December 31, 2020, and the billing period is September 1, 2021, through August 31, 2022.

Q. PLEASE DESCRIBE THE SCOPE OF THE PUBLIC STAFF'S INVESTIGATION.

A. The Public Staff's investigation included a review of the Company's test period and projected fuel and fuel-related costs and also the following: (1) the Company's application, testimony, supplemental testimony, and responses to Public Staff data requests; (2) documents related to the performance of the Company's power plants, including the specific performance of the Company's nuclear facilities; (3) the Company's purchased power transactions; (4) the cost of renewable energy and associated fuel prices; and (5) the

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Company's coal, natural gas, nuclear, and reagent procurement practices and contracts.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR INVESTIGATION AND YOUR RECOMMENDATIONS.

- For the test year, the Company achieved the capacity factor standard in Commission Rule R8-55(k), and calculated the proposed base system average fuel factor for the billing period appropriately.
- The Company correctly calculated the proposed fuel and fuel-related cost factors in this proceeding.
- The inadvertent overstatement of power purchased from Duke Energy Progress, LLC (DEP) will be reviewed/audited in DEC's next annual fuel rider.

Q. DID THE COMPANY ACHIEVE THE STANDARDS OF COMMISSION RULE R8-55(K) FOR THE TEST YEAR?

A. Yes. For the test year, the Company achieved the standards found in Commission Rule R8-55(k) with an actual system-wide nuclear capacity factor that exceeded the NERC (North American Electric Reliability Corporation) weighted average nuclear capacity factor. Additionally, the Company's two-year simple average of its system-wide nuclear capacity factor exceeded the NERC weighted average nuclear capacity factor.

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May 17 2021

Q. DID THE PUBLIC STAFF REVIEW THE BILLING PERIOD OR PROJECTED FUEL AND FUEL-RELATED COSTS AS SET FORTH BY THE COMPANY IN THIS FILING?

A. Yes. The projected fuel and reagent costs are reasonable and were calculated appropriately. The projected fuel and fuel-related costs are impacted by minor projected fluctuations in the costs of nuclear fuel, coal, and natural gas. DEC based its proposed fuel and fuel-related costs on a 93.21% system nuclear capacity factor, which the Company anticipates for the billing period.[1]

Q. PLEASE PROVIDE THE PROPOSED FUEL AND FUEL-RELATED COST FACTORS.

A. Metz Exhibit No. 1 shows the Proposed Fuel and Fuel-Related Cost Factors. The Public Staff recommends approval of the fuel components and total fuel factors (excluding the regulatory fee), shown in Metz Exhibit No. 1, Table 1, effective for the twelve months beginning September 1, 2021.

Public Staff witness June Chiu discusses the Public Staff's review of the test period Experience Modification Factor (EMF) and EMF interest in her affidavit, and I have incorporated her recommendations in Metz Exhibit No. 1.

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[1] The Company's actual system nuclear capacity factor for the test year was 95.05%. In comparison, the most recent North American Electric Reliability Council (NERC) five-year average weighted for the size and type of reactors in DEC's nuclear fleet was 91.05% during the test period.

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Q. YOU STATED PREVIOUSLY THAT YOU REVIEWED TEST YEAR POWER PLANT PERFORMANCE. DID ANY PARTICULAR OUTAGES OR EVENTS OCCUR THAT YOU WOULD LIKE TO BRING TO THE COMMISSION'S ATTENTION?

A. Yes. In previous Orders,[2] the Commission instructed the Public Staff to continue to investigate and present its concerns to the Commission regarding test year outages. For the test period in this proceeding, the Public Staff identified two outages at the Catawba Nuclear Station that merited in-depth investigations.

Q. ARE YOU RECOMMENDING DISALLOWANCE OF REPLACEMENT POWER COSTS FOR THESE TWO OUTAGES?

A. No.

Q. IF YOU ARE NOT RECOMMENDING DISALLOWANCE OF REPLACEMENT POWER COSTS, PLEASE EXPLAIN WHY YOU ARE BRINGING THESE OUTAGES TO THE COMMISSION'S ATTENTION.

