PLACE: Held via Videoconference REDACTED

DATE: Friday, September 11, 2020

TIME: 8:30 A.M. - 12:56 P.M.

DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

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:

DOCKET NO. E-7, SUB 1214

Application of Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

Noteworthy Reporting Services, LLC

DOCKET NO. E-7, SUB 1213

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

Application of Duke Energy Carolinas, LLC,

for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 20

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

FOR DUKE ENERGY CAROLINAS, LLC:

Camal Robinson, Esq., Associate General Counsel
Brian Heslin, Esq., Deputy General Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, North Carolina 28202

Lawrence B. Somers, Esq., Deputy General Counsel
Duke Energy Corporation
410 South Wilmington Street
Raleigh, North Carolina 27601

James H. Jeffries, IV, Esq.
McGuireWoods LLP
201 North Tryon Street, Suite 3000
Charlotte, North Carolina 28202

Andrea Kells, Esq.
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

Molly McIntosh Jagannathan, Esq., Partner
Kiran H. Mehta, Esq., Partner
Troutman Pepper Hamilton Sanders LLP
301 South College Street, Suite 3400
Charlotte, North Carolina 28202

Brandon F. Marzo, Esq.
Troutman Pepper
600 Peachtree Street, NE, Suite 3000
Atlanta, Georgia 30308

FOR SIERRA CLUB:
Bridget Lee, Esq.
Sierra Club
9 Pine Street
New York, New York 10005

Catherine Cralle Jones, Esq.
Law Office of F. Bryan Brice, Jr.
127 W. Hargett Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

FOR NC JUSTICE CENTER, NC HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL and SIERRA CLUB:

Gudrun Thompson, Esq., Senior Attorney
David L. Neal, Esq., Senior Attorney
Tirrill Moore, Esq., Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES III:

Christina D. Cress, Esq.
Bailey & Dixon, LLP
Post Office Box 1351
Raleigh, North Carolina 27602

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

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

A P P E A R A N C E S Cont'd:

FOR NC WARN:
Matthew D. Quinn, Esq.
Lewis & Roberts PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

FOR VOTE SOLAR:
Thadeus B. Culley, Esq., Regulatory Counsel
Senior Regional Director
1911 Ephesus Church Road
Chapel Hill, North Carolina 27517

FOR NORTH CAROLINA LEAGUE OF MUNICIPALITIES:
Deborah Ross, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:
Karen Kemerait, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd:

FOR THE COMMERCIAL GROUP:

Alan R. Jenkins, Esq.
Jenkins At Law, LLC
2950 Yellowtail Avenue
Marathon, Florida 33050

Brian O. Beverly, Esq.
Young Moore and Henderson, P.A.
3101 Glenwood Avenue
Raleigh, North Carolina 27622

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Peter H. Ledford, Esq., General Counsel
Benjamin Smith, Esq., Regulatory Counsel
North Carolina Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd:

FOR THE TECH CUSTOMERS:

Marcus W. Trathen, Esq.

Craig D. Schauer, Esq.

Matthew B. Tynan, Esq.

Charles E. Coble, Esq.

Brooks, Pierce, McLendon, Humphrey & Leonard, L.L.P.

150 Fayetteville Street, Suite 1700

Raleigh, North Carolina 27601

FOR BIOLOGICAL DIVERSITY AND APPALACHIAN VOICES:

Howard M. Crystal, Esq.

Senior Attorney

Jean Su, Esq.

Staff Attorney and Energy Director

Biological Diversity

1411 K Street NW, Suite 1300

Washington, DC 20005

A P P E A R A N C E S Cont'd:

FOR HARRIS TEETER:

Kurt J. Boehm, Esq.

Jody Kyler Cohn, Esq.

Boehm, Kurtz, & Lowry

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

Benjamin M. Royster, Esq.

Royster and Royster, PLLC

851 Marshall Street

Mount Airy, North Carolina 27030

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER THAT AFFECTS THE PUBLIC INTEREST:

Margaret A. Force, Esq., Assistant Attorney General

Teresa Townsend, Esq., Special Deputy Attorney General

North Carolina Department of Justice

Post Office Box 629

Raleigh, North Carolina 27603

T A B L E O F C O N T E N T S

E X A M I N A T I O N S

PANEL OF CHARLES JUNIS AND MICHAEL C. MANESS — PAGE

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL: CUCA, you may call your witness.

MS. DOWNEY: Chair Mitchell, if I might, I'm sorry --

CHAIR MITCHELL: Yes, ma'am, Ms. Downey.

MS. DOWNEY: I've got a couple of preliminary matters I'd like to raise.

CHAIR MITCHELL: All right. Proceed.

MS. DOWNEY: First, Chair Mitchell, regarding witness Roxie McCullar's testimony, in requesting that her testimony and exhibits be entered into the record, I inadvertently left out a filing that was made on February 19th correcting an exhibit. And, at this time, I would like to move that into the record, and we will provide that to the court reporter and the other parties.

CHAIR MITCHELL: All right. Ms. Downey, hearing no objection to your motion, Ms. McCullar's filing made on February 17, 2020, in this docket will be admitted into evidence.

MS. DOWNEY: It was February 19th, but we will file that.

CHAIR MITCHELL: All right. For

purposes of the record, her filing made February 19, 2020, will be admitted into evidence.

(Exhibit RMM-1 was admitted into evidence.)

MS. DOWNEY: And one other thing I wanted to alert the Chair to, as requested. We don't know the nature of the cross that's going to be provided for Garrett and Moore and Commission questions, but did want to alert the Chair that there's a number -- there's a lot of confidential in their testimony. So I just wanted to aler you to that.

CHAIR MITCHELL: All right. Thank you, Ms. Downey. I will rely on counsel to alert me when we get to questions that could illicit confidential information from the witnesses. And as a reminder, if and when we get there, we will leave the video conference technology, and we will call in to a phone line that has been established for this purpose. I believe all parties should have that number at this point in time. So again, I will just rely on counsel to alert me when we get there.

MS. DOWNEY: Thank you, Chair Mitchell.

That's all I had.

CHAIR MITCHELL: All right. Any --

MR. MEHTA: Chair Mitchell, this is Kiran Mehta, and I have three procedural and administrative matters, if I could.

CHAIR MITCHELL: All right. Mr. Mehta, proceed, please.

MR. MEHTA: First off, Chair Mitchell, I did inform both Mr. Page and Ms. Downey about this yesterday evening, that Duke Energy Carolinas is the only party that listed cross examination for Mr. O'Donnell. And on further review, we decided we didn't really need to do that. But, obviously, he's here, and Mr. Page, I'm sure, will proceed.

Secondly, Chair Mitchell, no party has indicated cross for Erik Lioy, who is a rebuttal witness in the Duke Energy Carolinas case. And unless the Commission has any questions for Mr. Lioy, I would ask that he be excused.

CHAIR MITCHELL: Mr. Mehta, as to your request regarding witness Lioy, I would like to consult with my colleagues during our first break, and we will -- I will give you a response to your question immediately following that first break.

MR. MEHTA: That's perfectly fine, Chair Mitchell. And the third matter is purely administrative. Yesterday, I think during the examination of Sierra Club witness Wilson, she was asked to take a look at, I believe, Duke Exhibit -- DEC Exhibit 3, which was one of the prior orders in this case. When she did, she found that the version that she had didn't have any page numbers. And I just wanted to remind all the parties that I think on September 2nd, Monica Smith sent out an email indicating that corrected versions of DEC Exhibits 1, 2, and 3, including the page numbers, had been posted to DataSite; and that they should download those corrected versions from DataSite so that we're not fumbling around the next time one of those prior orders is referenced in -- at least by DEC or any other attorney, for that matter. And that's all I had to say.

CHAIR MITCHELL: All right. Thank you, Mr. Mehta. And those corrected exhibits were also provided to the Commission and Commission staff as well. So thank you, Mr. Mehta, for that housekeeping -- that housekeeping notice. All right.

Any additional preliminary matters before we begin?

MR. ROBINSON: Chair Mitchell, Camal Robinson. Just one quick clarification. So the parties have not received the confidential phone line number yet, should be receiving it shortly. So for any parties that did not receive it or thought they did not receive it, it just hasn't come out yet. And as a matter of fact, I think I just saw an email that just shared it, so for those parties to be aware of that.

CHAIR MITCHELL: Thank you, Mr. Robinson.

All right. Any additional matters?

MR. PAGE: Madam Chair, this is Bob Page. I have one additional matter. In view of the date today, I wonder if it would be appropriate for the record to show that we paused briefly to remember the events of 19 years ago, the horror and the heroism, and the shadow that still exists over our country. But I may be a cockeyed optimist, but I just happen to believe that, as Americans, there's a lot more that unites us than temporarily divides us, and that maybe we should bear that in mind today as we struggle through the events that confront us.

CHAIR MITCHELL: All right. Thank you, Mr. Page, for that reminder. It is appreciated.

MR. PAGE: Mr. O'Donnell, are you there?

MR. O'DONNELL: Yes, I'm here.

CHAIR MITCHELL: All right. Mr. O'Donnell, let's go ahead and get you under oath.

Whereupon,

KEVIN W. O'DONNELL,

having first been duly affirmed, was examined and testified as follows:

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

MR. PAGE: Thank you, Madam Chair.

DIRECT EXAMINATION BY MR. PAGE:

Q. Mr. O'Donnell, would you identify yourself for the record by giving us your name and business, and your business address?

A. Kevin O'Donnell. I'm a financial analyst with Nova Energy Consultants, 1350 Southeast Maynard Road, Suite 101, Cary, North Carolina.

Q. Mr. O'Donnell, with the Chair's permission, I'm going to ask you a serious of leading questions to try to get these qualifications and the housekeeping matters out of the way as quickly as possible.

This is actually your third appearance as a witness in this case; is it not?

A. Yes, it is.

Q. And previously you testified twice during the consolidated phase of these hearings; did you not?

A. Yes, I did.

Q. And the first such occasion, you presented the portions of your testimony dealing with the cost of capital issues, including capital structure, and rate of return, and return on equity; is that correct?

A. Yes, that's correct.

Q. And in the second phase, most recent phase of your testimony, you presented those portions of your testimony which discuss the GIP, or grid improvement, or grid modernization; is that correct?

A. Yes, that's correct.

Q. And the purpose of your testimony today is to present the other two topics discussed in your testimony, which are, first, coal ash -- costs of coal ash cleanup and cost recovery of those costs, and the second issue being cost of service and rate design; is that correct?

A. Yes, that's correct.

Q. All right. Mr. O'Donnell, the testimony you were sponsoring in this case is the updated testimony which was filed on or about April 23, 2020, consisting of some 132 pages of written question-and-answer narrative, an Appendix A, and exhibits entitled KWO-1 through KWO-8; is that correct?

A. Yes, that's correct.

Q. Are there any further updates, or changes, or corrections that should be made to either the testimony narrative, or the appendix, or the exhibits at this time?

A. No, there are not.

Q. If I were to ask you the same questions that appear in the prefiled testimony as filed in the updated version on April 23rd, would your answers today be the same as when prefiled?

A. Yes.

MR. PAGE: Madam Chair, we request that Mr. O'Donnell's prefiled testimony be copied into the record as though given orally from the stand, and that his appendix and exhibits be identified as prefiled.

CHAIR MITCHELL: All right, Mr. Page, motion is allowed.

(Exhibits KWO-1 thorough KWO-8 and O'Donnell Appendix A were identified as they were marked when prefiled.)

(Whereupon, the prefiled updated direct testimony of Kevin W. O'Donnell was copied into the record as if given orally from the stand.)

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I. CONTENTS

II. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Carolina Utility Customers Association (CUCA). A number of CUCA members take retail electric service from the applicant, Duke Energy Carolinas (DEC, Duke, or Company), and the outcome of this proceeding will have a direct bearing on these CUCA members.

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from the Florida State University. I earned the designation of Chartered Financial Analyst ("CFA") in 1988.

I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission ("NCUC"). I left the NCUC Public Staff in 1991 and have worked continuously since then in utility consulting: first with Booth & Associates, Inc. as a financial analyst and then as Director of Retail Rates for the North Carolina Electric Membership Corporation from 1994 to 1995, and since then as principal for my own consulting firm.

I have been admitted as an expert witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the following regulatory bodies: the North Carolina Utilities Commission; the South Carolina Public Service Commission; the Wisconsin Public Service Commission; the Maryland Public Service Commission; the Virginia State Corporation Commission; the Minnesota Public Service Commission; the New Jersey Board of Public Utilities; the Colorado Public Utilities Commission; the District of Columbia Public Service Commission; the Indiana Utility Regulatory Commission; and the Florida Public Service Commission.

In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in Appendix A of this testimony.

III. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the following issues:

- the trend in DEC industrial rates in North Carolina and the associated impact on the state's economy;
- DEC's proposed grid investment plan;
- the appropriate amount of coal ash expense to be included in DEC's rates;
- a review of the DEC real-time pricing (RTP) rates;
- a review of the DEC interruptible rates; and
- the proper return on equity (ROE) and capital structure upon which DEC rates should be based.

IV. SUMMARY/RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. My findings are as follows:

- DEC's manufacturing rates are rising faster than the southeastern and national averages and, given the stated rate increases on the horizon, Duke will be above the national average, thereby costing North Carolina its competitive edge in areas served by the Company;
- DEC's proposed grid expenditures are too expensive and lack customer support
- Many of the DEC proposed grid projects lack basic evidence, such as cost benefit analyses (CBAs), showing the projects are cost beneficial and, therefore, should be disallowed;
- The Commission should only allow recovery of grid update projects in situations where DEC's promised reliability standards, upon which their CBAs are based, are met in the future;
- the Commission should disallow the incremental costs associated with Coal Ash Management Act (CAMA) versus the federal Coal Combustion Residual (CCR) rule;
- DEC's hourly pricing rates should be capped at the lower of DEC's costs or the market cost;
- The Commission should require DEC to immediately convene meetings with large consumers in an effort to arrive at a mutually agreed upon set of new and enhanced interruptible rates and products no later than January 1, 2021; and
- DEC's return on equity (ROE) should be set at 8.75% with a capital structure of 50% common equity and 50% long-term debt;

- The overall rate of return DEC should be allowed in this case is 6.64%.

V. RATE HIKE IMPACTS TO MANUFACTURERS

Q. WHAT IS THE TOTAL RATE HIKE REQUESTED BY DUKE ENERGY CAROLINAS IN THIS RATE CASE?

A. According to DEC's response to CUCA DR 1-15, the Company is seeking a total increase of $445 million that accounts to an overall increase of 9.2%. However, this stated increase does not tell the entire story as the Company is also seeking to return to customers consumer money associated with the return of excess deferred income taxes (EDIT). As a result of the return of the EDIT to those to which it is owed (consumers), the net increase is $291 million which equates to a net 6.0% overall increase.

Q. PLEASE EXPLAIN EXCESS DEFERRED INCOME TAXES (EDIT).

A. Excess deferred income taxes (EDIT) are taxes that consumers have paid to the utility in prior years that were planned to be paid by the utility in future years. Excess deferred taxes are, essentially, a product of the tax difference between accelerated depreciation and straight line depreciation. In ratemaking, taxes are calculated using straight line depreciation. However, in reality, the utility uses accelerated depreciation to calculate its taxes and, therefore, pays lower taxes than is the case with straight line depreciation used for ratemaking purposes. As an asset ages, the taxes that the Company collected but did not pay to the governments are eventually paid so that the net result, over time, is the consumer pays the tax owed by the utility.

When the federal government reduced taxes from 35% to 21% in 2017, EDITs were created on Duke's books. As a result, in the current case, the EDIT funds need to be returned to their rightful owners – the North Carolina retail consumers of DEC.

Q. **HOW IS THE FLOWBACK OF EDIT TO CONSUMERS AFFECTING THIS RATE CASE?**

A. The rate increases sought by DEC in this rate case are significantly lower when the return of customer money, as represented by the EDIT, is considered. Table 1 below shows the impact the EDIT has on the Duke requested rate hikes in this case.

Table 1: EDIT Impact on Requested DEC Rate Increases

Customer Class	Rate Increase Before EDIT Credit	EDIT Credit	Rate Increase After EDIT Credit
Residential	10.7%	3.9%	6.8%
Gen. Svc (non-TOU)	7.8%	2.8%	5.0%
OPT	9.3%	3.7%	5.6%
Industrial	5.7%	2.4%	3.3%
Lighting	17.6%	5.1%	12.5%

Source for raw data: Pirro Exhibit 2

Q. **PLEASE EXPLAIN THE IMPORTANCE OF ENERGY COSTS TO LARGE MANUFACTURING OPERATIONS.**

A. Manufacturers are in a constant battle to compete. The competition is international, domestic, and amongst sister plants of the same manufacturer. If the cost to manufacture a particular product is less expensive in another state or country, the manufacturer has a duty to its customers and stockholders to move the manufacturing to the area of least cost. Sometimes the movements result in permanent plant shutdowns and mass layoffs. Other times, the movements result in line reductions such that the current plant temporarily ceases operation. There are several risks associated with unnecessarily high electric costs for manufacturers. These include temporary or permanent plant closures and lost expansion opportunities which could have resulted in job growth, load growth and other ancillary economic benefits.

An example of a temporary shutdown is a NC plant that produces an identical product as, for example, a sister plant in Georgia. Manufacturers planning their daily production schedules can look at NC prices on a day ahead hourly basis and compare those prices to the Georgia hourly prices. If RTP prices are too high in NC, these plants don't operate. Instead, the manufacturer will allocate that production to its Georgia plant.

In many circumstances, the NC hourly electric prices are higher than the Georgia prices and the NC plant does not operate a certain line on those days. In such a case, the NC utility loses a potential sale, but the loss is not reported in the press such as the reporting of a permanent plant closing. However, over time, the daily losses of load add up and jobs are eventually lost.

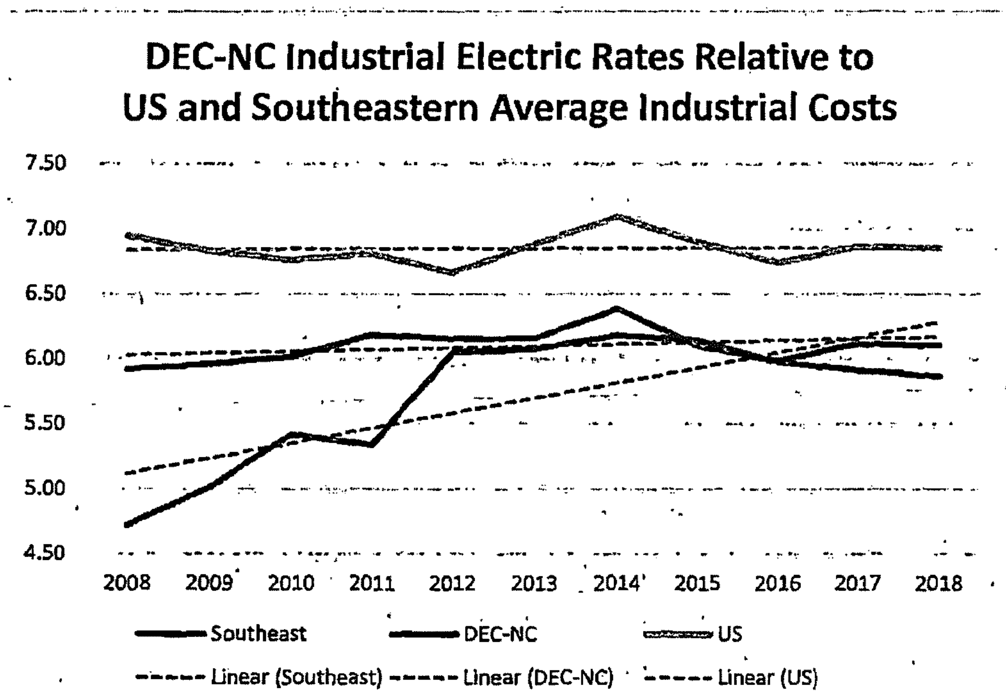
Q. **ARE YOU SAYING THAT ELECTRIC COSTS ARE THE ONLY REASON MANUFACTURERS CHOOSE TO LOCATE/OPERATE IN A PARTICULAR STATE?**

A. No. Manufacturers locate and operate in certain areas for a myriad of different reasons. The cost of electricity is one concern for manufacturers, but that concern is magnified when the state being examined is out-of-line relative to competing states. Energy intensive industries such as steel, air products, auto manufacturers, and paper companies are particularly sensitive to cost imbalances in the electric industry.

Q. HOW HAVE THE DEC NORTH CAROLINA AVERAGE INDUSTRIAL COSTS COMPARED TO INDUSTRIAL COSTS IN OTHER SOUTEHASTERN STATES?

A. Chart 1 below shows DEC North Carolina average industrial costs relative to average industrial costs in South Carolina, Alabama, and Georgia. While DEC's average industrial costs are below other southeastern states, the trend is ominous. DEC rates are increasing at a faster pace relative to electric rates in other southeastern states.

Chart 1: Disappearing Competitive Advantage of NC Electric Industrial Rates



Source for raw data: US Energy Information Administration

Q WHY SHOULD THIS COMMISSION BE CONCERNED ABOUT DEC'S NORTH CAROLINA ELECTRIC COSTS RELATIVE TO THE NATIONAL AVERAGE?

A. Historically, states in the southeastern United States have held a competitive advantage over other states across the country. The above chart shows that DEC North Carolina is quickly losing this competitive advantage. Such a situation does not bode well for the long-term prognosis of the state's manufacturing industry, which depends on reasonably and competitively priced electric power. Given Duke management's very outspoken decision to drive earnings through massive grid investments, the North Carolina Utilities Commission is faced with a dilemma of allowing utility earnings to grow at the expense of the state's manufacturing industry—an industry that has long been vital to North Carolina's overall competitiveness.

Q. WHY IS DEC LOSING ITS ENERGY COST ADVANTAGE RELATIVE TO THE NATIONAL AVERAGE?

A. North Carolina operates a monopoly utility system in which customers have no choice but to buy power supplies from the utility that owns the franchise rights to serve them. Consequently, the dynamic that exists in regulation is almost completely divorced from the market forces and competition.

Q. IS ANY PART OF THE NORTH CAROLINA ELECTRIC MARKET CURRENTLY DEREGULATED?

A. Yes. Wholesale (sales for resale) electric sales were deregulated through the Energy Policy Act (EPACT) of 1992. Since that time, wholesale competition has existed in some form in North Carolina. The competition has not been vibrant, but recent activities have shown that it is picking up in the state. As an example, NTE Energy recently opened a plant in Kings

Mountain, North Carolina that serves many municipal and university electric systems in both South Carolina and North Carolina.

Southern Power, a division of the Southern Company, also owns several unregulated generating facilities located throughout the southeast. Southern serves a very large electric cooperative located in Duke's service territory in North Carolina.

Q. **DO CUSTOMERS IN DEREGULATED WHOLESALE POWER MARKETS ALWAYS PLACE PRICE AT THE TOP OF THE LIST WHEN DECIDING UPON A NEW POWER SUPPLY ARRANGEMENT?**

A. No. I have completed approximately 30 wholesale power transactions on behalf of clients in South Carolina and North Carolina. While price is, without a doubt, incredibly important, price certainty, credit quality, being comfortable with company representatives, and assistance with economic development all play important roles in choosing a power supplier in an open market. With price certainty, businesses can better manage their future costs, which can help attract additional businesses to North Carolina.

One inherent disadvantage incumbent utilities have in competing in the open wholesale markets is that the regulatory business model incentivizes utilities to build plant, such as generation, distribution, and transmission plant, as a means to drive earnings. Competitive suppliers, on the other hand, maximize profits by running lean operations and controlling their costs.

The best way to sum up my work in both the deregulated wholesale power markets and the regulated retail markets is that, in the wholesale markets, I often get to CUT rates for my clients. In the regulated retail markets, I largely work to minimize the monopoly utility requested rate increases.

Q. ARE YOU RECOMMENDING THIS COMMISSION MOVE TO DEREGULATE THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA?

A. Not in relation to this current proceeding, as it is not a referendum on deregulation. However, as noted in Chart 1 above, DEC North Carolina is losing its competitive advantage in terms of energy costs. Under the current regulatory model, Duke is not incentivized to lower costs. It is, instead, incentivized to grow earnings by investing in large amounts of plant and equipment and raising rates to consumers to pay for the plant and an associated return.

Table 1 above shows DEC's rate hike equates to 10.7% for a residential consumer, 7.8% for General Service (non-TOU) consumers, 9.3% for OPT consumers, and 5.7% for Industrial consumers. Such rate hikes are hard for individuals and manufacturers to absorb. Unfortunately, as rates rise to accommodate Duke executives' plans to drive earnings, the electric cost advantage in North Carolina will continue to erode and become an increasingly serious liability to the State.

1. Duke's Planned Grid "Updates"

Q. PLEASE EXPLAIN THE CURRENT STATE OF GRID MODERNIZATION EFFORTS ACROSS THE UNITED STATES.

A. In the second quarter of 2019, 44 states, the District of Columbia, and Puerto Rico took actions related to grid modernization.[1] Most of these

[1] The 50 States of Grid Modernization: U.S. Grid Modernization Activity Continues to Climb in the Second Quarter of 2019, NC Clean Energy Technology Center press release, July 31, 2019

actions involved energy storage deployment, data access policies, distribution system planning, utility business model reforms, and integrated resource planning.[2]

Q. IS THERE AN INCENTIVE FOR UTILITIES TO CONSTRUCT PLANT AND INVEST IN GRID MODERNIZATION ASSETS?

A. Absolutely. Being a regulated utility with a captive set of customers, a utility is incentivized to build plants and put those plants in rate base where they can recover its full investment and earn a rate of return on that investment. In essence, a utility can drive earnings by constantly investing in plant and equipment. The "gatekeeper" in preventing a utility from over-investing to the detriment of ratepayers is the state regulator, which is tasked with weighing the interests of both the utility, DEC in this case, and captive consumers.

Q. PLEASE EXPLAIN HOW ENERGY CONSUMPTION TRENDS RELATE TO GRID MODERNIZATION EFFORTS.

A. As has been well-documented in the media, electricity consumption is stagnant across the United States.[3] Utility sales growth around the United States is flat-to-barely growing. In past years, a utility could meet its earnings goal by simply investing in generation plant. However, with flat load growth, there is less of a need for new generation resources. As a

2 Id

3 *See e.g.*, *Most Utilities Executives Agree Risk of Consumers Going Largely Off-Grid Will Increase Significantly in Next Two Years, According to Research from Accenture*, BUSINESSWIRE (Feb. 5, 2019, 7:59 AM EST), https://www.businesswire.com/news/home/20190205005078/en/Utilities-Executives-Agree-Risk-Consumers-Largely-Off-Grid; Justin Fox, *Americans Keep Using Less Electricity*, BLOOMBERG OPINION (Mar. 1, 2018, 7:00 AM EST), https://www.bloomberg.com/opinion/articles/2018-03-01/americans-electricity-use-just-keeps-falling; Dave Flessner, *TVA Plots New Future With Stagnant or Declining Demand for Power*, CHATTANOOGA TIMES FREE PRESS (Feb. 11, 2018), https://www.timesfreepress.com/news/business/aroundregion/story/2018/feb/11/tvplots-new-future/463259/;

result, utilities are looking for other means to grow earnings to satisfy investors. One area in which utilities are looking to invest is in grid modernization plans, such as the plan DEC is proposing in this case.

On Nov. 8, 2017, Bloomberg chronicled the growing calls around the country by utilities for "grid modernization" when it published an article entitled "No Sales Growth? No Problem! Utilities See Money in Grid Repairs." The article succinctly captures the grid "modernization/transformation" efforts in the following statement:

> Utilities make money by investing in wires, poles, substations and power plants and getting a guaranteed return by their regulators on those investments. But as demand for electricity has flat-lined for nearly a decade, companies are finding it harder to justify just building more stuff for growth. So now, they're talking about making the grids they do operate more efficient and flexible, which also happens to cost money. [4]

As the article states, these grid modernization plans *can* provide benefits to customers, but they also provide utilities an opportunity to make a return on their investments.

Q. HOW IS THE TASK OF UTILITY REGULATION CHANGING WITH GRID MODERNIZATION EFFORTS PROPOSED BY UTILITIES?

A. Historically, a utility simply needed to build a plant and operate that plant to meet the requirements for inclusion in rate base and, therefore, rate recovery. Typically, utility regulators could easily predict and quantify the

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4 Mark Chediak, *No Sales Growth? No Problem! Utilities See Money in Grid Repairs*, BLOOMBERG, (Nov. 8, 2017, 4:21 PM EST, updated Nov. 8, 2017, 6:01 AM EST), https://www.bloomberg.com/news/articles/2017-11-07/-grid-mod-the-new-mantra-as-utilities-counter-stagnant-sales

benefits and costs of the generation source. For example, if one knew the cost of a combined cycle gas plant, the output capacity rating, the price of a natural gas delivered to the plant, and the heat rate of the plant, it is only a matter of math to calculate the all-in cost of the natural gas plant. Today, however, utility regulators are being asked to take a leap of faith in assuming that the promised benefits of grid modernization/transformation actually come to fruition. Utility regulators are being presented plans by utilities in which the utility is seeking to invest in relatively high-tech equipment with the hope/goal of reducing outages and saving consumers money. Unlike in times past when there was little question as to the performance of new plant being brought into rate base, current grid modification plans are contingent upon improvements of reliability indices, such as SAIDI and SAIFI, as well as other measures. As a result, there are no guarantees of performance in these grid investments and, indeed, DEC is offering no such performance guarantees to this Commission in the present filing.

Q. PLEASE EXPLAIN DEC'S GRID MODERNIZATION REQUEST IN THE CURRENT CASE?

A. Duke has made a very public announcement that it intends to "invest" $13 billion to "modernize" the electric infrastructure in the Carolinas over a period of 10 years. Duke NC President Stephen De May states the need for grid modernization in the following statement from his prefiled testimony:

> Today, the need for consistent, reliable service isn't just the expectation of industry and manufacturing, but extends into every home and business—even at a time when that reliability is challenged by the increasing frequency of severe weather events and the threat of physical and cyber-attack. Customers today want a new and better experience,

> driven by information about how they consume energy and by tools that help them manage their consumption. [5]

Q. IS THERE A DIFFERENCE IN THE TOTAL REVENUE FORECAST OF DUKE'S PROPOSED GRID MOD EFFORTS IN THIS CASE VERSUS ITS PREVIOUS REQUESTS?

A. No. Based on recent media reports, it is clear that Duke **still** anticipates spending $13 billion in grid investments in the Carolinas. On January 22, 2019, the *Charlotte Business Journal* published an article that stated, in part:

> Duke says the overall scale of the $13 billion, 10-year program is still "directionally correct." [6]

In Duke's Q4 earnings call with analysts, Duke CEO Lynn Good admitted that Duke was going to push its earnings driver regardless of the forum. Below is part of the transcript from the Q4 earnings call that took place on February 14, 2019:

> **Shar Pourreza** -- *Guggenheim Securities LLC -- Analyst*
>
> Okay, so that's in there. Okay and then Lynn I know you're working through a legislation around sort of grid mod and how to sort of think about potentially getting a rider mechanism, but assuming legislation doesn't sort of time the well (sic) the way you're anticipating, you guys are going to be in for serial filings on an annual basis. So, how should we sort of think about the spending of that profile, assuming that you don't get legislation, maybe the

[5] Prefiled Direct Testimony of Stephen De May, p. 5.

[6] *Charlotte Business Journal*, Jan., 22, 2019

> commission approves trackers, but if you don't and you're going to be in rate cases, do you see sort of -- any sort of downside to that grid mod spend?
>
> **Lynn J. Good** -- *Chairman, President and Chief Executive Officer*
> You know, Shar, I think the capital we've put in front of you is capital that we would spend under the rate case scenario as well. So, we have contemplated both scenarios in our long-term guidance. So I don't see a lot of downside to grid spend as a result of what you're describing. (underline added) [7]

Based on the comments above, Duke still has every intention of spending large amounts of money and seeking cost recovery from captive ratepayers. Since the Company was not successful in obtaining legislation for a rate rider or a multi-year rate plan, DEC is, herein, taking the first of many steps for cost recovery in multiple rate cases. Hence, at the end of the day, the Company is still seeking massive rate hikes over 10 years. Company executives simply re-packaged the old "Power Forward" proposal and put a different bow on it.

The Company proposal for grid updates is a Trojan horse. The Company wants the Commission to believe that it has learned its lesson from its failures for a grid rider and a multi-year rate plan and that it has scaled back its grid investment plans that would hike rates over 50% for consumers. Consumers are wary of Duke's real intention in this process and regulators should be concerned as well.

$13 billion is a huge amount of money for Duke consumers in the Carolinas to absorb. Executives are so focused on driving earnings through grid investments that they are not considering how these cost

[7] https://www.duke-energy.com/_/media/pdfs/our-company/investors/news-and-events/2018/4qresults/4q-18-edited-transcript.pdf?la=en

increases will negatively impact the North Carolina economy OR how consumers may respond.

Q. HOW DO YOU KNOW THAT COMPANY EXECUTIVES HAVE NOT FOCUSED ON HOW RATE INCREASES WILL IMPACT THE STATE'S ECONOMY?

A. I asked that exact question and received the following response in a data request response from DEC:

> **<u>Request:</u>**
>
> 16. Has DEC done any study to investigate how the proposed rate increase in this case will impact the economy of the DEC service territory? If so, please provide that study.
>
> **<u>Response:</u>**
> No.[8]

Q. ARE YOU SAYING THAT NO GRID INVESTMENT IS NEEDED?

A. No. I realize that some investment in the grid is warranted. However, the amount that Duke is requesting across the Carolinas is huge and the associated rate hikes are simply job killers. In addition, while the public, in general, supports some form of grid investment, Duke's own internal polling shows that customers do not support the massive rate hikes Duke has in its plans.[9]

Q. DO YOU HAVE AN ESTIMATE OF THE RATE INCREASES THE COMPANY MAY, ULTIMATELY, ASK THE NORTH CAROLINA CONSUMERS TO PAY FOR ITS GRID INVESTMENTS?

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[8] CUCA Data Request No. 1-16

[9] DEC Response to CUCA RTP 1-4 Electric Grid Assessment, Final Report, July 6, 2015.

A. Yes. I have presented these figures in previous testimony to this Commission as well as to the South Carolina Public Service Commission. Duke has, in the past, attempted to refute these figures as just "estimates" but, to my knowledge, the Company has never submitted testimony in any public setting with a full set of cost estimates for the next 10 years.

Now, to be fair, Duke has shortened their plans down to 3-year increments but, as stated above, the Company's CEO still intends to spend an estimated $13 billion on grid mod to drive earnings for her employer.

Q. PLEASE STATE HOW YOU CAME INTO DUKE'S ESTIMATED COST INCREASES ASSOCIATED WITH ITS GRID MOD PLANS?

A. On Feb. 10, 2017, Ms. Kendal Bowman of Duke Energy made a presentation to the North Carolina Legislative Working Group and provided the **annual** rate increases expected by Duke over the next 10 years to pay for its proposed "investment" in grid modernization. Table 2 below provides these **annual rate hikes** as stated by Ms. Bowman on Feb. 10, 2017:

Table 2: Duke Energy Rate Increases for Grid Modernization

Customer Class	Utility	
	DEC	DEP
Residential	4.31%	4.05%
Commercial	1.18%	3.45%
Industrial	2.65%	0.86%

Source: Ms. Kendal Bowman at NC Leg. Working Group on Feb. 10, 2017

As noted above from the *Charlotte Business Journal* article of January 22, 2018, these anticipated Duke rate hikes are "directionally correct." In other words, the Duke rate hikes are going to be substantial and painful for Duke consumers and hard on the NC economy.

Q. CAN YOU PUT THE RATE INCREASES FROM TABLE 3 INTO BETTER PERSPECTIVE IN TERMS OF THE ACTUAL COSTS TO NORTH CAROLINA CONSUMERS?

A. Yes, the above-stated rate impacts are best put into context by translating these annual rate hikes into a cumulative rate increase over 10 years. Table 3 below provides the cumulative rate hike percentages expected to be requested by Duke for the grid updates.

Table 3: Cumulative Rate Increase for Duke's Proposed Grid Investments

Customer Class	Utility	
	DEC	DEP
Residential	52.50%	48.74%
Commercial	12.45%	40.38%
Industrial	29.89%	8.94%

P. 12 of Duke presentation of 2-10-17 calls for 10-year grid program

The above percentage rate change increases can be further granulated into annual cost increases for Duke customers over the life of Duke's proposed 10-year roll-out of its grid update plans. Table 4 below provides the cumulative cost increases associated strictly with Duke's grid updates.

Table 4: Per Customer Cost for Duke Grid Updates

$13 Billion Spend		
Customer Class	Utility	
	DEC	DEP
Residential	$3,777	$3,726
Commercial	$174,982	$613,056
Industrial	$11,993,265	$4,194,747

For residential consumers, the above table assumes a consumption of 1,100 kWhs per month using the average 2017 DEC residential cost in North Carolina as reported by the EIA. For commercial consumers, the table was constructed using a 500 kW load with a 70% load factor and a corresponding 2017 EIA average cost. Lastly, the industrial values were calculated using a 20 MW load, an 85% load factor, and cost data as reported by EIA.

The above-stated cost increases are massive. Residential consumers are looking at cost increases of close to $4,000. Commercial consumers are looking at cost increases over $175,000. Industrial consumers are faced with cost increases of close to $12 million. For industrial consumers, a $12 million cost increase over 10 years represents a single year payroll for 150 persons earning an average of $80,000 per year. There can be no doubt that the cost—and jobs—impact on the North Carolina economy will be incredibly painful.

Q. **HAS DUKE COMPLETED ANY MARKETING SURVEYS TO ASSESS HOW MUCH CUSTOMERS ARE WILLING TO PAY FOR DUKE'S PROPOSED GRID MODERNIZATION?**

A. Not lately. In the current case, I asked if Duke had completed any such customer surveys and received the following response.

Request:

17. Has DEC done any study or customer survey to examine how its customer opinions about rate increases associated with grid modernization investments?

Response:

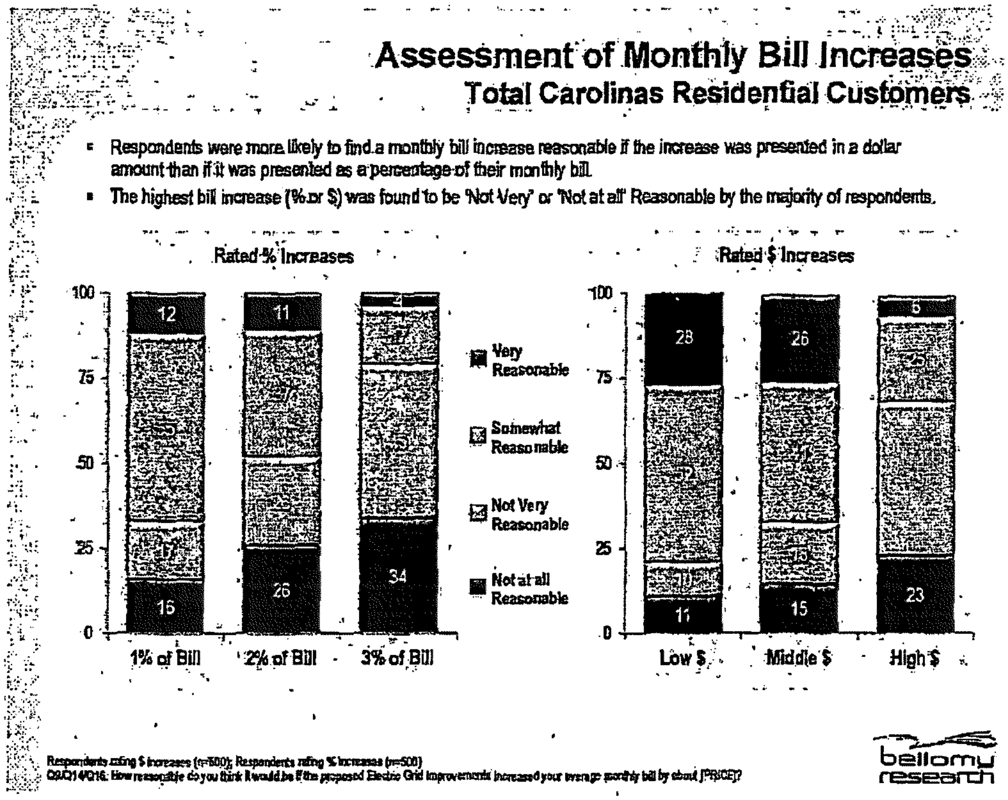
While not surveys, the Company has conducted several workshops and webinars with customer groups and interested parties regarding its Grid Improvement Plan. Details and reports from those events are included in Witness Oliver's direct testimony in Exhibits 11, 13, and 16.

In Duke's 2017 rate case, I also asked the Company if it completed a customer survey on its grid investment plans. The response I received in the 2017 rate case was different from its most recent response. Specifically, in DEC's response in the 2017 rate case, the Company admitted that, way back in 2015, customers were opposed to the massive rate hikes proposed to pay for its grid investments.

On July 6, 2015, Bellomy Research presented the findings of its marketing survey regarding Duke's "Electric Grid Improvements."[10] While most individuals indicated they were in favor of an improved grid, the data below shows consumers have their limit. Specifically, the data below shows that 79% polled found Duke's grid improvements were "not very reasonable" or "not at all reasonable" when the cost increase was 3% per month (see Chart 2). Below is a chart showing the results of the survey.

Chart 2: Duke Customer Survey

[10] NCUC Docket No. E-7, Sub 11467, O'Donnell prefiled testimony, p. 15. DEC Response to CUCA DR 2-21.



If 79% of respondents feel that 3% is too much to pay for the grid updates, common sense dictates an overwhelming percentage of consumers would be opposed to a 10.7% rate hike from Duke as noted in Table 2 above or, even worse, the 52.5% rate hike as calculated by the material presented by Ms. Bowman before the North Carolina General Assembly in 2017.

Q. IS THE ABOVE INFORMATION THE SAME MATERIAL YOU PRESENTED IN THE 2017 DEC RATE CASE?

A. Yes.

Q. WHY DO YOU FEEL IT IS IMPORTANT FOR THE COMMISSION TO SEE THIS INFORMATION AGAIN?

A. First, there are several new members on the Commission that have not, heretofore, seen this material. Second, the above survey is from the general public and is not an "industry insider" workgroup informal poll as DEC has indicated in the above data request response.

Second, it is common sense that no one likes rate hikes. However, the magnitude of the rate hikes for the grid mod planned by Duke is stunning and, potentially, crippling to the NC economy. I feel the Commission should be aware of these significant rate hikes so that it can see the long-term impact Duke's plans will have on the public and the state.

Third, Duke's media blitz "Building a Smarter Energy Future" would be much more informative if the general public were told in those advertisements how high their bills were going in order to pay for DEC's planned investments.

Q. DOES DUKE CURRENTLY RECOVER THE COST FOR MAINTAINING AND IMPROVING RELIABILITY?

A. Yes, Duke currently collects in its rates the charges to support maintenance of the bulk electric system. Unfortunately, it appears that consumers are not getting a good bargain on the grid investments for which we are already paying Duke. On February 1, 2019, *The Wall Street Journal* reported that Duke was fined $10 million by the North American Electric Reliability Council (NERC) for safety and reliability violations. The article was entitled "Duke Energy Broke Rules Designed to Keep Electric Grid Safe." The first two sentences of the article state as follows:

> Duke Energy Corp. DUK +0.52% faces a record $10 million fine from federal authorities for serious and pervasive violations of rules designed to keep the nation's electric system safe from physical and cyber attacks, according to people familiar with the matter.
>
> Some violations lasted for years; others apparently are continuing, according to the people and newly released documents in a federal regulatory filing.

The article goes on to state:

> It (Duke) committed 127 violations of safety rules, federal investigators said, which "posed a serious risk to the security and reliability" of the eastern interconnection, the web of electric utilities east of the Rocky Mountains that furnishes electricity to most Americans.

In regard to foreign entities possibly infiltrating the Duke system, the *Wall Street Journal* states:

> The revelation of the extensive cybersecurity breakdown at a major utility comes as federal authorities are increasingly vocal about efforts by foreign actors, including those in Russia, to hack into U.S. utilities.

It is clear from the news as reported by *The Wall Street Journal*, Duke has not been a good steward of customer revenues paid to it for grid reliability. Allowing Duke multiple rate hikes totaling $13 billion in the Carolinas and then hoping it can correct its mismanagement is simply too great of a risk for the North Carolina consumer.

Q. IS THE DECISION BY DUKE MANAGEMENT TO FOCUS ON GRID EXPANSION UNIQUE TO DUKE OR IS IT AN INDUSTRY TREND?

A. Grid "modernization" efforts are an industry trend. Electric utility load growth is much flatter than in previous years and this lack of sales has caused utilities across the country to search for new ways to drive earnings. On Nov. 8, 2017, <u>Bloomberg</u> published an article entitled "No Sales Growth? No Problem! Utilities See Money in Grid Repairs." The article succinctly captures the grid "modernization" efforts in the following statement:

> Utilities make money by investing in wires, poles, substations and power plants and getting a guaranteed return by their regulators on those investments. But as demand for electricity has flat-lined for nearly a decade, companies are finding it harder to justify just building more

> stuff for growth. So now, they're talking about making the grids they do operate more efficient and flexible, which also happens to cost money. [11]

So, in essence, Duke management has realized that, to continue to grow earnings, it has to stop focusing on building new generation plant and, instead, build something else. In this case, the "something else" is grid "modernization" plant. The core questions for this Commission is whether Duke's massive grid efforts are needed and if so are they cost beneficial and prudent expenditures for North Carolina consumers.

Manufacturers, in particular, stand to be hurt by these Duke grid updates as they will simply be forced to absorb these massive rate increases.

Q. ARE ALL "GRID MODERNIZATION PLANS" THE SAME AROUND THE COUNTRY?

A. No. In February, 2019, the NC Clean Energy Technology Center issued its 2018 report entitled the "50 States of Grid Modernization" and made the following statement as to grid modernization.

> **Grid modernization is a broad term, lacking a universally accepted definition.**

I agree with this statement from the NC Clean Energy Technology Center. Indeed, Duke's own programs filed in this case show that the term "grid modernization" has different meanings among industry observers. Some grid plans are called Grid Transformation Plans (GTPs)[12], while others are

[11] Bloomberg, Nov. 8, 2017, "No Sales Growth? No Problem! Utilities See Money in Grid Repairs"

[12] Dominion Virginia Power before the Virginia State Corporation Commission, Docket No. PUR-2019-00038

known as Grid Investment Modernization (GRIM); still others are known as Power Forward.

Naming issues aside, the actual details of grid modernization also vary tremendously among utilities nationwide. Some utilities are focusing on relatively high-tech programs, such as self-healing grids, whereas others are working to provide more grid hardening while mixing in some technology innovation. Based on my review of DEC's application in this case, I believe the Company fits into this last category in that it is currently focusing on grid hardening and a relatively small amount of technology advancements.

Q. PLEASE DESCRIBE SOME OF THE ELECTRIC GRID TECHNOLOGY ADVANCEMENTS BEING CONSIDERED AROUND THE UNITED STATES.

A. Below is a non-exhaustive list of various grid modernization efforts seen around the country and a synopsis of the program:

Battery storage – batteries are being considered for use in areas of frequent voltage drops in an effort to maintain frequency levels;

Advanced Metering Infrastructure (AMI) – two-way meters are allowing the implementation of customer communication/interaction and the adoption of new rate designs:

Integrated Volt-VAR Control (IVVC) – system that manages voltage along the entire distribution circuit.

Self-Healing Grid – the use of bi-directional data and power flows to allow a system to isolate a problem on the electrical grid and contain or fix that problem before it spreads to other areas of the electric system.

Cyber Security – added layers of software security to thwart efforts by outside entities seeking to do harm to the electrical grid.

Q. IS DEC SEEKING TO EMPLOY THESE TYPES OF TECHNOLOGIES AS PART OF ITS 2020-2022 FILING IN THIS CASE?

A. Yes, according to Oliver Exhibit 10, p. 3 of the Company's filing in this case, DEC is seeking to implement many of these same technologies. Its capital spend request in this case is as follows:

Chart 3: DEC Proposed Grid CapEx Plan 2020-2022

Capital Expenditure Plan [1]	2020	2021	2022
Self-Optimizing Grid	$90,604	$153,733	$175,802
IVVC	$30,797	$86,311	$89,550
Transmission H&R	$13,986	$20,418	$68,059
Undergrounding	$6,424	$15,313	$38,104
Energy Storage	$8,199	$6,199	$42,100
Distribution Transformer Retrofit	$0	$0	$8,293
Long Duration Int/High Impact Sites	$2,354	$5,725	$3,245
T-Transformer Bank Replacement	$6,193	$18,174	$9,274
Oil Breaker Replacements	$28,244	$53,998	$33,415
Enterprise Communications	$26,990	$35,878	$40,896
Distribution Automation	$36,142	$17,863	$61,382
Transmission System Intelligence	$24,008	$30,290	$8,414
Enterprise Applications	$4,348	$3,140	$9,555
Integrated Systems Operations Planning	$3,028	$379	$749
DER Dispatch Tool	$1,738	$2,032	$762
Electric Transportation	$19,117	$19,117	$0
Power Electronics for Volts/BAR Control	$0	$347	$347
Physical & Cyber Control	$51,911	$10,873	$2,302
Annual Totals	$354,083	$479,790	$592,249

Cost Benefit Analysis Summary	$213,791	$359,871	$508,738
% Projects with Cost Benefit Analysis	60.38%	75.01%	85.90%
3-Year DEC CapEx	$1,426,122		

1[1] Oliver Schedule 10, p. 3:

Notes: Items marked in yellow have accompanying cost-benefit analyses.

Q. WHY DID YOU MARK SOME OF THE ABOVE-STATED CAPITAL EXPENDITURE REQUEST ITEMS IN YELLOW?

A. The items in yellow are the only cost items for which the Company claims is cost justified through a cost-benefit analyses (CBA). As can be seen in the chart, the Company has only justified 60.38% of its capex plans for 2020; 75.01% for 2021; and 85.90% for 2022.

Q. WHY DID DUKE NOT PROVIDE A CBA FOR ALL THE PROJECTS FOR WHICH IT IS SEEKING APPROVAL IN THIS CASE?

A. In his prefiled testimony, Company Witness Oliver stated that Duke provided CBAs only for projects for which CBAs are "appropriate."[13] In the footnote for that statement, Mr. Oliver says:

> Some programs/projects cannot be effectively measured by detailed performance metrics and targets. For example, computer hardware and software that enables grid assets to communicate with each other either works or does not work, and measures taken to prevent substations from flooding in major storms either keep water out or do not keep water out.[14]

[13] Oliver prefiled testimony, p. 42
[14] Id.

Q. DO YOU AGREE WITH MR. OLIVER'S CLAIM THAT THE VALUE OF SOME PROJECTS CANNOT BE MEASURED IN A CBA?

A. No, I do not. Mr. Oliver's footnote above seems like common sense, but it omits the reality that the installation of all such equipment can be measured in terms of costs and benefits. For example, Mr. Oliver claims that hardware and software either work or they don't work. What Mr. Oliver fails to acknowledge is there are costs associated with hardware and software that don't work. Such costs can be quantified in terms of outages, lost work hours, lost productivity, etc. Just because an item appears to be difficult to quantify does not excuse the analyst from working hard to proffer a cost estimate.

Similarly, there are costs associated with a flooded substation in a major storm. There are restoration costs and customer lost values associated with an outage. Again, just because it is hard to quantify such costs does not mean that the analyst should not try to come up with a value and provide the evidence upon which he calculated his cost estimate.

Lastly, to the extent that a project, say enterprise communications, must be undertaken before another project, say self-healing grid, can be placed in operation, the cost of that project (enterprise communication) should be considered as part of the final project (self-healing grid). Excluding the cost of the independent project, such as the enterprise communication in the example above, will skew the results of the CBA and not give the Commission an accurate view of the real costs of the projects.

If an independent project's assets will be used in multiple grid projects, the cost of the independent project (enterprise communication) can be apportioned in the various projects.

Q. **HAVE YOU REVIEWED DEC'S COST-BENEFIT ANALYSES FOR THOSE ITEMS WHICH IT DID OFFER SUCH CALCULATIONS?**

A. Yes.

Q. **DO YOU AGREE WITH THE METHODS WHICH MR. OLIVER FOLLOWED IN PERFORMING HIS CBAs?**

A. Mr. Oliver followed what I would consider to be a standard CBA. However, where I differ with Mr. Oliver is that it does not appear he tested his assumptions with a sensitivity analyses In my view, Mr. Oliver should have tested his forecasted SAIDI/SAIFI values and the cost inputs to the CBA model by assuming a +/- 25% variation in the benefits and costs. He could then have presented his findings as part of the results in this case so as to give the Commission a full range of results that were possible.

Q. **HOW DO YOU SUGGEST THE COMMISSION DEAL WITH DEC'S APPLICATION FOR COST RECOVERY OF GRID MODERNIZATION ASSETS?**

A. I have two recommendations.

First, to the extent that DEC did not provide a CBA for a specific project, that requested project should be denied. If the project that is denied was critical to the CBA of a project which DEC has deemed to be economically feasible, both projects should be denied. The reason is that DEC would not have performed the CBA in a proper manner if it did not include ALL costs associated with a specific project. As a result, the Commission would not have all necessary information on which to make a judgement as to the appropriateness of a particular grid investment.

If the Commission rejects a grid investment project, I recommend that DEC be allowed to re-file its grid plan without prejudice and be required to include ALL costs in the plan AND to apply a contingency factor of +/- 25% on various inputs into the model.

As stated above, just because performing a CBA is hard does not excuse the Company and its analysts from working hard to prepare such an analysis. Given that the Company's request in this case amounts to an investment of $1.4 billion and a massive rate hike to consumers, it should have presented a complete CBA for each project to this Commission and intervenors.

Second, I recommend the Commission make cost recovery of the grid modernization assets contingent upon DEC meeting the reliability targets as set forth by the Company in its CBAs. Specifically, each-and-every year, the Company is granted cost recovery if–and-only-if–the reliability targets are reached. Duke needs to be held accountable for its promises to consumers. Granting cost recovery before obtaining evidence that the plant constructed by Duke will work as advertised is putting consumers at extreme risk.

Q. **DO YOU KNOW OF ANY OTHER STATE REGULATORY AGENCY THAT HAS APPROVED AN ASSET BEING PLACED IN RATES CONTINGENT UPON THE UTILITY MEETING A PERFORMANCE TARGET?**

A. Yes. The State Corporation Commission of Virginia recently required Dominion Energy Virginia (DEV) to attain a minimum capacity factor in order to have a solar generation asset added to rate base.

In Case No. PUR-2018-00101, which was filed on July 24, 2018, DEV requested approval to construct and operate two large solar facilities. The facilities were the Colonial Trail West Solar Facility, which was an approximately 142 MW facility located in Surry County and the Spring

Grove 1 Solar Facility, an approximately 98 MW AC facility also located in Surry County.

In its testimony, the Company stated that it expected the solar plants to achieve a capacity factor of 28% and its economic feasibility models were based on such a high capacity factor.[15] The Commission stated the following in regard to the 28% capacity factor:

> The actual performance in Virginia of solar generating resources has demonstrated actual capacity factors significantly below 28%, actually below 20%. To the extent the actual performance of the Projects falls below 28%, the cost to customers goes up, and the NPV becomes negative for customers below 25%.[16]

The Commission went on to require a 25% minimum annual capacity factor. In its order the Commission stated its reasons for this minimum capacity factor as follows:

> Based on the instant record, the Commission finds that a performance guarantee is appropriate and necessary to address the risk of rising and excessive costs to customers attendant to the proposed Projects. As discussed below, however, we further find that Dominion's proffered performance guarantee is insufficient for this purpose.
>
> Performance Guarantee
>
> The Commission finds that the Projects, as proposed in the Petition, are not "required by the public convenience and necessity" under Code § 56-580 D due to the performance and financial risks that would be placed on Dominion's customers. Dominion's cost analyses are based on a 28% solar capacity factor. The capacity factor at which customers essentially break even is 25%. Based on the record herein, we do not find that it is reasonable for

15 Final Order in Case No. PUR-2018-00101, p. 15

16 Id, p.

> customers to bear the risks, for the life of the Projects, that either of these assumed capacity factors will be met. The actual performance of solar generating resources in Virginia has been below 20%, and the Company's existing US-2 solar facilities have underperformed with capacity factors as low as 16%.

My recommendation in this DEC grid investment request case is the same line of reasoning the Virginia SCC followed in the above-stated solar cases. Consumers should not bear the performance risk of DEC's assumptions. DEC should bear that risk as it will earn healthy returns if/when the assets are placed into service and achieve the reliability factors upon which the CBA model is built.

Q. IS DUKE WILLING TO GUARANTEE CONSUMERS WILL REALIZE A REDUCTION IN OUTAGES FROM ITS REQUESTED GRID INVESTMENT STRATEGY?

A. No. I asked DEC if it could offer any such guarantees from its grid investments and the Company answered no. Below are a series of questions posed to DEC and its responses:

> **<u>CUCA 2-8 Request:</u>**
>
> 8. Will DEC provide any guarantee as to the achievable SAIDI/SAIFI ratios on which it has based its cost benefit analyses as presented in this case?
>
> **<u>Response:</u>**
> DEC has not based its cost benefit analyses in this case on "achievable SAIDI/SAIFI ratios." Instead, each cost benefit analysis contains reliability benefits for only the specific work.

CUCA 2-9 Request:

9. Will DEC be agreeable to make cost recovery of its grid mod investments contingent upon achievable reliability targets as represented by SAIDI and SAIFI?

Response:
No. See response to 8.

Q. **HOW DO YOU RESPOND TO DUKE'S UNWILLINGNESS TO ACCEPT RESPONSIBILITY FOR THE PERFORMANCE OF ITS GRID INVESTMENTS.**

A. As explained above, the "old" utility model is that the utility builds plant and equipment for which it seeks rate recovery. It is presumed that this plant and equipment will operate as planned. However, with these grid modifications, DEC wants unfettered rate recovery without even a review of the ability of the assets to work as promised. In essence, Duke is seeking to shift the entire risk of the plant assets to consumers without any corresponding reduction in risk. Duke's position in this case is unacceptable and should be rejected.

Duke's request in this case is akin to an auto manufacturer selling a car to a consumer without any assurance it will even operate. No one would buy a car without even a basic warranty. Consumers need such a warranty and should not be asked to spend a single dime until we receive such assurances from Duke.

Q. **HAS DUKE HELD OPEN WORKSHOPS REGARDING ITS GRID MODERNIZATION INVESTMENTS?**

A. Yes, but the <u>general public</u> has not been engaged in this process. The workshops consisted almost entirely of industry insiders that understood, to a degree, the grid investment process. My attendance at the workshop at the NC State University Faculty Club in 2018 left me with the following major question:

How much is all this investment going to cost consumers?

As noted previously, Duke has a current marketing campaign dubbed "Building a Smarter Energy Future," but the Company has been silent in this media blitz as to the true cost of the grid investments to the consumer. If Duke were being totally transparent in this process, it would state to the consumer that it plans to raise rates upwards of 50% for the grid updates such that the typical homeowner would pay about $4,000 over the next 10 years for the Company's "Smarter Energy Future."

Q. HOW IS RAPIDLY CHANGING TECHNOLOGY IMPACTING THE NEED TO UPDATE THE DUKE GRID?

A. As noted above, Duke has not changed its long-term plan of spending up to $13 billion on its electric grid. This amount of spending translates into approximately $4,000 to the typical residential consumer that will still be subjected to outages. An alternative to spending $4,000 for these grid updates would be home batteries, which continue to fall in price. As an example, a 5-kW Tesla Powerwall currently costs $8,000 installed.[17] It is illogical to spend $4,000 with Duke and still endure outages when the consumer could spend $8,000 and be assured of almost no interruptions (and Duke would not be charging a rate of return on the battery, since it would be owned by the customer).

[17] https://www.energysage.com/solar/solar-energy-storage/tesla-powerwall-home-battery/

As technology continues to evolve, solutions like the one outlined above will continue to present themselves such that the massive Duke grid investment might be outdated and worthless as compared to alternatives.

VI. COAL ASH COSTS

Q. MR. O'DONNELL, PLEASE EXPLAIN THE BACKGROUND THAT HAS LED DEC TO REQUEST RECOVERY OF $200 MILLION OF COAL ASH COSTS IN THIS CASE.

A. On February 2, 2014, DEC spilled a large amount of coal ash in the Dan River. This spill made the national press. The Dan River spill will be cleaned up with Duke stockholder funds. Information exposed in the Duke federal plea deal, which is described below, revealed that on two separate occasions, Duke engineers at the Dan River plant requested an immaterial amount of budget funding to pay for video equipment to scope the pipe that later failed. <u>Duke engineers were denied the request.</u> [18]

In September 2014, in response to the Dan River spill, the North Carolina Legislature passed the Coal Ash Management Act (CAMA), requiring the closure of existing coal ash ponds as well as conversion from wet ash to dry ash handling. CAMA was the first such coal ash management law in the United States. This initial legislation required basins at four Duke plants to be closed by 2019.

On December 19, 2014, the EPA issued the Coal Combustion Residual (CCR) Order that provided minimum national criteria for CCR landfills, CCR surface impoundments, and lateral expansion of coal-fired units. The CCR federal rule was designated as "self-implementing," meaning that

[18] United States District Court for Eastern District of North Carolina, Case Nos. 5:15-CR-62-H, 5:15-CR-67-G, 5:15-CR-68-H, ordering paragraphs 69-80

Duke was not under any requirement to act UNLESS it is sued by a state or other entity and loses that lawsuit.

On May 14, 2015, DEC, Duke Energy Progress, and Duke Energy Business Services pled guilty to nine violations of the Clean Water Act; as a result, Duke was fined $102 million by the federal courts[19]. Below are some of the issues to which Duke admitted guilt:

- From at least January 1, 2012, Duke Energy Carolinas and Duke Energy Business services failed to properly maintain and inspect the two storm water pipes underneath the primary coal ash basins at the Dan River Steam Station in Eden, North Carolina. On February 2, 2014, one of those pipes failed, resulting in the discharge of approximately 27 million gallons of coal ash wastewater and between 30,000 and 39,000 tons of coal ash into the Dan River[20]
- Duke Energy Progress and Duke Energy Business Services also failed to maintain the riser structures in two of the coal ash basins at the Cape Fear Steam Electric Plant, resulting in the unauthorized discharges of leaking coal ash wastewater into the Cape Fear River.[21]
- Additionally, Duke Energy Carolinas and Duke Energy Progress's coal combustion facilities throughout North Carolina allowed unauthorized discharges of pollutants from coal ash basins via

[19] United States DE Ct. of Justice press release, May 14, 2015, 1

[20] United States District Court for Eastern District of North Carolina, Case Nos. 5:15-CR-62-H, 5:15-CR-67-G, 5:15-CR-68-H, 2

[21] Id at 3

"seeps" into adjacent waters of the United States.[22]

- The Defendants' conduct violated the Federal Water Control Act (commonly referred to as the "Clean Water Act," or "CWA"). 33.U.S.C. 1251. [23]

Below is what an official with the United States Environmental Protection Agency said about Duke officials and coal ash:

> "Duke management failed in their responsibility to the people of North Carolina. Their criminal negligence is what caused this disaster," said Cynthia Giles, assistant administrator for enforcement for the U.S. Environmental Protection Agency. [24]

Q. CAN YOU PROVIDE ANY EVIDENCE THAT THE NORTH CAROLINA CAMA LEGISLATION WAS PROMPTED BY THE DAN RIVER SPILL?

A. Yes. An early version of the CAMA legislation, dated May 14, 2014, version that was working its way through the NC General Assembly stateds as follows:

> Whereas, the issue of coal ash storage has not been adequately addressed in North Carolina for more than six decades; and
>
> Whereas, on February 2, 2014, an estimated 39,000 tons of coal ash was released into the Dan River following the

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22 Id at 3

23 Id at 4

24 http://www.wral.com/duke-energy-pleads-guilty-to-environmental-charges-linked-to-coal-ash-spill-leaks/14645414/)

failure of a stormwater pipe under a utility coal ash impoundment pond in Eden, North Carolina; and

Whereas, the Department of Environment and Natural Resources ("Department") finds that coal combustion products have settled into the sediment of the river bottom and will require an extensive clean-up plan to complete remediation; and

Whereas, the Department is in the process of reassessing previous efforts at achieving compliance at coal ash facilities and developing short term and long term policies in light of the Dan River spill, violations discovered in light of increased inspections of coal combustion products disposal facilities and anticipated new federal regulations on coal combustion products; and

Whereas, it is the intent of the Department to ensure that spills of wastewater are reported to the Department in a defined and adequate time frame; and

Whereas, it is the intent of the Department to protect surface water and groundwater resources for their best usage; and

Whereas, it is the intent of the Department to ensure that all unpermitted wastewater discharges are eliminated or addressed in an environmentally responsible manner; and

Whereas, it is the intent of the Department to equally subject all dams under jurisdiction of G.S. 143-215.23 to the requirements of statute and administrative code; and

Whereas, it is the intent of the Department for the owners of all dams under jurisdiction of G.S. 143-215.23 deemed intermediate and high hazard by the Department to prepare at their own cost documents that describe full and adequate response to emergency situations at their dams and to submit those documents to the Department; and

Whereas, it is the intent of the Department to ensure that emergency situations at dams are reported to the Department in a defined and adequate time frame; and

> Whereas, the it is the intent of the Department to increase oversight of dam structure integrity to protect the health and safety of the public; and
>
> Whereas, state law exempts coal combustion products removed from impoundments from being defined as a solid waste; and
>
> Whereas, the Department finds that consistent environmental standards should apply to coal combustion products removed from impoundments for management or disposal and coal combustion products managed or disposed of as a solid waste; and
>
> Whereas, the Department finds the federal Environmental Protection Agency is under consent decree to complete new regulations by December 31 2014 for coal combustion products that are proposed to bring consistency to requirements for large fills such as structural fills and landfills; and
>
> Whereas, the Department finds that conversion and closure of coal ash storage ponds is necessary for protection of the health and safety of the public;[25]

In addition to the above quotes from this early version of CAMA, North Carolina legislators went on the record to state that the Dan River spill prompted CAMA. Evidence for this statement can be found in a WRAL.com article that demonstrates CAMA was a direct result of the Dan River spill. As the article states:

> According to one of Duke Energy's top leaders, North Carolina's 2014 coal ash legislation didn't necessarily result from a company ash spill in the Dan River.
>
> Federal coal ash rules were already being drafted at the time, and it's possible, Duke state President David Fountain testified Monday during a rate increase hearing, that the

[25] https://www.ncleg.gov/Sessions/2013/Bills/Senate/PDF/S729v1.pdf

> North Carolina General Assembly would have passed its law anyway.
>
> Twice, Sierra Club attorney Matthew Quinn asked Fountain whether the law was motivated, or partially motivated, by a spill that turned parts of the river gray.
>
> "I really can't admit that," Fountain replied.
>
> State Rep. Pricey Harrison, D-Guilford, who saw her push for coal ash regulations gain traction only after the spill, scoffed at this Monday evening. When the bill passed in 2014, Senate negotiator Tom Apodaca specifically said that, "When I saw the Dan River thing, I said, 'We've got to do something.'" State Rep. Chuck McGrady, R-Henderson, who negotiated the bill for the House, told the Associated Press that, "unfortunately, sometimes we wait until we have a really big problem before we address it."
>
> "It makes sense for (Fountain) to say that, but he is flat wrong," Harrison said Monday. [26]

Q. IS CAMA MORE OR LESS STRINGENT THAN THE FEDERAL COAL COMBUSTION RESIDUAL (CCR) RULE?

A. Duke has publicly admitted that CAMA is more stringent than CCR. In the May 24, 2016 edition of Utility Dive, Mr. Mark McIntire, director of environmental policy at Duke, is quoted as saying:

> "The NC law came before the CCR [rule]," he said. "We find that NC CAMA that is specific to NC is generally driving decision making on a management perspective on coal ash … From a comparison perspective the CAMA is generally a good bit more stringent."

The *Utility Dive* article went on to state:

[26] http://www.wral.com/seeking-rate-increase-duke-energy-dodges-link-between-coal-ash-spill-and-coal-ash-bill/17145054/

> McIntire noted the CCR rule doesn't stipulate closure of coal ash ponds, nor contemplate a method by which they can be closed — it simply sets minimum requirements for coal ash waste disposal.
>
> The CAMA, however, directs state environmental regulators to set timelines for closing the coal ash facilities.

Q. HOW DO UTILITIES RECOGNIZE IMPENDING FINANCIAL LIABILITIES SUCH AS COAL ASH EXPENSES?

A. Utilities will book expenses as asset retirement obligations (AROs) in recognition of future liabilities.

Q. HAVE YOU ANALYZED AROs RELATED TO COAL ASH FOR DEC AND COMPARED THAT ARO TO OTHER UTILITIES?

A. **Yes.** Using data obtained from SNL Financial, I extracted AROs on the books of utilities from across the country and ranked the utilities by AROs from largest to smallest. Table 5 provides the utilities in the US with the highest AROs.

Table 5: Total AROs

Ranking	Company Name	Asset Retirement Obligations (ARO) ($) 2018Y	
1	Georgia Power Company	$	5,829,413
2	Duke Energy Progress, LLC	$	4,819,760
3	Duke Energy Carolinas, LLC	$	3,948,779
4	Alabama Power Company	$	3,210,340
5	DTE Electric Company	$	2,271,437
6	Florida Power & Light Company	$	2,130,520
7	Indiana Michigan Power Company	$	1,681,320
8	Virginia Electric and Power Company	$	1,445,698
9	Entergy Arkansas, LLC	$	1,048,428
10	Arizona Public Service Company	$	726,545
11	Duke Energy Indiana, LLC	$	721,716
12	Duke Energy Florida, LLC	$	591,138
13	Evergy Metro, Inc.	$	261,038

14	PacifiCorp	$	227,372
15	Evergy Kansas South, Inc.	$	217,485
16	Kentucky Utilities Company	$	199,408
17	Portland General Electric Company	$	197,326
19	Gulf Power Company	$	169,061
21	Mississippi Power Company	$	160,285
22	Public Service Company of New Mexico	$	157,814
23	Indianapolis Power & Light Company	$	129,451
24	Southwestern Electric Power Company	$	126,331
25	Commonwealth Edison Company	$	120,661
26	Appalachian Power Company	$	116,077
27	El Paso Electric Company	$	101,108
28	ALLETE (Minnesota Power)	$	96,901
29	Oklahoma Gas and Electric Company	$	83,942
30	Nevada Power Company	$	82,610
31	Tucson Electric Power Company	$	70,694
32	Tampa Electric Company	$	63,982
33	Westar Energy (KPL)	$	63,612
34	NSTAR Electric Company	$	63,400
35	Monongahela Power Company	$	46,889
36	Public Service Company of Oklahoma	$	46,858
37	Kentucky Power Company	$	41,681
38	Potomac Electric Power Company	$	37,192
39	Connecticut Light and Power Company	$	33,499
40	CenterPoint Energy Houston Electric, LLC	$	33,483

The AROs booked by DEC and DEP indicate that, in comparison to utilities across the United States, these Duke subsidiaries are carrying a sizable future liability.

Q. DO YOU AGREE WITH DUKE'S POSITION THAT CONSUMERS SHOULD PAY ALL THE COSTS OF CLEANUP?

A. No. Duke management made specific decisions that resulted in the coal ash spill in North Carolina that, in turn, led to the creation of the Coal Ash Management Act (CAMA).

Q. WHAT WAS THE NCUC'S RULING ON COAL ASH IN DEC'S 2018 GENERAL RATE CASE PROCEEDING?

A. In its last rate case (Docket No. E-7, Sub 1146), the NCUC awarded recovery of $545.7 million of coal ash remediation costs to DEC to be amortized over 5 years.[27] The only disallowance was that the NCUC did not allow Duke a carrying cost on deferred coal ash expenses.[28] However, in that ruling, the NCUC vote was not unanimous as Commissioners Clodfelter and Brown-Bland dissented from the majority's decision to allow recovery of the $545.7 million in coal ash remediation costs.

Q. HAVE THERE BEEN ANY LEGAL ACTIONS TAKEN ON THE COAL ASH ORDER SINCE THE COMMISSION'S FINAL ORDER IN THE 2017 CASE?

A. Yes, the NC Attorney General and the Public Staff have both filed appeals to the NC Supreme Court. If the NC Supreme Court agrees with the Attorney General and the Public Staff that errors were made in the Commission's final order, the case will be remanded back to the Commission. If that occurs, the 2017 case may be re-opened for interpretation by this Commission again.

Q. HAS ANY OTHER STATE REGULATORY BODY RULED ON THE ISSUE OF DUKE'S COAL ASH REMEDIATION COSTS?

A. Yes. The South Carolina Public Service Commission (SC PSC) ruled that consumers should only pay for the federal CCR costs and not the incremental cost of the CAMA legislation.

Q. DID THE SC PSC FIND THE CAMA LEGISLATION IS MORE STRINGENT THAN THE FEDERAL CCR?

[27] NCUC Final Order in Docket No. E-7 Sub 1146, Ordering paragraph 70

[28] Id, Ordering paragraph 71

A. Yes. In its final order in the case, the SC PSC stated:

> ...this Commission has received evidence that confirms that North Carolina's CAMA is much more stringent and results in costs in excess of those that would be incurred absent CAMA.

Q. ON A TOTAL COMPANY BASIS, WHAT WERE THE TOTAL COAL ASH REMEDIATION COSTS REQUESTED FOR RECOVERY BY DEC IN SC AND HOW MUCH OF THAT REQUEST WAS DISALLOWED BY THE SC PSC?

A. The Commission disallowed $469.9 million[29] on a total-Company basis as compared to the total request of $876.2 million[30] of coal ash expenses. This amount of disallowance represents approximately 53.6% of the total coal ash remediation expenses requested by DEC in its 2019 SC rate case.

Q. ARE THERE PENDING LEGAL ACTIONS IN THE 2019 DEC RATE CASE IN SC?

A. Yes. Duke has appealed the final order from the SC PSC so, like the case in NC, the issue may return to the Commission for further review.

Q. WHAT IS THE TOTAL AMOUNT OF COAL ASH REMEDIATION EXPENSES REQUESTED BY DEC IN THIS CASE?

A. According to DEC's response to CUCA DR 1.15, the Company is seeking recovery of $123 million in coal ash remediation costs in this case alone. This increase amounts to 2.5% of the gross increase (pre-EDIT credits) of 9.2%.

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[29] SC PSC Final Order 2019-323, p. 53

[30] Prefiled testimony of ORS Witness Dan Whittliff in SC PSC Docket No. 2018-319-E, p. 9

Q. **PLEASE STATE THE DIFFERENCES BETWEEN THE NORTH CAROLINA CAMA AND THE FEDERAL CCR.**

A. Below are the list of the differences between CAMA and CCR as it relates to cost recovery in the current case.

1. Closure Methods – CCR allows for cap-in-place closure as compared to CAMA which allows only "low risk" basins to be closed by cap in place;
2. Closure Mandates – CCR requires closure if basins cannot meet various safety and reliability requirements as compared to CAMA that is based solely on priority designation;
3. Closure Timing – the CCR closure timing runs from 5 years to 15.5 years as compared to CAMA that has closure timelines of 5, 10, and 15 years;
4. Inactive Sites – CCR does not apply to inactive sites whereas CAMA does;
5. Benefication – CCR does not require benefication as compared to CAMA that does require benefication at 3 sites.

Q. **DOES THIS AMOUNT OF $123 MILLION INCLUDE CLOSED AND OPEN PLANTS?**

A. Yes, that is my understanding.

Q. **IS THE CCR APPLICABLE TO PLANTS WHERE THE COAL ASH SITE IS NO LONGER OPEN?**

A. If a surface impoundment is closed and no longer receiving coal ash, it is not subject to the CCR rule. [31]

[31] https://www.epa.gov/sites/production/files/2014-12/documents/factsheet_ccrfinal_2.pdf

Q. WOULD A SITE THAT IS NO LONGER RECEIVING COAL ASH BE SUBJECTED TO CAMA?

A. Yes.

Q. BASED ON THIS CLOSURE RULE, DO YOU BELIEVE DEC SHOULD RECEIVE COMPLETE RECOVERY OF ITS REQUESTED COAL ASH EXPENSES?

A. No. My recommendation is that DEC not be allowed to recover coal ash expenses associated with any plant that is not subjected to CCR but is subjected to CAMA. To the extent that any site is no longer receiving coal ash, I don't believe its remediation costs should be paid for by ratepayers in this case or any future cases.

VII. DEC MANUFACTURING RATE CONCERNS

1. Hourly Pricing Rates

Q. DOES DUKE OFFER A REAL-TIME HOURLY PRICE RATE?

A. Yes, it does.

Q. DO DEC INDUSTRIAL CONSUMERS TAKE ADVANTAGE OF THE HOURLY PRICING RATE OFFERED BY DEC?

A. Yes, but in the past two years, I have heard consistent concerns from manufacturers regarding the excessive costs of Duke hourly prices in relation to prices found in other parts of the country and, in particular, with a another southeastern competitor, Georgia.

Q. PLEASE EXPLAIN THE CONCERN ABOUT DUKE'S HOURLY PRICES RELATIVE TO PRICES IN OTHER PARTS OF THE COUNTRY.

A. Duke operates a closed system as it relates to its hourly prices to consumers. The price offered to consumers on an hourly basis is the DEC marginal cost for its generation. However, at the same time DEC is selling marginal cost power to its RTP customers, the Company is also operating in the competitive wholesale power market where opportunity purchases and sales are being made. There may be times throughout the year when DEC's marginal cost of power offered to its manufacturing customers is greater than the price the Company could pay for that same power in the open wholesale market. Unfortunately, since Duke operates a closed system and prices its RTP costs at its own marginal costs, manufacturers are paying higher costs than necessary. On the same front, by failing to take advantage of lower cost power on the wholesale market, Duke is also needlessly running its higher cost generating plants, leading to higher fuel costs for all consumers.

Q. IS THIS ARGUMENT THE SAME DATA YOU PRESENTED IN DEC'S LAST RATE CASE IN SOUTH CAROLINA?

A. Yes, it is.

Q. WHY ARE YOU PRESENTING THIS ARGUMENT AGAIN IN THIS CASE?

A. Because DEC has not made any effort to address its hourly pricing issues with large manufacturers. My concern is that manufacturers need every option available to them to help mitigate the massive rate increases Duke has in store for them through grid transformation and coal ash clean up. Duke should be working hard to help manufacturers develop rate alternatives.

Manufacturers in NC need DEC to become more competitive. This issue is one that does not cost DEC any funds and, therefore, should be of no contention to the utility. If DEC is indifferent and it saves manufacturers in higher power bills, I see no reason why DEC should not be ordered to set the RTP rates at the lower of the Company's marginal cost or the price as set by the open wholesale power market, as adjusted for transmission costs and line losses for moving the power to the DEC service territory.

Q. **DO YOU HAVE ANY RECOMMENDATION FOR DEC IN AMENDING ITS RTP RATE SCHEDULE IN THIS PROCEEDING?**

A. Yes. DEC's hourly pricing should be set at the lower of DEC's marginal cost or the price set by the open wholesale power market adjusted for transmission costs and line losses.

The above recommendation to improve the DEC hourly pricing rates is but one way that Duke can improve its relationship with its business customers.

2. Interruptible Rates

Q. **IS THERE ANY RATE THAT DEC CAN IMPLEMENT IN ORDER TO IMPROVE THE COMPETITIVE POSITION OF THE RATES IT OFFERS TO MANUFACTURERS?**

A. Yes. DEC should re-examine its interruptible rates to offer a higher credit to those large consumers that have the ability to go offline at times of peak demand.

Q. **WHAT IS THE CURRENT INTERRUPTIBLE RATE OFFERED BY DEC?**

A. DEC offers an interruptible rate of $3.50 per kW.

Q. **PLEASE EXPLAIN YOUR CONCERN IN TERMS OF DEC'S INTERRUPTIBLE RATE.**

A. As noted previously, manufacturers in NC are in competition with plants from around the country. As I have also previously shown, DEC's rates are on a steep upward trajectory, thereby threatening the ongoing viability of manufacturers in the state. If manufacturing load is flat-to-falling in NC, residential and commercial rates will go up to pick up the lost margins from industrial load. For the sake of NC's economy and the finances of all its consumers, DEC must work hard to ameliorate its ever-rising rate increases.

One way DEC can help manufacturers while helping itself is to increase its interruptible rate, which is low in comparison to service from its western neighbor (TVA).

Q. WHAT IS THE INTERRUPTIBLE RATE OFFERED BY TVA?

A. The IP 30 rate is a very attractive interruptible rate offered by TVA and provides a credit of $5.75 per kW on a monthly basis. This TVA rate is $2.25 per kW HIGHER than the corresponding DEC rate.

Q. PLEASE PUT THIS $2.25 PER KW IN PERSPECTIVE FOR THE COMMISSION.

A. A credit of $2.25 per kW for the ability to interrupt would equate to $90,000 per month in savings for a customer with a 40 MW load. On an annual basis, this difference in the TVA credit and the DEC credit equates to $1.08 million.

Such a large sum of annual savings may definitely push a large manufacturer into Tennessee as opposed to NC. If such a move was made, NC would lose the tax revenue from the manufacturer as well as potentially hundreds of jobs that would instead go to Tennessee.

In addition to the above-stated cost savings, I suggest the Commission consider how an increase in the interruptible credit may help manufacturers mitigate the cost increases anticipated by Duke for its grid modernization efforts.

Q. **PLEASE EXPLAIN YOUR POINT AS TO HOW AN INCREASE IN DEC'S INTERRUPTIBLE RATE CAN HELP MANUFACTURERS ABSORB THE MASSIVE RATE HIKES EXPECTED BY DEC DUE TO ITS GRID TRANSFORMATION PROJECTS.**

A. DEC's grid transformation projects will be based on investments in the transmission and distribution portions of the DEC system. These two parts of the electric system are, historically, allocated on a demand basis. Indeed, in the current case, Company Witness Hager allocates transmission and a significant amount of distribution costs on a demand basis.[32]

Since the transmission and distribution costs will increase disproportionately in the Company-filed cost of service study relative to generation costs, the amount of costs recovered using a fixed component in the rates (e.g. the demand rate) is going to likewise increase significantly to pay for the grid updates. To the extent that an increase in the amount of interruptible power can be added to the DEC grid thereby lessening the need for some of the DEC grid transformation, DEC should credit large customers that have the ability to interrupt service.

Furthermore, to the extent that DEC intends to increase its demand rates to pay for the grid transformation, which is a likely scenario, the increase in

[32] Hager prefiled direct testimony, p. 7

the interruptible credit will allow large customers to better absorb the massive rate hikes expected by the Company.

Q. **IS THERE ANOTHER WAY THAT INTERRUPTIBLE LOADS CAN BE USED TO MAKE THE DEC SYSTEM MORE PRODUCTIVE?**

A. Yes. An increase in the interruptible credit may entice more customers to participate in the rate and, thereby, allow DEC to use this load to offset certain ancillary costs, such as spinning reserves, non-spinning reserves, and supplemental reserves.

Q. **WHAT ARE SPINNING AND NON-SPINNING RESERVES?**

A Spinning and non-spinning reserves are resources that the grid balancing authority uses to serve load immediately in the case of an emergency.

Q. **ARE LOAD RESOURCES SUCH AS INTERRUPTIBLE CUSTOMERS CAPABLE OF BEING INTERRUPTED QUICKLY SO AS TO PROVIDE NON-SPINNING RESERVES?**

A. Yes. Industrial processes such as air separation and metal melting are capable of dropping large amounts of load quickly in order to provide non-spinning, supplemental, and frequency reserves. However, there is a cost associated with dropping load immediately and that cost should be considered in deriving a rate that is specific to providing non-spinning and, then, supplemental and frequency reserves.

Q. **HAS THE SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL (SERC) RECOGNIZED INTERRUPTIBLE LOAD AS NON-SPINNING RESERVES?**

A. Yes, Attachment 1 of NERC reliability Standard BAL-02 states as follows in terms of the permissible mix of spinning and supplemental reserves:

> Balancing Authorities carry Contingency Reserves of sufficient capacity to meet the Disturbance Recovery Criterion of NERC Standard BAL-002-1 within the Disturbance Recovery Period for 100% of reportable Disturbances. Contingency Reserve Resources are either online (spinning) or off-line (non-spinning) <u>which may consist of interruptible load</u>, fast-start capacity and hydro capacity, provide the capacity can be made available within 15 minutes. These capacity resources must be under the direct control of the Balancing Authority operator. (underline added)

Q. ARE THERE DIFFERENT TIME LIMITS FOR RESPONDING TO DEMAND INTERRUPTIONS?

A. Yes. The current DEC interruptible rate (Rider IS) requires DEC to provide 30 minutes notice before a curtailment is called, which may work fine for a supplemental reserve. However, 30 minutes is too long for a spinning reserve. A time requirement for a spinning reserve must be shorter than 30 minutes and, thereby, must be priced (i.e. credited) higher than the current Rider IS which, itself, should be raised.

Q. WHAT IS YOUR RECOMMENDATION IN REGARD TO INTERRUPTIBLE RATES OFFERED BY DEC?

A. My recommendation is that the Commission require DEC to immediately convene meetings with the Company's large customers to ascertain and offer new interruptible rates to its large customers no later than January 1, 2021.

As I stated previously, Duke's intention is to massively raise rates to consumers in the Carolinas. If the Company does not take steps to help mitigate those rate increases for large industrial consumers, the remaining consumers (residential, commercial, and industrial) will see their rates increasing higher as a result of DEC's industrial loads migrating to other states.

VIII. COST OF CAPITAL

A. Review of Company's Requested ROE

Q. WHAT ROE DID DEC ASK THE COMMISSION TO GRANT IT IN THIS PROCEEDING?

A. According to Company Witness Hevert, the ROE that should be afforded the Company in this proceeding is 10.50%.

Q. DO YOU AGREE WITH DEC'S REQUESTED ROE?

A. No. I disagree with DEC's requested ROE. The requested ROE is excessive and unwarranted given the current financial market conditions; it simply does not comport with the current economic reality facing investor-owned utilities. Moreover, the models and inputs used by Company Witness Hevert to determine DEC's cost of equity are biased, in nearly every sense, to artificially inflate his ROE results.

Q. PLEASE EXPLAIN HOW MR. HEVERT'S DCF ANALYSIS IS BIASED.

A. In his DCF analysis, Mr. Hevert uses only forecasted earnings growth rates. As discussed in my testimony herein, there is ample financial literature demonstrating the errors that accompany the exclusive use of forecasted earnings growth rates. Mr. Hevert made no adjustments to account for the upward nature of analyst forecast estimates.

As I note in my ROE analysis below, it is immensely important that the analyst present as much relevant information as possible to utility regulators so they can make informed decisions. Historical information as well as information on dividend growth, earnings growth, and book value growth are critical pieces of information omitted by Mr. Hevert, whose forecasted earnings-only analysis is very limited and restricted. I believe a more complete and robust analysis is required in every cost of equity analysis.

In addition, it goes without saying that Mr. Hevert's DCF analysis is stale and needs to be updated. Mr. Hevert's dividend yield component was derived by using the 30-day, 90-day, and 180-day average stock price as reported by Bloomberg on June 28, 2019. On that date, the Dow Jones Utility Average was 810.66. On January 13, 2020, the Dow Jones Utility Average was 879.51, thereby representing a 7.8% increase in the utility index. A simple update will show the dividend yield component of Mr. Hevert's DCF analysis has fallen and, accordingly, his ROE results must fall as well.

Q. HOW DO YOU RESPOND TO MR. HEVERT'S COMMENTS DISAVOWING HIS DCF RESULTS?

A. On pages 5-6 of his direct testimony, Mr. Hevert provides reasons why he recommends the Commission give less weight to his DCF results than the results of other models. Specifically, Mr. Hevert states:

> In developing my recommendation, I recognized that the low end of the range of results (set by the low end of the range of Constant Growth DCF model results) is not likely to be a reasonable estimate of the Company's Cost of Equity. In large measure, that is the case because those

> results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions. Because Risk Premium-based methods directly reflect measures of capital market risk, they are more likely than other approaches (such s the Constant Growth DCF method) to provide reliable estimates of the Cost of Equity during periods of market instability.[33]

The statement sounds simple but, in reality, it is misleading. The DCF model is used to estimate the current market ROE of investors. Stock prices go up and stock prices go down. As such, the current return changes each and every day as investors are bidding the stock price up and down to account for perceived levels of risk changes. However, Mr. Hevert wants this Commission to believe that ROEs are static and do not change in response to high stock prices. The following quote is from page 29 of Mr. Hevert's direct testimony in the general rate case of Pepco before the District of Columbia Public Service Commission

:

> In one sense, relatively low dividend yields should be associated with relatively high growth rates. That is, low dividend yields are the result of relatively high stock prices which, in turn, should be associated with relatively high growth rates. If those relationships do not hold, the model's results should be viewed with some caution.[34]

The above statement inappropriately implies that returns are static. They are not. As this Commission is aware, the stock market is regularly hitting record highs. As such, investors are paying more and more for a given level of income. When such a situation occurs, it is a mathematical

33 Hevert prefiled direct, p. 5-6.

34 Exhibit Pepco (G) (Hevert) at 29:14-18.

certainty that the current return is going to fall, a concept that Mr. Hevert's testimony fails to acknowledge. Indeed, Mr. Hevert's implication that model results should not be given as much credence when they produce lower returns as a result of higher stock prices simply fails the "common sense" test and does nothing but provide a misleading analysis to support Mr. Hevert's irrational proposal for a higher ROE than even his own DCF analysis produces.

Q. **CAN YOU PROVIDE AN EXAMPLE OF HIGH INCREASING MARKET PRICES DRIVING DOWN THE CURRENT RETURN OF ANY STOCK INVESTMENT.**

A. Yes. Suppose a stock that paid \$1.00 in dividends was projected to increase the dividend by 4% per year into the indefinite future, and the current stock price was \$20 per share. In this scenario, the DCF formula would be:

$$ROE = ((D_0 * (1+g))/P_0)) + G$$

Where D_0 is the current dividend paid
G is the growth in the dividend; and
P_0 is the current price.

Which translates into the following:
$ROE = ((\$1.0*(1+.04))/\$20) + 4\%$
$ROE = 9.2\%$

Now, if the market bids up the price of the stock to \$25, the formula and result is as follows:

$ROE = ((\$1.0*(1+.04))/\$25) + 4\%$
$ROE = 8.2\%$

The above example shows that, contrary to Mr. Hevert's argument, the market is NOT static and, by mathematical definition, higher stock prices in the face of unchanging dividend growth forecasts translates into lower ROEs.

Mr. Hevert's arguments are simply an effort to mislead the Commission into believing that market returns do not change. Such a position is simply wrong from a basic mathematical standpoint and financial position, as well as from a simple common sense position.

The fundamental problem with Mr. Hevert's analysis is that his models don't produce the results he wants for his utility clients. Mr. Hevert has been claiming for over three years that interest rates will rise and utility stock prices will fall.[35] He has been flat wrong in his prognostications. Instead of accepting the fact that we are in a period of sustained low market returns, Mr. Hevert's analyses are constantly changing in an attempt to present unrealistic returns for his utility clients.

There is no problem with the DCF model. It is working exactly as it should in today's market in that as prices move upward, returns go down. Such is a basic mathematical reality, as noted above, that Mr. Hevert fails to appreciate.

35 *See, e.g.*, Prefiled testimony of Robert Hevert before the NC Utilities Commission in Docket No. E-7, Sub 1146, p. 82 (June 1, 2017) (stating that investors clearly expect interest rates to rise in the near- and long-term).

Q. WHAT IS THE RANGE OF RESULT FOR MR. HEVERT'S DCF ANALYSIS?

A. Table 1a of Mr. Hevert's pre-filed direct testimony shows DCF results of 8.86% to 9.96%. The midpoint of this range of 9.41%. Despite the results of his own DCF analysis, Mr. Hevert recommends a significantly higher 10.5% ROE in this proceeding.

Q. HOW IS MR. HEVERT'S CAPM ANLYSIS BIASED UPWARD?

A. The risk premiums used by Mr. Hevert in his analysis are grossly in excess of forecasts cited by market professionals. Specifically, Mr. Hevert's risk premium range of 12.15% to 12.25% are contingent upon Mr. Hevert's overall market forecast of 14.78% to 14.88% return on the market[36]

Mr. Hevert's Chart 16, which is found on page 95 of his pre-filed testimony, shows that Mr. Hevert's market premiums tend to increase when interest rates decrease.[37] In this case, Mr. Hevert is using a market risk premium of 12.15% to 12.25% at a time when 30-year Treasury bonds are yielding less than 2.0%[38]. However, when one looks at Mr. Hevert's Chart 16, the risk premium for 30-year U.S. Treasury bonds yielding 2% is approximately 8%, not the 12.15% to 12.25% as claimed by Mr. Hevert. In fact, a risk premium of anything over 8% is not even found on Mr.

[36] Exhibit RBH-27 p. 1, 8

[37] Hevert prefiled direct, p. 95

[38] *See* U.S. Department of Energy, Daily Treasury Yield Curve Rates, available at https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield (showing a 30-year Treasury bond yield rate of 1.99% on January 31, 2020).

Hevert's Chart 16, thereby showing Mr. Hevert's own data prove his methods are biased to generate a high ROE for his utility clients.

Q. WHAT EXPECTED MARKET RETURN DOES MR. HEVERT USE IN THE CAPM ANALYSIS HE EMPLOYS IN THIS CASE?

A. In his direct testimony in this case, Mr. Hevert uses expected market return estimates of 14.78% to 14.88% return on the market.[39] As I will demonstrate in this testimony, market professionals are expecting total returns of approximately half of Mr. Hevert's outrageous forecast of 14.78% to 15.78%.

Q. HOW DOES THIS MARKET FORECAST OF 14.78% TO 15.78% COMPARE WITH HISTORICAL RETURNS?

A. Historically, as noted previously, the market returns have averaged 10.0% (geometric mean) to 12.0% (arithmetic mean), both of which are well below the bottom end of Mr. Hevert's forecast. I urge the Commission to consider whether Mr. Hevert's market return forecast of nearly 15% makes sense in today's marketplace. Below is an old saying that I believe is accurate for Mr. Hevert's forecasted returns on the market:

> When something sounds too good to be true, it probably is not true. (unknown)

Q. HOW IS MR. HEVERT'S RISK PREMIUM ANALYSIS BIASED UPWARDS FOR HIS UTILITY CLIENTS?

[39] Hevert prefiled direct testimony, Exhibit RBH-2, p. 1, 8

A. The same errors cited above in regard to market forecasts and risk premium embedded in Mr. Hevert's CAPM have flowed through to his Risk Premium analysis. Specifically, the risk premiums espoused by Mr. Hevert are nonsensical and have no fundamental basis in reality. As I demonstrated above, one need only to look at Mr. Hevert's Chart 1 to see that the risk premiums he suggests in this case do not match the risk premiums as found in his own chart.

Q. HAS ANY NEARBY STATE REGULATORY BODY RECENTLY RECOGNIZED OBVIOUS FLAWS EXHIBITED IN MR. HEVERT'S TESTIMONY?

A. Yes. Mr. Hevert filed testimony on behalf of Dominion Virginia Power at the Virginia State Corporation Commission ("Virginia SCC") in Case No. PUR-2017-00038. Mr. Hevert's recommendation was that Dominion Virginia Power ("DVP") should be granted a 10.5% ROE which, ironically, is the same ROE he is recommending in this case. The Virginia SCC weighed the evidence and instead granted DVP a 9.2% ROE. The Virginia SCC found the following:

1. Mr. Hevert's proposed cost of equity of 10.25% to 10.75% did not represent the actual cost of equity in the marketplace nor a reasonable ROE for DVP;[40]

40 *Application of Virginia Electric and Power Company For the Determination of the Fair Rate of Return on Common Equity to be Applied to its Rate Adjustment Clauses*, Case No. PUR-2017-00038, Final Order, 4 (Nov. 29, 2017).

2. Mr. Hevert's recommended ROE of 10.5% is not supported by reasonable growth rates, DCF methods or risk premium analyses;[41]
3. Mr. Hevert's application of the CAPM is flawed and his application of the Bond Yield Plus Risk Premium model contains similar flaws as his CAPM analysis;[42] and
4. Mr. Hevert's claim of Dominion deserving a 10.5% ROE due to certain business risk was summarily rejected because the majority of DVP's future cap-ex could be recovered through automatic revenue adjustment clauses.[43]

Q. ARE YOU AWARE OF ANY REGULATORY BODY THAT HAS RECENTLY AUTHORIZED A ROE OF LESS THAN 9.0%?

A. Yes. For one, on May 28, 2019, the Public Utility Commission of South Dakota authorized an 8.75% ROE for Otter Tail Power in Docket No. EL 18-021.

Q. WHO WAS THE RATE OF RETURN WITNESS FOR OTTER TAIL POWER IN THAT RATE CASE AND WHAT WAS HIS/HER RECOMMENDATION?

A. Mr. Robert Hevert was the witness for Otter Tail Power in the South Dakota proceeding. Mr. Hevert's recommendation in the South Dakota case was 10.3%

41 *Id.*

42 *Id.* at 5.

43 *Id.* at 6.

Q. ARE YOU AWARE OF ANY STATE REGULATORY BODY IN THE SOUTHEAST THAT HAS RECENTLY ENTERED AN ORDER IN WHICH MR. HEVERT HAS BEEN THE WITNESS FOR THE PETITIONING UTILITY? IF SO, WHAT WAS THE ALLOWED ROE SET BY THAT REGUALTORY BODY?