A. First, the Public Staff believes the Commission and the Company should be aware of the Public Staff's investigation and conclusions should the issues continue or recur.

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[2] Docket No. E-22, Sub 546, Order Approving Fuel Charge Adjustment, Evidence and Conclusions for Findings of Fact Nos. 6-9, p. 19, January 25, 2018; and Docket No. E-7, Sub 1163, Order Approving Fuel Charge Adjustment, Evidence and Conclusions for Findings of Fact Nos. 4-6, p. 28, August 20, 2018.

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May 17 2021

Second, while the Public Staff did not find imprudence or mismanagement on the Company's part, the Public Staff believes the Company should implement and continue mitigation actions to prevent future similar outages, while evaluating the costs (both monetary and non-monetary) against potential gains in safety and reliability.

Third, the replacement power costs to DEC retail customers for the outages in the test year are relatively small, primarily due to the joint ownership of Catawba Nuclear Station[3], along with continued low natural gas costs, and the relatively short outage durations. As a result, the replacement power costs do not change the proposed fuel factors.

Fourth, to the extent these issues continue or recur at Catawba or at other nuclear stations, the Public Staff may find imprudence or mismanagement on the Company's part that justifies a disallowance of replacement power costs.

Q. PLEASE DISCUSS YOUR PARTICULAR OBSERVATIONS AND FINDINGS ABOUT THE NUCLEAR-RELATED OUTAGES FROM THE TEST PERIOD.

A. The two outages of concern were distinct, but occurred at the same facility.

[3] Duke Energy Carolinas has a ~19.2% ownership.

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The first outage occurred on February 12, 2020, and was the result of a component failure on a generator exciter in the proximity of the exciter's brush[4] location. The failure resulted in a turbine trip and subsequent reactor trip. Based upon my review of the event, and interviews with Company staff, the outage and the contributing events that led up to the unit trip are very complex and stem from procedural changes over the past decade. While some of the Company's actions that contributed to this outage were not ideal, the Company had completed on-schedule general bi-weekly inspections (preventative maintenance activities) to ensure component operation. I give substantial weight to the Company's completion of bi-weekly inspections per schedule just prior to the turbine trip. Based on my professional experience, I understand the risk and conditions associated with entering, inspecting, and working in the limited space in which the generator exciter is located. Based on my interviews and discussion with Company staff, I believe the Company has identified potential program enhancements to mitigate exciter failure while balancing worker and equipment safety.

The second outage occurred on September 8, 2020, and was the result of a technician performing a routine scheduled calibration. In

[4] A brush is a component used to transmit electric current from a non-moving (static) device to a rotating piece of equipment (generator or exciter).

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May 17 2021

doing so, the technician inadvertently performed an action on an incorrect piece of equipment. This inadvertent action resulted in a reactor trip. Based upon my review of the events, as well as interviews with Company staff, the Company adhered to the proper procedures and general work practices. The Company considered the event to be human error/performance deficiency. In my professional opinion, I agree with the Company's determination. To my knowledge, all safety control systems responded in accordance with technical specifications.

Q. PLEASE DISCUSS THE INADVERTENT OVERSTATED PURCHASES FROM DEP.

A. Just prior to the filing of Company witness Sykes' supplemental testimony, the Company informed the Public Staff of an internal finding related to the inadvertent overstatement of power purchased under the Joint Dispatch Agreement (JDA) between DEC and DEP. The Company's supplemental filing provides supporting information on the error that started in September 2020 and was corrected in March 2021. The Public Staff requests that the Commission allow the correction to flow through the as-filed revised exhibits of witness Sykes, but to allow the Public Staff to review the costs in DEC's next annual fuel rider. If an error is found in the September 2020 through March 2021 correction, an adjustment will be made in DEC's next annual fuel rider and likely cause an accompanying offset in DEP's annual fuel rider.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, this concludes my testimony.

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May 17 2021

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009, respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012, respectively, and an Associate of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I completed engineering graduate course work in 2019 and 2020 from North Carolina State University.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear

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May 17 2021

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May 17 2021

power plants, including plants owned by both Duke and Dominion. I also worked for six years for an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

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STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-7, Sub 1250, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 15th day of June, 2021.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150