A. Yes. Mr. Hevert testified in the Duke Energy subsidiary rate cases heard in South Carolina. Mr. Hevert recommended a 10.75% ROE in both cases. However, on May 1, 2019, the South Carolina Public Service Commission ("SCPSC") authorized Duke Energy Progress to earn a 9.50% ROE. On May 21, 2019, the SCPSC authorized Duke Energy Carolinas to earn a 9.50% ROE.

B. O'Donnell Cost of Capital Analysis

1. Economic and Regulatory Policy Guidelines for a Fair Rate of Return

Q. PLEASE EXPLAIN THE CONCEPT OF RISK AND RETURN AND HOW THAT RELATIONSHIP IMPACTS THE COST OF CAPITAL IN UTILITY RATEMAKING.

A. In order for a utility, such as DEC, to provide safe, reliable, and adequate service, it must invest in capital equipment to meet the needs of the citizens and businesses located in its service area. To raise the funds needed for the investments, DEC must ask investors to invest in the

Company by purchasing equity in a company, or to loan it funds by purchasing debt from the Company. Investors will only buy equity in a Company or loan it money if the promised returns for those invested or borrowed funds are commensurate with the level of risk of the Company. As one might expect, the riskier the business, the higher the return investors expect from that investment. Correspondingly, the lower the risk, the lower the cost of capital.

Q. **IS THE OPERATION OF A REGULATED UTILITY CONSIDERED TO BE LOW-RISK, MEDIUM RISK, OR HIGH RISK?**

A. Operating a regulated utility with a defined service territory is considered a low-risk business in that it has a monopoly of such service within its territory and that it can ask for higher rates when it needs or wants more revenue to meet the needs in its service territory.

Q. **IS THERE A WAY TO MEASURE THE RISK OF A UTILITY VERSUS ANOTHER COMPANY OPERATING IN COMPETITIVE MARKETS?**

A. Yes. As will be discussed later in this testimony, beta represents a measure of risk of owning a company relative to the total overall market. Specifically, beta is a measurement of the volatility of one investment relative to the overall volatility in the entire equity market. The overall market has a beta of 1.0. A company with low risk, as measured in volatility, has a beta of less than 1.0, whereas a company with high risk has a beta of greater than 1.0. The concept of beta is a well-known financial tool used in risk assessment and the CAPM for many decades.

Q. WHAT IS THE BETA OF DEC?

A. DEC does not have a beta as it is owned by Duke Energy Corp., which is a utility holding company. Duke Energy Corp., however, has a beta of 0.45, thereby showing it is far less risky than the overall market.

Q. HOW DOES THIS LOW-RISK UTILITY OPERATION TRANSLATE INTO THE EXPECTED RETURN FROM INVESTORS?

A. Investors in a low-risk utility operation should receive a return commensurate with that risk. Specifically, investors in a low-risk utility venture expect returns lower than more risky entities, represented by the total investment opportunities in the marketplace.

Q. DOES THE FACT THAT A UTILITY IS REGULATED POSE ANY RISK TO A UTILITY?

A. No. Despite the fact that regulation involves requirements, such as reporting, and an obligation to serve, a regulated utility has less risk overall. The fact that the utility has the protection of regulation, including the opportunity to recover its cost of service and earn a fair return, is a risk-reducing component of operating a business.

Q. **PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE FAIR RATE OF RETURN THAT UTILITY COMPANIES SHOULD HAVE AN OPPORTUNITY TO EARN.**

A. The theory of utility regulation assumes that public utilities perform functions that are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. Even though deregulation for the procurement of natural gas and generation of electric power and energy is spreading, delivery of these products to end-use customers is still a monopoly business and will, for the foreseeable future, be regulated. On this basis, state legislatures or Commissions establish exclusive franchised territories to public utilities or determine territorial boundaries where disputes arise, in order for these utilities to provide services more efficiently and at the lowest reasonable cost. In exchange for the protection within its monopoly service area, the utility is obligated to provide adequate, universal service at fair, regulated rates.

Q. WHAT CONSTITUTES A JUST AND REASONABLE RATE OF RETURN?

A. The generally accepted answer is that a prudently managed electric utility should be allowed to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a fair rate of return on invested capital. This just and reasonable rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators. If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise new investment or working capital on reasonable terms. Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the fair rate of return for a utility.

Q. PLEASE SUMMARIZE THE LEGAL STANDARDS FOR DETERMINING A UTILITY RATE OF RETURN.

A. Although I am not a lawyer, based on my experience, I have come to understand certain basic legal tenets regarding rate of return determinations. Regulatory law and policy recognize that utilities compete with other firms in the market for investor capital. The United States Supreme Court set the guidelines for a fair rate of return in two often-cited seminal cases: *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692; (1923) ("*Bluefield*") and the *Federal Power Comm'n v. Hope Natural Gas Co.*,. 320 U.S. 591, 603 (1944) ("*Hope Natural Gas*").

In the *Bluefield* case, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[44]

In the above finding, the Court found that utilities are entitled to earn a return on investment similar to companies of comparable risks and that the corresponding return should be sufficient enough to support credit activities and to raise funds to carry out its mission. In *Hope Natural Gas*, the U.S. Supreme Court also recognized that utilities compete with other firms in the market for investor capital.

44 *Bluefield*, 262 U.S. at 692.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE HOPE NATURAL GAS CASE AS IT APPLIES TO THE CURRENT RATEMAKING PURPOSES?

A. Over the years, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn. In *Hope Natural Gas*, the U.S. Supreme Court stated that the return to equity owners (or shareholders) of a regulated public utility should be "commensurate" to returns on investments in *other* enterprises whose "*risks* correspond" to those of the utility being examined:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital.[45]

The *Hope Natural Gas* case is still the guideline for ratemaking. Specifically, the guideline set by the Commission is to ensure that the returns set by regulatory bodies are commensurate with risks of like-investments.

Q. HAS THE HOPE/BLUEFIELD STANDARD BEEN ADOPTED BY THE COMMISSION?

A. Yes. This Commission has emphasized that a rate of return on common equity must fall within the range of reasonableness under the

[45] *Hope Natural Gas*, 320 U.S. at 603.

Commission's statutory authority to set just, reasonable, and nondiscriminatory rates.[46] The Commission has previously approved standards such as these described by the D.C. Court of Appeals, as follows:

> The Commission, not this court, has the responsibility for establishing rate designs and for setting specific utility rates . . . . Rate design principles and specific rates approved by the Commission, however, must be "reasonable, just, and nondiscriminatory." . . . This statutory authority is deliberately broad and gives the Commission authority to formulate its own standards and to exercise its ratemaking function free from judicial interference, provided the rates fall within a zone of reasonableness which assures that the Commission is safeguarding the public interest that is, the interests of both investors and consumers . . . . From the investor standpoint, courts have defined the lower boundary of this zone of reasonableness as "one which is not confiscatory in the constitutional sense." . . . From the consumer standpoint, the upper boundary cannot be so high that the rate would be classified as "exorbitant."[47]

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE LEGAL PRECEDENT DESCRIBED IN THIS TESTIMONY?

Yes. I want to reiterate and make clear that I am a financial analyst and not an attorney. As such, all descriptions of relevant law included in this testimony are my personal interpretations and I am not offering legal advice.

46 *See Formal Case No. 1139*, Order No. 18846¶ 276, July 25, 2017 at p. 87; *Formal Case No. 1093*, Order No. 17132 ¶ 40, May 15, 2013 , at p. 16,.

47 *See, e.g.*, In the Matter of the Application of Potomac Electric Power Co. for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, Formal Case No. 1139, Opinion and Order No. 18846 (Jul. 25, 2017) at P 276, citing *Metropolitan Board of Trade v. Pub. Serv. Comm'n of the District of Columbia*, 432 A.2d 343, 350 (D.C. 1981).

2. Current State of the Financial Markets

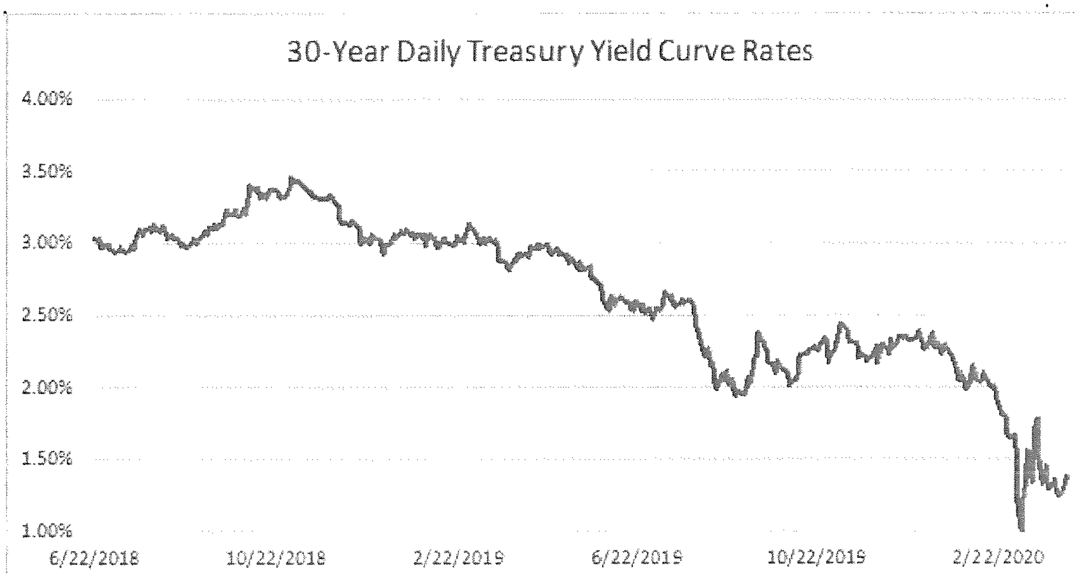
Q. HOW HAS THE DEBT MARKET FOR DEC CHANGED SINCE THE COMPANY'S LAST RATE CASE?

A. The Company's last rate case was in 2018 and a final order was issued on June 22, 2018. Long-term interest rates have fallen since the Company's last rate case.[48] In Chart 6 below, I have provided the change in the 30-year U.S. Treasury bonds since June 22, 2018. On that date, the yield on 30-year U.S. Treasury bonds was 3.04%. As of April 9, 2020, the yield on 30-year U.S. Treasury bonds was 1.35%, which equates to a 169 basis point decrease in the yield on 30-year U.S. Treasury bonds. This drop in interest rates implies the cost of capital has fallen significantly since DEC's last rate case, thereby indicating the Company's cost of capital is lower in 2020 than it was in 2018.

Chart 6: Yield on 30-Year U.S. Treasury Bonds[49]

48 S&P Global, Rate Case History, available at snl.com (data retrieved January 21, 2020).

49 U.S. Department of Treasure, *Daily Treasury Yield Curve Rates*, available at **https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2018-2020** (data for 2018, 2019, and 2020 retrieved April 10 2020).



Q. HAS THE FEDERAL RESERVE RECENTLY LOWERED INTEREST RATES?

A. Yes, on September 18, 2019, the Federal Reserve decreased the Federal Funds target range to 1.75% from 2.0%.[50] On October 30, 2019, the Federal Reserve lowered the target federal funds rate to 1.5% from 1.75%.[51] In its mid-December meeting, the Federal Reserve chose not to change interest rates.[52]

50 *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Sept. 18, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20190918a.htm.

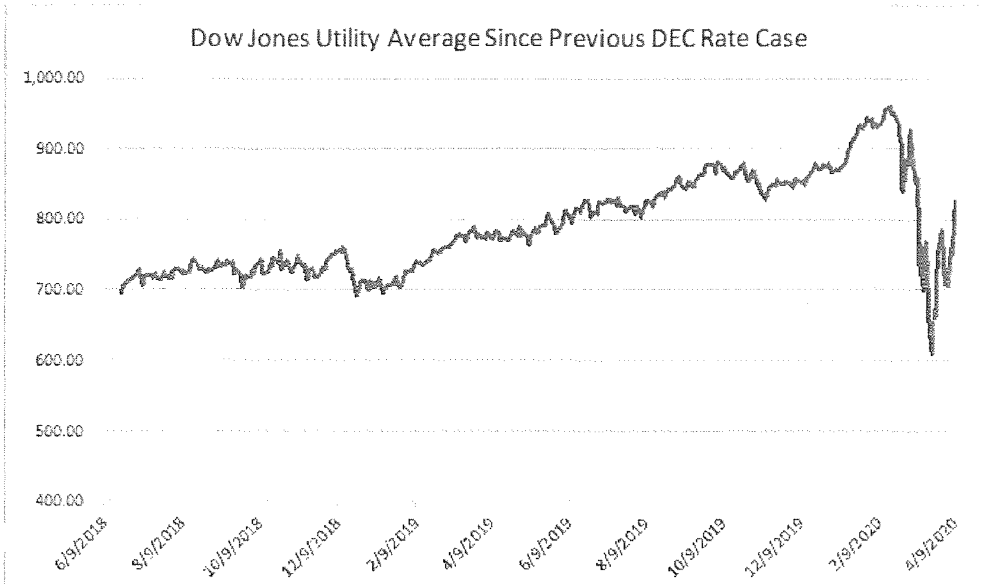
51 *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Oct. 30, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20191030a.htm.

52 *See* Board of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Dec. 11, 2019), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20191211a.htm.

Q. HOW HAS THE STOCK MARKET FOR UTILITIES CHANGED SINCE THE COMPANY'S LAST RATE CASE?

A. Since June 22, 2018, the Dow Jones Utility Average has risen from 696.60 to 827.83, as of April 9, 2020. This meteoric rise in the utility index equates to a return of 18.8% since the Company's last rate case. Chart 7 below provides the Dow Jones Utility Average over this time period and, without a doubt, shows how utility investors continue to bid up utility stock prices for known future payouts in future dividends, thereby, on a pure mathematical basis, proving that ROEs are declining.

Chart 7: Dow Jones Utility Average Since Last DEC Rate Case[53]



Q. WHEN WAS THE LAST ELECTRIC RATE CASE HEARD BY THIS COMMISSION AND WHAT ROE CAME FROM THAT CASE?

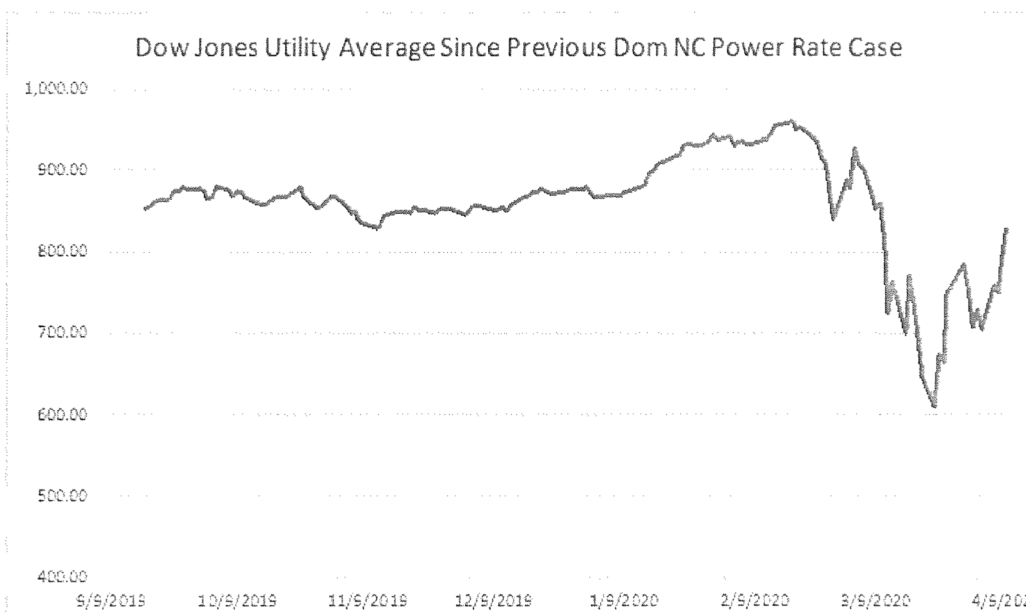
A. On Sept. 17, 2019, the Public Staff and Dominion North Carolina Power filed a joint settlement agreement whereby the parties agreed to a 9.75% ROE.

Q. DO YOU BELIEVE THE COMMISSION SHOULD AWARD DEC A 9.75% ROE IN THIS CASE?

53 Yahoo Finance, https://finance.yahoo.com/ (data retrieved April 10, 2020).

A. Absolutely not. Chart 8 below shows the tremendous runup in the Dow Jones Utility Average since the Sept. 17, 2019 settlement between the Public Staff and Dominion NC Power. Accepting a ROE of 9.75% would ignore the tremendous increase in the equity markets since the settlement between the Public Staff and Dominion NC Power. Acceptance of such a high ROE would be grossly unfair and unjust to consumers in NC who would be forced to pay higher rates for a ROE that is not current, fair, or balanced.

Chart 8: Dow Jones Utility Average Since Dom NC Power Rate Case[54]



54 Yahoo Finance, https://finance.yahoo.com/ (data retrieved April 10, 2020).

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE CURRENT CAPITAL MARKET?

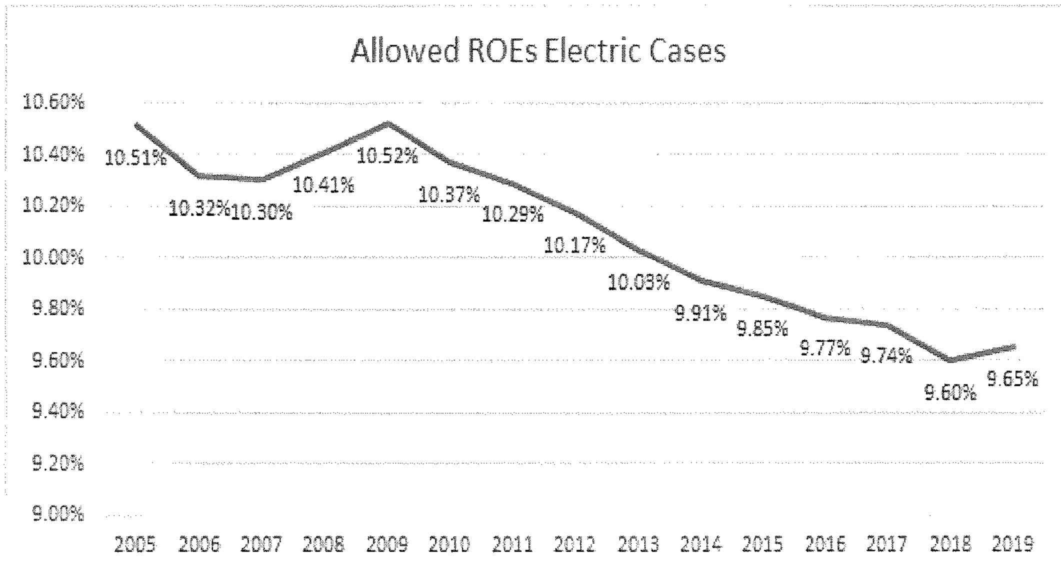
A. In its mid-December meeting, the Federal Reserve chose not to change interest rates and indicated that it would pause interest rate changes in 2020.[55] The United States Gross Domestic Product ("GDP") continues to hover right around 2.0%, thereby showing solid and steady, but not spectacular, growth in our economy.

Q. HOW DOES THE COMPANY'S REQUEST IN THIS CASE COMPARE TO THE OVERALL TREND IN ALLOWED ROEs?

A. As this Commission is likely aware, regulated ROEs have trended down over the past 15 years. In Chart 9 below, I have provided a chart that shows the ROEs allowed for electric utilities by state regulators across the United States from 2005 through 2019.

55 *See* Heeb, G., *Fed leaves interest rates unchanged, signals it will pause through 2020*, Markets Insider (Dec, 11, 2019), available at: https://markets.businessinsider.com/news/stocks/federal-reserve-interest-rate-decision-unchanged-signals-pause-in-2020-2019-12-1028756431

Chart 9: Allowed ROEs 2005 – 2019[56]



As for the most recent year, 2019, the overall allowed ROE for electric utilities was 9.65%,[57] which included a recent ruling from the nearby Virginia State Corporation Commission which authorized a 9.2% ROE for Dominion Virginia Power[58] Given that interest rates appear to be on-track for a period of sustained low rates and the stock market is showing no signs of any significant slowdown, I believe allowed ROEs will continue to fall as regulators recognize the lower rates of return facing investors across the investment spectrum.

56 S&P Global Market Intelligence, *RRA Regulatory Focus Major Rate Case Decisions* –, (data retrieved March 16, 2019) (source for raw data)

57 S&P Global, Rate Case History, available at snl.com (data retrieved March 16, 2020).

58 Virginia SCC Final Order, Case No. PUR-2017-00038, *Application of Virginia Electric and Power Company For the Determination of the Fair Rate of Return on Common Equity to be Applied to its Rate Adjustment Clauses* (November 29, 2017) at p. 4

3. Development of DEC's Proxy Group

Q. **COULD YOU PERFORM A COST OF EQUITY ANALYSIS DIRECTLY ON DEC?**

A. No. DEC is a wholly-owned subsidiary of Duke Energy Corp. Since DEC's stock is not publicly traded, I could not develop a cost of equity specifically for DEC. For that reason, I developed a proxy group of companies to assess the risk and corresponding return for DEC.

Q. **PLEASE EXPLAIN HOW YOU DEVELOPED A PROXY GROUP FOR DEC.**

A. I used the following parameters for developing a proxy group of similarly situated companies to DEC from which to derive a just and reasonable ROE:

1. All companies must be followed by the Value Line Investment Survey ("Value Line") as an electric utility;
2. All companies must derive at least 50% of their 2018 revenues from regulated utilities;
3. All companies have an investment grade credit rating;
4. No company can be in the midst of merger or acquisition discussions;
5. All companies must have at least 5 years of historical data; and
6. All companies must have paid a dividend each quarter in the past year.

Q. PLEASE EXPLAIN THE REASONING FOR THE FIRST PARAMETER IN THE CREATION OF YOUR COMPARABLE GROUP.

A. The *Value Line Investment Survey* is, in my opinion, the most trusted and referenced financial information publication in today's marketplace. Value Line provides a tremendous amount of information, both on a historical basis and on a forecasted basis. I focused solely on electric utilities as followed by Value Line. In today's world of large utility holding companies, it is virtually impossible to find a comparable group of large utilities that are well followed by the investment community that contain only electric utilities.

Q. PLEASE EXPLAIN THE REASONING FOR THE SECOND PARAMETER.

A. The second parameter requires that the utility obtain at least 50% of its revenues from regulated operations. Again, in today's world of utility holding companies, many companies have unregulated generation affiliates or other such subsidiaries, which is why this screen is important.[59] I used a threshold of 50% revenues to screen just for

59 My revenue threshold screen runs somewhat parallel to Mr. Hevert's decision to examine regulated operating income. *See* Exhibit Pepco (G) (Hevert) at 18:3-6.

regulated utility operations in order to ensure the level of risk for the comparable group was consistent with low-risk utility operations.

Q. PLEASE EXPLAIN THE REASONING FOR THE THIRD PARAMETER.

A. The third parameter includes companies with only investment grade credit ratings to ensure that no companies that are currently in, or close to, bankruptcy would be included in the group. The reason for the exclusion of companies in bankruptcy is that bankruptcy adds an element of risk that is counter to the low-risk nature of a utility, such as DEC. Companies that continue to operate in bankruptcy proceedings are, generally, much more risky than those that are not in bankruptcy.

Q. PLEASE EXPLAIN THE REASONING FOR THE FOURTH PARAMETER.

A. For the fourth parameter, I excluded companies that are in the midst of merger or acquisition discussions as stock prices for those utilities often operate based on immediate financial gain instead of long-term operating abilities. This has the effect of distorting the DCF returns as short-term capital gains becomes part of the pricing process.

Q. PLEASE EXPLAIN THE REASONING FOR THE FIFTH PARAMETER.

A. I believe investors' confidence is strengthened with historical information from which they can gather and assess trends. When a company does not have such history, I don't feel it is truly comparable to a company, such as Pepco, that does have such a long track record.

Q. PLEASE EXPLAIN YOUR SIXTH PARAMETER

A. Finally, I required all companies in my proxy group to have consistently paid dividends over the past year, with no cuts. The reason for this parameter is to ensure the utility's stock price is reacting to long-term operating characteristics and not in reaction to short-term dividend payments.

Q. DOES DEC MEET ALL THE PARAMETERS AS SET FORTH IN YOUR COMPARABLE GROUP GUIDELINES?

A. DEC does not meet all of the above-stated guidelines because it is a wholly-owned subsidiary of Duke Energy Corp. However, these guidelines do reflect the relatively low-risk nature of utility operating companies and are, therefore, comparable to DEC in their operating natures.

Q. DID YOU PERFORM A COST OF EQUITY ANALYSIS ON ANY OTHER PROXY GROUP INTRODUCED IN THIS CASE?

A. Yes, I also used the Hevert proxy group in my cost of equity analysis in this case. Specifically, I subjected the Hevert proxy group to my cost of capital analysis in the same manner as I did with the O'Donnell proxy group.

Q. **IS DUKE ENERGY PART OF MR. HEVERT'S COMPARABLE GROUP?**

A. No, for the reasons stated above, DEC is not part of Mr. Hevert's comparable group in that it is a subsidiary of Duke Energy and does not have publicly traded stock.

Q. **WHY DID YOU ALSO ANALYZE THE HEVERT PROXY GROUP AS PART OF YOUR COST OF CAPITAL ANALYSIS IN THIS CASE?**

A. I analyzed the Hevert proxy group to provide the Commission with as much information as possible on which to make its decision. The addition of the Hevert proxy group to my analysis also provides a benchmark on which to check the O'Donnell proxy group and assists in providing a complete and robust analysis.

4. Cost of Common Equity

Q. **PLEASE EXPLAIN HOW THE ISSUE OF DETERMINING AN APPROPRIATE RETURN ON A UTILITY'S COMMON EQUITY**

INVESTMENT FITS INTO A REGULATORY AUTHORITY'S DETERMINATION OF JUST AND REASONABLE RATES FOR THE UTILITY.

A. In North Carolina, as in virtually all regulatory jurisdictions, a utility's rates generally must be "just and reasonable." Thus, regulation recognizes that utilities are entitled to an opportunity to recover the reasonable and prudent costs of providing service, and the opportunity to earn a fair rate of return on the capital invested in the utility's facilities, such as electric distribution equipment, buildings, vehicles, and similar long-lived capital assets.

Q. HOW DOES THE MANNER IN WHICH UTILITIES OBTAIN CAPITAL FUNDING RELATE TO THE COMMISSION'S DETERMINATION OF THE APPROPRIATE COST OF CAPITAL FOR A SPECIFIC UTILITY?

A. Utilities obtain capital funding through a combination of borrowing (debt financing) and issuing stock (equity financing). The allowed ROE is the amount that is determined to be just and reasonable for the utility's common stockholders to earn on the capital that they invest in the utility when they buy its stock when balanced against the interests of ratepayers to avoid overpaying to allow the company with access to capital. If the regulatory authority sets the ROE too low, the stockholders will not have the opportunity to earn a fair return and this may either cause existing shareholders to sell their shares or deter new investors from buying shares. If, on the other hand, the regulatory authority sets the ROE too high, the ratepayers will pay too much. Because ratepayers cannot choose a different utility due to the monopolistic service territory restrictions, countervailing competitive market forces are absent and the resulting rates will be unjust and unreasonable to the ratepayer.

Q. **HOW IS THE ESTIMATED SHARE PRICE USED IN DETERMINING THE LEVEL OF A UTILITY'S ALLOWED EARNINGS?**

A. A cost of capital model, such as the DCF, uses current stock price values to determine the return that investors expect from that stock. The relationship between stock prices are inversely related in that when stock prices go up, the expected returns go down. The opposite is also true in that, when stock prices go down, returns go up. As a result, utility stock prices have a direct and immediate bearing on the return allowed by state regulators.

Q. **HOW DO REGULATORY AUTHORITIES GO ABOUT DETERMINING A JUST AND REASONABLE RATE OF RETURN ON EQUITY FOR A UTILITY COMPANY?**

A. Regulatory commissions and boards, as well as financial industry analysts, institutional investors, and individual investors, use different analytical models and methodologies to estimate/calculate reasonable rates of return on equity, including the DCF model and the Capital Asset Pricing Model ("CAPM").

Q. CAN YOU EXPLAIN WHY REGULATORY AUTHORITIES AND FINANCIAL ANALYSTS NEED TO USE SUCH METHODOLOGIES TO DERIVE A COMPANY'S ESTIMATED RATE OF RETURN ON EQUITY?

A. Yes. There is no direct, observable way to determine the rate of return required by equity investors in any company or group of companies. Investors must make do with indications from market data and analysts' predictions to estimate the appropriate price of a share.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE DCF MODEL IS SUPERIOR TO OTHER APPROACHES.

A. The DCF is a pure investor-driven model that incorporates current investor expectations based on daily and ongoing market prices. When a situation develops in a company that affects its earnings and/or perceived risk level, the price of the stock adjusts immediately. Since the stock price is a major component in the DCF model, the change in risk level and/or earnings expectations is captured in the investor return requirement with either an upward or downward movement to account for the change in the company.

This stands in stark contrast to book-based methodologies that are based on earned returns from book equity, not market equity. In these models, there is no direct and immediate stockholder input and thus, has no bearing on stockholder expectations.

a. **Discounted Cash Flow Model.**

Q. PLEASE EXPLAIN THE DISCOUNTED CASH FLOW MODEL.

A. The DCF method is a widely used method for estimating an investor's required return on a firm's common equity. In my thirty-four years of experience, first with the Public Staff of the North Carolina Utilities Commission and later as a consultant, I have seen the DCF method used much more often than any other method for estimating the appropriate return on common equity. Consumer advocate witnesses, utility witnesses and other intervenor witnesses have used the DCF method, as do many regulators, including the Federal Energy Regulatory Commission, either by itself or in conjunction with other methods such as the CAPM, in their analyses.

The DCF method is based on the concept that the price which the investor is willing to pay for a stock is the discounted present value (*i.e.*, its present worth) of what the investor expects to receive in the future as a result of purchasing that stock. This return to the investor is in the form of future dividends and price appreciation. However, price appreciation is only realized when the investor sells the stock, and a subsequent purchaser presumably is also focused on dividend growth following his or her purchase of the stock. Mathematically, the relationship is:

Let D = dividends per share in the initial future period

g = expected growth rate in dividends

k = cost of equity capital

P = price of asset (or present value of a future stream of dividends).

$$\text{then } P = \frac{D}{(1+k)} + \frac{D(1+g)}{(1+k)^2} + \frac{D(1+g)}{(1+k)^3} + \ldots\ldots + \frac{D(1+g)}{(1+k)^t}$$

This equation represents the amount (P) an investor will be willing to pay *today* for a share of common equity with a given dividend stream over (t) periods.

Reducing the formula to an infinite geometric series, we have:

$$P = \frac{D}{k-g}$$

Solving for k yields:

$$k = \frac{D}{P} + G$$

Q. MR. O'DONNELL, DO INVESTORS IN UTILITY COMMON STOCKS REALLY USE THE CONSTANT GROWTH DCF MODEL IN MAKING INVESTMENT DECISIONS?

A. Yes, I believe that to be so. There are three primary reasons for my conclusion. First, there is extensive literature that supports the fact that, while so-called "irrational" behavior in the short term may affect (and has affected) share prices, over the long term a company's financial fundamentals drive the market.[60] Second, analysts give great weight to earnings, dividend, and book value growth in formulating their recommendations to clients. Finally, even a casual search on the internet produces hundreds of pages discussing the definition of the DCF methodology and how to apply it for investment decisions, from which I infer that general investor interest in DCF analysis is significant and widespread.

Thus, in today's investment environment, a stock investor will likely calculate (or seek a calculation of) the amount of funds he/she will receive relative to the initial investment, which is defined as the current dividend yield, as well as the amount of funds that the investor can expect in the future from the growth in the dividend.

The combination of the current dividend yield and the future growth in dividends is central to the basic tenet of the DCF model.

Q. IS THE DCF FORMULA EASY TO UNDERSTAND?

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60 *See, e.g.*, Koller, T. et al., *Valuation: Measuring and Managing the Value of Companies*, 4th Edition, McKinsey & Company (2010) ("Provided that a company's share price eventually returns to its intrinsic value in the long run, managers would benefit from using a discounted-cash-flow approach for strategic decisions. What should matter is the long-term behavior of the share price of a company, not whether it is undervalued by 5 or 10 percent at any given time."); see also Goedhart, M. et al., *Do fundamentals—or emotions—drive the stock market?*, McKinsey & Company, (March 2005), available at: **http://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/do-fundamentalsor-emotionsdrive-the-stock-market;** Weisenthal, J., *And Now We Know For Sure What's Really Been Driving The Market The Last Few Years...*, Business Insider (Aug. 15, 2012), available at: **http://www.businessinsider.com/what-drives-the-stock-market-2012-8**.

A. Yes. While the DCF formula stated above may appear complicated, it is intuitively a very simple model to understand. To determine the total rate of return one expects from investing in a particular equity security, the investor adds the dividend yield, which he or she expects to receive in the future, to the expected growth in dividends over time. If the regulatory authority sets the rate at a level consistent with the foundational principles established in *Hope Natural Gas* and *Bluefield*, the utility will be able to attract capital, without forcing the utility's customers to pay more than necessary to attract needed capital.

Q. CAN YOU GIVE AN EXAMPLE?

A. Yes. If investors expect a current dividend yield of 5%, and also expect that dividends will grow at 4% for a particular utility, then the Constant Growth DCF model indicates that investors would buy the utility's common stock if it provided a return on equity of 9%.

Q. WHAT DIVIDEND YIELD DO YOU THINK IS APPROPRIATE FOR USE IN THE DCF MODEL?

A. Because the DCF formula relies upon the expected dividend yield in deriving investor expectations, I have calculated the appropriate dividend yield by averaging the dividend yield expected over the next 12 months for each proxy company, as reported by the <u>Value Line Investment Survey.</u> For purposes of my calculation, I relied on the values reported for the period of January 17, 2020 through April 10, 2020 by Value Line. In order to study the short-term as well as long-term movements in expected dividend yields, I incorporated the 13-week, 4-week, and 1-week average dividend yields expected over the next 12 months as reported by Value Line for each of the proxy groups. My results appear in Exhibit KWO-1, showing a range of 3.2% to 3.7% across all study periods for the O'Donnell proxy group. Exhibit KWO-5 shows a range of 3.1% to 3.6% across the same study period range.

It is important to note that my calculations as described above provide the forecasted annual dividend yields, exactly as prescribed by the DCF model. The Value Line forecasted dividend yield represents the Value Line expected dividend to-be paid over the next 12 months divided by the current price.[61]

Q **HOW DID YOU DEVELOP THE SPECIFIC DIVIDEND YIELD RANGES DISCUSSED ABOVE?**

A. Each week, Value Line issues a Summary and Index report that provides the estimated yield over the next 12 months, as noted above, for the stocks it follows. To develop the market expectation of the dividend yield over the next year, I averaged these weekly expected yield values over three time periods: 13-weeks; 4 weeks; and 1-week. This range of time periods captures investor sentiment over a long-time period (13-weeks), a middle time period (4-weeks), and the most recent time period (1-week).

Q. **HOW DID YOU DERIVE THE EXPECTED GROWTH RATE FOR YOUR DCF ANALYSIS?**

61 Value Line, *Glossary* (last viewed, Jan. 20, 2020) available at: https://www.valueline.com/Glossary/GlossaryDisplay.aspx?taxonomyid=4294967301.

A. I used five different methods in determining the growth in dividends that investors expect. These five methods, in my opinion, give a wide range of investor expectations and, therefore, reflect the market's understanding of the underlying securities. Specifically, these five methods examine earnings, dividends, and book value growth over a 5-year and 10-year period, as well as several forecasts of earnings, dividends, and book value. Such a holistic approach to Company financial details provides the Commission with the best perspective of investment opportunities.[62] These five methods provide me a solid reference of investor expectations in regard to future dividend growth expectations that are the second element in the DCF model.

Q. PLEASE DESCRIBE THE FIRST METHOD YOU USED TO DETERMINE GROWTH RATE.

A. The first method I used was an analysis commonly referred to as the "plowback ratio" method. If a company is earning a rate of return (r) on its common equity, and it retains a percentage of these earnings (b), then each year the earnings per share (EPS) are expected to increase by the product (br) of its EPS in the previous year. Therefore, br is a good measure of growth in dividends per share. For example, if a company earns 10% on its equity and retains 50% (the other 50% being paid out in dividends), then the expected growth rate in earnings and dividends is 5% (50% of 10%). To calculate a plowback for the proxy group, I used the following formula:

62 In contrast, Pepco witness Hevert offers testimony attempting to limit the Commission's review to only forecasted earnings growth rates.

$$g = \frac{br(2017) + br(2018) + br(2019/2019E) + br(2022E\text{-}2025E\ Avg)}{4}$$

The 2022E to 2025E referenced above represents the average plowback estimate over the time period of 2022 through 2024 or 2023 through 2025 dependent upon the Company. While this estimate incorporates a period of 3 years, the above-stated formula provides a single estimate for this time period that is incorporated with the actual plowback values for 2017 and 2018 as well as the expected or actual plowback ratio for 2019. The plowback estimates for all companies in the proxy group can be obtained from The Value Line Investment Survey under the title "percent retained to common equity." Exhibit KWO-2 lists the plowback ratios for each company in the proxy group.

A key component in the DCF Method is the expected growth in dividends. In analyzing the proper dividend growth rate to use in the DCF Method, the analyst must consider how dividends are created. Over the long term, dividends cannot be paid out without a corporation having sufficient earnings to pay for the dividends. Put another way, over the long-term, dividends cannot consistently outpace earnings as, if they do, the corporation cannot sustain the dividend payments. As a result, earnings growth is a key element in analyzing what if any growth can be expected in dividends. Similarly, what remains in a corporation after it pays its dividend is reinvested, or "plowed back", into a corporation in order to generate future growth. As a result, book value growth is another element that, in my opinion, must be considered in analyzing a corporation's expected dividend growth.

Q. PLEASE DESCRIBE THE SECOND METHOD YOU USED TO DETERMINE GROWTH RATE.

A. To analyze the expected growth in dividends, I believe the analyst should first examine the historical record of past earnings, dividends, and book value. Hence, the second method I used to estimate the expected growth rate was to analyze the historical 10-year and 5-year historical compound annual rates of change for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BPS") as reported by <u>Value Line</u> for each of the relevant corporations.

<u>Value Line</u> is the most recognized investment publication in the industry and, as such, is used by professional money managers, financial analysts, and individual investors worldwide. A prudent investor tries to examine all aspects of an enterprise's performance when making a capital investment decision. As such, it is only practical to examine historical growth rates for the corporation for which the analysis is being performed. The historical growth rates for the O'Donnell proxy group can be seen in Exhibit KWO-1 and in Exhibit KWO-5 for the Hevert comparable group.

Some analysts do not present historical growth rates in their DCF analyses. I believe analysts that do not present such available data fail to completely inform the respective regulatory bodies of the full extent of information on which investors base their expectations. As the old saying goes, "history has a way of repeating itself."

Q. PLEASE DESCRIBE THE THIRD METHOD YOU USED TO DETERMINE GROWTH RATE.

A. The third method I used was to rely upon the Value Line forecasted compound annual rates of change for earnings per share, dividends per share, and book value per share.

Q. PLEASE DESCRIBE THE FOURTH METHOD YOU USED TO DETERMINE GROWTH RATE.

A. The fourth method I used relied upon the forecasted rate of change for earnings per share as recorded by Center for Financial Research ("CFRA"), a publication of S&P Global Market Intelligence.

Q. PLEASE DESCRIBE THE FIFTH METHOD YOU USED TO DETERMINE GROWTH RATE.

A. The last method was another forecasted earnings growth rate as reported by the Charles Schwab & Co. This forecasted rate of change is not a forecast supplied by Charles Schwab & Co. but is, instead, a compilation of forecasts by industry analysts.

The details of my constant growth DCF analysis can be seen in Exhibit KWO-1 for the O'Donnell Comparable Group.

Q. WHAT ARE THE DIVIDEND YIELD RANGES FROM THE DCF ANALYSIS FOR THE O'DONNELL PROXY GROUP?

A. As shown on Exhibit KWO-1, the expected dividend yield over the next 12 months as derived by for the average over the three time-frames discussed above (*i.e.*, 13-weeks. 4-weeks, and 1-week) range from 3.2% to 3.7%. For the Hevert comparable group, the dividend yield over the same time periods was 3.1% - 3.6%.

Q. WHAT ARE THE GROWTH RATE RANGES FROM THE DCF ANALYSIS FOR THE O'DONNELL PROXY GROUP?

A. In terms of the growth rates, the proxy group has grown at a solid and steady pace. Over the past 10-years, the proxy group has grown in the range of approximately 3.7% (Value Line 5-year earnings per share (EPS)) to 6.1% (Value Line 5-year DPS). The forecasted growth rates for the proxy group trend higher than the historical growth rates and are in the range of 4.8% (Value Line Forecasted BPS) to 5.7% (CFrA Forecasted EPS). The plowback growth rate average for the comparable group is 3.7%.

As for the proper dividend growth rate to employ for the comparable group in the DCF analysis, it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future. An examination of the 10-year and 5-year historical growth rates for the proxy group shows that dividends have been growing slightly faster than earnings. Dividends cannot, however, sustain a higher growth rate than earnings over the long-term as, eventually, there will not be sufficient earnings to pay dividends. The market expects this situation to self-correct in the future as the Value Line forecasted earnings and dividends for the group are 5.4% and 5.5%, respectively.

Based on these results, I believe the proper growth rate range to use in the DCF model for the comparable group is 4.0% to 6.0%. The low-end (4.0%) of this range is significantly above the low point (3.7% for 5-year EPS) of the range of results. The high end (6.1%) of the range is slightly higher than any of the high-end growth rates as found on Exhibit KWO-1. By using a range of results well above the very low points of the range of results and slightly higher than the high points of the DCF results, the DCF results are, if anything, favorable to the Company.

Q. **WHAT ARE THE GROWTH RATE RANGES FROM THE DCF ANALYSIS FOR THE HEVERT PROXY GROUP?**

A. Over the past 10-years, the Hevert proxy group has grown in the range of approximately 4.5% (Value Line 10-year book value per share (BPS)) to 6.3% (Value Line 5-year DPS). The forecasted growth rates for the proxy group trend higher than the historical growth rates and are in the range of 4.7% (Value Line Forecasted BPS) to 6.1% (CFrA Forecasted EPS).

The plowback growth rate average for the Hevert comparable group is 3.5%.

Based on these results, I believe the proper growth rate range to use in the DCF model for the comparable group is 4.0% to 6.0%. The low-end (4.0%) of this range is below the low point (4.5% for 10-year BPS) of the range of results. The high end (6.0%) of the range is slightly below the high-end growth of 6.3% for the 5-year Value Line DPS.

Q. IN LIGHT OF ACADEMIC LITERATURE THAT QUESTIONS THE ACCURACY OF ANALYST FORECASTS, HAVE YOU TAILORED THE IMPLEMENTATION OF THE DCF METHODOLOGY?

A. In the June/July, 1999 edition of the Journal of Business Finance and Accounting, Richard D.F. Harris authored a study entitled "The Accuracy, Bias and Efficiency of Analysts' Long Run Earnings Growth Forecasts." His conclusions regarding analyst forecasts were, in part, as follows:

1. the accuracy of forecasts was extremely low;
2. analyst forecasts are overly optimistic; and
3. forecasts by analysts are inefficient.[63]

In November, 2003, Louis K. C. Chan, Jason Karceski and Josef Lakonishok published an article entitled "Analysts' Conflict of Interest and Biases in Earnings Forecasts" in the Journal of Finance. The conclusion of the paper stated:

> ...it is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic.[64]

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63 *The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts*, Journal of Business Finance & Accounting, at 751 (June/July 1999).

64 Chan, L. et al., *The Level and Persistence of Growth Rates*, Journal of Finance, at 683 (2003).

In 2010, Marc H. Goedhart, Rishi Raj, and Abhishek Saxena wrote "Equity analysts: Still too bullish" that was published in McKinsey on Finance. The article stated:

> No executive would dispute that analysts' forecasts serve as an important benchmark of the current and future health of companies. To better understand their accuracy, we undertook research nearly a decade ago that produced sobering results. Analysts, we found, were typically overoptimistic, slow to revise their forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined.[65]

In June, 2007, in the Journal of Accounting Research, Peter D. Easton and Gregory A. Sommers wrote a paper entitled "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts".

> We show that, on average, the difference between the estimate of the expected rate of return based on analysts' earnings forecasts and the estimate based on current earnings realizations is 2.84%. When estimates of the expected rate of return in the extant literature are adjusted to remove the effect of optimistic bias in analysts' forecasts, the equally weighted estimate of the equity risk premium appears to be close to zero.[66]

As can be seen in these academic articles and contrary to the statement as provided by Mr. Hevert, the concept that analysts provide accurate expectations for investors is still a highly debated topic.

To mitigate the problems as cited above, I have presented EPS, DPS, and BPS figures to the Commission and systematically explained my rationale for arriving at the above stated growth rates. I believe it is incumbent upon

65 *Equity Analysts, Still Too Bullish*, McKinsey on Finance, at 14 (Spring 2010).

66 *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, Journal of Accounting Research, at 1012 (December, 2007).

every analyst presenting testimony in this case to present such a robust analysis to the Commission.

Q. SHOULD ONLY EARNINGS GROWTH RATES IN THE DCF METHODOLOGY BE USED?

A. No. Since the DCF formula is dependent on future dividend growth, it would be inaccurate to use only earnings growth rates in the DCF. Doing so produces unrealistically high ROE numbers that cannot be sustained in real life.

Q. WHAT IS THE DCF RANGE THAT YOUR ANALYSES PRODUCED?

A. Combining the O'Donnell proxy group's dividend yield of 3.2 to 3.7% with the growth rate range of 4.0% to 6.0% produces a DCF range of 7.2% to 9.7%.

In repeating the same process for the Hevert proxy group, the group's 3.1-3.6% dividend yield is combined with the same 4.0% to 6.0% growth rate range found appropriate in the O'Donnell group to arrive at the same DCF estimate for the Hevert group as that of the O'Donnell group: 7.0% to 10.0%.

Due to the similar results of both groups, I view this as further validation for my recommendation. I believe the proper DCF range is 7.0% to 10.0%.

b Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL.

A. The CAPM is a risk premium model that determines a firm's ROE relative to the overall market return on equity. The formula for the CAPM is as follows:

ROE = Rf + Beta [E(RM) – Rf]; where:

ROE is the return on equity;

Rf is the risk-free rate;

Beta is the risk of the studied company relative to the overall market; and

E(RM) is the expected return on the market.

To be specific, the CAPM is a measure of firm-specific risk, known as unsystematic risk and measured by beta, as well as overall market risk, otherwise known as systematic risk and measured by the expected return on the market.

The CAPM calculates ROE based on a company's risk and can be restated as follows:

ROE = Rf + (Beta * Risk Premium)

Where Risk Premium represents the adjusted company-specific risk of the company.

Q. HOW IS THE RISK-FREE RATE MEASURED?

A. The risk-free rate is designated as the yield on United States government bonds because the risk of default is seen as highly unlikely (*i.e.*, "risk-free"). Utility witnesses and consumer witnesses regularly use United States government bond yields as the risk-free rate in the CAPM. However, what is often debated in the risk-free portion of the CAPM is the term of those bonds. In my analysis for this case, I have developed risk premiums relative to the 30-year U.S. Treasury bonds as this time period is the longest available in the marketplace, thereby affording consumers the longest protection at the risk-free rate. Notably, this is also the proxy used by the Federal Energy Regulatory Commission to determine the risk-free rate in the CAPM.[67] Chart 7, which I provided earlier in this testimony, provides the yield on 30-year U.S. Treasury bonds over the past year.

Q. IS THE CURRENT LEVEL OF INTEREST RATES EXPECTED TO CHANGE MATERIALLY IN THE FORESEEABLE FUTURE?

A. No. Economic forecasters as well as the Federal Reserve all believe that the current interest rate environment is expected to remain relatively stable for many years to come. In fact, in June 16, 2016, Bloomberg published an article entitled "Yellen Says Forces Holding Down Rates May Be Long Lasting." The key takeaway from the article is the following statement:

> In a press conference after the Fed held policy steady, Yellen spoke of a sense that rates may be depressed by

67 *Ass'n of Bus. Advocating Tariff Equity, et al. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, Opinion No. 569, 169 FERC ¶ 61,129, at P 238 (2019) ("FERC Opinon No. 569").

> "factors that are not going to be rapidly disappearing, but will be part of the new normal."[68]

I recognize this statement from Chairperson Yellen is over 3 years old, but what the chairperson said in 2016 still rings true today. The Federal Reserve cut rates in 2019 and then, in its December meeting, announced plans to keep interest rates at current levels throughout 2020.69 Mr. Hevert, on the other hand, has been predicting interest rates to rise for several years. As an example, in 2017, Mr. Hevert provided testimony in the general rate case of Duke Energy Progress before the North Carolina Utilities Commission in which he analyzed the interest rate prospects at that time and stated the following:

> Q. WHAT DO YOU CONCLUDE FROM THOSE ANALYSES?
> A. First, it is clear that interest rates have increased from the low levels experienced in early 2016. Second, it is clear that market-based data indicate investors' expectations of rising interest rates in the near- and longer-term.
> The observation that interest rates have increased indicates that the financial community sees the strong prospect of increased growth throughout the economy. As that occurs, and as interest rates continue to rise, it would be reasonable to expect lower utility valuations, higher dividend yields <u>and higher growth rates. In the context of the Discounted</u>

68 Miller, R., *Yellen Says Forces Holding Down Rates May Be Long Lasting*, Bloomberg (June 15, 2016), available at: **https://www.bloomberg.com/news/articles/2016-06-15/yellen-seems-to-sign-on-to-summers-view-of-lingering-low-rates.**

69 Rugaber, C., *Federal Reserve leaves interest rates unchanged and foresees no moves in 2020*, PBS News Hour (Dec. 11, 2019), available at: https://www.pbs.org/newshour/economy/federal-reserve-leaves-interest-rates-unchanged-and-foresees-no-moves-in-2020.

<u>Cash Flow model, those variables would combine to indicate increases in the Cost of Equity.</u>[70]

As I have demonstrated above, interest rates continue to trend at lower levels AND utility stock prices have skyrocketed since Mr. Hevert's testimony in 2017. Put simply, Mr. Hevert's forecast regarding interest rates and utility stock prices was wrong.

Q. HOW IS BETA MEASURED IN THE CAPM?

A. Beta is a statistical calculation of a company's stock price movement relative to the overall stock movement. A company whose stock price is less volatile than the overall market will have a beta less than 1.0. A company whose stock price is more volatile than the overall market will have a beta more than 1.0. Since utilities are generally conservative equity investments, utility betas are almost always less than 1.0.

Q. WHAT IS THE CURRENT MARKET RISK PREMIUM APPROPRIATE FOR USE IN THE CAPM?

A. The development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. I believe one measure to analyze current premiums is to look at historical risk premiums. To gauge the historical risk premium, I turned to the Ibbotson database published by Morningstar. The long-term geometric and

70 *Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, NCUC Docket No. E-2, Sub 1142, Direct Testimony of Robert Hevert, at p. 82 (June 1, 2017) (emphasis added).

arithmetic returns for both equities and fixed income securities and the resulting risk premiums are as follows:

Table 6: Equity Risk Premium Calculations[71]

Asset Class	Geometric Mean	Arithmetic Mean
Large Company Stocks	10.0%	11.9%
Long-Term Govt. Bonds	5.9%	6.3%
Resulting Risk Premium	4.1%	5.6%

Q. WHAT MARKET RETURNS ARE WELL-KNOWN PROFESSIONAL INVESTORS EXPECTING FOR THE FORESEEABLE FUTURE?

A. On January 16, 2020, Morningstar.com published an article entitled "Experts Forecast Long-Term Stock and Bond Returns: 2019 Edition."[72] By future returns, these market experts are discussing total market returns, and not just the equity risk premium. Below are some of the market return forecasts from this article:

BlackRock Investment Institute

71 Ibbotson® SBBI®, *2019 Classic Yearbook: Stocks, Bonds, Bills, and Inflation, 1926-2018*, at Exhibit 2.3.

72 Benz, C., *Experts Forecast Long-Term Stock and Bond Returns: 2020 Edition*, Morningstar (Jan. 16, 2020), available at: **https://www.morningstar.com/articles/962169/experts-forecast-long-term-stock-and-bond-returns-2020-edition**.

6.1% nominal (not inflation adjusted) return for US large caps over the next decade, 6.5% for European equities, and 7.5% for emerging markets equities.

Grantham, Mayo, & van Otterloo ("GMO")

-4.4% real (inflation adjusted) returns for US large caps over the next 7 years

JP Morgan Asset Management

5.6% nominal return for US equities over a 10-15 year horizon

Morningstar Investment Management

1.7% 10-year nominal returns for US stocks

Research Affiliates

0.3% real (inflation adjusted) returns for US large caps furring the next 10 yearsVanguard

Nominal equity market returns of 3.5% to 5.5% during the next decade

The above-stated equity returns display a very large range. On the low side is GMO, which forecasts that US large caps will, after inflation, lose 4.4% of asset value annually over the next seven years. On the more positive side is BlackRock Investment that expects a nominal (before inflation adjustment) of 6.1% per year. Of the above-stated returns, Vanguard, JP Morgan, and BlackRock all forecast nominal (not inflation adjusted) returns in the range of 3.5% to 6.5%. A mid-range estimate is 4% to 6% for the group.

In 2018, Duke University finance professors published their annual equity risk premium estimates that stated the expected average risk premium exhibited by a survey of U.S. Chief Financial Officers around the country is 4.42%.[73] The article states as follows:

> During the past 18 years, we have collected almost 25,000 responses to the survey. Panel A of Table 1 presents the date that the survey window opened, the number of responses for each survey, the 10-year Treasury bond rate, as well as the average and median expected excess returns. There is relatively little time variation in the risk premium. This is confirmed in Fig. 1a, which displays the historical risk premiums contained in Table 1. **The current premium, 4.42%, is above the historical average of 3.64%.** The December 2017 survey shows that the expected annual S&P 500 return is 6.79% (=4.42%+2.37%) which is slightly below the overall average of 7.11%. The total return forecasts are presented in Fig. 1b.2.[74]

Q. WHAT IS YOUR CONCLUSION AS TO THE ESTIMATED EQUITY RISK PREMIUM FOR USE IN THE CAPM?

A. Using historical data, such as the data noted above in Table 2, as well as ex ante (forecasts) data, the evidence suggests the equity risk premium is clearly within the range of 4% to 6%.

Q. HOW DID YOU DETERMINE THE BETA YOU USED IN THE CAPM?

A. I used the Value Line derived beta that I found in the most recent Value Line editions[75] for each company in the proxy group.

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73 Graham, J. & Harvey, C., *The Equity Risk Premium in 2018*, Duke University, at 3-4 (March 28, 2018) (emphasis added).

74 *Id.*

75 *The Value Line Investment Survey*, Value Line (Dec. 13, 2019); *The Value Line Investment Survey*, Value Line (Nov. 15, 2019); *The Value Line Investment Survey*, Value Line (Oct. 25, 2019).

Q. WHAT WERE YOUR CAPM RESULTS?

A. The actual calculations for the CAPM can be seen in Exhibit KWO-3 for the O'Donnell comparable group and in Exhibit KWO-6 for the Hevert comparable group. The yield on 30-year U.S. Treasury yields (Rf) has ranged from 0.99% to 3.46%. The average beta for the O'Donnell proxy group is 0.55, which was calculated by averaging the beta reported by <u>Value Line</u> for all companies in the group. I then multiplied this average beta of 0.55 by the risk premium range of 4.0% to 6.0% to produce a beta-adjusted risk premium of 2.20% to 3.30%. The 30- year US Treasury yield (Rf) range of 0.99% to 3.46% is next added to the beta-adjusted risk premium range of 2.20% to 3.30% to arrive at the proxy group CAPM result range of 3.17% to 6.74% ROE for the O'Donnell comparable group.

I followed the same process for the Hevert comparable group, which has an average beta of 0.54, to arrive at an identical CAPM range of 3.15% to 6.69%.

Based on this range of results for the CAPM, I find the proper ROE derived from the CAPM is in the range of 5.0% to 7.0%. The low-end (5.0%) of this range is 183 basis point higher than the low-end of the O'Donnell proxy group CAPM results using the 4.0% of the equity risk premium. The high end (7.0%) of the range is slightly higher than the high end of the O'Donnell proxy group CAPM results.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR CAPM ANALYSIS?

A. Although I derive DEC's ROE from my DCF analysis, the CAPM results offered here present a critical check on those results. CAPM has been relied on heavily by both the financial and regulatory communities and should serve as the principal alternative to confirm the veracity of the DCF results.

c. Comparable Earnings Analysis

Q. PLEASE EXPLAIN THE COMPARABLE EARNINGS (CE) ANALYSIS AND HOW YOU PERFORMED THIS ANALYSIS.

A. The Comparable Earnings (CE) analysis is a process whereby companies that are deemed similar in risk are compared to assess a relative valuation. In this process, the analyst simply examines details of companies within its comparable group and within its industry to assess a relative return for the examined company.

In the CE analysis I performed in this case, I examined the allowed actual earned returns on book value, not market value. As a result, the earned returns I examined were higher than what investors are actually requiring in today's marketplace.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE.

A. Market values reflect the actual price that investors are willing to pay for a share of a company's stock. Book value, on the other hand, is the actual net assets of a company divided by the number of shares outstanding.

Q. HOW DOES THE MARKET VALUE OF UTILITIES, IN GENERAL, COMPARE TO BOOK VALUE?

A. The market value of utilities is currently about 1.5X to 2.0X that of the book value of utilities. As an example, the book value of Duke Energy Corp. at year-end 2018 was, according to Value Line, $60.27. However, its market price as of December 31, 2018 was $83.59, thereby representing a market-to-book (M/B) ratio of 1.39X.

As noted in the above example with Duke Energy Corp, a return on book value will be far greater than a return on market value as the denominator in a return on book value (*see* e.g. $60.27 above) is less than the dominator in a return on market value (*see* e.g. $83.59 above). Hence, when the book value is less than the market value and the net income is the same under both scenarios, it is a mathematical fact that the return on book value will be greater than the return on market value.

The above example illustrates why I believe the stated returns on book value, such as provided by Value Line, should be used only as a guide to the DCF market-required estimates. Simply put, analysts can mistakenly and/or improperly equate the two returns (return on book value and return on market value) and cause confusion for regulators.

Q. PLEASE EXPLAIN HOW YOU PERFORMED THE COMPARABLE EARNINGS ANALYSIS.

A. Exhibit KWO-4 presents a list of the earned returns on equity of the O Donnell comparable group over the period of 2017 through 2025. Exhibit KWO-8 presents the earned returns on equity of the Hevert comparable group over the same time period. I picked this range to provide the Commission with two years of historical returns and five years of forecasted returns. As can be seen in this exhibit, the average earned returns on equity for the proxy group ranges from 9.9% to 10.6% for the

O'Donnell proxy group. For the Hevert proxy group, the range is from 9.5% to 10.3%.

Q. DO YOU HAVE ANOTHER COMPARABLE EARNINGS ANALYSIS TO PRESENT IN THIS CASE?

A. Yes. I also examined ROEs granted by state regulators across the country.

It is important to understand what state regulatory commissions across the country are allowing for earned ROEs. Allowed ROEs are widely known and discussed in the financial community and investors take these regulatory decisions into account when they set prices in the open market for which they are willing to purchase the stock of a regulated utility.

As this Commission is likely aware, regulated ROEs have trended down over the past 15 years. In Chart 9 above, I provided a chart that shows the allowed ROEs for electric utilities by state regulators across the United States from 2005 through 2019. The average allowed ROE for 2019 was 9.65%.

Q. ARE YOU AWARE OF A STATE REGULATORY BODY THAT HAS RECENTLY ISSUED AN ORDER FOR A DUKE ENERGY SUBSIDIARY, IN WHICH MR. HEVERT HAS BEEN THE WITNESS? IF SO, WHAT WAS THE ALLOWED ROE SET BY THAT REGUALTORY BODY?

A. Yes. Mr. Hevert testified in the Duke Energy subsidiary rate cases (Duke Energy Carolinas and Duke Energy Progress) heard in South Carolina. Mr. Hevert recommended a 10.75% ROE in both cases. On May 1, 2019, the SCPSC authorized a 9.50% ROE for Duke Energy Carolinas.[76] On May

76 Snl.com

8, 2019, the SCPSC authorized Duke Energy Progress the opportunity to earn a 9.50% ROE.[77]

Q. ARE YOU AWARE OF ANY REGULATORY BODY THAT HAS RECENTLY AUTHORIZED A ROE OF LESS THAN 9.50%?

A. Yes. On May 28, 2019, the Public Utility Commission of South Dakota authorized an 8.75% ROE for Otter Tail Power in Docket No. EL 18-021.

Q. WHO WAS THE ROR WITNESS FOR OTTER TAIL POWER IN THAT RATE CASE AND WHAT WAS HIS/HER RECOMMENDATION?

A. Mr. Robert Hevert was the witness for Otter Tail Power in the South Dakota proceeding. Mr. Hevert's recommendation in the South Dakota case was 10.3%, slightly less than the 10.4% ROE he is recommending in the current proceeding.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPARABLE EARNINGS ANALYSIS?

A. Regulators across the United States have continued to recognize the decrease in capital cost and, as shown in Chart 4 above, steadily reduced the allowed returns of utilities over the past 15 years.

Based on the above-stated findings, I believe the proper ROE using a comparable earnings analysis is in the range of 9.25% to 10.25%. The lower end of this range recognizes the unmistakable downward trend of the average ROE allowed by state regulators for electric utilities dating back to 2005 The high end of the range recognizes high forecasted earned

77 *Id.*

returns on equity for the O'Donnell and Hevert comparable groups in the 2022-2025 timeframe.

d. Return on Equity Summary

Q. MR. O'DONNELL, PLEASE SUMMARIZE THE RESULTS OF YOUR ROE ANALYSIS IN THIS CASE.

A. Table 8 below lists the results of my DCF analysis and CAPM analysis.

Table 7: ROE Method Results

Method	ROE Results		
	Low	High	Midpoint
DCF	7.0%	10.0%	8.50%
CAPM	5.0%	7.0%	6.50%
Comparable Earnings	9.25%	10.25%	9.75%

Q. DO YOU THINK THAT THE MIDPOINT OF YOUR DCF ANALYSIS WOULD PROVIDE THE COMPANY WITH A FAIR RETURN?

A. I believe the midpoint of the DCF analysis is an accurate portrayal of market conditions and my CAPM analysis provides further support for an ROE at the midpoint of my DCF analysis, if not lower. However, I am also mindful of current allowed returns from around the country. Given that the allowed returns from other jurisdictions are above the 8.5% midpoint of the DCF range, I believe choosing a return in the upper end of the DCF range is more appropriate for use in this case.

Q. WHAT IS YOUR RETURN ON EQUITY RECOMMENDATION IN THIS PROCEEDING?

A. My recommendation in this case is for the Commission to grant DEC a return on equity of 8.75%. This 8.75% ROE is towards the high end the range of reasonableness established by the DCF range and is well above the CAPM results.

Q. WOULD YOU PLEASE PROVIDE THE REASONS FOR YOUR RECOMMENDATION?

A. As the Commission is aware, interest rates remain quite low relative to historic levels. Individuals seeking an income stream see utility dividends as good alternatives at the present time with the lack of adequate fixed income (bond) opportunities. This "chase for yield" is part of the reason that the Dow Jones Utility Average has nearly doubled since 2013.

When stock prices increase, dividend yields decrease even though the dollar amount of the dividend remains the same or even increases. Hence, during the bull run over the past 10 years, the increase in utility stock prices has driven dividend yields of utility stocks downward. Thus, we cannot ignore the current low cost of capital environment. If a utility's rates are set too high, the economy in its service territory will suffer and stockholders will receive a windfall at the expense of captive ratepayers.

Although the midpoint of my DCF analysis is 8.50%, I am recommending an 8.75% ROE in recognition of the higher allowed ROEs from across the country.

C Capital Structure

Q. **WHAT IS A CAPITAL STRUCTURE AND HOW WILL IT IMPACT THE REVENUES THAT DEC OR ANY OTHER UTILITY IS SEEKING IN A RATE CASE?**

A. The term "capital structure" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments. For simplicity, there are three financing methods. The first method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Returns on common equity, which in part take the form of dividends to stockholders, are not tax deductible which, on a pre-tax basis alone, makes this form of financing about 28% more expensive than debt financing. The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock are not tax deductible.

Corporate debt is the third major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in a year or less. Both long-term debt and short-term debt represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment.

Q. HOW IS A UTILITY'S TOTAL RETURN CALCULATED?

A. A utility's total return is developed by multiplying the component percentages of its capital structure represented by the percentage ratios of the various forms of capital financing relative to the total financing on the company's books by the cost rates associated with each form of capital and then totaling the results over all of the capital components. When these percentage ratios are applied to various cost rates, a total after-tax rate of return is developed. Because the utility must pay dividends associated with common equity and preferred stock with after-tax funds, the post-tax returns are then converted to pre-tax returns by grossing up the common equity and preferred stock dividends for taxes. The final pre-tax return is then multiplied by the Company's rate base in order to develop the amount of money that customers must pay to the utility for return on investment and tax payments associated with that investment. This return, or profit, is awarded in addition to the utility being allowed to recover its reasonable level of annual operating expenses.

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

A. Costs to consumers are greater when the utility finances a higher proportion of its rate base investment with common equity and preferred stock versus long-term debt. Long-term debt, which is first in line for repayment, imposes a contractual obligation to make fixed payments on a pre-established schedule, as opposed to common equity where no similar obligations exist. Thus, long-term debt is a less risky investment warranting a lower cost.

Q. WHY SHOULD THIS COMMISSION BE CONCERNED ABOUT HOW DEC FINANCES ITS RATE BASE INVESTMENT?

A. There are two reasons that the Commission should be concerned about how DEC finances its rate base investment. First, DEC's cost of common equity is higher than the cost of long-term debt, meaning that an equity percentage above an optimal level will translate into higher costs to DEC's customers without any corresponding improvement in quality of service. Long-term debt is a financial promise made by the company and is carried as a liability on the company's books. Common stock is ownership in the company. Due to the nature of this investment, common stockholders require higher rates of return to compensate them for the extra risk involved in owning part of the company versus having a more senior claim against the company's assets.

The second reason the Commission should be concerned about DEC's capital structure is due to the tax treatment of debt versus common equity. Public corporations, such as DEC, can deduct payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds, which are more expensive than pre-tax funds. Because the regulatory process allows utilities to recover reasonable and prudent expenses, including taxes, rates must be set so that the utility is able to pay all its taxes and has enough left over to pay its common stock dividend. If a utility is allowed to use a capital structure for ratemaking purposes that is top-heavy in common stock, customers will be forced to pay the associated income tax burden, resulting in unjust, unreasonable, and unnecessarily high rates. Setting rates through the use of capital structure that is top-heavy in common equity violates the fundamental principles of utility regulation that rates must be just and reasonable and only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. HOW IS SETTING A CAPITAL STRUCTURE FOR A RATE-REGULATED ELECTRIC UTILITY COMPANY DIFFERENT THAN SETTING A CAPITAL STRUCTURE FOR A NON-REGULATED COMPANY THAT OPERATES IN A COMPETITIVE ENVIRONMENT?

A. Unregulated companies in competitive markets must carefully weigh the risk of using lower cost debt that can be used to leverage profits versus the use of the more expensive common equity that dilutes profits. Such a capital sourcing decision is based, in large part, on the competitive nature of the business in which the entity operates.

In the case of a rate-regulated electric utility with a licensed service territory that has little-to-no competition in its service territory, there is a strong incentive for the company to use common equity to build assets that can be placed in rate base. The utility is guaranteed the opportunity to earn its allowed rate of return on plant investment and, as such, can maximize profits by building plant and receiving favorable regulatory treatment from state regulators. In essence, normal competitive markets serve to lower capital costs through efficient capital cost decisions whereas electric utility rate regulation can act as an incentive for excessive or unnecessary plant investment.

Q. **PLEASE EXPLAIN HOW ONGOING CONSTRUCTION NEEDS ARE IMPACTING UTILITIES AND THEIR CUSTOMERS.**

A. Utilities finance construction with three primary sources of capital: retained earnings; common equity issuances; and long-term debt issuances. Financing construction with retained earnings is preferable to the utility because using funds from ongoing operations does not dilute common equity (as would an equity issuance) and does not add debt leverage to the utility's balance sheet. However, in most cases, financing a large asset with only retained earnings may not be possible due to sheer size of the plant investment. As a result, utilities undergoing large construction projects often issue common equity or long-term debt to finance these projects.

Selecting the ratio of equity to debt is important. Entities in more competitive markets have a profit motive that provides an incentive for such entities to select the most efficient capitalization ratio. However, electric utilities operating in exclusive, rate-regulated service territories have an incentive to maximize the amount of common equity in their capital structure so as to increase rates and, correspondingly, the utility profit. Rate-regulated electric utilities should only be allowed to recover in rates a revenue requirement derived from a capitalization ratio that allows the utility to provide reliable service at the least cost. Finding the right balance between debt and equity is critical.

Q. **PLEASE EXPLAIN THE RAMIFICATIONS OF RATES BEING SET AT AN UNBALANCED DEBT/EQUITY LEVEL.**

A. If a utility issues too much common equity and not enough debt for a certain project, the ratepayers pay higher rates to support a capital structure that is neither prudent nor reasonable. It is also important to recognize how rate levels affect economic development. The reality in today's economy is that economic development occurs in places where costs are lower. A utility with high rates will, all else being equal, cause its service territory to lose out on economic development opportunities.

If, on the other hand, the utility incurs too much debt, the utility's capitalization ratio presents excess financial risk to the capital markets, thereby driving up the costs required by the markets to compensate them for the added risk. In this case, the consumer would also lose because the cost it must pay the utility for accessing the capital markets is higher than it would pay using a less debt-leveraged capital structure.

One role of regulation is to balance the needs of the capital markets, including utility stockholders, with the needs of ratepayers. Too much equity or too much debt can harm both the stockholders of the corporation as well as the consuming public. Careful study of the risks and costs of various capitalization ratios is important.

Q. **HAVE YOU REVIEWED THE CAPITAL STRUCTURE REQUESTED BY THE COMPANY IN THIS PROCEEDING?**

A. Yes, I have.

Q. WHAT CAPITAL STRUCTURE IS DEC SEEKING IN THIS CASE?

A. According to McManeus Exhibit 1, page 2, the Company is seeking the following capital structure:

Table 8: DEC's Requested Capital Structure

Component	Capital Structure Ratio (%)
Long-Term Debt	47.0%
Common Equity	53.0%
Total Capitalization	100.0%

Q. DO YOU FEEL THIS CAPITAL STRUCTURE IS APPROPRIATE FOR RATEMAKING PURPOSES IN THIS CASE?

A. No, I do not.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE REQUESTED CAPITAL STRUCTURE IS INAPPROPRIATE FOR USE IN SETTING RATES IN THIS PROCEEDING.

A. The above-requested capital structure is the Company's capital structure as of Dec. 31, 2018, but it is actually a reflection of the amount of equity financing that DEC's owner, Duke Energy Corp, wishes to infuse into the utility relative to the amount of debt DEC issues. As a result, the actual capital structure of a utility operating company, such as DEC, does not reflect market forces but, instead, represents a decision by its parent holding company as to the capital structure on which it wishes rates to be determined.

Due to the decision-making ability of Duke Energy to set an equity ratio for DEC without the influence of market forces, I believe the Commission should examine similarly-situated utility holding companies and equity ratios set by utility regulators across the country to ascertain a more market-driven capital structure that is best used in setting rates.

Q. **WHAT IS THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN YOUR TWO PROXY GROUPs?**

A. Table 5 below shows the average common equity ratio of each company in the proxy group which I developed.

Table 9: O'Donnell Proxy Group Equity Ratio[78]

Company	2018 Ratio
American Electric Power Co Inc	46.8%
ALLETE Inc	60.1%
Alliant Energy Corp	46.6%
Ameren Corp	48.8%
CMS Energy Corp	30.7%
Consolidated Edison Inc	48.9%
Dominion Resources Inc	39.2%
Duke Energy Corp	46.2%
Edison International	38.3%

78 *The Value Line Investment Survey*, Value Line (January 24, 2020); *The Value Line Investment Survey*, Value Line (Feb 14, 2020); *The Value Line Investment Survey*, Value Line (March 13, 2020).

Entergy Corp	35.9%
Eversource Energy	46.9%
FirstEnergy Corp	27.4%
Hawaiian Electric Industries Inc	51.7%
IDACORP Inc	56.4%
MGE Energy Inc	62.3%
NextEra Energy Inc	56.0%
Northwestern	47.8%
OGE Energy Corp	58.0%
Otter Tail	55.3%
Pinnacle West Capital Corp	53.0%
PNM Resources Inc	38.6%
Portland General	53.5%
Public Service Enterprise Group Inc	52.2%
Sempra Energy	38.4%
Southern Co (The)	37.6%
WEC Energy Group Inc	49.4%
Xcel Energy Inc	43.6%
Average	47.8%

Table 10 provides the common equity ratios of the Hevert comparable group.

Table 10: Hevert Proxy Group Equity Ratio[79]

Company	2018 Ratio
American Electric Power Co Inc	46.8%
ALLETE Inc	60.1%
Alliant Energy Corp	46.6%
Ameren Corp	48.8%
Avangrid	73.8%
CMS Energy Corp	30.7%
DTE Energy Co	45.8%

79 *The Value Line Investment Survey*, Value Line (Jan 24, 2020); *The Value Line Investment Survey*, Value Line (Feb 14, 2020); and *The Value Line Investment Survey*, Value Line (March 13, 2020).

Evergy Corp.	60.0%
Hawaiian Electric Industries Inc	51.7%
NextEra Energy Inc	56.0%
Northwestern Corp	47.8%
OGE Energy Corp	58.0%
Otter Tail Corp	55.3%
Pinnacle West Capital Corp	53.0%
PNM Resources Inc	38.6%
Portland General Electric Co	53.5%
Southern Co (The)	37.6%
WEC Energy Group Inc	49.4%
Xcel Energy Inc	43.6%
Average	50.4%

As can be seen in the table above, the average common equity ratio in the two proxy groups is 47.8% and 50.4%, both of which are below the requested equity ratio in this case of 53.0%.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED BY UTIILTY REGULATORS ACROSS THE UNITED STATES IN 2019?

A. The average common equity ratio granted by regulators in 2019 to electric utilities was 49.9%.[80]

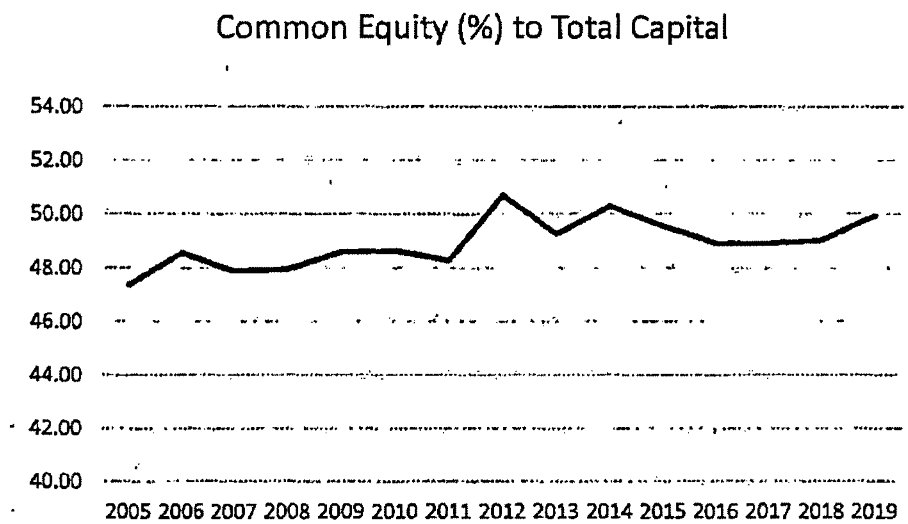
Q. WHAT COMMON EQUITY RATIO HAVE STATE REGULATORS ACROSS THE UNITED STATES GRANTED TO ELECTRIC UTILITIES OVER THE PAST 15 YEARS?

[80] S&P Global Market Intelligence, *RRA Regulatory Focus Major Rate Case Decisions* – (Data retrieved March 16, 2020).

A. State regulators have been quite consistent in their rulings in electric utility cases over the past 15 years. From 2005 through 2019, state regulators from across the country allowed common equity ratios in the range of roughly 47% to 51%.[81] The average common equity ratio for each year over the past 15 years can be seen in Chart 4 below.

[81] S&P Global, Rate Case History, available at snl.com (Data retrieved March 16, 2020).

Chart 3: Common Equity Ratio Granted by State Regulators (2005-2019)



The data for Chart 3 is found in Table 7 below.

Table 11: Common Equity Ratios82

Year	Common Equity (%) to Total Capital
2005	47.3%
2006	48.5%
2007	47.9%
2008	47.9%
2009	48.6%
2010	48.6%
2011	48.3%
2012	50.7%
2013	49.3%
2014	50.3%
2015	49.5%
2016	48.9%
2017	48.9%
2018	49.0%
2019	49.9%

82 *Id.*

The average common equity ratio from 2005 through 2019 was slightly below 50%, at 48.9%.

Q. PLEASE SUMMARIZE YOUR FINDINGS IN REGARD TO THE REQUESTED EQUITY RATO IN THIS CASE RELATIVE TO THE EQUITY RATIO OF OTHER ELECTRIC UTILITIES.

A. Table 8 below provides a summary of how DEC's request in this case compares to the following equity ratios: the equity ratio requested by the Company, the equity ratio of the two proxy groups, and the average allowed equity ratio by state regulators across the country in 2019.

Table 12: Common Equity Comparison

DEC Request	53.0%
O'Donnell Proxy Group Average	47.2%
Hevert Proxy Group Average	50.4%
2019 Average Reg Eq Ratio	49.9%

Q. GIVEN THE ABOVE, DO YOU BELIEVE THAT THE CAPITAL STRUCTURE BEING PROPOSED BY DEC IN THIS CASE IS APPROPRIATE FOR RATEMAKING PURPOSES?

A. No, the Company's request in this case is higher than any of the standards as I have noted above. Specifically, the requested equity ratio of 53.0% is:

- Higher than the O'Donnell proxy group's equity ratio;
- Higher than the Hevert proxy group's equity ratio;
- Higher than the average allowed equity ratio from state regulators across the United States in 2019;

- Higher than the allowed equity ratio of 52.0% from the 2017 DEC rate case.[83]

Based on these comparisons and, specifically, DEC's previous goal of maintaining an equity ratio between 49% and 50%, I believe the proper capital structure the Commission should employ in this proceeding should consist of 50% common equity and 50% long-term debt. My recommended capital structure for DEC is found below in Table139.

Table 13: O'Donnell Recommended Capital Structure

Component	Capital Structure Ratio (%)	Cost Rate (%)
Long-Term Debt	50.00%	4.51%
Common Equity	50.00%	---
Total Capitalization	100.00%	

IX. OVERALL RATE OF RETURN

Q. WHAT IS YOUR OVERALL RECOMMENDED RATE OF RETURN IN THIS PROCEEDING?

A. The overall rate of return I am recommending is 6.64% and can be seen in the table below.

83 See final Order in Docket No. E-7 Sub 1146 .

Table 14: Recommended Overall Rate of Return

Component	Capital Structure Ratio (%)	Cost Rate (%)	Wgtd. Cost Rate (%)
Long-Term Debt	50.00%	4.51%	2.26%
Common Equity	50.00%	8.75%	4.38%
Total Capitalization	100.00%		6.64%

IX. RECOMMENDATIONS AND CONCLUSION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS IN THIS CASE.

A. I began my analysis in this case by examining the DEC rates relative to utilities across the United States and, in particular, the southeast. My conclusion follows: DEC's industrial rates are losing its competitive position and will soon be above the national average if the Commission approves of Duke's long-term plan of multiple rate cases over the next 10 years;

On the issue of grid investment expenses, the evidence shows Duke's consumers are simply not willing to pay for massive rate hikes to enjoy a potential increase in system reliability, and Duke is unwilling to guarantee any such improvement in reliability. While some sort of grid investment may be warranted, the rate hikes requested by Duke in this proceeding are unreasonable, particularly in light of the fact that Duke was reported to have been recently fined $10 million by the NERC for repeated cybersecurity lapses since 2015.

My recommendation is the Commission deny Duke's planned grid updates for which they cannot/will not provide a cost benefit analysis (CBA).

Without such an analysis, the Company has provided no evidence in the record to show that its investment, and corresponding rate hikes, are warranted. For those projects which DEC did provide a CBA, I recommend the Commission order Duke to perform a sensitivity analysis on each project so it can assess the level of reasonableness of the DEC inputs.

In regard to coal ash, I have provided evidence in this proceeding that the Dan River spill caused the passage of the Coal Ash Management Act (CAMA) in North Carolina. After the coal ash spill, the federal government investigated the actions of Duke Energy at its coal ash ponds and subsequently charged the Company with nine violations of the Clean Water Act. Duke and the federal government reached a plea deal where Duke admitted guilt and was fined $102 million.

North Carolina consumers should only pay for coal ash costs that are the result of prudent operations. Duke's admission of guilt to imprudent operation of its coal ash ponds resulted in the passage of CAMA. My analysis attempted to determine a dividing line between Company actions before-and-after CAMA. The fact that Duke's mismanagement of coal ash resulted in the passage of CAMA should require that Duke's shareholders, not ratepayers, bear any cost burdens that exceed CCR requirements to meet the requirements of CAMA.

My recommendation is the Commission disallow all coal ash remediation costs for sites that are no longer accepting coal ash. Doing so will prevent consumers from paying at least a part of the incrementally more expensive costs associated with CAMA as opposed to the federal CCR costs.

The Commission should order DEC to change its hourly pricing rates to guarantee that manufacturers in DEC's service territory are receiving the lower cost power available, either from DEC, itself, or from the marketplace.

I also recommend the Commission immediately require DEC to meet with its large industrial consumers to develop and offer interruptible rates that are advantageous to the utility as well as its consumers no later than January 1, 2021.

In terms of the proper rate of return on which the Commission should set rates, I recommend the ROE be set at 8.75%, the capital structure be set at 50% common equity and 50% long-term debt, and the overall rate of return be set at 6.64%.

Q. **DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

A. Yes.

Q. Mr. O'Donnell, did you also prepare and cause to be filed in this case with the Commission and the parties, a summary of the testimony you are about to present today?

A. Yes, I did.

Q. And are there any changes that need to be made to the summary?

A. No.

MR. PAGE: Madam Chair, we request that Mr. O'Donnell's summary of the issues he is discussing today be copied into the record as though given orally. And with that, Mr. O'Donnell is available for, I assume, cross examination by the Commission since Duke has waived.

CHAIR MITCHELL: All right. Mr. Page, your motion is allowed.

(Whereupon, the prefiled summary of testimony of Kevin W. O'Donnell was copied into the record as if given orally from the stand.)

Summary of Kevin O'Donnell

DEC General Rate Case

Docket No. E-7 Sub 1214

My summary today will focus only on my observations and recommendations in regard to coal ash and cost of service/rate design.

Coal Ash

The circumstances surrounding Duke's coal ash spill, subsequent federal prosecution, and the development of the Coal Ash Management Act (CAMA) are well known. I will not repeat that well known history in this summary.

My position on coal ash in this case is consistent with my testimony in DEC and DEP's last rate cases as well as my position in DEC and DEP's South Carolina rate cases last year. Specifically, consumers should only pay for federal CCR costs and not the incremental cost associated with CAMA. In South Carolina, the Public Service Commission stated in its final order (Docket No. 2018-319-E) that it had received evidence that confirms CAMA is more stringent than CCR and that Commission disallowed a large part of Duke's coal ash request. I recommend this Commission make a similar finding and a similar reduction in this case.

Rate Design

I made two recommendations in this case regarding rate design for DEC. First, in regard to hourly pricing rates, I recommend that DEC be required to set hourly pricing rates based on the lower of Duke's marginal costs OR costs found in the competitive wholesale power markets as adjusted for transmission costs and line losses.

Second, DEC should re-examine its interruptible rates to offer a higher credit to those large consumers that have the ability to go offline at times of peak demand. In my testimony, I cited the interruptible rate offered by TVA which, at $5.75 per kW, is $2.25 per kW higher than the corresponding DEC rate. On a 40 MW load, for example, this difference in the interruptible credit between TVA and DEC amounts to $1.08 million. My specific recommendation is the Commission require DEC to immediately convene meetings with its large customers to design new interruptible rates for its large customers no later than January 1, 2021.

This completes my summary.

CHAIR MITCHELL: We're getting a lot of feedback from the line this morning. I believe it's when you and Mr. O'Donnell are both unmuted. So I'd ask that you-all just keep your lines muted until you need to speak.

All right. So the witness is available for questions. The only party who has indicated cross examination or reserved cross examination time for the witness is Duke. We've heard that Duke has no questions for the witness.

Any other cross examination for the witness?

MR. JENKINS: Yes, Chair. Alan Jenkins.

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

MR. JENKINS: Thank you.

CROSS EXAMINATION BY MR. JENKINS:

Q. Mr. O'Donnell, Alan Jenkins for the Commercial Group. How are you today?

A. I'm good, sir; how are you?

Q. Good. There were some questions yesterday that I thought you might shed some light on. You've been involved with the OPT issues for many years, haven't you?

A. Yes. Many is kind.

Q. Now, do you recall the process where the current OPT structure was negotiated between parties and finally approved by the Commission several cases ago?

A. I'll be honest with you, Mr. Jenkins, I don't remember the parties negotiating the OPT. I do remember it being approved. But I don't -- put it to you this way, I wasn't part of any negotiating process, or at least I can't remember it.

Q. But you gave input over the years on how to structure an OPT program; is that right?

A. Yeah, I think that's probably correct. I mean, I have definitely submitted testimony in terms of rate design and cost of service study before this Commission. Specific to OPT, I just -- I don't remember, I'm sorry.

Q. Okay. No problem. Have you heard any discussion about a potential comprehensive rate design process?

A. Yes, I have.

Q. And would you say, of all the rate schedules of DEC, that the OPT has had more review than perhaps any other?

A. I couldn't testify to that. It may make logical sense, but I really don't know the details of whatever else has been examined. I'm sorry.

Q. Fair enough. Would you expect, in the upcoming process, that your client would agree to, let's say, an SWPA class cost of service study being implemented?

A. No. Can I explain my reason why?

Q. Sure.

A. And I think this Commission knows that I've done a lot of wholesale power work in my day. I've done about 30 wholesale power deals around the Carolinas. And in the wholesale power markets, the fixed costs were always allocated on peak demand. Variable costs were always on -- excuse me, let me back up. Peak cost -- fixed costs were always priced, not allocated, but they were always priced on demand. Typically peak -- well, always peak demand. Variable costs are always priced at -- on energy. There is no allocations. They are always priced in that way.

I think, if the theory of regulation is to mimic what is available in the open comparative markets, then the price signals we ought to be sending ought to be based on peak and not summer/winter peak and average. And I have a tremendous amount of respect and admiration for Mr. McLawhorn, I heard his discussion yesterday. I just don't know too many, if any, industrials that have the ability to shut down their factories at time of the system peak. I mean, I just don't see it.

On top of that, on retail, you're not giving load signals. It's not like Duke sends out a load signal to everyone and says, "Hey, shut down." On the wholesale side, yeah, you know, you could do that. You could run a diesel generator in your back and clip the peak, because wholesale has coincident peak in Duke's formula regulated rates. You don't have that on the retail side.

So that's a long answer to say, Mr. Jenkins, that I do not believe that my clients would welcome a summer/winter peak and average because it is not market driven, at least not in the markets that I see -- in the competitive markets that I see here in the Carolinas.

Q. Do you have any opinion as to whether a comprehensive rate design review process, as is being discussed, would resolve all these issues ahead of the next DEC rate case?

A. I think it's going to be a tall order. From what I understand, Duke's going to be coming in for rate cases on a very frequent basis. I can understand the worthwhile -- the need for the process. I would just argue, again, that if what we're looking for is to lower rates for our respective clients, then we perhaps ought to look at market pricing, and we ought to go towards market pricing, because that's how you're going to lower rates for our clients, the consumers.

I can take you to several places in the Carolinas where market prices have lowered rates for residential customers a whole lot more than what we could be discussing in pricing reform such as the minimum system study.

Q. Thank you. And one further question.

Do you have any opinion as to whether rate design suggestions that you've made in this case or other parties have made in this case for, say, adjustments to the OPT should be postponed until there's a comprehensive rate review process done?

A. I would hope not. The arguments that I've made here in this case have been made previously and have not been addressed by Duke. So what I'm saying here is not new to Duke, they've seen it before, and we haven't received any traction on it. In terms of waiting until the next rate case, as you well know, Mr. Jenkins, and I think you pointed out yesterday regarding loss of Penneys, we have several manufacturers around the state that may not come back into play or may not come back into business. And these rate increases -- and I indicate this in my testimony, between grid mod coal ash and coal to gas, we're looking at pretty sizable rate hikes.

That's going to really harm manufacturing in North Carolina, which was the backbone of the state's economy. And it's obviously going to harm your customers as well. So I would argue that we really can't wait too much longer. A lot of our folks are not going to be coming back.

Q. Thank you.

MR. JENKINS: Nothing further.

CHAIR MITCHELL: All right. Any additional cross examination for the witness?

(No response.)

CHAIR MITCHELL: All right. Mr. Page, any redirect for your witness?

MR. PAGE: Very shortly, Madam Chair, thank you.

REDIRECT EXAMINATION BY MR. PAGE:

Q. Mr. O'Donnell, I believe you stated in response to one of Mr. Jenkins' questions that you did hear the discussions yesterday afternoon by the Public Staff panel, including Mr. McLawhorn and Mr. Floyd; is that correct?

A. Yes, I did.

Q. And did you hear the portion where, if I understood his testimony correctly, Mr. Floyd was saying that the landscape over the last 40, 50 years in the electric business has changed, and there are all these new things coming online with diversified generation, and smart metering, and smart grids, and this, and that, and the other thing, and all of that is proposed, as I understand it, to be taken up in these new rate studies.

My question to you is, are you aware of anything in those proposed new rate studies that would change the principle that has been around since before Professor Bonbright's book that what you do in a cost of service study is you allocate costs to the group of customers who are imposing those costs on the system? Do you see that changing?

A. I would hope not, because, again, that is not reflective of what happens in competitive markets. That's not what happens outside the world of regulation.

Q. Thank you, Mr. O'Donnell. That's all I have.

CHAIR MITCHELL: All right. Questions from Commissioners, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I don't have any questions.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: All right. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Nothing from me this morning. Thank you.

CHAIR MITCHELL: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

CHAIR MITCHELL: All right. And Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

CHAIR MITCHELL: All right. Mr. O'Donnell, you are off the hook.

MR. PAGE: Madam Chair, we'd like to move that Mr. O'Donnell's appendix and exhibits be admitted into the record at this time, and that Mr. O'Donnell be excused from further participation in the Duke Carolinas case.

CHAIR MITCHELL: All right. Mr. Page, your motion is allowed.

(Exhibits KWO-1 through KWO-8 and O'Donnell Appendix A were admitted into evidence.)

CHAIR MITCHELL: Thank you for your time this morning, Mr. O'Donnell.

THE WITNESS: Thank you.

CHAIR MITCHELL: All right. Ms. Downey, we return to the Public Staff. You may call your witnesses.

MS. JOST: Good morning, this is Megan Jost with Public Staff. The Public Staff calls Bernie Garrett and Vance Moore.

CHAIR MITCHELL: All right. Good morning, Ms. Jost. And let me see if I can find the witnesses. There's Mr. Moore. Mr. Garrett, I need your video turned on, please.

(Pause.)

CHAIR MITCHELL: All right.

Mr. Garrett, still can't see you.

MR. MOORE: Give me one second, I may try to assist.

CHAIR MITCHELL: There he is.

Whereupon,

VANCE F. MOORE AND BERNARD L. GARRETT,

having first been duly affirmed, were examined and testified as follows:

CHAIR MITCHELL: All right. Ms. Jost, you may proceed.

MS. JOST: Thank you. I'll begin with Mr. Moore.

DIRECT EXAMINATION BY MS. JOST:

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

A. (Vance F. Moore) My name is Vance Moore. My business address is 206 High House Road, Cary, North Carolina.

Q. By whom are you employed and in what capacity?

A. I am employed by Garrett & Moore,

Incorporated, and I am the president.

Q. Did you caused to be filed in this docket on February 18, 2020, direct testimony consisting of 25 pages and seven exhibits, six of which were marked confidential?

A. I did.

Q. Do you have any corrections to that testimony?

A. I do not.

Q. If you were asked the same questions today, would your answers be the same?

A. They would.

Q. And did you prepare a summary of your testimony?

A. I did.

MS. JOST: Chair Mitchell, at this time, I would move that Mr. Moore's prefiled direct testimony and summary be copied into the record as if given orally from the stand, and that his seven exhibits be marked for identification as premarked in the filing.

CHAIR MITCHELL: All right. The witness' testimony and summary of that testimony will be copied into the record as if given orally from the stand. The exhibits to that prefiled testimony will be marked for identification as they were when prefiled.

MS. JOST: Thank you.

(Public Staff Confidential Moore Exhibits 1 through 6 and Public Staff Moore Exhibit 7 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony with Appendix A and summary of testimony of Vance F. Moore was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET No. E-7, SUB 1213

DOCKET NO. E-7, SUB 1214

TESTIMONY OF VANCE F. MOORE
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

FEBRUARY 18, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Vance Moore. My business address is 206 High House Road, Suite 259, Cary, North Carolina. I am the President of Garrett and Moore, Inc.

Q. BRIEFLY STATE YOUR QUALIFICATIONS.

A. I am a registered professional engineer with over 30 years of experience engineering coal ash management projects, including coal ash landfills and impoundments, with services including, but not limited to, facility layout and master planning; ash landfill design, permitting, construction and quality assurance, and closure; ash impoundment closure investigations, closure design and permitting, and closure construction and quality assurance; cost engineering; facility and life of site development and operational cost projections and alternative analyses; ash management facility operations; ash impoundment material recovery and recycling; public meetings and community involvement; environmental monitoring and regulatory compliance, corrective actions, CCR Rule compliance demonstrations, and comprehensive assessments of program and facility environmental liabilities and associated costs. Relevant projects include:

- Canadys Station (Dominion Energy South Carolina, DESC, formerly South Carolina Electric & Gas, SCE&G or SCANA) near Walterboro, South Carolina
  - Ash pond closure
  - Ash landfill development
  - Corrective actions
- Cope Station (DESC) near Cope, South Carolina
  - Ash landfill development
  - Ash landfill wastewater management facility development
  - Ash landfill closure
  - Ash landfill wastewater pond closure
- Cross Station (Santee Cooper) near Pineville, South Carolina
  - Ash Landfill development and closure
- McMeekin Station (DESC) near Columbia, South Carolina
  - Ash pond closure

- Ash landfill development and closure
- Ash landfill wastewater pond closure

- Urquhart Station (DESC) near Beech Island, South Carolina
  - Ash landfill closure
  - Ash pond closure
  - Ash landfill wastewater pond closure
  - Corrective Actions
- Wateree Station (DESC) near Eastover, South Carolina
  - Ash pond closure
  - Ash landfill development
  - Ash landfill wastewater management facility development
  - Corrective Actions
- Williams Station (DESC) near Charleston, South Carolina
  - Ash landfill development
  - Ash landfill wastewater management facility development
  - Ash landfill closure
  - Ash landfill wastewater pond closure

Additional qualifications are set forth in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the North Carolina Utilities Commission the results of my investigation into whether the approach to environmental regulatory compliance taken by Duke Energy Carolinas, LLC (DEC), at its Coal Combustion Residuals (CCR) units located at the Allen, Belews Creek, Buck, Cliffside, and Marshall stations in North Carolina was the most prudent and reasonable method of achieving compliance with the laws and regulations governing coal ash management.[1]

Q. WHY DO YOU SAY "PRUDENT AND REASONABLE"?

A. I am not an expert in utility regulation, but have relied upon guidance from the Public Staff attorneys with respect to the legal standard for my investigation. Those attorneys inform me that under N.C. Gen. Stat. § 62-133, a utility's operating expenses must be "reasonable" to be included in the revenue requirement that is the basis for setting rates the utility may charge to consumers. Likewise, the cost of utility property allowed in the rate base, to which an authorized return may be applied, must also be "reasonable." Furthermore, I have been advised that management prudence is one aspect of this statutory reasonableness, and yet some costs or expenses can be prudent but still not reasonable for recovery as a component of the revenue requirement used for setting rates. For purposes of my testimony, I do not attempt to present the legal theory for a distinction between

[1] Due to constraints on time and resources, I did not perform an in-depth investigation of DEC's environmental regulatory compliance actions at its CCR units located at the W.S. Lee Station in South Carolina.

"prudence" and other "reasonableness"; rather, I simply describe the facts that led me to conclude that a particular cost or expense is not reasonable for purposes of rate recovery.

Q. HOW DOES YOUR TESTIMONY DIFFER FROM THAT OF THE OTHER PUBLIC STAFF WITNESSES IN THIS CASE?

A. I understand that Public Staff witnesses Junis and Maness speak to adjustments for environmental violations and the appropriate regulatory accounting treatment for coal ash-related costs. I do not address those issues. The testimony of Public Staff witness Garrett evaluates the prudence and reasonableness of DEC's costs incurred at its two high-priority sites, Dan River and Riverbend. Our testimony together provides a combined perspective on the prudence and reasonableness of the coal ash closure costs for which DEC is seeking cost recovery in this proceeding.

Q. WHAT IS THE SCOPE OF YOUR INVESTIGATION INTO THE PRUDENCE AND REASONABLENESS OF DEC'S COAL ASH MANAGEMENT COSTS?

A. I reviewed the actions and costs incurred by DEC at its Allen, Belews Creek, Buck, Cliffside, and Marshall plants to comply with the Coal Ash Management Act (CAMA),[2] including DEC's actions and costs

[2] 2014 N.C. Sess. Law 122, as amended by 2016 N.C. Sess. Law 95.

incurred in connection with the SEFA STAR ash beneficiation plant at its Buck Station.

Q. PLEASE DESCRIBE THE RESOURCES UTILIZED IN CONDUCTING YOUR INVESTIGATION.

A. In order to prepare this testimony, I reviewed the testimony and work papers of DEC witnesses Bednarcik and Immel. Through the Public Staff, I also submitted extensive discovery to DEC regarding its actions taken at its CCR units and DEC's technical and financial basis for such decisions. I also participated in site visits and conference calls with DEC personnel.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony first presents my opinion on the prudency and reasonableness of DEC's selected methods for general CCR management at each CCR unit I investigated and the related costs from January 1, 2018, through November 30, 2019. The majority of my testimony focuses on my investigation of the prudency and reasonableness of Duke Energy's approach to compliance with the requirement to beneficiate coal ash imposed by the amendment to CAMA[3] and the associated costs incurred. Based on my investigation, I recommend that the Commission disallow

[3] N.C. Gen. Stat. § 130A-309.216 (2016).

$67,809,160 in costs to construct DEC's Buck beneficiation project that I do not believe were reasonable or prudent.

Q. WHAT IS YOUR OPINION REGARDING THE COSTS DEC SEEKS RECOVERY OF IN THIS RATE CASE FOR ALLEN, BELEWS CREEK, CLIFFSIDE, AND MARSHALL?

A. The North Carolina Department of Environmental Quality (NCDEQ) issued Closure Determinations on April 1, 2019, which mandated that CCR impoundments at DEC's Allen, Belews Creek, Cliffside, and Marshall Stations and Duke Energy Progress, LLC's (DEP), Mayo and Roxboro Stations be excavated. After NCDEQ issued these excavation orders, Duke Energy filed a contested case challenging the orders.

DEC witness Bednarcik states on pages 13 and 14 of her direct testimony:

> With the exception of preliminary closure plan development, none of the site work that has been conducted at [Allen, Belews, Cliffside, and Marshall] is specific to cap-in-place closure. All site work to date would also have to be conducted in an excavation closure. Later in 2019, DE Carolinas anticipates conducting preliminary site evaluations at these four sites, including boring wells, to evaluate potential onsite locations for landfills. This will be done to ensure that the Company will be able to proceed with closure if the NC DEQ Order is upheld.

On December 31, 2019, Duke Energy, NCDEQ, and community and environmental groups entered into a settlement agreement that, among other things, resolved the litigation over the excavation orders. Pursuant to the settlement agreement, Duke Energy will be required to excavate and place in lined landfills a majority of the CCR at DEC's Allen, Belews Creek, Cliffside, and Marshall Stations, and at DEP's Mayo and Roxboro Stations. The direct testimony of Public Staff witness Junis discusses the current regulatory status of closure of DEC's CCR sites in greater detail.

Based on my review of DEC's approach to compliance with NCDEQ requirements, I take no exception to DEC's requested reimbursements for site work performed at Allen, Belews Creek, Cliffside, and Marshall.

Q. PLEASE DESCRIBE DUKE ENERGY'S REQUIREMENT TO BUILD ASH BENEFICIATION PROJECTS THAT WILL PROCESS COAL ASH INTO CEMENTITIOUS PRODUCTS.

A. In 2016, the North Carolina General Assembly amended CAMA. Among other things, the CAMA Amendment added N.C.G.S. § 130A-309.216 regarding ash beneficiation projects. That section requires Duke Energy to process coal ash into a form suitable for use in cementitious products. Part (a) states in part:

> On or before January 1, 2017, an impoundment owner shall (i) identify, at a minimum, impoundments at two sites located within the State with ash stored in the impoundments on that date that is suitable for processing for cementitious purposes and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of

> annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundment(s) located at the sites.

Part (b) requires Duke Energy to identify an additional beneficiation site on or before July 1, 2017, and part (c) sets the closure deadline for intermediate and low-risk impoundments at ash beneficiation sites as no later than December 31, 2029.

Q. PLEASE SUMMARIZE THE ACTIONS DUKE ENERGY TOOK TO COMPLY WITH THE CAMA AMENDMENT'S REQUIREMENT TO SELECT THREE SITES FOR THE CONSTRUCTION AND OPERATION OF BENEFICIATION PROJECTS.

A. In response to a Public Staff data request,[4] DEC stated, "During the Q4 2016 quarterly ARO process, Duke Energy established ash beneficiation site selection criteria based on carbon content, ash inventory volume and product market area associated with the plant location and cost savings comparisons." DEC further stated that "[t]he first two ash beneficiation sites were selected Q4 2016" and "[t]he third site was selected Q2 2017. . . ."

Q. WHAT PLANTS DID DUKE ENERGY CHOOSE FOR THE THREE BENEFICIATION SITES?

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[4] DEC response to Public Staff Data Request No. 202-5 in Docket No. E-7, Sub 1214.

A. Duke Energy chose the DEC Buck plant and the DEP Cape Fear and H. F. Lee plants as the three beneficiation sites. The Buck plant was selected on October 5, 2016.[5]

Q. PLEASE SUMMARIZE THE ACTIONS DUKE ENERGY TOOK TO COMPLY WITH THE CAMA AMENDMENT'S REQUIREMENT TO ENTER INTO AN AGREEMENT FOR THE CONSTRUCTION AND OPERATION OF ASH BENEFICIATION PROJECTS AT THE THREE SITES.

A. On August 11, 2016, Duke Energy Business Services, LLC, as an agent for and on behalf of DEC and DEP (Duke Energy), advertised the Request for Information (RFI) for the Beneficiation of Ponded Ash into Concrete Specification Ash.[6] **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. HOW DID DUKE ENERGY EVALUATE THE RFI RESPONSES?

A. **[BEGIN CONFIDENTIAL]** [redacted]

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[5] Page 3 of 12, Exhibit 10, Direct Testimony of DEC Witness Jessica Bednarcik filed in Docket No. E-7, Sub 1214, on September 30, 2019.

Press Release *Available at* https://news.duke-energy.com/releases/duke-energy-to-recycle-coal-ash-at-buck-steam-station-in-salisbury (last visited February 7, 2020).

[6] DEC confidential supplemental response to Public Staff Data Request No. 5-4(e) in Docket No. E-7, Sub 1146.

[redacted]. **[END CONFIDENTIAL]** SEFA calls its beneficiation system Staged Turbulent Air Reactor (STAR).

Q. DID SEFA'S RESPONSE TO THE RFI INCLUDE COST ESTIMATES FOR THE STAR FACILITY?

A. In reference to SEFA's response to the RFI, DEC clarified that the construction estimate for the STAR facility is $64 million including "approximately $14.8M in SEFA engineering and Project Indirect cost, as well as $50.2M for [Engineering, Procurement, and Construction] Direct Construction cost and balance of plant procurement."[8] These estimates are for a single STAR facility. As stated above, the CAMA Amendment requires Duke Energy to install and operate beneficiation projects at three sites.

[7] DEC confidential supplemental response to Public Staff Data Request No. 5-4(e) in Docket No. E-7, Sub 1146.

[8] DEC response to Public Staff Data Request No. 202-1 in Docket No. E-7, Sub 1214.

Duke Energy's intent was to have SEFA supply the STAR system and provide technical expertise. The remainder of the beneficiation project would be built by a separate contractor.

Q DID SEFA'S RESPONSE TO THE RFI PROPOSE A CONTRACTOR TO CONSTRUCT THE STAR FACILITY?

A. Yes. SEFA's response[9] to the RFI specifically named **[BEGIN CONFIDENTIAL]** [redacted]

> [redacted]

[redacted]

> [redacted]

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[9] DEC confidential response to Public Staff Data Request No. 150-1 in Docket No. E-7, Sub 1214.

[redacted]

[END CONFIDENTIAL]

Q. DID DUKE ENERGY'S CONSTRUCTION ESTIMATES FOR THE STAR FACILITY INCREASE AFTER SEFA'S RESPONSE TO THE RFI?

A. Yes. Duke Energy's December 31, 2017, ARO cost spreadsheet,[10] **[BEGIN CONFIDENTIAL]** [redacted]

[10] DEC confidential supplemental response to Public Staff Data Request No. 5-19 in Docket No. E-7, Sub 1146.

[11] DEC confidential response to Public Staff Data Request No. 150-3 in Docket No. E-7, Sub 1214.

[12] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[redacted].

[END CONFIDENTIAL]

As stated above, SEFA's response to the RFI includes approximately $14.8 million in SEFA engineering and Project Indirect cost. **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. DID DUKE ENERGY CONTRACT WITH H&M TO CONSTRUCT THE BENEFICIATION UNIT AT BUCK?

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[13] DEC confidential response to Public Staff Data Request No. 183-5 in Docket No. E-7, Sub 1214.

[14] DEC response to Public Staff Data Request No. 202-1 in Docket No. E-7, Sub 1214.

A. No. In response to a Public Staff data request, DEC indicated that **[BEGIN CONFIDENTIAL]** [redacted]

> [redacted].

[END CONFIDENTIAL]

Q. PLEASE DESCRIBE DUKE ENERGY'S PROCESS TO SELECT A CONTRACTOR TO CONSTRUCT THE BENEFICIATION UNITS.

A. For the engineering, procurement, and construction of the three beneficiation units, Duke Energy advertised a request for proposals (RFP) dated **[BEGIN CONFIDENTIAL]** [redacted]

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[15] DEC confidential response to Public Staff Data Request No. 183-3 in Docket No. E-7, Sub 1214.

DEC response to Public Staff Data Request No. 202-6 in Docket No. E-7, Sub 1214.

[16] DEC confidential response to Public Staff Data Request No. 183-4 in Docket No. E-7, Sub 1214.

[redacted]. **[END CONFIDENTIAL]** A summary table of the change order descriptions and cost impacts to the project is provided as **Confidential Moore Exhibit 5**.[17]

Q. DID THE DESIGN AND SCOPE OF WORK FOR THE CONSTRUCTION OF THE BENEFICIATION UNITS CHANGE BETWEEN THE TIME OF SEFA'S RESPONSE TO THE RFI AND DUKE ENERGY'S AWARD OF THE CONSTRUCTION CONTRACT TO ZACHRY?

A. I was not able to determine whether there were any design modifications that would account for the increase in construction costs between the H&M estimate and the Zachry estimate. However, Duke Energy's Adjustments to Construction Base Estimate

[17] DEC confidential response to Public Staff Data Request No. 150-14 in Docket No. E-7, Sub 1214.

increased substantially in October 2017. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[18] DEC confidential response to Public Staff Data Request No. 202-7 in Docket No. E-7, Sub 1214.

[redacted]. **[END CONFIDENTIAL]** See **Confidential Moore Exhibit 6**.

Q. BASED ON YOUR ANALYSIS, WHAT HAS BEEN THE MOST SIGNIFICANT SOURCE OF COST INCREASES FOR THE BUCK BENEFICIATION PROJECT?

A. The most significant source of cost increases has been the increased construction costs, which applies to all the beneficiation units. **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Duke Energy selected SEFA for Engineering, Procurement, Start-Up and Commissioning with an initial contract for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which has increased to **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Duke Energy selected Zachry with an initial contract amount of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which has increased to **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** as stated above.

Q. DO YOU BELIEVE DUKE ENERGY'S DECISION TO AWARD THE ENGINEERING CONTRACT TO SEFA WAS REASONABLE AND PRUDENT?

A. Yes, in recognition of the Commission's guidance in its Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in the E-7, Sub 1146, proceeding. In the Order, the Commission concluded that "the most reasonable reading of N.C. Gen. Stat. § 130A-309-216 indicates that the General Assembly intended that Duke Energy install and operate technology, such as carbon burn-out plants and STAR technology . . . ." Technologies available to process ponded ash to specifications appropriate for a replacement for Portland cement for ready mix concrete are limited. SEFA was the only responder to Duke's "Request for Information (RFI) for the Beneficiation of Ponded Ash into Concrete Specification Ash" dated August 11, 2016, that had demonstrated the ability to process ponded ash to specifications appropriate for a replacement for Portland cement.

Q. DO YOU BELIEVE THE CHANGE ORDERS TO THE ENGINEERING CONTRACT WITH SEFA WERE REASONABLE AND PRUDENT?

A. Yes. Based on my review, I believe the change orders and the associated costs were reasonable and prudent given the circumstances.

Q. DO YOU BELIEVE DUKE ENERGY'S DECISION TO AWARD THE CONSTRUCTION CONTRACT TO ZACHRY FOR THE AMOUNT CONTRACTED WAS REASONABLE AND PRUDENT?

A. No. H&M had constructed similar facilities designed by SEFA and **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Readily available articles state that capital costs for SEFA's beneficiation unit at Winyah Station in South Carolina, which is capable of processing similar quantities of ponded ash, were approximately $40 million**.** See **Moore Exhibit 7.**

Duke Energy's selection of Zachry to construct the beneficiation unit at the Buck Station more than doubled the construction cost when compared to the combination of H&M's cost estimate plus Duke Energy's adjustment. Therefore, I do not believe Duke Energy's selection of Zachry to construct the beneficiation unit at the Buck Station for the amount contracted was reasonable and prudent.

Q. WHAT SHOULD DUKE ENERGY HAVE DONE DIFFERENTLY TO KEEP COSTS WITHIN THE INITIAL PROJECTED AMOUNT?

A. When Duke Energy received the construction estimate from Zachry and learned that the estimated cost for the STAR facilities would be far higher than originally estimated, it should have attempted to mitigate the costs. The following are examples of options Duke Energy could have pursued:

1) Upon receiving the estimate from Zachry (which was more than double the H&M estimate), Duke should have sent the construction contract out for bid again to a broader group of companies.

2) Instead of contracting with a single company to construct all three STAR facilities, Duke Energy could have entered into three separate contracts for the construction of one STAR facility each. Because the scope of each individual project would be less, this would have almost certainly expanded the pool of bidders **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Duke Energy could have further divided the

construction of each STAR facility into separate contracts for the various components of each facility.

3) Before entering into the construction contract with Zachry for more than double the amount of the H&M estimate, Duke Energy should have sought statutory relief from the CAMA Amendment's beneficiation requirements from the General Assembly. I have been informed that such a statutory relief option exists in the context of the Renewable Energy and Energy Efficiency Portfolio Standard in NC. Gen. Stat. § 62-133.8(i)(2), and that DEC and other electric power suppliers have utilized this option multiple times to seek delays in certain requirements related to swine and poultry waste set-asides upon a showing to the Commission that the electric power suppliers made a reasonable effort to meet the requirements, and it was in the public interest to grant the delay or modification.

4) Upon receiving the estimate from Zachry and learning that the estimated cost of the beneficiation projects would be far higher than originally estimated, Duke Energy should have sought guidance from the regulator, NCDEQ, as to whether some waiver or compromise would be possible, and what the consequences would be if it did not comply with the beneficiation requirements of the CAMA Amendment.

Q. DO YOU BELIEVE THE CHANGE ORDERS TO THE CONSTRUCTION CONTRACT WITH ZACHRY WERE REASONABLE AND PRUDENT?

A. Yes. Based on my review, I believe the change orders and the associated costs were reasonable and prudent given the circumstances.

Q. PLEASE SUMMARIZE THE FOUR COST ESTIMATES DESCRIBED IN YOUR TESTIMONY.

A. The following table summarizes the cost estimates to construct the beneficiation unit at the Buck Station described in my testimony:

Table 1 (In Millions) **[BEGIN CONFIDENTIAL]**

[redacted]

[END CONFIDENTIAL]

---

[19] See **Confidential Moore Exhibit 6**.

Q. WHAT IS YOUR OPINION REGARDING WHETHER DEC'S CUSTOMERS SHOULD BE REQUIRED TO PAY FOR COSTS ASSOCIATED WITH CONSTRUCTION OF THE BENEFICIATION UNIT AT THE BUCK STATION?

A. I recommend that the Commission disallow $67,809,160 of the construction costs. The disallowance amount is the difference between Duke Energy's reasonable expectation of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which is the sum of H&M's cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and Zachry's initial total contract amount of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Qualifications of Garrett and Moore, Inc.

Garrett and Moore, Inc., specializes in engineering services for power and waste industries. We remain focused and specialized in these markets and are dedicated to continuing to advance the reputation of excellence our staff has established through the years. Our company has been responsible for the construction administration and Construction Quality Assurance for about $90 million worth of lined landfill, final cover system, and lined wastewater pond construction since 2007, with much of that work specific to CCR landfills and ash basins. We have familiarity with the federal CCR Rule and the North Carolina Coal Ash Management Act, and have tremendous experience with CCR disposal methods and their associated costs.

Vance Moore and Bernie Garrett have specialized expertise in the following areas:

Coal Combustion Residuals

Through our firm of Garrett and Moore, Inc., we have provided engineering and consulting services to support power companies in the management of coal combustion residuals (CCRs), including but not limited to the following:

- Groundwater Monitoring
- Groundwater Corrective Action
- Hydrogeological Investigations
- Site Characterization Studies
- Geotechnical Evaluations
- Stability and Liquefaction Analysis
- Ash Pond Closure Design
- FIN 47 Cost Liability Estimating
- Ash Pond Closure Construction
- Ash Pond to Landfill Conversion
- Source Remediation
- Dewatering Design
- Ash Landfill Siting & Design
- Ash Landfill Construction
- Landfill Closure & Post-Closure
- Federal CCR & CAMA Rule Guidance
- Regulatory Compliance
- Environmental / Permit Audits

Solid Waste Engineering

Through our firm of Garrett and Moore, Inc., we have provided full-service solid waste design and permitting services for municipal solid waste (MSW), construction and demolition debris (C&D), land clearing and inert debris (LCID), industrial waste, tire monofills, and coal combustion ash landfills. We have a very successful track record of overseeing landfill development projects from concept to operations. Our expertise in solid waste engineering includes the following:

- Facility Siting Studies
- USEPA HELP Modeling Analysis
- Settlement and Bearing Capacity Design
- Alternative Liner Analysis
- Stormwater Management & Design
- Equivalency Determinations
- Recyclables Program Management
- Landfill Closure & Post-Closure
- Convenience Center Planning / Design
- Waste Treatment & Processing
- Landfill Gas Remediation Plans
- Engineering Design
- Slope Stability & Liquefaction
- Leachate Management System
- Landfill Gas Planning and Design
- Operations Planning
- Life of Site Analysis
- Alternate Final Cover Evaluations
- Transfer Stations
- Compost Systems
- Special Waste Permitting
- Operations & Maintenance

Bernie Garrett and Vance Moore have been providing engineering services for CCR management projects continuously since 1995. Over the last 10 years, we have performed all engineering associated with CCR management projects at all six of SCE&G's coal fired power plants, as well as facilities owned and operated by Santee Cooper. Our credentials include the following:

■ **Vance F. Moore, P.E**

Mr. Moore is a principal and founding member of Garrett & Moore.
Mr. Moore has over 30 years of experience providing environmental engineering and consulting services to the power and waste industries. He has provided design, permitting, construction quality assurance, and operations support for numerous RCRA Subtitle D landfill projects, ash landfill projects, ash landfill closure projects, and ash pond closures in North and South Carolina.
Registrations: Professional Engineer – Georgia, North Carolina, South Carolina
Education: B.S., Civil Engineering, North Carolina State University, 1989
Associations: North Carolina SWANA Chapter - Technical Committee.
South Carolina SWANA Chapter

■ **Bernie Garrett, P.E.**

Mr. Garrett is a principal and founding member of Garrett & Moore.
Mr. Garrett has over 30 years of experience providing environmental engineering and consulting services to the power and waste industries. His experience and professional responsibilities have progressed from project engineer with a major national engineering firm, project manager on solid waste landfill projects with a regional engineering firm, to client/project manager responsible for comprehensive engineering and consulting at Garrett & Moore, Inc.
Mr. Garrett has been working on coal ash management projects continuously since 1999. He has provided design, permitting, and construction quality assurance and operations support for ash pond closures, ash landfill projects, and ash landfill closure projects.

Registrations: Professional Engineer - Georgia, North Carolina, South Carolina, Virginia.
Education: B.S. Civil Engineering, Virginia Tech (1989);
M.S. Environmental Engineering, Old Dominion University (1996)
Associations: PENC Central Carolina Chapter Board of Directors

ACEC/PENC Solid and Hazardous Waste Subcommittee

Summary of Testimony of Vance F. Moore
Docket Nos. E-7, Sub 1213, E-7, Sub 1214, and E-7, Sub 1187

The purpose of my testimony is to make recommendations on behalf of the Public Staff to the Commission regarding the closure methods selected by Duke Energy Carolinas, LLC, and the associated costs incurred between January 1, 2018, and November 30, 2019, at the coal combustion residuals units at its Allen, Belews Creek, Buck, Cliffside, and Marshall stations to comply with the Coal Ash Management Act, or “CAMA.” My testimony focuses principally on whether the Company’s actions and costs incurred in connection with the SEFA STAR ash beneficiation plant at the Company’s Buck station were reasonable and prudent.

I am a registered professional engineer with over 30 years of experience engineering coal ash management projects, including operational cost projections and alternative analyses, and construction contract administration.

In preparing my testimony I reviewed the testimony, exhibits, and workpapers of Duke Energy Carolinas’ witnesses Bednarcik and Immel. Through the Public Staff, I also submitted extensive discovery to the Company regarding its selection and analysis of coal ash beneficiation technology, and contractors to design and construct that technology. I also participated in site visits to the Company’s Buck, Belews Creek, Dan River, and Marshall stations.

Based on my review of Company records and having given due consideration to factors including CAMA and NCDEQ’s Closure Determinations on

April 1, 2019, I take no exception to the Company's requested costs for site work related to CCR storage and disposal performed at Allen, Belews Creek, Cliffside, and Marshall.

Based on my investigation, I determined that the project change orders and associated costs and SEFA's initial contract amount were reasonable and prudent given the circumstances. I also determined that the estimated cost to build the SEFA STAR facility selected by Duke Energy to comply with the CAMA Amendment's requirement to beneficiate ash more than doubled between the time of SEFA's response to Duke's Request for Information, or "RFI," and the time Zachry Construction Corporation submitted its initial contract amount to construct the SEFA STAR facility at Buck station. Through the Public Staff, I served numerous discovery requests on the Company but the Company did not provide evidence to justify this massive increase. I provide examples of possible actions Duke Energy could have pursued to mitigate the project costs. Based on my investigation, I recommend that the Commission disallow $67,809,160 of the construction costs of the ash beneficiation plant at the Company's Buck station that I believe were unreasonable and imprudent. The disallowance amount is the difference between the combination of the construction estimate provided in SEFA's response to Duke Energy's RFI and its contingency adjustment and Zachry's initial contract amount.

This completes my summary.

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

A. (Bernard L. Garrett) My name is Bernie Garrett. My business address is 206 High House Road, Suite 259, Cary, North Carolina. I'm the secretary and treasurer of Garrett & Moore, Incorporated.

Q. Thank you. Did you cause to be filed in this docket on February 18, 2020, direct testimony consisting of 50 pages and 21 exhibits, 12 of which were marked confidential?

A. Yes, I did.

Q. Do you have any corrections to that testimony?

A. No, I do not.

Q. If you were asked the same questions today, would your answers be the same?

A. Yes, they would.

Q. And, Mr. Garrett, did you prepare a summary of your testimony?

A. Yes, I did.

MS. JOST: Chair Mitchell, at this time, I move that Mr. Garrett's prefiled direct testimony and summary be copied into the record as if given orally from the stand, and that his 21 exhibits be marked for identification as premarked in the filing.

CHAIR MITCHELL: All right. Mr. Garrett's prefiled testimony and summary of that prefiled testimony will be copied into the record as if given orally from the stand. The exhibits to Mr. Garrett's prefiled testimony will be marked for identification as they were when prefiled.

(Public Staff Garrett Exhibits 3, 4, 7, 8, 9, 14, 16, 19 and Public Staff Confidential Garrett Exhibits 1, 2, 5, 6, 10 through 13, 15, 17, 18, 20 and 21 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony with Appendix A and summary of testimony of Bernard L. Garrett were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

TESTIMONY OF L. BERNARD GARRETT
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

FEBRUARY 18, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Bernie Garrett. My business address is 206 High House Road, Suite 259, Cary North Carolina. I am the Secretary/Treasurer of Garrett and Moore, Inc.

Q. BRIEFLY STATE YOUR QUALIFICATIONS.

A. I am a licensed professional engineer with 30 years of experience engineering coal ash management projects, including coal ash landfills and impoundments with services including, but not limited to, facility layout and master planning; ash landfill design, permitting, construction and quality assurance, and closure; ash impoundment closure investigations, closure design and permitting, and closure construction and quality assurance; cost engineering; facility and life of site development and operational cost projections and alternative analyses; ash management facility operations; ash impoundment material recovery and recycling; public meetings and community involvement; environmental monitoring and regulatory compliance, corrective actions, CCR Rule compliance demonstrations, and comprehensive assessments of program and facility environmental liabilities and associated costs. Relevant projects include:

- Canadys Station (Dominion Energy South Carolina, DESC, formerly South Carolina Electric & Gas, SCE&G or SCANA) near Walterboro, South Carolina
  - Ash pond closure
  - Ash landfill development
  - Corrective actions
- Cope Station (DESC) near Cope, South Carolina
  - Ash landfill development
  - Ash landfill wastewater management facility development
  - Ash landfill closure
  - Ash landfill wastewater pond closure
- Cross Station (Santee Cooper) near Pineville, South Carolina
  - Ash Landfill development and closure
- McMeekin Station (DESC) near Columbia, South Carolina
  - Ash pond closure
  - Ash landfill development and closure
  - Ash landfill wastewater pond closure
- Urquhart Station (DESC) near Beech Island, South Carolina
  - Ash landfill closure
  - Ash pond closure

- Ash landfill wastewater pond closure
- Corrective Actions

o Wateree Station (DESC) near Eastover, South Carolina
- Ash pond closure
- Ash landfill development
- Ash landfill wastewater management facility development
- Corrective Actions

o Williams Station (DESC) near Charleston, South Carolina
- Ash landfill development
- Ash landfill wastewater management facility development
- Ash landfill closure
- Ash landfill wastewater pond closure

Additional qualifications are set forth in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the results of my investigation into the prudence and reasonableness of costs incurred by Duke Energy Carolinas, LLC (DEC or Company), at its two high-priority sites, Dan River and Riverbend.

Q. WHY DO YOU SAY "PRUDENCE AND REASONABLENESS"?

A. I am not an expert in utility regulation, but have relied upon guidance from the Public Staff attorneys with respect to the legal standard for my investigation. Those attorneys inform me that under N.C. Gen. Stat. § 62-133, a utility's operating expenses must be "reasonable" to be included in the revenue requirement that is the basis for setting rates the utility may charge to consumers. Likewise, the cost of utility property allowed in the rate base, to which an authorized return may be applied, must also be "reasonable." Furthermore, I have been advised that management prudence is one aspect of this statutory reasonableness, and yet some costs or expenses can be prudent but still not reasonable for recovery as a component of the revenue requirement used for setting rates. For purposes of my testimony, I do not attempt to present the legal theory for a distinction between "prudence" and other "reasonableness"; rather, I just describe the facts that led me to conclude that a particular cost or expense is not reasonable for purposes of rate recovery.

Q. HOW DOES YOUR TESTIMONY DIFFER FROM THAT OF THE OTHER PUBLIC STAFF WITNESSES IN THIS CASE?

A. I understand that Public Staff witnesses Junis and Maness recommend adjustments based on environmental violations and the appropriate regulatory accounting treatment for coal ash-related costs. I do not address those issues. The testimony of Public Staff witness Vance Moore evaluated DEC's costs with respect to environmental regulatory compliance at its Coal Combustion Residuals (CCR) units located at the Allen, Belews Creek, Buck, Cliffside, and Marshall stations, and so our testimony together provides a combined perspective on the prudence and reasonableness of the coal ash closure costs for which DEC is seeking cost recovery in this proceeding.

Q. WHAT IS THE SCOPE OF YOUR INVESTIGATION INTO THE PRUDENCE AND REASONABLENESS OF DEC'S COAL ASH MANAGEMENT COSTS?

A. I reviewed the actions and costs incurred by DEC at the high-priority sites, Dan River and Riverbend, in meeting the Coal Ash Management Act (CAMA)[1] deadline for closure by August 1, 2019. To the extent I determined that DEC's actions and costs incurred were not reasonable and prudent, I recommend that the Commission disallow these costs.

Q. PLEASE DESCRIBE THE RESOURCES UTILIZED IN CONDUCT OF YOUR INVESTIGATION.

A. In order to prepare this testimony, I reviewed the testimony and work papers of DEC witnesses Bednarcik and Immel. Through the Public Staff, I also submitted extensive discovery to DEC regarding its actions taken and costs incurred at its high-priority sites. I also participated in site visits and conference calls with DEC personnel.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony is focused on specific aspects of DEC's CAMA compliance efforts for the two high-priority sites. First, DEC paid a fulfillment fee related to the disposal of ash from Riverbend at the

[1] 2014 N.C. Sess. Law 122, as amended by 2016 N.C. Sess. Law 95.

Brickhaven structural fill project that was not reasonable and prudent. I recommend a disallowance in the amount of $46,142,699 related to the fulfillment fee. Second, at Dan River, DEC paid a significant premium for ash excavation and disposal at the site that was not reasonable and prudent. I recommend a disallowance of $29,250,905 related to the Dan River excavation.

CHARAH FULFILLMENT FEE

Q. PLEASE DESCRIBE THE PURPOSE OF THE BRICKHAVEN STRUCTURAL FILL PROJECT.

A. The purpose of the Brickhaven Structural Fill Project was to provide disposal capacity for ash from DEC's Riverbend Station and from Duke Energy Progress, LLC's (DEP), Sutton Station.

Riverbend was a high-priority site with a closure deadline of August 1, 2019, under CAMA. Permitting an onsite landfill was not possible and therefore DEC committed to sending the approximately 5.5 million tons of ash from Riverbend off site for disposal.

Sutton was also a high-priority site with a closure deadline of August 1, 2019. Permitting an onsite landfill was possible at Sutton, but at the time DEP was contemplating the Brickhaven project, Duke Energy had not begun the permitting process and obtaining the permit was likely, but not guaranteed. In order to meet the deadline, DEP committed to sending approximately two million tons of ash from Sutton off site for disposal. DEP's plan was to then revert to the onsite landfill to save hauling costs.

Q. HOW DID THE COMPANY EXECUTE THE PROJECTS DESCRIBED ABOVE?

A. Following a request for proposal process that resulted in the selection of Charah, Inc. (Charah), as contractor and the Brickhaven and Sanford Mines[2] as alternative disposal sites, Duke Energy Business Services LLC (DEBS) on behalf of DEC and DEP (Duke Energy) and Charah executed eMax Master Contract Number 8323 (Contract 8323).[3]

Q. PLEASE BRIEFLY DESCRIBE THE SUBJECT OF CONTRACT 8323.

A. Along with **[BEGIN CONFIDENTIAL]** [redacted]

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[2] In her direct testimony, DEC witness Bednarcik refers to the Sanford Mine as the Colon Mine.

[3] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** provided by DEC as a confidential responses to Public Staff Data Request No. 20-2 in Docket No. E-7, Sub 1146, and Public Staff Data Request No. 112-19 in Docket No. E-7, Sub 1214.

[redacted]. **[END CONFIDENTIAL]** A copy of Contract 8323 is provided as **Confidential Garrett Exhibit 1.**

Q. DID EXECUTION OF CONTRACT 8323 FINANCIALLY COMMIT DUKE ENERGY TO CHARAH?

A. No. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. WHEN DID DUKE ENERGY BECOME FINANCIALLY COMMITTED TO CHARAH UNDER CONTRACT 8323?

A. Purchase Order **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. WHAT WERE THE TERMS OF THE FINANCIAL COMMITMENT FOR ASH DESTINED FOR BRICKHAVEN?

A. For ash excavated from the Riverbend Station destined for disposal at Brickhaven, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. WHAT WERE THE TERMS OF THE FINANCIAL COMMITMENT FOR ASH DESTINED FOR SANFORD?

A. Duke Energy was not financially committed for ash destined for the Sanford Mine because no purchase orders were issued for ash to be disposed of there.

Q. WHEN DID THE TERMINATION PROVISIONS OF THE CONTRACT BECOME EFFECTIVE?

A. The Termination provisions of Contract 8323 became effective on May 29, 2019. This is referred to in the contract as the Deemed Termination and is defined in Amendments 1 and 3 to Contract 8323 as follows: **[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. WHAT WAS THE STATUS OF THE PURCHASE ORDERS AT THE TIME OF THE DEEMED TERMINATION?

A. As of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** No purchase orders were issued for ash excavated from DEP's Cape Fear, H.F. Lee, or Weatherspoon Stations, or for ash to be disposed at the Sanford Mine.

Q. HOW MUCH OF THE ASH AUTHORIZED BY ALL PURCHASED ORDERS WAS DELIVERED TO BRICKHAVEN?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** were delivered to Brickhaven.

Q. DO YOU AGREE THAT THE TERMINATION PROVISIONS OF THE CONTRACT WERE TRIGGERED RESULTING IN A PRORATED COSTS CALCULATION?

A. Yes. The Prorated Cost Triggering Event occurred on June 19, 2015. As of that date, Charah had obtained all the necessary permits required to begin placing ash at Brickhaven and Duke Energy issued a purchase order for the contractor to begin placing ash at Brickhaven. Deemed Termination occurred on May 29, 2019, thereby triggering the Termination provisions of Contract 8323.

Q. HOW ARE PRORATED COSTS CALCULATED UNDER THE CONTRACT?

A. There are two components to the Prorated Costs calculation: 1) **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

Q. AT THE TIME OF THE DEEMED TERMINATION, HAD DUKE ENERGY FULFILLED ITS FINANCIAL COMMITMENTS UNDER THE AUTHORIZED PURCHASE ORDERS?

A. Yes. My answer is based on the following four key parts of the excerpts from Contract 8323 quoted above: 1) **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** In order to give effect to these terms and conditions, the quantity of ash Duke Energy was financially committed for and which should have formed the denominator in the formula for calculating the **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

Q. HAVE YOU PERFORMED YOUR OWN PRORATED COSTS CALCULATION?

A. Yes. As is noted above, the two components of the **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

.

[redacted]

[redacted] **[END CONFIDENTIAL]**

Q. DO YOU PROPOSE AN ALTERNATIVE PRORATED PERCENTAGE CALCULATION THAT WOULD BE REASONABLE AND PRUDENT?

A. Yes. For the Prorated Percentage calculation to achieve the intended and reasonable purpose of compensating Charah for the costs it was authorized to incur under Contract 8323, the denominator in the calculation (Contracted Tons) must equal the quantity of ash authorized by purchase orders. Based on the actual purchase orders, my Prorated Percentage calculation is as follows: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. DO YOU PROPOSE AN ALTERNATIVE PRORATED COSTS CALCULATION THAT WOULD BE REASONABLE AND PRUDENT?

A. Yes. Based on my recommended **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The workpaper provided as **Confidential Garrett Exhibit 2** utilizes unit rates for 1) development as calculated in **Garrett Exhibit 3** and 2) unloading and placement as shown in **Garrett Exhibit 4**.[4]

[4] DEC response to Public Staff Data Request No. 127-3 in Docket No. E-7, Sub 1214.

Q. DO YOU RECOMMEND A SPECIFIC DISALLOWANCE IN THIS RATE CASE?

A. Yes. DEC's Riverbend Station would be allocated the entire Prorated Costs amount above because **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Therefore, I recommend the fulfillment fee included in the ARO costs be reduced from $46,329,946 ($2,820.70 per ton), the portion of the fulfillment fee settlement allocated to DEC, to $187,247 ($11.40 per ton).

Q. PLEASE PROVIDE A SUMMARY OF THE FULFILLMENT FEE IN THE TESTIMONY OF DEC WITNESS JESSICA BEDNARCIK.

A. On pages 23 and 24 of her direct testimony filed on September 30, 2019, DEC witness Jessica Bednarcik discusses contracting with Charah, changes to the closure strategy, and the fulfillment fee of $80 million. Witness Bednarcik states that the "contract with Charah required Duke Energy to provide a minimum amount of coal ash for disposal at Charah's Brickhaven and Colon mines" from DEC's Riverbend Station and DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon Stations. The Charah contract was terminated after "Duke Energy did not provide the amount contracted for Brickhaven and did not send any material to the Colon mine." Duke Energy has booked the fulfillment fee of $80 million as an Asset Retirement Obligation (ARO). Witness Bednarcik states that Duke Energy is requesting recovery for $46,329,946 that "has been allocated to DE Carolinas to account for costs incurred by Charah associated with the ash from the Riverbend location, as well as future estimated costs for leachate management, capping of the landfill, and post closure maintenance." Witness Bednarcik's workpapers calculating and allocating the fulfillment fee and the settlement agreement are provided as **Confidential Garrett Exhibit 5**.[5] As to the reasonableness and prudency of the contract terms for the fulfillment fee, witness Bednarcik states "it is common and reasonable to require minimum investment from the company receiving the service" and "Even with the fulfillment costs, the Charah option was the best option for customers compared to the other options that Duke Energy had available at the time to meet regulatory requirements."

Q. IF THE COMMISSION GIVES SUBSTANTIAL WEIGHT TO THE SETTLEMENT AND PRORATED COSTS CALCULATIONS OF DUKE ENERGY AND CHARAH, DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

[5] DEC confidential responses to Public Staff Data Request Nos. 1-8 and 112-20 in Docket No. E-7, Sub 1214.

A. Yes. I have further investigated the available data leading up to and including the settlement. I describe my investigation and alternative recommendation regarding the fulfillment fee below.

Q. DO YOU AGREE THAT THE METHODOLOGY USED BY DUKE ENERGY TO CALCULATE THE PRORATED COSTS WAS CONSISTENT WITH THE TERMINATION PROVISION OF CONTRACT 8323?

A. No. Pricing was established in Contract 8323 for ash excavated from Riverbend for disposal at Brickhaven and for ash excavated from Sutton for disposal at Brickhaven. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Total costs should have been calculated based on the applicable tons of ash authorized in purchase orders and the development portion of the $/ton pricing as shown in **Confidential Garrett Exhibit 2**.

Q. CAN YOU DESCRIBE THE METHODOLOGY USED BY DUKE ENERGY?

A. Duke Energy did not use the pricing established in Contract 8323 and instead asked Charah to provide it with the development-related costs incurred. It appears that Duke Energy then reviewed the data for the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in what Charah asserted were development-related costs and excluded costs that it did not consider development-related, ultimately arriving at a figure of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The Prorated Cost calculations of Duke Energy and Charah are provided as **Confidential Garrett Exhibit 6**.[6]

The **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** discrepancy between the total development-related costs calculated by Charah and Duke Energy is evidence of the significant flaws in the Termination provisions of Contract 8323 and of the unreasonableness and imprudence of Duke Energy's execution of the contract. Due to these flaws, and because using the development-related costs calculated by Charah to calculate Prorated Costs would result in a much larger figure than the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** cost cap contained in the Prorated Costs definition, Duke Energy should not have given Charah's Prorated Costs calculation any weight in settlement negotiations.

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[6] DEC confidential response to Public Staff Data Request No. 112-20 in Docket No. E-7, Sub 1214.

Q. DID YOU IDENTIFY ANY OTHER PROBLEMS WITH THE PRORATED COST CALCULATIONS BY DUKE ENERGY AND CHARAH?

A. Yes. I reviewed the notes provided by Charah for each line item presented in **Confidential Garrett Exhibit 6** and identified the following problems: **[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

Q. ARE YOU PROPOSING ANY ADJUSTMENTS BASED ON DUKE ENERGY'S OWN PRORATED COSTS ANALYSIS?

A. There are too many flaws and errors in the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to use the evaluations as the basis for total development cost in the Prorated Costs Calculation.

Q. DID YOU PERFORM YOUR OWN EVALUATION OF THE STATUS OF BRICKHAVEN DEVELOPMENT AT THE TIME CONTRACT 8323 WAS TERMINATED?

A. Yes. I first reviewed the status of the structural fill development relative to the permit drawings approved by NCDEQ.

The review was completed to understand the **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

I reviewed each "Permit to Operate, Approval to Commence Operations" issued by NCDEQ for the development and operations at Brickhaven. Once each cell or subcell is constructed, the Owner submits a Construction Quality Assurance certification report to NCDEQ for review and approval. The approval must be issued by NCDEQ before ash is placed in a cell or subcell.

Based on the dates tabulated in **Garrett Exhibit 7**, I believe Charah developed Brickhaven only as reasonably necessary to accommodate the phased ash volumes authorized under the applicable purchase orders.

Note that the majority of the cell development occurred in 2016 and 2017. The last subcell was ready for ash disposal on January 9, 2019, and the final ash delivery occurred in March 2019.

Charah was also required to submit "Partial Closure Notifications" to NCDEQ as the developed cells reached final grade. Charah submitted five "Partial Closure Notifications" for Brickhaven, the last of which was submitted on September 5, 2019. See **Garrett Exhibit 8**.

Based on this evaluation it appears that Charah fully utilized the capacity that was developed and did not become overextended (or prematurely incur costs prior to a purchase order) in the development of disposal capacity at Brickhaven.

Q. DID YOU PERFORM YOUR OWN EVALUATIONS OF THE DEVELOPMENT COST INCURRED AT BRICKHAVEN?

A. Yes. I prepared my own cost analysis, which is presented in **Garrett Exhibit 9**, to determine whether Charah was fully reimbursed for actual costs it incurred relative to the amounts recovered under the purchase orders. Knowing the status of development documented above, I relied upon my own expert, professional judgement to conclude that a reasonable cost for the work completed at the Brickhaven structural fill project was $82,313,644. It is important to note that my analysis was limited to the cost of work completed by Charah at Brickhaven, which was reimbursable under the Development portion of the Unloading/Development/Placement $/ton price. I excluded the cost of change order work at Brickhaven that was paid to Charah in a lump sum amount. As an example, at the time Charah entered Contract 8323, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** In other words, the Unloading/Development/Placement unit rate was not adjusted to compensate Charah for this oversight.

Q. WHAT CONCLUSIONS DID YOU DRAW FROM YOUR INDEPENDENT COST ANALYSIS?

A. In summary, there is not a significant disparity between my total cost calculation of $82,313,644 and Duke Energy's own total cost calculation of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Given that Charah was paid approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** under the development portion of the Unloading/Development/Placement $/ton price, I conclude that Charah was reasonably reimbursed for the actual development cost incurred at Brickhaven under the Development portion of the Unloading/Development/Placement $/ton price in the purchase orders.

Q. DO YOU HAVE A PRORATED COSTS CALCULATION BASED ON THE TOTAL COST PRESENTED ABOVE?

A. I strongly object to the use of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the reasons stated above. However, if the Prorated Percentage calculation as defined is utilized, the Prorated Percentage calculation is as follows: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** If this Prorated Percentage of 63.29% were to be used, which I find to be unreasonably high, then the fulfillment fee should be equal to my Prorated Costs calculation as follows: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** See **Confidential Garrett Exhibit 6**, page 2.[7]

Q. DO YOU HAVE A RECOMMENDATION FOR HOW TO ALLOCATE THE FULFILLMENT FEE IF THE COMMISSION DEEMS THIS PAYMENT WAS APPROPRIATE?

A. Yes. I recommend that the allocation be based on Duke Energy's methodology illustrated in **Confidential Garrett Exhibit 10**.[8] That

[7] DEC confidential response to Public Staff Data Request No. 112-20 in Docket No. E-7, Sub 1214.

[8] DEP confidential response to Public Staff Data Request No. 14-6 in Docket No. E-2, Sub 1142.

allocation methodology was used consistently throughout Duke Energy's own alternatives evaluations to select closure methods for the intermediate and low-priority sites. My calculation of the allocation percentage to Riverbend is as follows: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** My calculation of the fulfillment fee allocated to Riverbend is as follows: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** See **Confidential Garrett Exhibit 11**. Therefore, I recommend that the fulfillment fee included in the ARO costs in this proceeding be reduced from $46,329,946 to $59,880.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THE FULFILLMENT FEE?

A. Yes. Section 7.4 of Contract 8323 states: **[BEGIN CONFIDENTIAL]**

[redacted]

[END CONFIDENTIAL]

In addition to the Recovery Amount terms, the Company has a potential future need to supplement the beneficiation projects at

Buck, Cape Fear, and H.F. Lee with additional disposal capacity to meet closure deadlines. This could result in Duke Energy exercising the terms of Section 7.6 of Contract 8323 that states: **[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

See **Confidential Garrett Exhibit 1**. Considering these two factors, I recommend that any consideration of fees paid for land acquisition at the Sanford Mine be excluded from this proceeding.

DAN RIVER EXCAVATION

Q. PLEASE EXPLAIN THE PROBLEMS THAT OCCURRED WITH EXCAVATING COAL ASH AT THE DAN RIVER PLANT.

A. On October 3, 2016, DEC issued an invitation to bid on a contract for the Phase 2 excavation and transportation of coal ash from the Dan River plant impoundments to the on-site landfill area. **[BEGIN CONFIDENTIAL]** [redacted]. [redacted] **[END CONFIDENTIAL]** See **Confidential Garrett Exhibits 12 and 13**, respectively.[9]

Q. HOW WOULD YOU ASSESS PARSONS' PERFORMANCE ON THE PROJECT?

A. From March 15, 2017, to May 30, 2017, no ash was moved by Parsons because the landfill was not yet ready to receive ash. After issuance of a Permit to Operate by NCDEQ on May 30, 2017, Parsons was authorized to begin the Sequence 1 & 2 excavation. **[BEGIN CONFIDENTIAL]** [redacted]

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[9] DEC confidential response to Public Staff Data Request No. 2-9 in Docket No. E-7, Sub 1214.

[redacted] **[END CONFIDENTIAL]** Sequence 1 & 2 excavation ash includes all ash known at the time to be located in the impoundments (Primary Basin, Secondary Basin, and Intermediate Dike) and was subject to a closure date of August 1, 2019, under CAMA. This schedule provided a contingency of approximately 12 months for CAMA compliance.

I reviewed the Semi-Annual Report on Closure and Excavation Asheville, Dan River, Riverbend, and Sutton (Semi-Annual Report), [10] dated July 31, 2019, and concluded the following: 1) approximately 1.4 million tons of ash were moved between June 1, 2017, and September 1, 2018, and 2) there appear to be periods of time when no ash was moved. Comparing the Key Milestones to the actual figures from the Semi-Annual Report, the expectation was that Parsons would move approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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[10] *Available at* https://www.duke-energy.com/_/media/pdfs/our-company/ash-management/192394--seminnual-report-on-closure.pdf?la=en (last visited February 12, 2020).

Q. WERE THERE ANY EXTENUATING CIRCUMSTANCES THAT MAY HAVE CONTRIBUTED TO THE SHORTFALL?

A. Yes. **Garrett Exhibit 14** presents monthly precipitation data for 2018 for the City of Eden, where the Dan River Station is located.[11] The total precipitation for 2018 was 70.91 inches, as compared to an average annual precipitation of 45.56 inches. There were relatively high precipitation months in May, July, August, and September of 2018, which coincide with Duke Energy's termination of the Contract 20588 and the purchase orders.

Given my experience, it is not surprising that the frequent and severe rainfall events during 2018 caused significant delays in construction and earthwork across the State of North Carolina. Typically, during rain days or inclement weather days the labor force is called off and does not log time or invoices on the project.

Q. HOW WOULD YOU DESCRIBE DUKE ENERGY'S ASSESSMENT OF PARSONS' PERFORMANCE ON THE PROJECT?

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[11] Station 312631 – Eden Monthly Precipitation Data for 2018. *Available at* http://climate.ncsu.edu/ (last visited February 12, 2020).

A. I would characterize Duke Energy's assessment of Parsons' performance to be unflattering and unfair to Parsons given the circumstances. Duke Energy's assessment is provided as **Confidential Garrett Exhibit 15**[12] and **Garrett Exhibit 16**.[13]

Q. WHEN WAS CONTRACT 20588 TERMINATED AND WHY WAS IT TERMINATED?

A. On September 14, 2018, DEC sent Parsons a letter stating that it would terminate the contract effective October 12, 2018. The letter did not provide an explanation for the termination. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[12] DEC confidential response to Public Staff Data Request 112-13 in Docket No. E-7, Sub 1214.

[13] DEC response to Public Staff Data Request 193-1 in Docket No. E-7, Sub 1214.

[14] Confidential Garrett Exhibit 15.

Q. DID DEC HAVE REMEDIES SHORT OF TERMINATION IF IT BELIEVED PARSONS WAS NOT MEETING THE TERMS OF CONTRACT 20588?

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted]

[END CONFIDENTIAL]

Q. DO YOU HAVE ANY CONCERNS WITH THE WORK DEC PAID PARSONS FOR?

A. Yes. While Parsons was performing the excavation, DEC issued a series of revisions to the contract payments due to difficulties Parsons encountered during the project. I recommend that the Commission disallow some of the costs because I believe DEC overpaid for some of the revision work.

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]** I recommend that the Commission disallow this amount.

Q. PLEASE PROVIDE A SUMMARY OF THE DELAYS EXPERIENCED BY DEC DURING THE PROJECT.

A. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

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[15] DEC confidential response to Public Staff Data Request No. 112-13(d) in Docket No. E-7, Sub 1214.

[redacted]

[END CONFIDENTIAL] See **Confidential Garrett Exhibit 18**.

Q. CONSIDERING THE FACTORS NOTED ABOVE AND KNOWING THE DEADLINE FOR CAMA COMPLIANCE WAS LESS THAN 12 MONTHS AWAY, WOULD IT HAVE BEEN REASONABLE AND PRUDENT FOR DEC TO SEEK AN EXTENSION UNDER CAMA?

Yes. CAMA, as amended, provides a procedure for an impoundment owner to request a variance if compliance with the closure deadline

[16] DEC response to Public Staff Data Request No. 193-1(a)(ii) in Docket No. E-7, Sub 1214.

cannot be achieved.[17] Requesting such a variance would have been a reasonable and prudent way for Duke Energy to address the impact of the delays described above on the excavation schedule.

Q. DID DEC SEEK A VARIANCE?

No. The Public Staff requested through discovery that DEC "indicate whether the Company requested a variance from NCDEQ to the regulatory deadline for the Dan River excavation and closure." In response,[18] DEC stated, "The Company did not request a variance from NCDEQ to the regulatory deadline because the scheduled completion date of May 31, 2019, had sufficient margin for regulatory compliance." See **Garrett Exhibit 19**. This response insufficiently addresses and materially contradicts the concerns Duke repeatedly expressed about meeting the closure deadline of August 1, 2019, that led to its termination of its contract with Parsons.

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[17] In recognition of the complexity and magnitude of the issues surrounding the management of coal combustion residuals and coal combustion residuals surface impoundments, the General Assembly authorizes the Secretary to grant a variance to extend any deadline under this act, on the Secretary's own motion, or that of an impoundment owner, on the basis that compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public.

N.C. Gen. Stat. § 130A-309.215(a)

[18] DEC response to Public Staff Data Request No. 193-1(f) in Docket No. E-7, Sub 1214.

Q. DID DEC SEEK A VARIANCE AT ANY OTHER HIGH-PRIORITY SITES?

Yes. The Semi-Annual Report discussed above, states on page 29:

> On November 16, 2018, Duke Energy submitted to the North Carolina Department of Environmental Quality an application for a variance to extend by six months (until February 1, 2020) the CAMA closure deadline applicable to the 1971 and 1984 Ash Basins at Sutton. Based on NCDEQ's analysis of the information submitted by Duke Energy, NCDEQ partially granted the variance extending the closure date for Sutton by four months to December 1, 2019.
>
> However, the Sutton site has completed excavation required under CAMA without having to use the Variance extension. The excavation production quantities have been better than planned this reporting period. Good weather has been the major contributor for the results. The Wilmington area experienced below normal rainfall levels during the first six months of this year.

On March 26, 2019, NCDEQ issued its Decision Granting in Part Variance with Conditions[19] that extended the closure date four months to December 1, 2019, for the 1971 and 1984 Basins at Sutton and ordered Duke Energy to provide monthly reports detailing the quantities of ash removed and the estimated volume remaining. The granting of the variance is evidence that an extension was a viable option that Duke Energy was aware of.

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[19] *Available at* https://files.nc.gov/ncdeq/Coal%20Ash/Sutton-Variance-Combined.pdf (last visited February 17, 2020).

Q. PLEASE SUMMARIZE THE OPTIONS AVAILABLE TO ADDRESS THE SCHEDULE ISSUES.

A. As of September 2018 DEC had four options to address the schedule issues:

1. Request a variance to extend the CAMA regulatory deadline and continue excavation with Parsons as the contractor.
2. Request a variance to extend the CAMA regulatory deadline and continue excavation based on negotiated rates with a new contractor.
3. Attempt to meet the CAMA deadline by continuing excavation based on negotiated rates with Parsons as the contractor.
4. Attempt to meet the CAMA deadline by continuing excavation based on negotiated rates with a new contractor.

Duke Energy selected option four and elected to pay a premium to meet the CAMA closure deadline.

It is important to note that, while DEC had incurred delays in execution of the project that were beyond its control as noted above (i.e., zoning, permitting, and adverse weather), the discovery of what DEC believed was an additional 460,000 cubic yards of ash was a significant contributing factor to the cost premiums discussed later in my testimony. Unlike the zoning, permitting, and adverse weather delays, the delays caused by the additional ash were within Duke Energy's control because it was Duke Energy's responsibility to accurately quantify the ash to be excavated and define the scope of work for the contractor to meet CAMA compliance deadlines.

Q. EXPLAIN HOW DEC COMPLETED THE EXCAVATION OF COAL ASH AT THE DAN RIVER PLANT.

A. DEC **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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[20] Confidential Garrett Exhibit No. 15.

Q. DO YOU HAVE ANY CONCERNS WITH THE WORK DEC PAID TRANS ASH FOR?

A. Yes. While Trans Ash was performing the excavation, DEC issued a series of revisions to the contract payments due to difficulties that Trans Ash encountered during the project and issued a new purchase order for an entirely new scope of work to condition the ash prior to excavation and transport. I recommend that the Commission disallow some of these costs because I believe DEC overpaid for some of the revision work.

First, I recommend that the Commission disallow the cost for **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** Given that DEC had other, less costly options for completing the excavation at Dan River, I do not believe its payment to Trans Ash of costs **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was reasonable or prudent.

Second, I recommend that the Commission disallow the cost for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

As detailed above, there were other options available to DEC to address the delays in the excavation schedule, but DEC chose the most costly option by paying a premium to **[BEGIN CONFIENDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** which included scope that was not subject to the CAMA deadline.[21]

Q. WHAT CIRCUMSTANCES EXISTED THAT CONTRIBUTED TO PROJECT DELAYS?

A. The delays started before Parsons was selected to complete the work and continued as it attempted to begin the work. I briefly summarize below the circumstances as described in the Parsons-authorized change orders that led to delays. **[BEGIN CONFIDENTIAL]**

[redacted]

[21] Ash Stack 2 and the decommissioning of the dam, which combined made up approximately one-third of the ash that was excavated during the project, were not subject to the CAMA closure deadline.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

Q. PLEASE SUMMARIZE THE COSTS INCURRED AND THE SPECIFIC DISALLOWANCES THAT YOU RECOMMEND.

A. A summary of my recommended disallowances is shown below:

Table No. 1 **[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. WHAT DO YOU RECOMMEND REGARDING THE INCREASED COST CREATED BY PARSONS?

A. I recommend that the Commission disallow $29,250,905 on a system basis from the Asset Retirement Obligation cost for basin closure at the Dan River plant for the following reasons:

1. DEC had the opportunity to set a performance bond in the initial contract with Parsons but did not. This bond would have insured DEC against losses created by Parsons.
2. DEC had the opportunity to require security when it realized Parsons was falling behind schedule but did not.
3. DEC could have imposed back-charges on Parsons for work completed by Trans Ash but did not.
4. DEC overpaid Parsons for contract revisions as described above.
5. As a result of firing Parsons and hiring Trans Ash, DEC paid an unreasonable premium to have the scope of work completed, including the settlement.
6. DEC overpaid Trans Ash for contract revisions including **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** as described above.

7. DEC paid a premium to complete the excavation of ash that was not subject to CAMA requirements before the CAMA closure deadline.
8. DEC paid a premium to complete the excavation of ash that was not in the original plan before the CAMA closure deadline rather than seek a variance to the statutory deadline. Requesting a variance from NCDEQ would have taken little effort and offered potential cost savings.

In summary, had DEC obtained an extension to the CAMA closure deadline, as it did at Sutton, the premium costs identified above for disallowance would not have been incurred.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Qualifications of Garrett and Moore, Inc.

Garrett and Moore, Inc., specializes in engineering services for power and waste industries. We remain focused and specialized in these markets and are dedicated to continuing to advance the reputation of excellence our staff has established through the years. Our company has been responsible for the construction administration and construction quality assurance for about $140 million worth of landfill construction and closure, ash basin closure, and wastewater management facility construction since 2007, with much of that work specific to CCR landfills and ash basins. We have familiarity with the federal CCR Rule and the North Carolina Coal Ash Management Act and have tremendous experience with CCR disposal methods and their associated costs.

Vance Moore and Bernie Garrett have specialized expertise in the following areas:

Coal Combustion Residuals

Through our firm of Garrett and Moore, Inc., we have provided engineering and consulting services to support power companies in the management of coal combustion residuals (CCRs), including but not limited to the following:

- Environmental Monitoring
- Hydrogeological Investigations
- Geotechnical Evaluations
- Ash Pond Closure Design
- Ash Pond Closure Construction
- Source Remediation/Corrective Action
- Ash Landfill Siting & Design
- Ash Landfill Closure & Post-Closure
- Regulatory Compliance
- Ash Landfill & Ash Basin Operations
- Groundwater Corrective Action
- Site Characterization Studies
- Cost Engineering and Forecasting
- FIN 47 Cost Liability Cost Estimating
- Ash Pond to Landfill Conversion
- Dewatering Design
- Ash Landfill Construction
- Federal CCR & CAMA Rule Guidance
- Environmental / Permit Audits
- NPDES & Stormwater Management

Solid Waste Engineering

Through our firm of Garrett and Moore, Inc., we have provided full-service solid waste design and permitting services for municipal solid waste (MSW), industrial waste, coal combustion residual (CCR) waste, construction and demolition debris (C&D), land clearing and inert debris (LCID), MSW & CD waste processing and recovery, and scrap tire processing and monofills. We have a very successful track record of overseeing landfill development projects from concept to operations to closure. Our expertise in solid waste engineering includes the following:

- Facility Siting Studies
- USEPA HELP Modeling
- Geotechnical Engineering
- Alternative Liner and Final Cover Design
- Stormwater Management & Design
- Equivalency Determinations
- Recyclables Program Management
- Landfill Closure & Post-Closure
- Convenience Center Planning / Design
- Waste Treatment & Processing
- Landfill Gas Remediation Plans
- Engineering Design
- Cost Engineering
- Leachate Management Design & O&M
- NPDES Wastewater Design & O&M
- Landfill & Wastewater Operations Planning
- Life of Site Analysis
- Waste Processing and Recovery
- Transfer Stations
- Compost Systems
- Special Waste Permitting
- Operations & Maintenance

Bernie Garrett and Vance Moore have been providing engineering services for CCR management projects continuously since 1995. Over the last 14 years, we have performed all engineering associated with CCR management projects at all six of Dominion Energy South Carolina's coal fired power plants, as well as facilities owned and operated by Santee Cooper. Our credentials include the following:

■ **Vance F. Moore, P.E**

Mr. Moore is a principal and founding member of Garrett & Moore. Mr. Moore has 30 years of experience providing environmental engineering and consulting services to the power and waste industries. He has provided design, permitting, construction quality assurance, and operations support for numerous RCRA Subtitle D landfill projects, ash landfill projects, ash landfill closure projects, and ash pond closures in North and South Carolina.

Registrations: Professional Engineer – Georgia, North Carolina, South Carolina
Education: B.S., Civil Engineering, North Carolina State University, 1989
Associations: NC SWANA Chapter - Technical Committee; SC SWANA Chapter

■ **Bernie Garrett, P.E.**

Mr. Garrett is a principal and founding member of Garrett & Moore. Mr. Garrett has 30 years of experience providing environmental engineering and consulting services to the power and waste industries. His experience and professional responsibilities have progressed from project engineer with a major national engineering firm, project manager on solid waste landfill projects with a regional engineering firm, to client/project manager responsible for comprehensive engineering and consulting at Garrett & Moore, Inc.

Registrations: Professional Engineer - Georgia, North Carolina, South Carolina, Virginia.
Education: B.S. Civil Engineering, Virginia Tech (1989)
M.S. Environmental Engineering, Old Dominion University (1996)

Associations: PENC Central Carolina Chapter Board of Directors; ACEC/PENC Solid and Hazardous Waste Subcommittee

Summary of Testimony of L. Bernard Garrett
Docket Nos. E-7, Sub 1213, E-7, Sub 1214, and E-7, Sub 1187

The purpose of my testimony is to make recommendations on behalf of the Public Staff to the Commission regarding the closure methods selected by Duke Energy Carolinas, LLC, or "DE Carolinas," at its two high priority sites, Dan River and Riverbend, to comply with the Coal Ash Management Act, or "CAMA." The primary focuses of my testimony are whether the fulfillment fee DE Carolinas paid its contractor Charah, Inc., related to the disposal of ash from Riverbend station at the Brickhaven Mine, and the premium DE Carolinas paid for ash excavation at the Dan River site were reasonable and prudent.

I am a registered professional engineer with 30 years of experience engineering coal ash management projects, including the design and permitting of industrial landfills, the closure of coal ash impoundments, the closure of coal ash landfills, and facility and life of site development and operational cost projections and alternative analyses.

In preparing my testimony, I reviewed the testimony, exhibits, and workpapers of DE Carolinas witnesses Bednarcik and Immel. I also participated in site visits to the Buck, Belews Creek, Dan River, and Marshall stations and conducted extensive discovery through the Public Staff.

Based on my investigation, I concluded that DE Carolinas acted unreasonably and imprudently in entering into a contract with Charah for the disposal of ash from Riverbend station at the Brickhaven Mine. Specifically, I concluded that the termination provisions of the contract contained fundamental flaws that resulted in DE Carolinas paying an unreasonable and imprudent fulfillment fee to Charah which DE Carolinas seeks to recover in this rate case. Based on my analysis and conclusions, I recommend the fulfillment fee included in the ARO cost in this docket be reduced from $46,329,946, or $2,820.70 per ton, to $187,247, or $11.40 per ton.

I also concluded based on my investigation that DE Carolinas overpaid for ash excavation at the Dan River site as a result of its failure to reasonably plan and manage the work at the site to meet the CAMA deadline. Based on my analysis and conclusions, I recommend a disallowance in the amount of $29,250,905 related to the Dan River ash excavation. This disallowance is warranted due to a series of imprudent decisions by DE Carolinas' management team at Dan River, which led to DE Carolinas' unjustified firing of its original contractor and its hiring of a replacement contractor at a significant premium.

This completes my summary.

MS. JOST: Thank you. The witnesses are available for cross examination.

CHAIR MITCHELL: All right. We will begin with the Attorney General's Office.

MS. TOWNSEND: No questions, Chair Mitchell.

CHAIR MITCHELL: All right. Thank you, Ms. Townsend.

All right. Duke?

MR. MARZO: Thank you, Chair Mitchell. There is Brandon Marzo on behalf of Duke Energy Carolinas. I do have some questions for the witnesses this morning. We will get into confidential, Chair Mitchell, at some point. What I've tried to do, Mr. Garrett, Mr. Moore, as well as Chair Mitchell, is to organize my questions such that we could avoid that. At the point in time we cannot avoid it, I have tried to consolidate all that to one exercise so that we don't have to jump on and off the phone.

CHAIR MITCHELL: All right. Thank you, Mr. Marzo. Just make sure you alert me when we get to that point in time.

MR. MARZO: Okay. Thank you,

Chair Mitchell.

CROSS EXAMINATION BY MR. MARZO:

Q. Good morning, Mr. Garrett and Mr. Moore.

A. (Bernard L. Garrett) Good morning.

A. (Vance F. Moore) Good morning.

Q. I'm going to start off with some general questions to both of you, and then I'm going to ask some specific questions about your recommendations in this case starting with Mr. Garrett.

In regards to the general questions that I'd like to ask to both of you, my first question is essentially: Would you agree with me that reasonableness and prudence is decided on a case-by-case basis and must consider multiple factors?

A. (Bernard L. Garrett) Yes, I would agree with that.

A. (Vance F. Moore) I would also agree.

Q. Thank you, Mr. Moore. Thank you, Mr. Garrett.

Would you also agree that the lower cost options may not always be the reasonable and prudent decision?

A. (Bernard L. Garrett) Depending on specific circumstances, as you mentioned, and numerous factors,

yes, that could be the case.
A. (Vance F. Moore) I would agree that cost is just one of the factors.
Q. Thank you, gentlemen. And finally, would you agree that alternatives propose -- alternative proposed actions must be feasible in order to be truly alternatives?
A. (Bernard L. Garrett) Yes, I have no problem with that statement.
A. (Vance F. Moore) I would agree that it must be a practical alternative.
Q. Thank you, gentlemen. I think my questions now will be directed primarily to you, Mr. Garrett, for this first part in reference to your Dan River recommendation.
And it's my understanding from your testimony that you're recommending that the Commission disallow costs which you contend amount to premium rates for ash excavation and disposal at Dan River; is that correct?
A. (Bernard L. Garrett) Yes, sir; that's correct.
Q. And my understanding is that -- sorry.
My understanding is you question the Company's termination of Parsons and transition to

TransAsh; is that correct?
A. Yes, I did. That's part of the basis for my recommended disallowances.
Q. Can we agree that, at the time of Parsons' termination on the project, Parsons was experiencing significant difficulty?
A. I believe that Parsons, as far as their performance on the contract, was meeting their contractual obligations up until the time of around June of 2018 when they first fell behind their cumulative production schedule.
Q. Okay. Could you, if you would, please turn to DE Carolinas Cross Exhibit 34. Do you have that? I'll give you a second to grab that.
A. Cross Exhibit 34.
MR. MARZO: And while you're looking for that, the document I've referred Mr. Garrett to is Duke Energy's court-appointed monitor bimonthly update, which was submitted to United States District Court on September 14, 2018.
Chair Mitchell --
THE WITNESS: Yes. I have that up now.
Q. Thank you, Mr. Garrett.
MR. MARZO: Chair Mitchell, I'd like to

mark that as Garrett and Moore -- DEC Garrett and Moore Cross Exhibit 1.

CHAIR MITCHELL: All right. The document will be marked DEC Garrett and Moore Cross Examination Exhibit Number 1.

(DEC Garrett/Moore Cross Examination Exhibit Number 1 was marked for identification.)

Q. Okay. And I think, Mr. Garrett, you've seen this document before, correct?

A. Yes, I have reviewed this.

Q. Okay. And could you turn to page 4 of the document, please?

A. Yes, sir.

Q. And would you mind reading from the top paragraph that begins "while these problems"? Would you mind reading the first two sentences of that paragraph for me, and then I'm going to ask you some questions about that.

A. "While these problems originated with the contractor, Duke personnel acknowledged the need for increased oversight and were working to learn from this mistake while sharing successful strategies between other ash sites. The root" -- continue?

Q. Yes, continue. Yes, sir.

A. "The root cause appears to be ineffectiveness of the contractor's use of well-point dewatering, the use of groundwater pumps connected to chimneys in the ash basins to suck water out, which led to the land filling of overly moist ash and the cascade of other landfill erosion problems."

Q. Thank you, Mr. Garrett.

Now, are you aware that the contractor being referenced here is Parsons?

A. Yes, sir.

Q. And am I correct from the last sentence of this paragraph, the monitor has asked to be kept informed as to the progress; is that correct?

A. Yes, that's correct.

Q. Now, can we -- I'm sorry, go ahead, Mr. Garrett. I didn't mean to interrupt.

A. I see that in the last in the paragraph, yes.

Q. And can we agree that Dan River was a high-priority site with an August 1, 2019, excavation requirement in CAMA?

A. Yes, sir.

Q. And are you aware that, under the Parsons contract, Parsons was required to submit to Duke Energy recovery plans if key milestones were delayed or reasonably forecasted to be delayed?

A. I am familiar with the fact that Parsons submitted recovery plans at Duke Energy's request, yes.

Q. Okay. And to that point, recovery plans were submitted to Duke when the contractor had fallen behind, correct?

A. I'm aware of those, yes.

Q. Okay. And so are you aware that, from the period of March 16, 2018, to August 16, 2018, Parsons submitted six recovery plans?

A. I don't recall the exact number. But I --

Q. Okay. You take that subject to check?

A. They submitted recovery plans, yes.

Q. And those recovery plans were needed because of key delays in schedule in a five-month period; are you aware of that?

A. Well, the delays in the schedule occurred prior to this five-month period you're discussing. The delays are well documented in the record, and many of them -- and as far as the longest delays, most of those occurred prior to Parsons beginning work on the project.

Q. Okay. Mr. Garrett, let me understand this.

Do you disagree that Parsons fell behind and had to submit six recovery plans?

A. I believe that Parsons was behind schedule, as far as -- if you turn to my Exhibit 13. On page 39 of this exhibit, this is the Maximo purchase order number 5067043 --

MS. JOST: Excuse me, this is --

Q. And I think we're -- yeah. I just want to be careful here. And once again, Mr. Garrett, I want to give you an opportunity to respond, but are you going to read me something, or were you just going to point me to something?

A. I'm going to point to the --

Q. Because this document is still confidential, yeah.

A. Yeah. It's -- it is the key milestone schedule, which provides the month-by-month cubic yards that are in Parsons' contract. I don't believe that information would be confidential. There's no dollar amounts associated with it.

Q. It is part of the contract that is confidential, but to the extent you'd like to reference back to that, we will be going off to the phone line.

A. Well, I can just note that, in reference to this schedule, Parsons, based on my records, first fell behind in June of 2018.

Q. Okay. Thank you, Mr. Garrett. And I guess one of the questions I had about your review of Parsons and its interaction on the project, it's my understanding that you did not review any of the recovery plans prior to coming to your recommendation in this case; is that correct?

A. No, I believe I did. We did have recovery plans submitted during the data responses.

Q. Yeah. And they were submitted, for example, in response to Data Request 231-10, the recovery plans were submitted. And that data request was issued after Ms. Bednarcik responded to your testimony rebuttal; is that your understanding?

A. Thank you for clarifying that.

Q. Okay.

A. And I would say that, you know, I have a significant amount of experience preparing bid documents, construction documents, and performing construction administration on large-scale construction projects such as this. And, you know, the fact of the matter is, when a contractor loses a day of work due to adverse weather conditions, it's nearly impossible to make that day up. Once you have lost a day of work, the only real relief for a contractor is to have a day of extension on the contract.

So recovery plans, while they were required in the contract to be submitted, there is only so much a contractor can do once they've fallen behind due to adverse weather conditions.

Q. Okay. Mr. Garrett, I understand you're referring to adverse weather conditions, but can we agree that, on any complex project, there are going to be any number of factors that might cause or challenge the schedule to a project, correct?

A. Yes, sir.

Q. And weather may be one of those challenges, correct?

A. Well, weather -- weather is the -- I would say also it interrelates with weather, but the ability to dewater an ash pond in order to allow the contractor to maintain production is probably one of the most critical aspects. It interrelates with adverse weather. And based on my reading of Parsons' contract, Duke Energy was responsible for the discharge of all wastewaters from the Dan River site.

Q. Okay. And you understand that Duke Energy was also responsible for oversight of that contractor, correct?

A. They were responsible for maintaining adequate discharge so that the contractor could meet his production schedules, yes.

Q. Mr. Garrett, that wasn't my question.

What I asked you was, you understand that Duke Energy Carolinas, as the party that was overseeing the contractor, was also responsible in assessing the contractor's performance, correct?

A. Yes, they were -- they were overseeing the contract and --

Q. Okay.

A. -- the contractor simultaneously; yes, sir.

Q. Okay. And, for example, you could have a number of things that challenge a project. Weather could be a challenge, there could be a dewatering challenge, as you point out, but there could also be a contractor that's not performing; that's a challenge.

And am I correct that you would expect someone who was overseeing that type of project to address all of those challenges?

A. Within the -- as long as those challenges are within their control, yes.

Q. Okay. And clearly, whether or not you maintain a contractor on a site, on a project, is within the control of Duke Energy Carolinas in this case, correct?

A. Would you repeat that? I'm sorry.

Q. Sure. Clearly, whether or not you continue with a contractor is well within the purview of the Company as it pertains to these projects, correct?

A. Yes. Ultimately, that's their decision, whether to continue with a contractor, yes.

Q. Now, we talked about the recovery plans that weren't reviewed until after you had submitted your recommendation, but there were also sequenced excavation plans that were submitted to you after you had submitted your recommendation in this case, correct?

A. Are you talking about sequenced excavation plans submitted by Parsons?

Q. Exactly. Those weren't requested by you until after Ms. Bednarcik filed her testimony in this case, correct?

A. Yes.

Q. Okay. Now, Duke Energy terminated Parsons on October 12, 2018; is that your understanding?

A. Yes.

Q. Okay. And I know you said you didn't look closely at the recovery plans, but is it your understanding that the sixth recovery plan of the last one, which was the sixth one submitted by Parsons, was submitted about 12 months prior to the CAMA deadline?

A. Yes, it would have been right around September, yes.

Q. Now, in your testimony, you suggest that DE Carolinas should have sought an extension under CAMA; is that correct?

A. I believe, based on the adverse weather conditions almost alone, there was justification to go to DEQ and request an extension. I believe that was a feasible option for them at the time when they were making the decision to change contractors, yes.

Q. Okay. And specifically on page 50 of your testimony, you state that requesting a variance from DEQ would have taken little effort.

A. Little effort, as in relative to the amounts that were spent to recover TransAsh's schedule, yes.

Q. Okay. Let's talk about what would have been little effort. If you would, for me, would you turn to DEC Cross Exhibit 38?

A. 38?
Q. Yeah.
A. Could you tell me what that is.
Q. Sure. It's the variance authority regulations.
A. Okay. Is that Section 130-A-309.215?
Q. Yes, sir.
A. Okay. Yes, sir, I have that in front of me now.
Q. And just to be sure, Mr. Garrett, you're not getting an echo from me, are you?
A. I can hear you fine.
Q. Okay. I just wanted to be sure. Okay. This is a copy of the variance statute from CAMA which is the section of CAMA that addresses the deadline variance requirements.
MR. MARZO: Chair Mitchell, I would just ask that the Commission take notice of the statute. I don't think we need to mark it as an exhibit.
CHAIR MITCHELL: The Commission will take judicial notice of the statute.
Q. Now, although you're not a lawyer, you understand that the statute provides no assurance or guarantee that an extension request will be granted,

correct?

A. Yes, there would be no guarantee.

Q. And, in fact, the decision to grant or deny a variance request is solely within DEQ's discretion, correct?

A. The decision is made by DEQ, yes.

Q. And there are some key elements in the statute in terms of what is required to be shown in order to get a variance, and I want to point you to specifically section (a)(1); do you see that?

A. Yes, sir.

Q. Okay. And right around the middle, Mr. Garrett, of (a)(1), there is a sentence that begins with the words "the owner," and I'm just going to, for efficiency, read that for you, and you tell me if I read that correctly. It says:

"The owner of the impoundment shall also provide detailed information that demonstrates the owner has substantially complied with all other requirements and deadlines established by this part; ii, the owner has made good faith efforts to comply with the applicable deadline for closure of the impoundment; iii, the compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and will produce serious hardships without equal or greater benefits to the public."

Did I read that correctly?

A. Yes, sir. And I believe that, based on my review, Duke Energy could have checked all three of those boxes unless they, themselves, thought they had not made good faith efforts to comply with the applicable deadline.

Q. Okay. So let's talk about that, because the first element is a good faith element.

And are you aware that, as of September 2018, Duke believed that it could replace Parsons and complete the excavation work at Dan River?

A. I know that TransAsh provided a schedule and an ash production -- you know, monthly ash production rate to Duke Energy that Duke Energy relied on in making a decision to switch to TransAsh. And I do know that TransAsh, themselves, was unable to meet that production schedule that they submitted to Duke Energy. That was the basis for the decision to switch in October.

Q. But we both know -- I believe you know this, Mr. Garrett, is that switching to TransAsh, Duke didn't complete the Dan River excavation within the CAMA deadline, right?

A. Not on the basis of TransAsh's proposal to them. Only after incurring their costs that I have documented in my testimony, which were above and beyond costs that were the basis of their decision to switch to TransAsh.

Q. And I appreciate that, Mr. Garrett, but I do want to understand that you agree to my questions. So I want to make sure we don't have a disagreement on that.

Do we agree that Duke did replace Parsons with TransAsh and was able to complete the project within the CAMA deadline?

A. Yes. Only with incurring the costs that I have recommended for disallowance, yes.

Q. Okay. And you talked about there being some additional costs related to TransAsh, but are you aware that even switching to TransAsh, the project came under the forecasted contingency amount?

A. Well, you know -- and I believe that TransAsh had the benefit of Duke Energy seeking increases in the wastewater discharges that they were allowed and permitted to discharge. Parsons was not a beneficiary of that relief. So I -- in my opinion, you know, TransAsh's ability to meet the schedule was largely helped by the fact that Duke Energy sought to increase the amount of wastewater that they could discharge to the city of Eden.

They also increased the amount of discharge by implementing outfall 002 and a treatment system which went into effect early of 2019.

Q. So let me understand this, Mr. Garrett.

Are you suggesting that Duke Energy did not do things to assist Parsons to successfully complete the project?

A. I believe that Parsons' performance on the project was significantly limited by the permitted discharges to the city of Eden, which Duke sought to increase from 0.3 MGD to 0.6 MGD in October of 2018 while simultaneously submitting to DEQ, a request to utilize outfall 002, which gave them the ability to discharge 1.5 MGD of interstitial water.

Q. And, Mr. Garrett, I understand that you're focused on the dewatering aspect of the project, and I think we talked about earlier, there's often several challenges that can face a project like this. And one of the challenges could be a contractor that's not performing up to the level that's expected.

And is it your opinion that, in that occasion, you'd expect Duke to address each and every challenge; not just one challenge, but to address all the challenges, correct?

A. Yes. And I believe the most significant challenge facing Parsons was wet ash. And I believe Ms. Bednarcik even discussed this in her testimony about how you can't -- you can't excavate, and you certainly can't landfill and meet compaction requirements on wet ash. The ash must be dried. And if you're limited in the quantity of water that you can discharge from the site, you can't achieve adequate dewatering to maintain any type of production schedule.

Q. Now, have you reviewed Public Staff Data Request 193-1?

A. Could you just describe that?

Q. Sure. It's a nonconfidential data request. And I was going to ask you some questions, and I want to make sure you understand what I'm asking is not confidential. It may be part of a confidential document, but this particular request was not. So let me ask you a couple of questions, and feel free to respond to me with what I'm asking you, because it's not -- it's included within the data request that's not confidential.

Now, you mentioned earlier that you felt like Duke was not assisting Parsons, you know, may have been assisting TransAsh.

Are you aware that Duke held calls with senior management as early as May of 2018 with Parsons senior management to discuss issues with their work at the site?

A. Well, May of 2018 -- May of 2018 is the first date that Parsons began to fall behind schedule, yes. So I believe it would have been appropriate to have conversations with them at the time.

Q. And are you aware that the Company worked with Parsons and allowed their leadership team to visit active excavation sites, such as Sutton, where TransAsh was excavating to see how excavation was going well and to take those lessons learned?

A. Yes, sir. And I'd say that the chief difference between Dan River and Sutton was the quantity of water they could dewater and discharge from the plant. They were not limited at Sutton. The only limitation at Sutton was a specific flow of the interstitial water of around one and a half to two

million gallons a day. That was the primary difference between the two sites.
Q. I appreciate that, but you are aware that Duke also brought in teams from Sutton and River Bend to assist in giving lessons learned to Parsons at the Dan River site?
A. Yes. But I -- you know, I don't know that they, you know, showed them how to overcome handling wet ash.
Q. And are you aware that the Company helped Parsons with both the development of the stockpile management plan and the landfill weather resistant plan?
A. Well, yes, I'm familiar with those plans, yes.
Q. Okay. Now, have you reviewed the March 26, 2019, decision granting in part variance with conditions?
A. Would you repeat that?
Q. Yeah. It's DEC Exhibit 35. Cross Exhibit 35, Mr. Garrett.
A. Yes, I have read this. I believe I reviewed this during my preparation of my testimony.
Q. Okay. And it's the March 26, 2019, decision

granting in part variance with conditions, correct?
A. Yes.
Q. Okay. And this is in reference to Sutton, which you utilize in your testimony as an example of when Duke has sought a variance and gotten a variance, correct?
A. Yes. It's the only variance that I'm aware of that Duke has sought, yes.
Q. And I assumed from your statements in your prefiled testimony that you believe, in part at least, that this took little effort to seek and receive this extension?
A. I don't know that I would characterize it as little effort unless you are comparing it in terms of cost to the Company. This was an administrative exercise, gathering documents, personnel that had to work on this. But in contrast to dollar amounts in a construction project, yes, little effort.
Q. Okay. And I'm just using your language, Mr. Garrett, so however you mean little effort is what I'm using, is my clarification as to what I believe you were trying to say in your testimony.
A. Yes. No, it was an administrative exercise that took time to put together. I don't dispute that.

Q. Okay. You called it an administrative exercise, but let's look at some of the details and see how much is administrative and potentially how much is not.

A. Okay.

Q. Would you look at page 4 for me, paragraph 7 in particular. And this paragraph has paragraph --- subparagraph 7C, and this is the department's conclusions regarding certain steps and actions that Duke Energy had taken. And would you for a minute read 7C for me?

A. Yes. Like read it out loud or?

Q. No, you don't have to read it out loud, just to save you the time of having to do that.

A. Sure.

Q. Just let me know when you're finished with that, and I have a couple of questions I want to ask you about it.

A. (Witness peruses document.)

MR. MARZO: Chair Mitchell, for the record I would like to mark Exhibit 35, DEC G&M Cross Exhibit, I believe, 2.

THE WITNESS: Okay. Yes, I've read it.

CHAIR MITCHELL: All right. Mr. Marzo,

the document will be marked DEC Garrett and Moore Cross Examination Exhibit Number 2.

MR. MARZO: Thank you, Chair Mitchell.

(DEC Garrett/Moore Cross Examination Exhibit Number 2 was marked for identification.)

Q. Okay. So in making the application -- if I look at 7C, in making the application for variance, Mr. Garrett, DE Progress had to make a variety of showing, such as excavating an average rate of 150,000 tons per month of ash, expediting completion of that landfill, expanding dredging operations, adding a third conveyer, simultaneously operating three dredges, and taking various additional measures; is that correct?

A. That's what paragraph 7C states, yes.

Q. Okay. And that's more than administrative, correct?

A. That's -- that is a -- that's documenting efforts that were made at the project site.

Q. Okay. And those were efforts -- can we agree, efforts that were necessary to justify asking for a variance?

A. I believe that those were actions taken at the Sutton plant during the course of the project.

Q. Now, are you aware that one of the additional measures that DE Progress took was moving to a 24-hour, 7-day-a-week schedule?

A. Well, that's not exactly correct. Are you talking about Sutton plant?

Q. I'm talking about the application for Sutton's variance.

Are you aware before making this request they went to a 24-hour, 7-day-a-week schedule?

A. What I recall in this document is that they operated a double shift on the dredge. Sutton had very deep ash, which required deep excavations, which could only be accomplished by a dredge. And they went to, I believe, two 10-hour shifts on operation of the dredge. But I do not believe they went to any 24/7 hauling of ash from the ash basin to the landfill. If you could point that in here -- out in here, that would be great.

Q. Well, if you disagree, Ms. Bednarcik will be here to take that up later. I don't have a document to show you. But I'm just asking you are you --

A. It would be -- it would be in this document, correct?

Q. So you disagree that they went to a 24-hour-a-day, 7-day-a-week schedule?

A. I have not seen that document.

Q. Okay.

A. Yeah.

Q. Are you aware --

A. I know they did the dredge work on a double shift.

Q. Okay. And I understand that you disagree with that, Mr. Garrett, and we can definitely bring clarity to that in our rebuttal.

Are you aware that DE Progress also had provided detailed information regarding technology that DE Progress was deploying to overcome delays, as well as additional technology that had to be evaluated?

A. Yes, but there's really no specifics provided on the technology that I see in paragraph D. But I'm sure that, you know, they presented everything that they had used on the site to try and meet the deadline, which would be appropriate.

Q. Okay. And it's your perspective that that takes little effort to do that?

A. To write paragraph C or D?

Q. Well, let me understand your "little effort," because maybe there's just my confusion about how you're using that.

Are you simply saying it takes little effort to write up a variance application; or are you saying it takes little effort to actually justify one?

A. No. I believe that -- when I say little effort, I'm not talking about all the work that Duke did at the project site to try and achieve the deadline. When I refer to little effort, I'm talking about preparing the request, the paperwork required to request an extension. And as far as its applicability to Dan River, there's many documents in the record that detail delays that Duke had to overcome at Dan River, many of them which were not of their making, which all would have been efforts made, technology used to meet the CAMA deadline.

Q. Okay. And what we do know, Mr. Garrett, is that, by changing out the contractor, Duke did make the deadline that CAMA prescribes, correct?

A. They did, yes.

Q. Okay. And so -- and maybe I could sum up some of my clarification questions now that I have a better understanding of your little effort.

You do agree, then, that in terms of meeting the requirements in the statute to request a variance takes significant effort, correct?

A. I believe that -- that Duke undertook extraordinary efforts at Dan River with everything they had to accomplish in order to meet the CAMA deadline. But I believe that preparing a document to submit to DEQ would have been a relatively straightforward step for them to take in September when they were contemplating the change of contractors.

Q. And you would agree that would only be an appropriate step if Duke believed in good faith it could substantiate what's required by the statute in that request?

A. I believe, if Duke would have had the total cost in front of them that they ended up paying to TransAsh to meet the deadline, that they would have been more compelled to seek a variance.

Q. And as we mentioned earlier, you understand that the total costs expended for the project came in under the contingency amount for the project, correct?

A. Yes. Contingencies, that -- that still does not, in my mind, make these costs acceptable.

Q. Now, your final suggestion is that DE Carolinas continue to meet deadline -- the deadline by continuing excavation based on the negotiated rates with Parsons as the contractor.

Now, you understand that, as we talked before, Parsons had significant issues making schedule during the time period this decision would be made, correct?

A. I believe if -- if Duke had the ability to discharge one and a half million gallons per day the whole time that Parsons was on the project, their performance would have been significantly more acceptable.

Q. And that's not my question, Mr. Garrett.

What I'm asking you is that 12 months prior to the CAMA deadline, your alternative is that Duke should wait it out with Parsons who has not been performing up to schedule and just pray that they can make the CAMA deadline, correct?

A. I think the -- as far as meeting the deadline with Parsons, I'm not convinced that that was not a feasible option, considering the fact that they were providing relief through their additional dewatering.

Q. And I assume -- and you talk about that being a feasible option to make the CAMA deadline -- you are assuming that that would have to be done with some level of overtime as well as some conditioning requirements for the ash, correct?

A. Not -- not really. Based on -- if you look at Parsons' overall production rates, I believe, if you extrapolate those out, it's close to the deadline. But based on their historic performance, had they continued to achieve what they achieved prior to that, they would have been close to ending at the deadline.

Q. Okay. Even -- I'm sorry, Mr. Garrett, please finish.

A. I don't believe they would have finished by May of 2019, but it would have been -- it would have been feasible, I believe.

Q. And you think it would have been reasonable and prudent, based on the compliance deadline, that Duke Energy just roll the dice and hope that Parsons can improve its performance?

A. I would have sought a variance as a back-up plan.

Q. Okay. Thank you, Mr. Garrett. I'm going to move on to Mr. Moore.

Once again, Mr. Moore, I'm going to ask you some questions that hopefully are not intended to illicit any confidential information. We will have a confidential part of the call, so we may transition during this line to that, and I'll let the Chair know when that happens. Is that fine with you, Mr. Moore?

A. (Vance F. Moore) Yes, sir.

Q. Okay. Thank you. Now, if I understand your testimony correctly, you're recommending that the Commission disallow recovery of certain destruction costs at Duke Energy Progress, H.F. Lee, Cape Fear's beneficiation plant, and for this case, Bucks beneficiation plant; is that correct?

A. Specifically in this case, we're discussing Buck. If you want to go to Duke Energy Progress, we are talking about the other two beneficiation plants.

Q. I mean, the recommendation is for the -- your disallowance recommendation is generally the same for all of them, which is why I mentioned all of them; is that correct?

A. That is correct.

Q. Okay. We're only going to talk about Buck here, but I just wanted to clarify that the recommendation you're making here is generally the same recommendation in the Progress case.

Now, you're familiar with CAMA's beneficiation requirements, correct?

A. That is correct.

Q. And your testimony does not take issue with

Duke Energy's selection of Buck as a beneficiation site, correct?

A. Correct.

Q. Or any of the beneficiation sites, for that matter, in this case, correct?

A. Correct. Correct.

Q. And you agree that the Company's decision to award the engineering contract to SEFA was reasonable and prudent; is that correct?

A. That is correct.

Q. Okay. Okay. And my understanding from your testimony is you do not take issue with any of the change orders issued by SEFA or Zachry, correct?

A. Not in my testimony, correct.

Q. Okay. And your sole concern, from what I can garner, is that you believe the estimate of EPC project costs included in Zachry's master contract was higher than the construction streaming estimate provided in SEFA's response to the Company's request for information; is that a fair recitation of your position?

A. Yes, sir.

Q. Okay. Now, SEFA's RFI response included in part the EPC cost information from the Winyah STAR facility South Carolina; is that correct?

A. I disagree with that completely. I think that their response was based upon their experience of building a similar plant, but their costs were not simply saying this is what the SEFA Winyah plant costs. What they presented in their RFI response was, based on our experience building similar technologies, we believe a plant meeting CAMA requirements would cost in the amount that they presented. So I do not believe it is saying this is what the Winyah plant cost.

Q. Okay. We can agree, Mr. Moore, that that estimate had to be based much something, correct?

A. I believe it's based upon building a technology to meet the CAMA requirements.

Q. And what we know is, at the time that the RFI was provided to SEFA, there were no site-specific details provided to SEFA in order to respond and make its own estimate for site-specific specification; is that correct?

A. I believe that they did not identify the specific sites, correct.

Q. Okay. And at the time of the RFI, the Company had not determined the location for the beneficiation site or provide any sort of design detailed engineering upon which to base a cost estimate, correct?

A. That is correct.

Q. Okay. And --

A. I think that needs to be clarified is the importance of that. From the standpoint of -- you know, we use a term sometimes of you have a plant site that has certain -- you know, a building with certain components inside of that building. And are we talking about how the components would be different in each one based on the site, or are we talking about how the foundation for the floor will be different for the building based upon the site? So I think it's important to talk about Duke -- are we changing components and each plan is unique in the way that the process runs based about the site selection? Or is it the selection -- or how you have to build foundations and roads to access it make it unique?

Q. And you actually, I think, are partly maybe eliminating some of my questions by making the point that I'm trying to make.

A request for information, Mr. Moore, is a very different thing than a request for proposal, correct? In a -- for example -- and I'll let you obviously have a chance to respond.

A request for information is just that, an opportunity to gather information; and a response to request for information, you may have a SEFA, for example, provide information that it generally has about the cost of a facility somewhere as an estimate. And request for proposal, when you're actually committing, executing the contract, signing an agreement that will basically bind you to a cost, you need a lot more detailed information about what those costs will be and exactly what you're committing to; would you agree with that?

A. I would agree they did not have all the information. I believe that the information that they had were not orders of magnitude different than what the basis of their response were.

Q. Okay. You think -- is it your experience with requests for informations that the response you get are execution-ready estimates?

A. I do not. Therefore, my recommendations are not based upon it being execution.

Q. Okay. Now, it's your recommendation that Duke should have sought statutory leave from CAMA limits for beneficiation requirements from the General

Assembly; is that correct?

A. I believe I thought that that was one of the options they could have pursued; that is correct.

Q. Okay. And have you reviewed the beneficiation statute, which is in the CAMA amendments?

A. I have.

Q. Okay. And could you please turn to DEC Cross Exhibit 39.

A. Yes. Can you give me a minute? For some reason, my cross exhibits end at 37. I have 30 through 37.

Q. Sure. Take your time, Mr. Moore.

A. I think I can find them directly. Give me just a second.

Q. And I'm happy to give you the statute site too, if you prefer to just look it up online. Just let me know.

A. I would like to think that this is going to be a simple process. Give me just a second.

(Witness peruses document.)

All righty.

Q. If it helps, Mr. Moore, I mean, what I'm going to ask you -- I'm not going to mark this either. I was just going to ask the Chair to take judicial notice of it. But I think I'm going to ask you some questions that you're probably going to know just from having read the statute, I'm not going to have you --

A. Sure.

Q. -- read it. So if you want to take that subject to check, and your counsel can obviously jump in if she thinks I misread something.

A. I'm comfortable with that.

MR. MARZO: Chair Mitchell, because I did introduce it, if we could not mark -- not mark, if we could just take judicial notice of the statute.

CHAIR MITCHELL: The Commission will take judicial notice of 130A-309.216.

MR. MARZO: Thank you, Chair Mitchell.

Q. Now, can we agree that the General Assembly was very specific regarding the type of beneficiation projects it intended to have constructed and the timetable for that operation? And specifically, Mr. Moore, what I was going to refer you to was the fact that, within the statute it says explicitly that the beneficiation facility must be capable of processing 300,000 tons of ash annually to specifications appropriate for submitting as PURPA products?

A. Yeah. And I interpret this to mean 300,000 -- when you look at these, there's an input into the plant and there's an output on the back side of the plant. I will refer to the 300,000 as the output on the product side.

Q. And I think, as you indicated, you'd expect to get 300,000 tons out of the plant, correct? So you may have some more in to get that much out; is that correct?

A. I believe the record will show you do have to process more to get this much out.

Q. Now, no later than 24 months after issuance of all necessary permits, the statute provides that the units could be in operation; is that your understanding as well?

A. It says it in paragraph B for sure.

Q. Okay. And can we agree that the statute went into effect before the IFR -- RFI, I'm sorry, was issued by Duke?

A. Oh, it did; yes, sir.

Q. Okay. So it's fair to say that the requirements in the statute aren't premised on the RFI estimates submitted by SEFA, correct?

A. Restate that. Are --
Q. I just want to make clear. The RFI response that SEFA submitted, that has nothing to do with what the legislature took into account when the General Assembly put in place the statute, correct? Because --
A. Are you asking me was this statute available and known at the time that SEFA replied to the RFI?
Q. I'm actually asking you the reverse, the converse of that question, which is would you agree with me that the RFI was not available to the legislature, the General Assembly when they created the statute. It came --
A. I believe -- I believe this statute was created prior to any response to the RFI.
Q. Thank you.
A. I believe that the RFI was actually submitted in response to the requirements of this statute.
Q. Thank you. And you'd agree with me that there was no contemplation, at the time the statute was put in effect, that the contracting would be done with H&M; is that fair, kind of follow along to the earlier question?
A. Yes, sir.
Q. And we can agree, within this statute, there

is no mention of cost at all; is that correct?

A. Other than the variance authority.

Q. Okay. The variance authority is not in the statute we're reviewing right now, correct?

A. That's correct. It came out later.

Q. Now, in support of your alternative that the Company should have sought relief from CAMA, you reference, I believe -- and I'm going to probably get the site wrong, but it's North Carolina gen stat 62-133.8(i)(2), which I understand to be the renewable energy and efficiency portfolio standards.

A. Yes, sir.

Q. Okay. And I know you're not a lawyer, but you understand that the renewable energy and efficiency portfolio standard statute you reference is not part of CAMA?

A. Yes, sir, I do realize that.

Q. Okay. So this isn't a law that governs beneficiation projects, correct?

A. Correct.

Q. Now, you also suggest that the Company should have inquired of DEQ what the consequences would be if Duke did not comply with the beneficiation requirements of CAMA; is that correct?

A. Would you please repeat that?

Q. Sure. You also suggest in your testimony, or recommend as an alternative, that Duke should have inquired of DEQ what the consequences would be if Duke did not comply with the beneficiation requirements of CAMA, correct?

A. I believe that I thought that they should have informed DEQ of the -- of the excessive costs and sought a variance based upon that.

Q. Okay. So just so I completely understand it. So Duke being fully capable of complying and having taken steps to develop the beneficiation projects that are required by the General Assembly, it's your alternative recommendation that Duke should have just gone to DEQ and asked them what are you going to do if I choose not to comply with the law?

A. So I guess this is where -- I understand that you say Duke is fully capable of complying with the law, but what's happening is, by their action, they're making all ratepayers pay for their compliance of the law. They're not paying for it and saying -- just taking it out of Duke coffers; they're asking for reimbursement to comply based on ratepayers.

So I believe, due to the cost of this

regulation and the impact it may have to ratepayers, that they could have sought some relief; yes, sir.

Q. Well, let me ask this question, because I didn't see this in your testimony, Mr. Moore.

Do you have any information that the General Assembly did not understand the cost consequences of this statute before they issued it?

A. Well, only thing I can do is understand what I believe was really available information. I believe, based on being in the industry, that -- I believe that the legislature was lobbied for this type of legislation. I believe there was information where this type of technology had existed and what the costs were in other parts. So I believe the best information they had was the information that was provided to them at the time that they were adopting this legislation.

Q. And that's all speculation, isn't it, Mr. Moore?

A. It is absolutely speculation.

Q. Because I think earlier you said you do not know.

A. I do not know. It is speculation.

Q. Now, you reviewed the Commission's rate case order -- or have you reviewed the Commission's rate case order in Docket E-7, Sub 1146?

A. If I recall correctly, I provided testimony in that case, I believe.

Q. Yeah, you did, sir. And, in fact, that was the last Duke Energy Carolinas rate case that you testify in, and I should have probably identified it that way to make it a little easier in terms of not -- just giving docket numbers.

Have you reviewed that order?

A. I have. It's been some time since I read it, but I have definitely read it.

Q. And before I ask you this question related to the order, is it your position that statutory requirements and deadlines are just suggestions?

A. No, I don't believe they're just suggestions.

Q. Okay. Thank you. Let me site you to page 305 of that order, and that's actually DEC Exhibit -- Cross Exhibit, I believe, 1.

A. All right.

Q. Now, if you -- it's a long ordinance, a long page here, it's all single spaced. But if you would for me, look at the first -- first paragraph at the top.

A. Of the first page?

Q. Of 305, page 305.
A. 305. Give me a second to get there, please.
Q. Yes, sir. You just let me know when you -- when you've gotten there.
A. (Witness peruses document.)
Okay. Does it have at the top the ending of a previous paragraph and then the first complete paragraph starts with "Williams" --
Q. The first --
A. -- "proposal"?
Q. Exactly, sir; yes, sir. If you look roughly seven sentences -- seven sentences down -- or not sentences, but seven lines down, there's a sentence that starts with the word "the CAMA deadlines."
A. Yes, sir.
Q. Would you mind reading that for me?
A. "The CAMA deadlines provide the overarching framework by which prudency must be assessed. 2018 DEP rate order, page 185. In addition, witness Kerin noted" --
Q. You can keep going if you want to, Mr. Moore, but that's really all I wanted you to read.
A. Yes, sir.
Q. Yeah. And the order will speak for itself in

terms of the other part, but for efficiency, I don't need you to read the whole paragraph.

A. Yes, sir.

Q. The same language -- and I think you just maybe answered my next question by pointing out the cite.

So the same language also appears in a Duke Energy Progress order, correct?

A. That's correct.

Q. And would you expect the Company did read that order and has acted accordingly by trying to make sure its conduct falls in line with the deadlines required by CAMA?

A. Sure. Yes, sir.

Q. So let's turn, if we could -- well, let me ask you this question before we turn to confidential.

Now, turning to your contention that costs from Buck, Lee, and Cape Fear beneficiation units should have been analogous to costs to Winyah facility, have you looked at Ms. Bednarcik's rebuttal testimony in this case?

A. I have. And again, when you say analogous to Winyah --

Q. Yeah.

A. -- I believe Winyah is a point in data, but I do not believe -- it's an example. I do not believe that I have ever said that it should be -- Winyah is a comparable identify -- I mean, identical-type facility and it should be used as the basis. I believe what I have said is that Winyah is an actual operating facility that was constructed, and is in operation, and gives the people that build it an idea of what it will take to build a similar facility that meets the CAMA requirements.

Q. Okay. And it could, in fact, be the basis of SEFA's estimate, correct, from that part of the issue that we're discussing here?

A. Yes, sir, I believe it is the basis of their estimate.

Q. And did you review Ms. Bednarcik's DEP testimony prior to preparing your testimony today?

A. Did I -- my testimony that was filed in February?

Q. I'm sorry. I should correct that, Mr. Moore.

Did you review Ms. Bednarcik's DEP testimony prior to preparing to taking the stand today?

A. I have read Ms. Bednarcik's testimony for -- are we saying specifically Duke Energy Carolinas and

Duke Energy Progress?

Q. Yes, sir. And the exhibits. I assumed you had read them. I'm just asking that question.

A. Yes, sir. Yes, sir.

Q. Now, if you could, would you please turn to DEC Cross Exhibit 36.

(Reporter interruption due to overlapping speech.)

THE WITNESS: Number 36?

Q. Number 36.

CHAIR MITCHELL: All right. Mr. Marzo, I missed your direction. Would you point me again to where you were looking?

MR. MARZO: Sure, Chair Mitchell. I asked Mr. Moore if he will please turn to Duke Energy Carolinas Exhibit 36.

THE WITNESS: Would that be DEP Bednarcik Rebuttal Exhibit 8.

Q. Yes, sir. If you have that and it's more handy, that would be the exact same document.

A. Okay. I believe I have that document available.

Q. Okay. Thank you, Mr. Moore.

MR. MARZO: Chair Mitchell, I would like

to mark this document as DEC G&M Cross Exhibit Number 3.

CHAIR MITCHELL: All right. Mr. Marzo, the document will be marked DEC Garrett/Moore Cross Examination Exhibit Number 3.

(DEC Garrett/Moore Cross Examination Exhibit Number 3 was marked for identification.)

Q. Now, taking a look at paragraph 4 of this affidavit, which is the affidavit of William R. Fedorka, which was also, as you indicated, provided in response in Ms. Bednarcik's rebuttal in Duke Energy Progress.

He is the vice president of the SEFA group; is that correct?

A. That's correct, as identified here.

Q. Okay. And if you look at paragraph 4 of this document, how many tons of ash per year was the Winyah unit designed to generate?

A. It says:

"As originally designed, the Winyah STAR was intended to generate 250,000 tons per year of beneficiated fly ash under normal operation."

So that would be comparable -- that output would be comparable to the CAMA's 300,000 tons per year.

Q. Now, you say "comparable," but as you just acknowledged, there's about a 50,000-ton-of-ash difference per year. And as you suggested earlier, that in your opinion is the output needed, correct?

A. I believe this 250,000 tons stated here is an output that is consistent with the same 300,000 tons as an output referenced in CAMA. I'm not referring to them as being the same number. I'm saying that they both represent what comes out of the final product from the plant.

Q. Okay. And I did not see in your testimony any sort of design detailed analysis as to the impact of costs of going from 250 to 300, correct?

A. That is correct, I did not.

Q. Now, looking at paragraph 6 of the affidavit, what percentage of ponded versus production ash was the Winyah unit intended to process?

A. Well, I'm reading this, and I said as originally designed, the Winyah STAR specification assumed that 33 percent of the ash to be processed in the facility would be supplied directly from operations at the Winyah generating station. So I believe that

that's referring to production ash from the plant. It never went to an ash basin. And 67 percent of the ash to be processed and so it will be supplied from impoundments located at the state at the Winyah generation station are elsewhere in the Sandy Cooper system. So this is implying 67 percent would be ponded ash and 33 percent would be production ash.

And again, it's using the term "designed." I would like to expand on that, if we have some time. And what I would say is I don't disagree that this is what was designed. I'm saying there is other documents, as referenced in my exhibits, that talk about what Winyah station is fully capable of. It says in their response to the RFI that we were referring to earlier that Winyah station is fully capable of processing 100 percent ash supply from impoundments.

Q. Now --

A. It can operate at full capacity even when the Winyah generation station is offline.

Q. So are you disagreeing with the affidavit provided by the -- Mr. Fedorka who is the vice president of SEFA group and --

A. I'm not disagreeing with it -- excuse me, I didn't mean to overtalk. I'm not disagreeing. You know, this is specifically saying as originally designed. You know, that was the intended. I do not believe that he -- what he says here is contradicting even what SEFA said in their response to the RFI. I believe it may have been originally designed, but he's also saying it is fully capable of processing 100 percent ponded ash, which is also from SEFA.

Q. And it's your opinion that a unit that is designed to the specifications that are listed here by Mr. Fedorka, is equivalent to a unit that's designed to process 100 percent ponded ash? Because that's the design that's required in North Carolina for Duke's unit.

A. I understand that. But I'm saying that the -- it's not in this affidavit, but it's certainly in the response to the RFI that the Winyah station is fully capable of processing 100 percent ponded ash.

Q. And I understand that that's your response, but I want to make clear the Winyah station was not designed to process 100 percent ponded ash, correct?

A. I think we're discussing minutia when you talk about designed. And I'm not aware -- he didn't make any indication here of what designs would be changed for him to -- what -- if it was designed for

100 percent, that that would actually require differences in equipment and in such at the plant.

Q. Okay.

A. The design is fully capable of it.

Q. And you didn't do that type of analysis either, Mr. Moore, correct?

A. I did not. But I'm just saying, as it says here, doesn't indicate to me that, you know, the design actually changed, because he certainly indicated it is fully capable of doing 100 percent ponded ash.

Q. Looking at paragraph 8 of the affidavit, do you see that SEFA was able to repurpose significant existing infrastructure, including the storage dome, a load-out silo, truck loud-outs, a bag house, gas coolers, a control room, and elements of electrical equipment when building the Winyah STAR facility?

A. I believe that they did use some equipment at that facility that was repurposed and used ultimately for the STAR facility. And I believe that, in my opinion, the difference of -- when they said that, they're saying this is what the Winyah station. So of course the Winyah station to publish articles out there say that it was -- I don't believe if I say that number that's confidential, is it?

Q. Well, we're about to go into confidential in a moment. I've got one last question I can ask you, and if you want to reserve that.

A. I will reserve it without using the numbers. But I'm saying there are published numbers that are out there that are referred in my exhibits of what SEFA indicated the Winyah station costs. Those published articles do not indicate how much existing infrastructure was utilized and what was -- you know, does that refer only to new equipment or repurposed equipment. But I do not believe their response to the RFI was based on the assumption of using repurposed equipment.

Q. Would you agree with me -- I know in your testimony you reference various public articles, but in this case we have the affidavit of Mr. Fedorka from SEFA.

Would you agree with me that he is saying that they reuse significant equipment at the Winyah site?

A. Yes, I would -- I'll certainly agree that he indicated they used, you know, certain equipment. He certainly did not attempt to put the value of the significant equipment and what it would have cost or what this significant equipment, say versus building it from scratch.

Q. Okay. And just for clarity for the Commission's purposes, and I think you just said that Duke's units are entirely new construction, correct?

A. I agree; yes, sir.

Q. Okay.

MR. MARZO: Madam -- Chair Mitchell, at this point, the remainder of my questions will be confidential. Would you like us to transition over?

CHAIR MITCHELL: Mr. Marzo, yes, but I would like to take a break first, so let's do this. We are going to take a 15-minute break for the court reporter. At 10:20 we will join the -- we will join the teleconference line that you-all have provided for purposes of continued examination on confidential information. So just to be clear, we will take a break for the court reporter until 10:20. At 10:20, we will go back on the record, but we will be on the teleconference line.

MR. MARZO: Thank you.

CHAIR MITCHELL: All right. We are in recess until 10:20.

(At this time, a recess was taken from 10:05 a.m. to 10:26 a.m.)

(Due to the proprietary nature of the testimony found on pages 309 to 363, it was filed under seal.)

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CHAIR MITCHELL: All right. Let's go back on the record, please. Mr. Mehta -- I do not see Mr. Mehta at this point, but I want to respond to his request this morning regarding DEC witness Lioy. I have consulted with Commissioners and Commission staff, and we have no questions for Mr. Lioy, so he may be excused from being presented for examination purposes.

MR. MEHTA: Thank you, Chair Mitchell. I will let him know, and I'm sure he will not be unhappy.

CHAIR MITCHELL: All right. Let's proceed, Ms. Jost, with you.

MS. JOST: Thank you.

Q. Mr. Garrett, I have a few questions for you. If we could refer to what was marked as DEC Garrett/Moore Cross Exhibit 1.

MS. JOST: And, Mr. Marzo, if you could please remind us which potential cross exhibit this was.

MR. MARZO: I believe, 1 -- just give me one second. Yeah, number 1 was 34, Cross Exhibit 34.

MS. JOST: Thank you.

Q. And so Mr. Marzo referred you to the first paragraph on page 4 of that document; do you recall that?

A. (Bernie L. Garrett) Is this DEC Exhibit 34 Bednarcik Rebuttal? I'm not sure which document you're referring to.

Q. This is DEC -- yes. Exhibit 34. So this is the Duke Energy court-appointed monitor bimonthly update dated September 14, 2018.

A. Yes, that's the one I'm on.

Q. All right. And so he had you read the first -- from the first paragraph of page 4; do you recall that?

A. Yes, I do.

Q. And so can you tell me, is there anything in the second paragraph on that page that would have impacted the progress of the excavation?

A. The second paragraph says:

"Besides the logistical issues, the site has also faced severe rains over the summer, and recent measurements have revealed that original estimates of total ash did not account for approximately 460,000 tons of ash."

Q. Yeah. So is there anything about that that would have impacted the progress of the excavation by Parsons?

A. Yes. The severe rains over the summer would have impacted Parsons' progress, certainly with -- when you consider the limits on the discharge available from the site by the permits and the treatment capacity provided by Duke.

Q. Were those factors that were within Parsons' control?

A. Parsons was not in control of the quantity of wastewater that could be discharged from the site. And Parsons was also not responsible for quantifying the amount of ash that needed to be excavated by the CAMA deadline.

Q. And so was there anything that was done after -- subsequent to this date that would have helped Parsons deal with that water?

A. Yes. I'll walk you through the pretreatment permit with the city of Eden --

Q. And before you get there, let me go ahead and introduce that as an exhibit.

MS. JOST: And so I would request that what was premarked as Public Staff Redirect 57, and this begins -- let's see, this is the city of Eden, it's a request for approval of an increase of daily flow. This is document dated October 23, 2018.

THE WITNESS: Yes. The flow in the --

Q. And hold on, let me just -- I'm sorry. Let me get that marked.

CHAIR MITCHELL: Ms. Jost, could you give us the page number that appears at the bottom of the document?

MS. JOST: Yeah, hold on, let me -- I have a different copy, I'm afraid. Sure. So the page number appearing on the bottom of document is 1,637.

MR. MARZO: Ms. Jost, what redirect exhibit this was that again?

MS. JOST: 57. Oh, I'm sorry, actually let's see. I'm sorry, it was actually -- it's Redirect 23. It's also marked as Public Staff Cross 57, but the redirect is 23.

CHAIR MITCHELL: Okay. And can you restate the number at the bottom of the page, Ms. Jost?

MS. JOST: Yes. I apologize, I think I gave the wrong number. It should be in the redirect exhibits, 789.

(Pause.)

MS. JOST: I'll just wait until, Chair Mitchell, you signal that you have that document.

CHAIR MITCHELL: All right. I'm not seeing it, Ms. Jost, in the redirect compilations, so can you give me the number of the cross exam -- the cross examination number that was used.

MS. JOST: Sure. It should be 57 going by the cross numbers, and again, that would be --

CHAIR MITCHELL: Okay. I see it here. All right. So let's go ahead and get this document marked. I'm currently looking at Public Staff potential hearing exhibits, and it's behind tab number 57.

MS. JOST: So at the top it should say city of Eden.

CHAIR MITCHELL: Yes, that's correct. All right. Let's get this one marked.

MS. JOST: Okay. I would request that that exhibit be marked or identified for the record as Public Staff Garrett/Moore Redirect Exhibit 2.

CHAIR MITCHELL: All right. The document will be marked Public Staff Garrett/Moore

Redirect Examination Exhibit Number 2.

(Public Staff Garrett/Moore Redirect Examination Exhibit Number 2 was marked for identification.)

Q. All right. And, Mr. Garrett, can you tell us what the significance of this document is in terms of, you know, what would have allowed Parsons, or how it would have impacted Parsons' ability to maintain the excavation rate under the contract?

A. Well, the original pretreatment permit that was issued allowed for 0.3 million gallons per day to be discharged from the site. The document that you just referred to dated October of 2018 increased the allowable discharge to the city of Eden to 0.6 MGD, doubling the permitted capacity allowed to be discharged to the city.

And that -- the additional dewatering capacity certainly would have helped Parsons' efforts in drying ash, and excavating ash, and land-filling ash.

Q. But at what point in the process did Duke seek this approval to increase the flow?

A. The city of Eden approval was dated October of 2018, which is after they made a decision to remove Parsons.

Q. Okay. Mr. Marzo asked you about Parsons' sequenced excavation plans and recovery plans that were attained by the Public Staff in discovery after your testimony; do you recall that?

A. Yes, I do.

Q. Does any of the information contained in those documents change your recommendations in this case?

A. No, they don't.

Q. Could you explain why, please.

A. Well, because the recovery plans prepared by Parsons were not based on the increased flow or what subsequently happened later in December of 2018 where Duke Energy was allowed to begin using outfall 002, which would allow them to discharge an additional 1.5 MGD. So Parsons' performance on the project was based on their experience with the limited discharge that was available at the site.

Q. Thank you. And then just one final question, and you could probably do this as a subject to check, but I am going to refer to DEC Exhibit 2. This is the Commission's final order in the 2017 DEP rate case. And I believe it's on page 190 of that order. The --

there the Commission makes a disallowance of $9.5 million for contracted disposal costs with waste management.

Do you recall that disallowance from the last DEP rate case?

A. Yes, I do.

Q. And was that made based on your recommendation?

A. I believe it could have been, yes.

Q. All right. No further questions.

CHAIR MITCHELL: All right. At this point in time, just out of abundance of caution, I'm going to ask the parties if there is any additional cross examination for these witnesses that does not touch on confidential information, or that will not illicit confidential information.

MS. TOWNSEND: Nothing from the AG's office.

CHAIR MITCHELL: All right. Hearing none, we will proceed, then, to questions by Commissioners. And Commissioners, I just remind you that we are in public session now. To the extent that you need to ask questions that illicit confidential or that have the potential to illicit confidential information, we will need to return to confidential session.

All right. Let's begin with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: No questions.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions at this time, thank you.

CHAIR MITCHELL: Commissioner Clodfelter?

(No response.)

CHAIR MITCHELL: All right. I'm hearing none from Commissioner Clodfelter.

Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

CHAIR MITCHELL: All right. There you are, Commissioner Clodfelter. Just checking in with you one more time; questions from you?

COMMISSIONER CLODFELTER: Madam Chair, I have no questions for either Mr. Moore or Mr. Garrett. Thank you.

CHAIR MITCHELL: Thank you, sir. Commissioner Hughes?

COMMISSIONER HUGHES: No questions either.

CHAIR MITCHELL: All right. And Commissioner McKissick?

COMMISSIONER McKISSICK: No questions at this time, Madam Chair.

CHAIR MITCHELL: All right. Well, then, at this point, Mr. Garrett and Mr. Moore, we appreciate your testimony today. There appears to be nothing further for you, I will entertain motions from counsel.

MS. JOST: Thank you, Chair Mitchell. I move that Mr. Moore's Exhibits 1 through 7 and Mr. Garrett's Exhibits 1 through 21 attached to their prefiled testimony be admitted into evidence.

CHAIR MITCHELL: All right. Ms. Jost, hearing no objection to that motion, it is allowed.

MS. JOST: Thank you.

(Public Staff Confidential Moore Exhibits 1 through 6, Public Staff Moore Exhibit 7, Public Staff Garrett Exhibits 3, 4, 7, 8, 9, 14, 16, 19 and Public Staff Confidential Garrett Exhibits 1, 2, 5, 6, 10 through 13, 15, 17, 18, 20 and 21 were admitted into evidence.)

MS. JOST: And additionally, I move that Confidential Public Staff Garrett/Moore Redirect Exhibit 1, and Public Staff Garrett/Moore Redirect Exhibit 2 be admitted into evidence.

CHAIR MITCHELL: Hearing no objection, that motion is allowed as well.

MS. JOST: Thank you.

(Confidential Public Staff Garrett/Moore Redirect Exhibit 1, and Public Staff Garrett/Moore Redirect Exhibit 2 were admitted into evidence.)

MR. MARZO: Chair Mitchell, I would ask that my cross examination exhibits be moved into the record.

CHAIR MITCHELL: All right. Mr. Marzo, hearing no objection to that motion, it will be allowed. And I would just note for the record that at least one of those exhibits, the cross examination exhibits is confidential.

(DEC Garrett/Moore Cross Examination Exhibit Numbers 1 through 3 and Confidential DEC Garrett/Moore Cross Examination Exhibit Numbers 4 and 5 were admitted into evidence.)

CHAIR MITCHELL: All right. Anything further for these witnesses?

(No response.)

CHAIR MITCHELL: All right. Hearing none, gentlemen, you may step down. Thank you very much for your testimony today.

MS. DOWNEY: Chair Mitchell, this is Dianna Downey.

CHAIR MITCHELL: All right. Ms. Downey.

MS. DOWNEY: Chair Mitchell, in an abundance of caution and to make sure that we're ready, we have two motions to excuse pending for Dustin Metz and Jeff Thomas. Just wanted to know the status of those so that we can make sure they're available if needed.

CHAIR MITCHELL: All right. Ms. Downey, we will -- I will consult with my colleagues at the -- after the conclusion of the hearing today, and we will issue an order forthwith.

MS. DOWNEY: Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. Public Staff, you-all may call your next witness.

MS. LUHR: Chair Mitchell, this is

Nadia Luhr with the Public Staff. Our next panel is the Lucas/Maness panel, and no parties have indicated they have cross for this panel. So unless the Commission has questions, we would ask that they be excused.

CHAIR MITCHELL: All right. Ms. Luhr, I would ask -- Commissioners -- any questions from Commissioners for these witnesses?

(No response.)

CHAIR MITCHELL: For this witness panel. I'm not hearing -- I'm not hearing any of my fellow Commissioners indicating any questions. All right. So, Ms. Luhr, your witnesses -- well, at least Mr. Lucas may be excused. It appears that Mr. Maness is scheduled to appear with Mr. Junis in the panel immediately following this one, so he cannot -- he will not be excused at this point in time.

MS. LUHR: That's right. Thank you.

CHAIR MITCHELL: All right. So Mr. Lucas may be excused. I'll entertain motions on his testimony and exhibits at this point in time.

MS. LUHR: Yes. I would move that

Mr. Lucas and Mr. Maness' prefiled joint direct testimony, summary of testimony and errata sheet be entered into the record as if given orally from the stand, and that their exhibits attached to the prefiled joint testimony be entered into the record and marked for identification as premarked.

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

(Lucas and Maness Exhibit 1 and Confidential Lucas and Maness Exhibits 2 through 5 were admitted into evidence.)

(Whereupon, the prefiled joint direct testimony with Appendix A and summary and errata of the testimony of Jay Lucas and Michael C. Maness were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

Joint Testimony of Jay B. Lucas and Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

February 18, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jay B. Lucas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the

Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A of my separately filed testimony in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to respond to a portion of the Commission's Order Directing the Public Staff to File Testimony, dated January 22, 2020 (Order), in the general rate case filed by Duke Energy Carolinas, LLC (DEC or the Company), in Docket No. E-7, Sub 1214, on September 30, 2019. The Order required the Public Staff to file testimony on several topics, including: (1) whether DEC included coal ash impoundment closure costs in net salvage for decommissioning DEC's coal plants; and (2) estimated costs for coal combustion residuals (CCR) remediation as initially proposed and after the December 31, 2019, Settlement Agreement (Settlement Agreement) between DEC and the North Carolina Department of Environmental Quality (DEQ).

The Public Staff sent data requests to DEC on these issues. Our testimony, in part, reflects DEC's responses.

Q. PLEASE PROVIDE A SUMMARY OF THE RESULTS OF YOUR INVESTIGATION.

A. With regard to net salvage for decommissioning, the Company does not include impoundment closure costs in net salvage for decommissioning of its coal plants. For financial accounting purposes, DEC books these costs as Asset Retirement Obligations (AROs), and recognizes the costs in net income according to the requirements of the Financial Accounting Standards Board (FASB) for AROs.

With regard to cost estimates for CCR remediation as initially proposed and after the Settlement Agreement between DEC and DEQ, Confidential Lucas and Maness Table 1 below provides a summary of DEC's projected CCR remediation costs for 2015 through 2079 at various points in time:

[BEGIN CONFIDENTIAL]

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

[END CONFIDENTIAL]

All costs in our testimony are DEC only, but system-wide.

Depreciation and Decommissioning of Coal Plants

Q. WHAT DID THE COMMISSION REQUIRE THE PUBLIC STAFF TO INVESTIGATE AND REPORT ON REGARDING NET SALVAGE FOR DECOMMISSIONING OF DEC'S COAL PLANTS?

A. The Commission requested that the Public Staff:

1. Review DEC's depreciation studies from 2000 to the present to determine if any costs for coal ash impoundment closures were included in net salvage for decommissioning of the plants;

2. If so, provide workpapers or other analyses showing the amounts included, by coal ash basin and by Federal Energy Regulatory Commission (FERC) account, if possible; and

3. Investigate behind the face of the depreciation studies "to explore whether or not DEC and/or its consultants ever discussed, memorialized, or corresponded - such as in reports, memos, or email messages - about impoundment closure costs being included in net salvage."

FERC defines net salvage value as the salvage value of property retired less the cost of removal.

Q. WHAT HAS DEC STATED IN RESPONSE TO THE PUBLIC STAFF DATA REQUEST ON NET SALVAGE?

A. In response to the Public Staff's data request on net salvage, DEC stated in part, "None of those net salvage percentages [in DEC's depreciation studies] include or account for anticipated costs of coal ash removal or remediation, or retirement/decommissioning of coal ash impoundments or storage facilities." **Lucas and Maness Exhibit 1**.

Q. PLEASE GIVE A SUMMARY OF DEC'S DEPRECIATION STUDIES FROM 2000 TO THE PRESENT REGARDING COAL ASH IMPOUNDMENT CLOSURES.

A. DEC has filed four depreciation studies since 2000 and all share a similar format. The studies group all coal-fired plant assets by their FERC account numbers under "Steam Production Plant" as follows:

Account Name	FERC Account number
Structures and Improvements	311
Boiler Plant Equipment	312
Turbogenerator Units	314
Accessory Electric Equipment	315
Miscellaneous Power Plant Equipment	316

These FERC accounts are described in Title 18 of the Code of Federal Regulations "Conservation of Power and Water Resources" Chapter I, Subchapter C, Part 101 (18 CFR 101). In summary, 18 CFR 101 does not clearly categorize coal ash impoundments.

However, "Structures and Improvements" includes "ash pits (when located within the building)" and "water basins or reservoirs." Lucas and Maness Table 2 below describes the relevant details of the four depreciation studies. The "Net Salvage Percent" is the percent of the original cost of Structures and Improvements for each power plant to allow for dismantling the plant, but it does not include impoundment closure.

Lucas and Maness Table 2 – DEC's Depreciation Studies since 2000

Docket No.	**Effective Date**	**Net Salvage Percent in Structures and Improvements**
E-7, Sub 783	December 31, 2003	-20
E-7, Sub 909	December 31, 2008	-10
E-7, Sub 1026	December 31, 2011	-7
E-7, Sub 1146	December 31, 2016	-5 to -20

Q. PLEASE GIVE A SUMMARY OF DEC'S DECOMMISSIONING STUDY.

A. In its previous rate case in Docket No. E-7, Sub 1146, DEC filed its first and only decommissioning study. However, the study did not include the decommissioning of coal ash impoundments. In response to the Public Staff's data request on net salvage, DEC stated in part:

> The most recent depreciation study prepared for DEC, dated as of December 31, 2016 (E-7, Sub 1146), also does not include such [coal ash removal or impoundment decommissioning] costs, nor does the Burns & MacDonnell [sic] decommissioning study, dated as of April 19, 2017, upon which it was based, inasmuch as DEC had by the time of those studies established asset retirement obligations [AROs] in connection with anticipated coal ash basin closure costs.

Lucas and Maness Exhibit 1. The part of the statement regarding AROs is key to explaining the absence of impoundment closure costs in DEC's net salvage values. It is important to note that prior to DEC placing impoundment closure costs in ARO, DEC did not include impoundment closure in decommissioning or depreciation studies as explained by DEC in **Lucas and Maness Exhibit 1.**

Q. PLEASE EXPLAIN FURTHER WHY IMPOUNDMENT CLOSURE COSTS ARE NOT CURRENTLY PART OF DEC'S NET SALVAGE VALUES.

A. For financial accounting purposes and for FERC Uniform System of Accounts (USOA) purposes, DEC currently treats impoundment closure as an ARO instead of treating it as part of the depreciable expense of building a power plant. Therefore, DEC's booking of impoundment closure costs and recognition of those costs in expenses follows accounting policies specifically established for

AROs, and not depreciation expenses for other power plant costs, which are typically determined through traditional depreciation studies.[1] DEC stated the following in response to the Public Staff's data request on net salvage:

> The relevant asset retirement obligation accounting ("ARO") rules expressly exclude cost of removal as part of depreciation expense, and instead include such costs in the ARO. See 18 C.F.R. §101, Definitions 10 ("[c]ost of removal does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation.").

Lucas and Maness Exhibit 1. As quoted above, the Burns & McDonnell study includes decommissioning costs for seven of DEC's eight coal-fired plants, but it does not include impoundment closure. The Riverbend plant is missing from the study; however, a wide gap is still apparent between the Burns & McDonnell decommissioning costs for seven coal-fired plants ($283 million) and DEC's estimated impoundment closure costs (approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**).

In response to the Public Staff's data request on net salvage, DEC explained its treatment of future impoundment closure costs before the enactment of the Coal Ash Management Act (CAMA) in 2014

[1] As noted in the separate testimony of Public Staff witness Maness, for North Carolina retail regulatory accounting and ratemaking purposes, as determined by this Commission, DEC is accounting for and recovering its impoundment closure costs through a deferral and amortization process, rather than a traditional depreciation expense process or a financial accounting ARO process.

(N.C. Gen. Stat. § 130A309.200 through 216). Below is an excerpt from DEC's response:

> In the early part of the period specified in DR 1 above [early 2000s], it was not common to have decommissioning studies performed that included coal burning facilities because the prevailing presumption by electric companies at that time was that such facilities would continue to provide power in same [sic] function well into the future. Moreover, ash basins would continue serving their function of holding CCRs, and would in that connection continue to be managed and permitted.

Lucas and Maness Exhibit 1.

Q. HAS DEC PERFORMED ANY OTHER DECOMMISSIONING EVALUATIONS?

A. Yes. In October 2011, DEC performed a high-level decommissioning evaluation that is included in **Lucas and Maness Exhibit 1**. In its 2013 rate case (E-7, Sub 1026), DEC filed a depreciation study dated December 31, 2011, as Wiles Exhibit 3. On page II-29, the study stated that "[t]he estimates of net salvage by account were based in part on historical data." The depreciation study does not indicate that the 2011 evaluation was used to estimate net salvage values.

Q. BASED ON REVIEW OF THE INFORMATION PROVIDED BY DEC, WHAT IS YOUR OPINION AS TO WHETHER DEC INCLUDED COAL ASH IMPOUNDMENT CLOSURE COSTS IN NET SALVAGE FOR DECOMMISSIONING DEC'S COAL PLANTS?

A. A review of DEC's depreciation studies stretching back to 2003 does not indicate specifically whether the costs of decommissioning its coal ash impoundments were included in its net salvage percentages used to help determine depreciation rates. However, as discussed above, DEC states in its response to Public Staff discovery that the percentages used in the studies do not "include or account for anticipated costs of coal ash removal or remediation, or retirement/decommissioning of coal ash impoundments or storage facilities." Without more detailed information, we do not find it possible to conclude, with absolute certainty, that no portion of the previously utilized salvage percentages are allocable to impoundment retirement or closure costs. The Public Staff recommends that DEC address this issue in its rebuttal testimony.

CCR Remediation Costs

Q. WHAT DID THE COMMISSION REQUIRE THE PUBLIC STAFF TO INVESTIGATE AND REPORT ON REGARDING DEC'S CCR REMEDIATION COSTS?

A. The Order required the Public Staff to provide total estimated costs and an estimated breakdown of the costs for DEC's CCR remediation for each site and for each impoundment as follows: (1) as initially proposed by DEC, and (2) pursuant to the settlement agreement entered into by and between DEC and DEQ.

Q. DID YOU HAVE ANY DIFFICULTIES COMPLYING WITH THE COMMISSION'S ORDER?

A. Yes. I (Jay) was able to determine DEC's projected CCR remediation costs by site (or plant), but not by impoundment. DEC does not always individually perform remediation for each impoundment but will issue one contract to remediate the entire site or plant without separating costs between the various ash storage areas. For example, **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. PLEASE EXPLAIN THE RECENT HISTORY OF DEC'S CCR REMEDIATION COSTS AND ACTIONS TAKEN BY DEQ.

A. The testimony of Public Staff witness Charles Junis provides a detailed explanation of DEC's CCR remediation costs and actions taken by DEQ, but I will provide additional information. For ratemaking purposes, DEC's CCR remediation costs first became a large issue in its previous rate case (Docket No. E-7, Sub 1146). During that proceeding, DEC was in the process of excavating CCR from the Riverbend and Dan River plants because DEQ had designated them as high-risk under CAMA (N.C. Gen. Stat.

§ 130A309.214). DEQ designated the other five coal-fired plants in North Carolina as intermediate risk, which gave DEC more time to close those CCR impoundments and allowed DEC to use cap-in-place for remediation. Those five plants are: Allen, Belews Creek, Buck, Cliffside, and Marshall. The one remaining plant, W. S. Lee, is in South Carolina and not under the jurisdiction of DEQ or CAMA; however, DEC is excavating the W. S. Lee impoundments under a Consent Order from the South Carolina Department of Health and Environmental Control.

Q. IN 2017, WHAT WERE DEC'S ESTIMATED TOTAL CCR REMEDIATION COSTS?

A. In September 2017, DEC estimated that total CCR remediation costs for its eight coal-fired power plants would be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** This projection is for the years 2015 through 2079. **Confidential Lucas and Maness Exhibit 2** provides a breakdown of this estimate by plant. DEC based this estimate on its plan to use cap-in-place to remediate many of its CCR impoundments.

Q. WHAT SIGNIFICANT CHANGE OCCURRED THAT REQUIRED DEC TO REVISE ITS ESTIMATE?

A. On April 1, 2019, DEQ issued orders (Excavation Orders) to Duke Energy to excavate all impounded coal ash at six plants – Allen, Belews Creek, Cliffside, Marshall, Mayo, and Roxboro. The Excavation Orders eliminated cap-in-place as an option for these six plants, greatly increasing potential costs.

Q. AFTER THE EXCAVATION ORDERS WERE ISSUED, WHAT WERE DEC'S ESTIMATED TOTAL CCR REMEDIATION COSTS?

A. In September 2019, DEC estimated total CCR remediation costs for its eight coal-fired power plants as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This projection is for the years 2015 through 2079. **Confidential Lucas and Maness Exhibit 3** provides a breakdown of this estimate by plant.

Q. WHAT HAPPENED AFTER DEQ ISSUED THE EXCAVATION ORDERS?

A. Duke Energy filed a contested case challenging the Excavation Orders. However, on December 31, 2019, Duke Energy, DEQ, and community and environmental groups entered into a Settlement Agreement that resolved the appeal of the Excavation Orders, as well as other ongoing litigation between Duke Energy and the community and environmental organizations. The Settlement Agreement still requires excavation of a majority of the CCR in DEC's and DEP's unlined impoundments (80 million tons), but it allows approximately 25 million tons of CCR in unlined impoundments to remain in place. The Settlement Agreement also acknowledges that

DEQ, in the future, could grant variances that would allow the CCR beneficiation project at the Buck plant to extend operation from 2029, the CAMA-established closure deadline, to 2035. An extension would allow for longer use of the beneficiation project and could possibly avoid construction of a coal ash landfill at the plant site.

Q. WHAT EFFECT DID THE SETTLEMENT AGREEMENT HAVE ON DEC'S ESTIMATED TOTAL CCR REMEDIATION COSTS?

A. The Settlement Agreement decreased DEC's estimated total CCR remediation costs for its eight coal-fired power plants to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, compared to the estimated cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** following the Excavation Orders. This projection is for the years 2015 through 2079. **Confidential Lucas and Maness Exhibit 4** provides the effect of the Settlement Agreement savings on the amounts in **Confidential Lucas and Maness Exhibit 3**.

Q. DOES LUCAS AND MANESS EXHIBIT 4 PROVIDE DEC'S CURRENT ESTIMATED TOTAL CCR REMEDIATION COSTS?

A. No. DEC periodically evaluates and updates CCR remediation costs at all eight coal-fired plants. Changes other than the Settlement Agreement have affected current costs. DEC's current estimated total CCR remediation costs are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** This projection is for the years 2015 through 2079. **Confidential Lucas and Maness Exhibit 5** provides a breakdown of this estimate by plant.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Jay B. Lucas

I graduated from the Virginia Military Institute in 1985, earning a Bachelor of Science Degree in Civil Engineering. Afterwards, I served for four years as an engineer in the Air Force performing many civil and environmental engineering tasks. I left the Air Force in 1989 and attended the Virginia Polytechnic Institute and State University (Virginia Tech), earning a Master of Science degree in Environmental Engineering. After completing my graduate degree, I worked for an engineering consulting firm and worked for the North Carolina Department of Environmental Quality in its water quality programs. Since joining the Public Staff in January 2000, I have worked on utility cost recovery, renewable energy program management, customer complaints, and other aspects of utility regulation. I am a licensed Professional Engineer in North Carolina.

Summary of Joint Testimony of Jay B. Lucas and Michael C. Maness

Docket Nos. E-7, Sub 1213, E-7, Sub 1214, and E-7, Sub 1187

Public Staff witnesses Jay B. Lucas and Michael C. Maness investigated the last two portions of the Commission's order dated January 22, 2020, regarding net salvage for decommissioning of coal ash impoundments and total projected coal ash remediation costs.

With regard to net salvage for decommissioning its coal plants, Duke Energy Carolinas, or DEC, includes in its non-Asset Retirement Obligation (ARO) the costs for dismantling the plants but does not appear to include impoundment closure costs. Prior to the enactment of the Coal Ash Management Act (CAMA) in 2014, DEC presumed that coal-burning facilities would continue to operate well into the future; moreover, DEC assumed that existing coal ash basins would continue performing their storage function as well. Once CAMA was enacted, DEC accounted for the established obligations under the law as AROs, pursuant to financial accounting requirements and the requirements of the Federal Energy Regulatory Commission's Uniform System of Accounts. For financial accounting purposes, DEC currently books these costs as AROs, and recognizes the costs in net income according to the requirements of the Financial Accounting Standards Board for AROs.

With regard to projected coal ash remediation costs as initially proposed and after the December 31, 2019 Settlement Agreement between DEC and the North Carolina Department of Environmental Quality, or DEQ, the Public Staff reviewed the estimated costs, which are all confidential, at four points in time. First, the Public Staff reviewed the cost estimate from September 2017. Second, the Public Staff reviewed the cost estimate from September 2019, after the date of DEQ's April 2019 Excavation Orders, which required DEC to excavate all coal ash at its four active coal-fired plants. Third, the Public Staff reviewed the estimated costs as of January 2020, after DEC and DEQ entered into the Settlement Agreement. Lastly, the Public Staff reviewed DEC's estimated costs as of February 2020. DEC periodically evaluates and updates coal ash remediation costs at all eight coal-fired plants or plant sites. Changes other than the Settlement Agreement have affected current costs.

This completes our summary.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1187 In the Matter of Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego DOCKET NO. E-7, SUB 1213 In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program DOCKET NO. E-7, SUB 1214 In the Matter of Application of Duke Energy Carolinas, LLC, for an Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	PUBLIC STAFF CORRECTION TO JOINT DIRECT TESTIMONY OF JAY B. LUCAS AND MICHAEL C. MANESS

<u>CORRECTION TO THE JOINT DIRECT TESTIMONY OF</u>

<u>JAY B. LUCAS AND MICHAEL C. MANESS</u>

The joint direct testimony of witnesses Lucas and Maness should be corrected as follows:

Page 2, lines 4-6 – “an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission” should be changed to “the manager of the Electric Section – Operations and Planning in the Public Staff’s Energy Division.”

CHAIR MITCHELL: All right. Public Staff, you may call your next witness panel.

MS. LUHR: Thank you. The Public Staff now calls Mr. Junis and Mr. Maness to the stand.

CHAIR MITCHELL: All right. Mr. Junis and Mr. Maness. Mr. Maness, we have now seen you a number of times, but I'm going to go ahead and we're going to get you gentlemen under oath.

Whereupon,

CHARLES JUNIS AND MICHAEL C. MANESS,

having first been duly affirmed, were examined

and testified as follows:

CHAIR MITCHELL: Thank you, gentlemen. You may proceed, Ms. Luhr.

MS. LUHR: Thank you.

DIRECT EXAMINATION BY MS. LUHR:

Q. Mr. Junis, would you please state your name, business address and current position for the record.

A. (Charles Junis) Yes. My name is Charles Junis. I work at 430 North Salisbury Street in Raleigh, North Carolina, and I am a utilities engineer with the Public Staff water, sewer, and telephone division.

Q. And on February 18, 2020, did you prepare and cause to be filed, testimony consisting of 75 pages, an appendix, and 20 exhibits?

A. Yes.

Q. And on March 3, 2020, did you prepare and cause to be filed, corrections to Junis Exhibit 2 as well as corresponding corrections to page 28 of your testimony?

A. Yes.

Q. Do you have any other changes or corrections to your testimony, appendix or exhibits?

A. I do not.

Q. And if you were asked the same questions today, would your answers be the same?

A. Yes, they would be.

Q. Did you prepare a summary of your testimony?

A. Yes, I did.

MS. LUHR: Chair Mitchell, at this time, I would move that Mr. Junis' testimony and summary of testimony be entered into the record as if given orally from the stand, and that his exhibits be marked for identification as premarked.

CHAIR MITCHELL: Hearing no objection to that motion, it is allowed.

(Public Staff Junis Exhibits 1, 3

through 18, and 20; Public Staff Junis Corrected Exhibit 2; and Public Staff Junis Confidential Exhibit 19 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony with Appendix A and summary of the testimony of Charles Junis was copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

Testimony of Charles Junis

On Behalf of the Public Staff

North Carolina Utilities Commission

February 18, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Charles Junis. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Water, Sewer, and Telephone Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

A. My investigation in this proceeding included the review of company records ranging over 40 years pertaining to coal ash management, groundwater standard compliance data, state and federal environmental compliance records, company accounting records related to coal ash, and litigation records.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Commission the Public Staff's position on the following topics in the general rate case filed by Duke Energy Carolinas, LLC (DEC or the Company), in Docket No. E-7, Sub 1214, on September 30, 2019:

1. The environmental compliance record of the Company under applicable State and Federal laws and regulations governing the management and disposal of coal combustion residuals (CCR);
2. Whether the electric power industry, especially prominent utilities with substantial coal-fired power plant portfolios, such as DEC, was or should have been aware of the potential environmental impacts of CCR storage in unlined impoundments, was investigating the likelihood (or occurrence) of exposure of CCR constituents to surface waters, groundwater, or soils, and was planning and implementing improvements to CCR handling and storage practices;
3. Whether the Company reasonably and prudently managed its CCR, and cost impacts to the extent it did not; and

4. Whether there should be an equitable sharing between ratepayers and shareholders of CCR costs for which a specific imprudence disallowance has not been recommended.

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. As described in more detail later in my testimony, I make the following recommendations:

1. It is appropriate to exclude from rate recovery: (1) costs to remedy environmental violations where the costs exceed what the North Carolina Coal Ash Management Act (CAMA)[1] would have required in the absence of environmental violations; (2) costs to provide bottled water and permanent water supplies, including municipal connections and treatment systems, to neighboring properties either voluntarily or as required by CAMA; and (3) fines and penalties, or the equivalent, for environmental violations, including all costs required to be excluded under the probation conditions of the federal plea agreement.

2. It is appropriate to implement an equitable sharing methodology for coal ash clean-up and closure costs not otherwise disallowed. The Public Staff recommends that 50 percent of the costs for CCR remediation and closure should be paid by the Company's

[1] 2014 N.C. Sess. Law 122, as amended by 2016 N.C. Sess. Law 95.

shareholders and the remaining 50 percent be paid by the Company's customers.

Q. PLEASE SUMMARIZE YOUR SPECIFIC RECOMMENDATIONS FOR DISALLOWANCE OF COSTS.

A. The Public Staff is recommending disallowance of the following costs:

1. Costs to remedy violations where the costs exceed what CAMA would have required in the absence of violations. This position is consistent with the Public Staff's position in the Sub 1146 rate case and the pending appeal before the North Carolina Supreme Court. At the Belews Creek plant, DEC installed wells and appurtenances for the extraction and treatment of groundwater at a cost of $298,433. The plant has substantial violations of the state groundwater standards that have been further confirmed, and the nature and extent characterized and monitored, since DEC's last rate case. Groundwater extraction and treatment would not be required by CAMA or prior regulations, nor would it be necessary, if DEC had not caused violations of the groundwater quality standards.

2. Costs to provide bottled water and alternate permanent water supplies, including water treatment systems, to neighboring properties.

3. Fines and penalties or the equivalent for environmental violations, which have been appropriately excluded by the Company.

Q. PLEASE SUMMARIZE YOUR POSITION REGARDING THE EQUITABLE SHARING OF COSTS.

A. As described in more detail below, I recommend the Commission make findings and conclusions consistent with the following:

1. DEC has accumulated a record of significant environmental violations caused by leaking coal ash basins, which have resulted in unlawful releases of regulated contaminants to groundwater and surface water. These violations include unauthorized seeps that DEC has admitted to environmental regulators, in violation of its National Pollutant Discharge Elimination System (NPDES) permits, and 10,940 groundwater exceedances confirmed by DEC's own groundwater monitoring data, in violation of the state's 2L rules.[2]

2. DEC has culpability for its environmental violations, even without a showing of traditional imprudence. The Company had a duty to comply with long-standing North Carolina environmental regulations, and it failed that duty many times over many years at every coal-fired power plant it owns in North Carolina. The Company should not be able to claim that, in order to generate electricity, it had to create groundwater contamination. It would be manifestly unjust to require ratepayers to bear all the deferred coal ash costs where those costs

[2] Groundwater Classification and Standards, 15A N.C. Admin. Code 2L.

include corrective actions to remedy the Company's environmental violations.

3. DEC has estimated that the ultimate cost to clean up and close its existing coal ash disposal sites will be **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Corrective actions to address environmental impacts under CAMA and the Environmental Protection Agency's (EPA) Coal Combustion Residuals Final Rule (CCR Rule)[3], including the ultimate closure of all coal ash basins, should remedy the Company's environmental violations and eliminate the risk of significant future violations. DEC argues that its coal ash closure costs are reasonable and recoverable in rates because they are the costs of complying with state and federal law; namely, CAMA and the CCR Rule. However, these compliance costs include the costs of mitigating DEC's environmental violations. The corrective action requirements for the remediation of groundwater contamination pursuant to CAMA and the CCR Rule, which became effective in 2014 and 2015, respectively, largely overlap with the 2L rules. There is no doubt that substantial assessment and remediation costs would have been incurred without CAMA and the CCR Rule, but, in my opinion, those costs cannot be quantified without undue speculation. Furthermore, CAMA – as administered by the North

[3] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities, 80 Fed. Reg. 21301 (April 17, 2015).

Carolina Department of Environmental Quality (DEQ) – goes beyond the CCR Rule in that it requires closure of all ash basins and requires excavation of most of the ash from DEC's unlined basins. Given the difficulty in identifying the costs of corrective action for environmental violations that DEC would have incurred in the absence of CAMA and the CCR Rule, and also the difficulty of knowing if North Carolina would have required such rapid and expensive closure of ash basins in the absence of the Dan River spill, which gave impetus to CAMA, I do not believe the traditional imprudence approach is feasible for most of DEC's coal ash costs.

4. Equitable sharing is appropriate because the costs of remediation and closure of DEC's coal ash disposal sites are intertwined with the Company's failure to prevent groundwater contamination as required by the 2L rules. Public Staff witness Maness identifies additional reasons in support of equitable sharing in his testimony. This case presents factual circumstances (extensive environmental violations) where the determination of "reasonable and just rates" under N.C. Gen. Stat. § 62-133(d) requires a qualitative judgment of the Commission for a 50% - 50% sharing of coal ash disposal site closure and remediation costs.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF COAL ASH.

A. Coal ash, the main type of CCR, is one of the largest industrial waste streams in the United States.[4] In North Carolina, there are over 100 million tons of coal ash currently stored in landfills and surface impoundments owned by both DEC and DEP. CCRs are produced in the combustion process at coal-fired power plants and include by-products such as fly ash, bottom ash, coal slag, and flue gas desulfurization (FGD) material.[5] "Coal ash" includes both bottom ash and fly ash, and is often transported by mixing with water in a process known as sluicing, and then diverted into surface impoundments.[6] Surface impoundments are also known as ash basins, ponds, or lagoons. FGD material is often pre-treated in separate FGD blowdown ponds before also being sent to a CCR surface impoundment. The impoundments provide treatment of the wastewater by a combination of settling, attenuation, mixing, and dilution.

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[4] For example, 117 million tons of coal ash were generated in the United States in 2015. American Coal Ash Association's Coal Combustion Product Production & Use Survey Report, available at https://www.acaa-usa.org/Portals/9/Files/PDFs/2015-Survey_Results_Table.pdf (last visited February 10, 2020).

[5] Joint Factual Statement, United States of America v. Duke Energy Business Services, LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., Case No. 5:15-CR- 68-H in the Unites States District Court for the Eastern District of North Carolina (May 14, 2015) at 7.

[6] N.C. Gen. Stat. § 130A-290(2b) further defines CCRs as "residuals, including fly ash, bottom ash, boiler slag, mill rejects, and flue gas desulfurization residue produced by a coal-fired generating unit destined for disposal." For simplicity, my testimony sometimes refers to "coal ash" but means all types of CCRs.

HISTORY OF CCR MANAGEMENT

Q. WHAT IS THE HISTORY OF CCR MANAGEMENT IN THE UNITED STATES?

A. Coal has been used as a fuel in electric generating plants since the late nineteenth century and has been a dominant fuel for many decades. In the 1960s and 1970s, nuclear generation began to compete with coal-fired generation and beginning in 2010, natural gas-fired generation began to compete directly with coal-fired generation.

In the eastern United States, the availability of fresh water allowed electric generators to sluice the ash remaining in the boiler fire boxes after combustion (bottom ash) into ash storage ponds. Most coal ash constituents would settle to the bottom of the storage ponds, and cleaner wastewater from the top of the ponds would be discharged into a nearby natural water body.

The enactment of the Clean Air Act and subsequent air quality rules in the 1970s required treatment of the emissions released by coal-fired generating facilities. Air pollution control equipment such as electrostatic precipitators and later FGD created solid waste streams that were often placed in the ponds with bottom ash. Fly ash is a waste collected from air pollution control equipment.

CCR is a collective term that includes bottom ash and fly ash created by the burning of coal. Some CCRs can be recycled into raw materials for the concrete industry. CCR from FGD is known as synthetic gypsum and can be directly used by the drywall industry.

Groundwater contamination and accidental releases of CCR brought attention to the storage and disposal of CCR and ultimately led to the adoption of the EPA's CCR Rule, which is presented later in my testimony.

CCR STATE AND FEDERAL REGULATORY FRAMEWORK

Q. ARE YOU SPONSORING ANY ADDITIONAL TESTIMONY OR EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. My testimony incorporates by reference the Public Staff's testimony and exhibits in the last DEC rate case describing the development of state and federal regulations applicable to CCR management, especially coal ash impoundments.[7] I provide a summary discussion and appropriate updates to the regulatory framework in my testimony below.

Q. WHAT IS THE SIGNIFICANCE OF ENVIRONMENTAL REGULATIONS THAT APPLY TO CCR?

A. One of the reasons for the Public Staff's equitable sharing recommendation is that DEC has culpability for non-compliance with environmental regulations that are meant to protect groundwater and surface water from contamination by CCR constituents. Additionally, DEC's past management of coal ash has resulted in a risk of future contamination that EPA and the

[7] Page 14, line 1, through page 32, line 18, and Exhibits 1 and 2, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

North Carolina legislature have determined requires costly new management and closure requirements. Equitable sharing is explained more fully in the testimony of Public Staff witness Maness. I note that the equitable sharing recommendation is not based on the imprudence standard, which would result in a 100% disallowance, but instead is based in part on DEC's culpability for failure to comply with environmental regulations for the protection of groundwater and surface water. Therefore, a summary of those environmental regulations is important for understanding how DEC has been culpable.

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR CCR.

A. CCR surface impoundments contain certain elements, such as arsenic, boron, cadmium, sulfate, vanadium, and others that can, when present in sufficient concentrations, pollute surface water, groundwater, and drinking water. CCRs were originally considered for federal regulation under the Resource Conservation and Recovery Act (RCRA) of 1976, but were exempted by the 1980 Bevill Amendment as a category of special waste requiring further study and assessment.[8] In 1993, the EPA determined that regulation of coal combustion wastes as hazardous waste under Subtitle C of RCRA was not warranted.[9] In 2000, the EPA determined that coal

[8] The Bevill Amendment, one of the 1980 Solid Waste Disposal Act Amendments, exempted fossil fuel combustion waste from regulation as a hazardous waste under Subtitle C of RCRA until further study and assessment of risk could be performed. 42 U.S.C. § 6921(b)(3)(A).

[9] Final Regulatory Determination on Four Large-Volume Wastes from the Combustion of Coal by Electric Utility Power Plants, 58 Fed. Reg. 42,466 (Aug. 9, 1993).

combustion wastes should instead be regulated as non-hazardous solid waste under Subtitle D of RCRA.[10]

The EPA first proposed specific regulations for the disposal of CCRs in 2010, and conducted a nationwide assessment of CCR surface impoundments, ranking the safety of the impoundments on the basis of dam design, safety, and integrity.[11] The EPA finalized the CCR Rule in April 2015, regulating for the first time the disposal of CCRs as non-hazardous solid waste.[12] The CCR Rule became effective on October 19, 2015.

The regulatory framework in place prior to the CCR Rule, including the Clean Water Act (CWA) and state groundwater regulations, as well as more recent requirements, are all relevant to the review of the Company's coal ash management and disposal in this case.

Q. WHAT DOES THE CCR RULE REQUIRE?

A. The CCR Rule establishes minimum criteria that must be met by owners and operators of CCR surface impoundments and CCR landfills. The minimum criteria consist of location restrictions, design and operating requirements, groundwater monitoring and corrective action, closure of

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[10] Notice of Regulatory Determination on Wastes From the Combustion of Fossil Fuels, 65 Fed. Reg. 32,214 (May 22, 2000).

[11] CCR Impoundment Assessment Reports, *available at* https://www.epa.gov/sites/production/files/2016-06/documents/ccr_impoundmnt_asesmnt_rprts.pdf (last visited February 7, 2020).

[12] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities, 80 Fed. Reg. 21,301 (Apr. 17, 2015).

certain units, post-closure care, recordkeeping, and posting of information to the internet for public access.

The CCR Rule applies to new and existing CCR surface impoundments and landfills,[13] as well as lateral expansions of such units. The rule also applies to inactive CCR surface impoundments, defined as impoundments that no longer received CCR on or after October 19, 2015, and that still contained both CCR and liquids on or after that date.[14] The Rule does not apply to CCR landfills that ceased receiving CCR prior to October 19, 2015.

Q. HOW DOES THE CCR RULE APPLY TO CCR LANDFILLS AND IMPOUNDMENTS IN NORTH CAROLINA AND SOUTH CAROLINA?

A. As originally drafted, the CCR Rule was self-implementing, in that it had no associated federal permitting program or delegation of permitting authority to the states.[15] Facilities must comply with the CCR Rule regardless of whether they are directed to do so by a state regulatory agency, and enforcement can take place pursuant to the citizen suit provision of RCRA.

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[13] Existing surface impoundments and landfills are those that received CCR both before and after October 19, 2015, or for which construction commenced prior to October 19, 2015, and received CCR on or after October 19, 2015. 40 C.F.R. 257.53.

[14] The CCR Rule as it was originally adopted did not apply to inactive surface impoundments at inactive facilities. That exemption was vacated and remanded by the U.S. Court of Appeals for the D.C. Circuit on August 21, 2018. Utility Solid Waste Activities Group v. EPA (USWAG), 901 F.3d 414 (D.C. Cir. 2018).

[15] The Water Infrastructure for Improvements to the Nation Act was signed into law on December 16, 2016, and authorizes the states to create permitting programs to implement or act in lieu of the CCR Rule. For non-participating states, the Act directed the EPA to implement a permitting program "subject to the availability of appropriations . . . ." Pub. L. No. 114-322, 130 Stat. 1628, Section 2301 (2016). Neither North Carolina nor South Carolina have submitted permitting programs to the EPA for approval.

CCR units (ash pond impoundments and landfills) at each of the Company's coal-fired power plants in North Carolina—Allen Steam Station, Belews Creek Steam Station, Buck Steam Station, Cliffside Steam Station (Rogers Energy Complex), Dan River Steam Station, and Marshall Steam Station—are subject to the CCR Rule. According to DEC, EPA's CCR Rule is not applicable to the Riverbend Steam Station. The Company has one former coal-fired power plant in South Carolina—W.S. Lee Steam Station. The CCR Rule does not apply to the fill areas or the inactive ash basin at W.S. Lee.

Q. WHAT IS THE CURRENT STATUS OF THE CCR RULE?

A. On June 14, 2016, the United States Court of Appeals for the D.C. Circuit ordered the vacatur of the "early closure" provisions of the CCR Rule.[16] The early closure provisions allowed inactive impoundments to avoid the substantive requirements of the rule (e.g., location criteria, design and operating requirements, groundwater monitoring and corrective action, and closure and post-closure care) if they closed by April 17, 2018. In response to the Court's vacatur of the early closure provision, the EPA on August 5, 2016, issued a direct final rule extending the deadline by which inactive

[16] Util. Solid Waste Activities Grp. v. EPA, 2016 U.S. App. LEXIS 24320 (D.C. Cir. June 14, 2016).

surface impoundments must come into compliance with the substantive requirements of the CCR Rule.[17]

The EPA proposed additional revisions to the CCR Rule in March 2018,[18] and in July 2018 issued a rulemaking finalizing three of the proposed revisions.[19] This "Phase One, Part One" rulemaking adopted alternative performance standards where an authorized state or the EPA is acting as a permitting authority, set groundwater protection standards for four constituents that do not have maximum contaminant levels (MCLs), and provided certain units that are triggered into closure by the CCR Rule additional time to stop receiving waste and begin closure. In March 2019, however, the United States Court of Appeals for the D.C. Circuit remanded without vacatur at the EPA's request this "Phase One, Part One" rulemaking.[20] The compliance deadlines established by the remanded rule will remain in place until the EPA takes further action.

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[17] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Extension of Compliance Deadlines for Certain Inactive Surface Impoundments; Response to Partial Vacatur, 81 Fed. Reg. 51,802 (Aug. 5, 2016). The direct final rule took effect on October 4, 2016.

[18] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One); Proposed Rule, 83 Fed. Reg. 11,584 (Mar. 15, 2018).

[19] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One), 83 Fed. Reg. 36,435 (July 30, 2018).

[20] Waterkeeper Alliance, Inc. v. EPA, 2019 U.S. App. LEXIS 7443.

On August 21, 2018, the United States Court of Appeals for the D.C. Circuit vacated the portions of the CCR Rule that: allowed for the continued operation of unlined impoundments; classified clay-lined impoundments as lined; and, exempted inactive impoundments at inactive facilities from regulation.[21] It also granted the EPA's request for voluntary remand without vacatur of provisions concerning coal residuals piles, beneficial reuse, and alternative groundwater protection standards.

While the federal CCR Rule remains a work in progress, it should be noted that DEC's cost for coal ash corrective action and closure at its North Carolina disposal sites is driven largely by the requirements of CAMA.

Q. PLEASE SUMMARIZE THE FEDERAL REGULATORY FRAMEWORK FOR SURFACE WATER.

A. The CWA was enacted in 1972 to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters."[22] The CWA prohibits the discharge of pollutants from point sources[23] into a water of the United States, unless the discharge is authorized in accordance with a NPDES permit.[24] In 1974, the EPA promulgated the Steam Electric Power

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[21] Utility Solid Waste Activities Group v. EPA (USWAG), 901 F.3d 414 (D.C. Cir. 2018).

[22] 33 U.S.C. § 1251(a).

[23] A point source is defined as "any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft, from which pollutants are or may be discharged." 33 USCS § 1362(14).

[24] 13 U.S.C. § 402.

Generating Effluent Guidelines and Standards (ELG Rule), which are incorporated into NPDES permits and set effluent limitations on wastewater discharges from power plants.[25] Under a facility's NPDES permit, wastewater from coal ash impoundments that is discharged must meet the conditions prescribed in the permit.

Q. WHAT IS THE CURRENT STATUS OF THE ELG RULE?

A. On November 3, 2015, the EPA substantively amended the ELG Rule to include limitations and standards on various waste streams at electric power plants. Compliance deadlines, however, have been delayed due to legal and administrative challenges to the rule. On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit vacated portions of the 2015 ELG Rule applicable to legacy wastewater[26] and leachate.[27] The Court found that the best available technology economically achievable (BAT) set for legacy wastewater and leachate were outdated and inferior to other available technologies, and remanded those provisions back to the EPA. Most recently, in November 2019, the EPA proposed revisions to the ELG Rule that would reduce the stringency of effluent limitations, while also creating

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[25] 40 C.F.R. Part 423.

[26] Legacy wastewater refers to wastewater from five streams—FGD, fly ash, bottom ash, flue gas mercury control, and gasification wastewater—that is generated prior to the first compliance deadline (November 1, 2020).

[27] Southwestern Elec. Power Co. v. United States EPA, 920 F.3d 999 (Apr. 12, 2019).

a voluntary program that extends compliance deadlines for operators who implement measures that achieve more stringent effluent limitations.[28]

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR GROUNDWATER UNDER THE CCR RULE.

A. The CCR Rule is designed to address releases to groundwater from CCR waste disposal units. Pursuant to the CCR Rule, Groundwater Protection Monitoring must be performed at the waste boundary.[29] The standards in the CCR Rule are based on national MCLs[30] and SMCLs established by the EPA for drinking water quality pursuant to the Safe Drinking Water Act. Appendix III of the CCR Rule lists seven parameters — boron, calcium, chloride, fluoride, pH, sulfate, and total dissolved solids — that must be monitored semi-annually. These constituents are primary indicators of potential contamination from ash basins, and if discovered at certain levels, they trigger additional testing requirements for more constituents.

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[28] Proposed Rule, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 84 Fed. Reg. 64620 (Nov. 22, 2019).

[29] "*Waste boundary* means a vertical surface located at the hydraulically downgradient limit of the CCR unit. The vertical surface extends down into the uppermost aquifer." 80 Fed. Reg. 21471.

[30] A Maximum Contaminant Level (MCL) is "[t]he highest level of a contaminant that is allowed in drinking water. MCLs are set as close to MCLGs as feasible using the best available treatment technology and taking cost into consideration. MCLs are enforceable standards." *National Primary Drinking Water Regulations*, U.S. EPA (last visited February 12, 2020), *available at* https://www.epa.gov/ground-water-and-drinking-water/national-primary-drinking-water-regulations #one.

A Maximum Contaminant Level Goal (MCLG) is "[t]he level of a contaminant in drinking water below which there is no known or expected risk to health. MCLGs allow for a margin of safety and are non-enforceable public health goals." *Id.*

In particular, if it is determined that there has been a statistically significant increase over the established background level for any of the Appendix III parameters, then Groundwater Assessment Monitoring must begin within 90 days. The Assessment Monitoring shall include Appendix III and Appendix IV substances and establish a groundwater protection standard for each Appendix IV constituent. Appendix IV of the CCR Rule lists constituents including antimony, arsenic, barium, beryllium, cadmium, chromium, cobalt, fluoride, lead, lithium, mercury, molybdenum, selenium, thallium, and Radium 266-228 combined.[31] The groundwater protection standard is to be the maximum contaminant level or background level, whichever is higher. If any Appendix IV constituents are determined to have a statistically significant increase in exceedance of the groundwater protection standard, then the nature and extent of the release must be characterized, additional monitoring wells must be installed, and assessment of corrective action must be started.

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR GROUNDWATER UNDER STATE STANDARDS.

A. N.C. Gen. Stat. § 143-214.1 directs the North Carolina Environmental Management Commission (EMC) to develop water quality standards

[31] "With the exception of cobalt, lead, lithium and molybdenum (included on appendix IV because of their relevance in the risk assessment and damage cases), all appendix IV constituents have an MCL." 80 FR 21405

applicable to the groundwaters of the State. In 1979, those groundwater quality standards were established by the 2L rules.[32] In accordance with Section .0103 of the 2L rules, the EMC establishes the best usage of groundwater as a source of drinking water. This means contamination should be avoided if it would make groundwater unfit for human consumption.

The groundwater quality standards are listed in Section .0202 of the 2L rules. The 2L rules generally prohibit an exceedance of an established water quality standard at or beyond the compliance boundary of a permitted disposal system.[33] The compliance boundary is a certain distance from the waste boundary, depending on whether the permit was issued prior to or after December 30, 1983. If the permit was issued prior to December 30, 1983, the compliance boundary is 500 feet from the waste boundary, or at the facility property line if less than 500 feet.[34] If the permit was issued on or after December 30, 1983, the compliance boundary is 250 feet from the waste boundary, or 50 feet within the facility property line if less than 250 feet.[35]

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[32] 15A NCAC 02L .0101 et seq. (1979).

[33] "Compliance boundary" means a boundary around a disposal system at and beyond which groundwater quality standards may not be exceeded and only applies to facilities which have received a permit issued under the authority of G.S. 143-215.1 or G.S. 130A. 15A NCAC 02L .0102.

[34] 15A NCAC 02L .0107 (a).

[35] 15A NCAC 02L .0107 (b).

In addition to the listed groundwater quality standards, the 2L rules also provide for the establishment of interim standards for emerging constituents (e.g., acetic acid and butanol) for which a standard has not been established, known as interim maximum allowable concentrations (IMACs). The IMACs are adopted by DEQ and approved by the EMC. IMACs are enforceable groundwater standards pursuant to the 2L rules.[36]

Many of the constituents in CCRs are also naturally occurring in the soil. Per 15A NCAC 02L .0202(b)(3), where naturally occurring substances exceed the established standard, the standard is the naturally occurring concentration as determined by DEQ.[37] Background levels are typically determined by the use of upgradient monitoring wells as a baseline in comparison to downgradient monitoring wells. Fundamentally, as groundwater flows from an upgradient well location, then under the ash impoundment, then to the downgradient well location, a higher level of constituent in the downgradient well than in the upgradient well indicates the coal ash is the source of the higher reading. Any background levels that are calculated to be above the 2L groundwater standards or the IMACs become the enforceable groundwater standard. The 2L groundwater standards and IMACs together are referred to as "constituents of interest."

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[36] 15A NCAC 02L .0202(c).

[37] 15A NCAC 02L .0202(b)(3).

Pursuant to 15A NCAC 02L .0106(d) and (e), when activities result in an increase of the concentration of a substance in excess of the standards at or beyond a compliance boundary then the permittee shall respond according to subsection (f), conduct a site assessment per subsection (g), and submit corrective action plans per subsection (h). Pursuant to the 2L rules, the site assessment reporting and corrective action plan shall be conducted in accordance with a schedule established by DEQ. The site assessment shall include the "horizontal and vertical extent of soil and groundwater contamination and all significant factors affecting contamination transport" and "geological and hydrogeological features influencing the movement, chemical, and physical character of the contaminants."

CCR-RELATED ACTIONS TAKEN BY DEQ

Q. WHAT IS DEQ'S ROLE IN THE REGULATION OF COAL ASH?

A. DEQ is the agency responsible for enforcing environmental regulations including, but not limited to, CAMA and the 2L rules. It also issues and enforces NPDES permits subject to its delegated authority under the CWA.

Q. PLEASE DESCRIBE THE CCR SURFACE IMPOUNDMENT CLASSIFICATIONS ISSUED BY DEQ.

A. CAMA states in part:

> As soon as practicable, but no later than December 31, 2015, the Department shall develop proposed classifications for all

> coal combustion residuals surface impoundments, including active and retired sites, for the purpose of closure and remediation based on these sites' risks to public health, safety, and welfare; the environment; and natural resources and shall determine a schedule for closure and required remediation that is based on the degree of risk . . . .[38]

The risk categories and closure dates prescribed in CAMA are as follows: high-risk impoundments must close no later than December 31, 2019, intermediate-risk impoundments must close no later than December 31, 2024, and low-risk impoundments must close no later than December 31, 2029.[39]

On November 13, 2018, DEQ reclassified the impoundments at the Allen, Belews Creek, Buck, Cliffside, and Marshall plants from intermediate-risk to low-risk due to DEC's establishment of permanent water supplies and correction of dam safety deficiencies.

Q. PLEASE DESCRIBE THE EXCAVATION ORDERS ISSUED BY DEQ IN APRIL 2019.

A. On April 1, 2019, DEQ ordered Duke Energy to excavate impounded coal ash at six plants – Allen, Belews Creek, Cliffside, Marshall, Mayo, and Roxboro. Below is an excerpt from DEQ's Closure Determination for the Marshall plant, which is very similar to that for the other five plants:

> DEQ elects the provisions of CAMA Option A that require movement of coal ash to an existing or new CCR, industrial or municipal solid waste landfill located on-site or off-site for closure of the Active Ash Basin at the Marshall facility in accord with N.C. Gen. Stat. § 130A-309-214(a)(3). In addition,

[38] N.C. Gen. Stat. § 130A-309.213(a).

[39] N.C. Gen. Stat. § 130A-309.214.

> DEQ is open to considering beneficiation projects where coal ash is used as an ingredient in an industrial process to make a product as an approvable closure option under CAMA Option A.
>
> DEQ elects CAMA Option A because removing the coal ash from the unlined CCR surface impoundment at Marshall is more protective than leaving the material in place. DEQ determines that CAMA Option A is the most appropriate closure method because removing the primary source of groundwater contamination will reduce uncertainty and allow for flexibility in the deployment of future remedial measures.[40]

The excavation orders did not affect the Buck, Dan River, Riverbend, and W.S. Lee plants. DEQ had classified the impoundments at Dan River and Riverbend as high-risk in 2016, and DEC was already excavating the impoundments at those plants. DEC had selected the Buck plant as a cementitious beneficiation site, which also necessitates excavation. The W. S. Lee plant is in South Carolina and not under the jurisdiction of DEQ or CAMA. Junis Table 1 below summarizes the status of DEC's coal-fired power plants with DEQ:

[40] *Available at* https://deq.nc.gov/news/key-issues/coal-ash-excavation/marshall-steam-station-coal-ash-closure-plan#closure-determination-april-1,-2019 (last visited February 5, 2020)

Junis Table 1

Plant	Initial CAMA Classification	Current CAMA Classification	Did Excavation Orders Apply?
Allen	Intermediate	Low	Yes
Belews Creek	Intermediate	Low	Yes
Buck	Intermediate	Low	No
Cliffside	Intermediate	Low	Yes
Dan River	High	High	No
Marshall	Intermediate	Low	Yes
Riverbend	High	High	No
W. S. Lee	N/A	N/A	N/A

Q. WHAT HAPPENED AFTER THE ISSUANCE OF DEQ'S EXCAVATION ORDERS?

A. After DEQ issued the excavation orders on April 1, 2019, Duke Energy filed a contested case challenging the orders. On December 31, 2019, Duke Energy, DEQ, and community and environmental groups entered into a Settlement Agreement that resolved the litigation over the excavation orders, as well as other ongoing litigation between Duke Energy and the community and environmental organizations. The Settlement Agreement is shown in **Junis Exhibit 1**.

Q. PLEASE SUMMARIZE THE SETTLEMENT AGREEMENT.

A. The Settlement Agreement addresses CCR impoundments at DEC's Allen, Belews Creek, Cliffside, and Marshall plants, in addition to DEP's Mayo and Roxboro plants. It requires Duke Energy to excavate a majority of the coal ash and place it in a lined landfill. Coal ash in certain unlined portions of ash storage areas can remain in place if Duke Energy covers it with a geomembrane layer or constructs walls to stabilize the ash.[41] The Settlement contemplates ash remaining in the Pine Hall Road Landfill (~100,000 tons) at Belews Creek.[42] In addition, ash (~13,079,000 tons) would remain in four unlined areas at Marshall: 1) the subgrade fill beneath the Industrial Landfill (Cells 1-4); 2) the Structural Fill beneath the solar panels; 3) the Retired Landfill; and 4) the Ash Basin. Lastly, ash (~10,845,000 tons) will remain in the subgrade fill and unlined portion of the Monofill and the East Ash Basin at Roxboro.

According to the Settlement Agreement, all closure must be completed in compliance with the deadlines in CAMA. CAMA, however, allows DEC to request deadline variances, resulting in "no later than" closure deadlines in

[41] "Duke Energy on the one hand, and DEQ and the Community Groups on the other, have a dispute as to whether coal ash under a lawfully permitted landfill is regulated by CAMA." (Id. at p 4, Footnote 2).

[42] In addition, the closure plan at Allen provides that between 30,000 and 50,000 tons of unsaturated ash shall remain for structural stability around the footers for the transmission towers, and that all ash that remains will be covered with a geomembrane layer.

the Settlement Agreement. **Junis Exhibit 2** explains the key features of the Settlement Agreement.

Q. ARE OTHER DUKE ENERGY POWER PLANTS AFFECTED BY THE SETTLEMENT AGREEMENT?

A. Yes. The Settlement Agreement also indicates some relief for the closure deadlines for the Buck, H. F. Lee, and Cape Fear plants as follows, "The Community Groups agree not to oppose in court or before an administrative body, extensions to the CAMA closure dates as requested by Duke Energy, for the purposes of completing [sic] and beneficiation at Buck, Cape Fear, and HF Lee, through December 31, 2035."[43]

The Buck, H. F. Lee, and Cape Fear plants are the three plants selected by Duke Energy for ash beneficiation projects as required in N.C. Gen. Stat. § 130A-309.216. If DEQ does not grant an extension for closure, these three plants will have to complete closure by December 31, 2029. An extension would likely be more economical by allowing for longer use of the beneficiation facilities and possibly avoiding construction of coal ash landfills at the plant sites.

Q. PLEASE DESCRIBE HOW DEQ REGULATES WASTEWATER DISCHARGES FROM DUKE ENERGY'S COAL-FIRED PLANTS.

[43] Page 22, paragraph 45.

A. The Allen, Belews Creek, Buck, Cliffside, and Marshall plants discharge wastewater under NPDES permits issued by DEQ. These five plants also have Special Orders by Consent (SOCs) with DEQ that allow temporary variations from the NPDES requirements. The temporary variations give DEC time to eliminate unauthorized constructed seeps from ash basin dams by decanting the water and decommissioning the coal ash impoundments. Below is DEQ's explanation of SOCs:

> SOCs may be an appropriate course of action if a facility is unable to consistently comply with the terms, conditions, or limitations in an NPDES Permit. However, SOCs can only be issued if the reasons causing the non-compliance are not operational in nature (i.e., they must be tangible problems with plant design or infrastructure). Should you and the Environmental Management Commission enter into an SOC, limits set for particular parameters under the NPDES Permit may be relaxed, but only for a time determined to be reasonable for making necessary improvements to the facility.[44]

The permittee must apply for an SOC, include justification, and provide a complete discussion of the factors that led to non-compliance. After receiving the application, DEQ develops a draft SOC, releases it for public comment, and can issue it after 45 days.

Q. WHAT IS THE STATUS OF COAL ASH AT THE W.S. LEE PLANT IN SOUTH CAROLINA?

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[44] Available *at* https://deq.nc.gov/about/divisions/water-resources/water-quality-permitting/npdes-wastewater/npdes-compliance-and-2 (last visited February 12, 2020).

A. DEC has applied for a permit to build an on-site landfill for disposal of coal ash at the W.S. Lee plant pursuant to the terms of its Consent Agreement with the South Carolina Department of Health and Environmental Control (SCDHEC).

ENVIRONMENTAL LEGAL ACTIONS AGAINST THE COMPANY

Q. ARE YOU SPONSORING ANY ADDITIONAL TESTIMONY OR EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. My testimony incorporates by reference the Public Staff's testimony and exhibits in the last DEC rate case describing the legal actions filed against DEC for unlawful management of coal ash and pollution from coal ash.[45]

Q. WHAT IS THE NATURE OF THE LEGAL ACTIONS FILED AGAINST DEC WITH REGARD TO ITS COAL ASH MANAGEMENT?

A. Governmental agencies and environmental groups have sued DEC in state court with regard to the handling and impacts of coal ash, and private citizens have filed tort claims. It appears that the state enforcement actions filed by DEQ were prompted by "notice of intent to sue" letters from environmental groups represented by the Southern Environmental Law Center. DEQ also brought an administrative penalty proceeding against DEC in connection with the Dan River plant. In addition to the legal actions

[45] Page 63, line 15, through page 79, line 4, and Exhibits 17, and 27-32, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

against DEC in state courts, environmental groups have brought several federal citizen suits against DEC, and the federal government brought a criminal case against DEC for violations at the Dan River and Riverbend plants. A complete summary of these legal actions is presented in my testimony in the last rate case, as referenced above.

Q. HAS THE STATUS OF ENVIRONMENTAL LEGAL ACTION AGAINST THE COMPANY CHANGED SINCE DEC'S LAST RATE CASE?

A. Yes. In summary, the Settlement Agreement, dated December 31, 2019, between DEC, DEQ, and community and environmental groups resolved the following legal actions:

- <u>Mecklenburg County Superior Court, No. 13-CVS-14661</u> – Suits for violations at the Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, and Riverbend plants alleging unlawful discharges to surface waters, NPDES permit violations, and violations of the 2L rules.
- <u>US District Court for Middle District of North Carolina, No. 17-CV-1097</u> – Federal citizen suit filed on behalf of environmental and other citizen groups for violations at DEC's Belews Creek plant, alleging violations of DEC's wastewater permit and unpermitted discharges to surface waters.

In addition, the following cases were otherwise settled:

- <u>Rockingham County Superior Court, Nos. 17-CVS-298 and 17-CVS-241</u> – Tort claims in connection with the 2014 spill at the Dan River plant.
- <u>Wake County Superior Court, 17-CVS-10341</u> – Class-action litigation filed on behalf of property owners living near DEC's Allen, Belews Creek, Buck, Cliffside, and Marshall plants, and four DEP plants, alleging groundwater contamination.

Q. SINCE YOUR TESTIMONY IN THE LAST RATE CASE, HAVE YOU BECOME AWARE OF ANY ADDITIONAL CCR-RELATED LEGAL ACTIONS FILED AGAINST DEC?

A. Yes. One additional legal action was filed against the Company in December 2017, as summarized below.

<u>Gaston County Superior Court, No. 17-CVS-4780</u>

On December 15, 2017, a property owner neighboring DEC's Allen plant filed a complaint alleging groundwater contamination. This case was voluntarily dismissed by the plaintiff.

<u>SITE VISITS BY THE PUBLIC STAFF</u>

Q. HAS THE PUBLIC STAFF HAD THE OPPORTUNITY TO VISIT AND TOUR THE DEC CCR BASIN SITES?

A. Yes. On November 12, 2019, the Public Staff visited the Dan River and Belews Creek power plants. On November 13, 2019, the Public Staff visited the Marshall and Buck plants. **Junis Exhibit 3** shows photographs taken at each of these plants. In addition, **Junis Exhibit 4** lists the nomenclature used to identify the CCR storage units at each plant, the amount of CCR stored in each unit, years of operation, and modifications.

At each of those plants, the Public Staff, accompanied by consultants Vance Moore and Bernie Garrett of Garrett & Moore, Inc., met with key plant personnel. Those employees gave site-specific overviews regarding the status of ash removal and activities to achieve CCR Rule and North Carolina regulatory compliance and timelines going forward. At the time of our plant visits, the excavation orders issued by DEQ and pending appeal by the Company had created uncertainty as to the continuation of DEC's present closure activities and the future cost of compliance.

The Dan River coal-fired units were all retired in 2012. The combined cycle natural gas unit began operations that same year. The fuel oil-fired units were retired in 2013. As a high priority site, the CAMA deadline for removal of CCR from the Primary and Secondary Ash Basins was August 1, 2019. Water from the dewatering activities necessary for excavation was sent to the City of Eden for treatment and a wastewater treatment system on-site by lease. At the time of our site visit, the Primary and Secondary Ash Basins were completely excavated and crews were grading the former impoundments and decommissioning the dam.

The Belews Creek plant is an active coal-fired facility. In mid-2018, DEC made changes to transition from wet sluicing bottom ash with storage in the Active Ash Basin to dry handling with submerged flight conveyors and landfilling on-site in the Craig Road Landfill. In March 2019, the stormwater/process water redirection system was placed in service for intercepting flows to the Active Ash Basin and sending them to the Lined Retention Basin completed in December 2018. In addition, an ultrafiltration wastewater treatment system was placed in service in September 2018 to treat scrubber blowdown.

The Marshall plant is an active coal-fired facility. In March 2019, DEC discontinued placement of CCR in the Active Ash Basin by dry handling with a submerged flight conveyer system and landfilling on-site in the Industrial Landfill. In April 2019, DEC discontinued the flow of FGD wastewater to the Active Ash Basin by starting up the WWTP, which replaced the biotreatment wetlands. In addition, the stormwater redirection project decommissioned stormwater pipes that exist beneath the Photovoltaic Structural Fill and redirected flows around the area to temporary lined basins.

The Buck coal-fired units were all retired by 2013. The combined-cycle natural gas unit began operations in 2011. At the time of our site visit, the construction of the beneficiation system was approximately 45% complete. To meet the threshold of 300,000 tons of processed ash per year, the STAR plant will be fed approximately 425,000 tons of ash per year, operate nearly 24/7, and load approximately 60 tanker-style trucks per day. DEC is in the process of decanting the Additional Primary Pond (Basin 1), Primary Pond (Basin 2), and Secondary Pond (Basin 3), which flow into one another sequentially.

Q. WHAT IS THE STATUS OF CCR SITE REMEDIATION AT THE SITES NOT VISITED BY THE PUBLIC STAFF?

A. The Company is conducting groundwater monitoring at all of the sites described below.

The Allen plant is an active coal-fired facility. In accordance with SOC requirements, DEC initiated decanting of the Active Ash Basin in February 2019 and discontinued placement of CCR in the Active Ash Basin by dry handling with a submerged flight conveyer system and either landfilling on-site in the Retired Ash Basin Landfill or beneficially reusing the CCR. A holding basin and lined retention basin were constructed to provide preliminary and primary treatment for wastewater, which was facilitated by the water redirection project.

The Cliffside plant is an active coal-fired facility. Units 1-4 were decommissioned and demolished in 2012. The remaining Units 5 and 6 were upgraded to allow co-firing with natural gas. The Inactive Units 1-4 Ash Basin has been excavated, the dam lowered, and a lined retention basin constructed. DEC has begun decanting the Active Ash basin.

The Riverbend plant formerly consisted of seven coal-fired units that were all retired by 2013. The powerhouse building has been demolished and all the CCR stored on-site has been excavated and transported off-site. In April 2019, DEC submitted a CCR Removal Verification Report to DEQ for the Primary Ash Basin, the Secondary Ash Basin, the Dry Ash Stack area, and the Cinder Pit.

The W.S. Lee plant formerly consisted of three coal-fired units, two of which were retired in 2014. The third was converted to natural gas in 2015. The CCR from the Inactive Ash Basin and Ash Fill Area has been almost completely excavated and transported off-site. The Primary Ash Basin, Secondary Ash Basin, and Structural Fill are planned to be excavated and the CCR relocated to a new on-site landfill in the footprint of the former Secondary Ash Basin. In 2018, DEC constructed two lined sedimentation ponds to manage plant waste streams and a wastewater treatment system to treat water from decanting and dewatering activities.

PAST KNOWLEDGE ABOUT THE ENVIRONMENTAL IMPACTS OF THE STORAGE OF COAL ASH

Q. ARE YOU SPONSORING ANY ADDITIONAL TESTIMONY OR EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. My testimony incorporates by reference the Public Staff's voluminous record of exhibits and testimony in the last DEC rate case describing historic academic, industry, regulatory, and utility documents.[46] The principal topic

[46] Page 33, line 1, through page 53, line 3, and Exhibits 3-10, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018. *See also* Page 38, line 1, through page 60, line 27, and Exhibits 3-6, Direct Testimony of Public Staff Engineer Jay Lucas filed in Docket No. E-22, Sub 562, on August 23, 2019.

addressed by said exhibits and testimony is the history of known environmental impacts associated with the storage and management of coal ash in unlined surface impoundments.

Q. HAVE YOU CONDUCTED ANY FURTHER RESEARCH?

A. Yes. Per Commissioner Daniel G. Clodfelter's March 5, 2018 request in the hearing in Docket No. E-7, Sub 1146, Sierra Club submitted a copy of the Coal Ash Disposal Manual[47] published by the Electric Power Research Institute (EPRI) in October 1981. The following section briefly summarizes the manual, which my testimony incorporates by reference.

The 1981 EPRI Coal Ash Disposal Manual's stated purpose was "to present detailed procedures for the evaluation of the technical, environmental, and economic factors involved with the disposal of coal ashes which include fly ash and bottom ash" and "to aid utility design personnel in the selection and location of optimal disposal systems . . . ."[48]

Section 3 states that "[w]hile most coal ash is currently handled in wet systems, the national trend is away from wet disposal systems toward dry handling methods."[49] It also notes that wet disposal systems could make the use of land after site closure "perhaps difficult and costly."[50]

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[47] Coal Ash Disposal Manual, Second Edition, GAI Consultants, Inc., Electric Power Research Institute, October 1981. Filed in Docket No. E-7, Sub 1146 on March 15, 2018.

[48] *Id.* at S-1.

[49] *Id.* at 3-1.

[50] *Id.* at 3-3.

Importantly, Section 7 states that "it is difficult to prove non-contamination without monitoring, and the burden of proof is placed on the industry."[51]

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF HISTORICAL DOCUMENTS ON CCR RISKS.

A. In general, the exhibits are historic academic, industry, regulatory, and utility documents that show a growing awareness of environmental issues related to the storage and management of CCR. The documents are not a comprehensive review of the state of scientific and engineering knowledge about the risks of groundwater and surface water contamination from ash basins; it is a selection of documents that the Public Staff believes demonstrates an evolving body of scientific knowledge over more than 50 years concerning the risks of environmental contamination resulting from storing coal ash in unlined impoundments, and alternative methods of coal ash management.

These documents demonstrate that, by the early 1980s, the electric generating industry knew or should have known that the wet storage of CCR in unlined surface impoundments posed a serious risk to the quality of surrounding groundwater and surface water. This knowledge was evident in the 1979 report entitled "Health and Environmental Impacts of Increased Generation of Coal Ash and FGD Sludges," written by a research group from Arthur D. Little, Inc., and the Industrial Environmental Research

[51] *Id.* at 7-3.

Laboratory of the EPA. The report stated that FGD sludge and coal ash waste stored in "[w]et impoundments have the potential for contributing directly to groundwater contamination."[52] It further concluded that "areas using lined impoundments would tend to minimize the potential effects on ground and surface waters" (Id. at p 155).

This important realization was reinforced by the 1982 "Manual for Upgrading Existing Disposal Facilities" published by EPRI, of which Duke Energy is a member. The manual states "[b]ecause ponds by design maintain a hydraulic head of standing water above the settled waste, there is little that can be done to eliminate leachate generation and migration" and "[f]or this reason, ponding has fallen into disfavor with EPA as a permanent method of waste disposal."[53] "While groundwater can be protected and leachate generation can be minimized with sound engineering design and site operation, monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of a safe disposal practice." (Id. at p 4-19).

The 1988 Report to Congress by the EPA (1988 EPA Report)[54] was an extensive review of the quantities, physical and chemical characteristics,

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[52] Exhibit 7, NEP Study, p 153, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

[53] Exhibit 8, pp 8-2 and 8-3, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

[54] *Available at* https://www.epa.gov/sites/production/files/2015-08/documents/coal-rtc.pdf (last visited February 4, 2020).

and collection and storage methods of waste products from coal-fired electric generation. The report describes coal combustion waste disposal and re-use methods and technological advancements and assesses the use of each across the industry. At the time of the report, regulations on impoundments were becoming more restrictive, which was increasing the cost and decreasing the use of impoundments. The use of liners, leachate collection systems, and groundwater monitoring had increased in the years leading up to the publication of the 1988 EPA Report. The report states the following in the Executive Summary:

> Only about 25 percent of all facilities have liners to reduce off-site migration of leachate, although 40 percent of the generating units built since 1975 have liners. Additionally, only about 15 percent have leachate collection systems; about one-third of all facilities have ground-water monitoring systems to detect potential leachate problems. Both leachate collection and ground-water monitoring systems are more common at newer facilities.

1988 EPA Report, p ES-3.

Exhibits 2-7 (Id. at 2-17) and 4-4 (Id. at 4-19) of the report are a 1985 map of EPA regions with a pie chart of electricity generation by fuel type and a 1985 table of CCR waste management facilities by EPA region. It is worth noting that EPA Region 4, at nearly a 4:1 ratio, was the only region to use more surface impoundments than landfills. Exhibit 4-6 is a table of the quantity of liners installed for leachate control at utility waste management facilities by EPA region. (Id. at p 4-31). Of the available dataset, Region 4 used predominantly unlined facilities, accounting for over half of the unlined surface impoundments in the United States, and had the lowest percentage of lined disposal units with the exception of Region 10 in the Pacific Northwest.

DEC, as a large and prominent electric utility with a substantial portfolio of coal-fired generation, knew or should have known of EPRI and EPA publications addressing the risk of unlined ash impoundments. DEC failed to improve and modernize its practices despite the available knowledge described in my testimony above. In particular, given the state of knowledge as publications from 1979 and later warned of the risks of CCR constituents leaching into groundwater from unlined storage ponds, DEC should have installed comprehensive groundwater monitoring well networks in the 1980s to determine if the risk was materializing at their ash ponds.

DEC continued to operate ash impoundments (i.e., basins or ponds) at every coal-powered plant until at least 2012. In addition, the characteristics of the CCR disposed of in the impoundments changed over time. The enactment of the Clean Air Act and subsequent air quality rules in the 1970s required treatment of the emissions released by coal-fired generating facilities. Often, constituents previously emitted into the air became part of the waste stream that was disposed of in impoundments and landfills. **Junis Exhibit 5** is a table of when the Company implemented specific environmental controls.

Q. WHAT EVALUATIONS OR ANALYSES DID DEC CONDUCT WITH RESPECT TO THE HISTORICAL DOCUMENTS ON THE RISKS OF CCR STORAGE IN UNLINED IMPOUNDMENTS?

A. In response to a Public Staff data request, the Company stated that it was "unware of any CCR analysis performed in response to" the 1981 EPRI Coal Ash Disposal Manual, the 1982 EPRI Manual, the 1988 EPA Report, or the 2004 EPRI Decommissioning Handbook.

ENVIRONMENTAL COMPLIANCE

Q. ARE YOU SPONSORING ANY ADDITIONAL TESTIMONY OR EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. My testimony incorporates by reference the Public Staff's testimony and exhibits in the last DEC rate case describing what the Public Staff knew of the Company's environmental compliance up to the date of my testimony in that rate case.[55] I provide an update to the Company's environmental compliance record in my testimony below.

Q. WHAT IS THE STATUS OF THE COMPANY'S SEEPS?

A. DEC has identified its seeps in response to a Public Staff data request as provided in **Junis Exhibit 6**. Seeps arise from the seepage or movement of water through porous, earthen coal ash basin dams. While almost all earthen dams have seeps, most of the earthen dams across the state

[55] Page 53, line 4, through page 63, line 14, and Exhibits 11-26, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

impound fresh water whereas DEC's dams impound coal ash wastewater, which cannot be lawfully discharged – even by seeps – without a permit. "Engineered" or "constructed" seeps are discharge pipes or channels that were deliberately constructed.

On September 28, 2017, DEC submitted an application for an SOC related to coal ash basin seepage at Allen, Cliffside, Belews Creek, Buck, Marshall, and a number of DEP plants. On January 8, 2018, DEC executed a draft SOC with DEQ regarding 21 seeps of coal ash wastewater at the Allen, Cliffside, and Marshall plants. On April 12, 2018, the EMC approved the SOC for Allen, Cliffside, and Marshall. See **Junis Exhibit 7**. Under the SOC, the Company was required to pay an upfront penalty of $156,000 as settlement of all alleged violations due to seepage from 5 deliberately constructed seeps and 16 non-constructed seeps. In addition, the Company was required to accelerate compliance with CAMA, specifically N.C. Gen. Stat. §130A-309.210(d) and (f), by eliminating discharges of stormwater into the surface impoundments and converting to dry bottom ash handling prior to the decanting initiation and completion deadlines.

On July 12, 2018, the EMC approved an SOC for Belews Creek and Buck. See **Junis Exhibit 8**. Under the SOC, the Company was required to pay an upfront penalty of $84,000 as settlement of all alleged violations due to seepage from two deliberately constructed seeps and ten non-constructed seeps. In addition, the Company was required to accelerate compliance with CAMA, specifically N.C. Gen. Stat. §130A-309.210(d) and (f), by eliminating discharges of stormwater into the surface impoundments and converting to dry bottom ash handling prior to the decanting initiation and completion deadlines.

In addition, the Belews Creek plant is under an SOC dated March 21, 2019, to allow DEC to build a lined retention basin, decant the existing ash basin, and redirect treated wastewater to the Dan River. See **Junis Exhibit 9**. The discharge from the Belews Creek ash basin was not meeting the requirements of the March 21, 2019, SOC, and DEC temporarily halted decanting this basin until it could correct the problem.

Deliberately constructed seeps such as toe drains have been included in the renewed or modified NPDES permits for Allen, Belews Creek, Buck, Cliffside, Marshall, and W.S. Lee. Including these seeps in the Company's permits, however, does not retroactively condone them. Rather, their inclusion in a renewed or modified NPDES permit means that the seep must be monitored for contaminant levels, affording a level of environmental protection that did not previously exist.

Q. WHAT IS THE STATUS OF COMPLIANCE WITH STATE GROUNDWATER STANDARDS FOR DEC'S NORTH CAROLINA PLANTS?

A. DEQ requires DEC to monitor, assess, and characterize groundwater quality at or beyond the compliance boundary of the coal ash impoundments. Any exceedance of the applicable groundwater standards is evaluated against background levels (also known as provisional background threshold levels or PBTVs) to determine if the exceedance is attributable to the migration of constituents from the ash basins, natural causes, or offsite impacts. Legal counsel advises me that an exceedance of the state groundwater standards at or beyond the compliance boundary, not due to background levels, constitutes a violation of the groundwater standards. Furthermore, such an exceedance is a violation regardless of whether corrective action is undertaken.[56] See **Junis Exhibit 10**, pp 4-15. Based on DEC's groundwater monitoring, the cumulative total of groundwater violations has reached 10,940.[57] See **Junis Exhibit 11**.

Q. WHAT IS THE STATUS OF COMPLIANCE WITH STATE GROUNDWATER STANDARDS FOR DEC'S W.S. LEE PLANT IN SOUTH CAROLINA?

A. The Company is required by SCDHEC to monitor groundwater quality around coal ash storage units. Based on DEC's groundwater monitoring, the total number of groundwater exceedances at the W.S. Lee Plant has reached 1,280. See **Junis Exhibit 12**.

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[56] This was corroborated by DEQ in a September 25, 2019, amicus brief filed at the North Carolina Supreme Court in State of North Carolina ex rel. Utilities Commission v. Attorney General, Docket Nos. 271A18 and 401A18.

[57] In the E-7, Sub 1146, rate case, the Public Staff presented 3,091 groundwater violations as identified by DEC. The updated total of 10,940 is representative of the cumulative number of violations, including the 3,091 identified in the previous rate case and the 7,849 identified since then.

Q. WHAT IS THE STATUS OF THE ENVIRONMENTAL AUDITS OVERSEEN BY THE COURT-APPOINTED MONITOR?

A. The federal criminal case brought against DEC, DEP, and Duke Energy Business Services resulted in a requirement that a court-appointed monitor oversees the Company's compliance with the conditions of probation. One of those conditions is the completion of environmental audits by an independent auditor for each of DEC's and DEP's facilities with CCR surface impoundments. The scope of the audits includes a review and evaluation of environmental compliance.

The Final Audit Reports, conducted by Advanced GeoServices Corp. and The Elm Consulting Group International, LLC, have identified numerous exceedances of the groundwater quality standards at DEC's generating stations. In addition, the Audit Team identified unauthorized seeps, which are violations of the CWA and the Company's NPDES permits. Each of the 2016, 2017, 2018, and 2019 Final Audit Reports for DEC's eight coal-fired power plants are posted online[58] by the Company in accordance with the terms of the federal plea agreement.

The findings in the Audit Reports of groundwater exceedances at or beyond the compliance boundary and unauthorized seeps are summarized in **Junis Exhibit 13** and **Junis Exhibit 14**, respectively.

[58] *Available at* https://www.duke-energy.com/our-company/environment/compliance-and-reporting/environmental-compliance-plans (last visited February 6, 2020).

Q. WHAT IS THE STATUS OF COMPLIANCE WITH FEDERAL CCR RULE GROUNDWATER STANDARDS FOR DEC'S NORTH CAROLINA AND SOUTH CAROLINA SURFACE IMPOUNDMENTS?

A. The Company is required by the CCR Rule to monitor groundwater at the waste boundary for constituents regulated by EPA. More specifically, DEC is required to perform background sampling and then detection monitoring for Appendix III parameters. As noted earlier, the location of monitoring wells and the types of constituents that must be monitored under the CCR Rule differ somewhat from monitoring required by DEQ. The Company has compiled a table quantifying 4,592 testing results determined to be statistically significant increases over background levels for Appendix III parameters. See **Junis Exhibit 15**. If a statistically significant increase is detected for one or more constituents, then assessment monitoring is required for Appendix IV parameters. If the testing results exceed the groundwater protection standards, the facility owner must characterize the nature and extent and initiate an assessment of corrective action. For all but one of its coal-fired power plants[59], DEC has been required to submit an assessment of corrective measures as a result of exceedances of the background levels and groundwater protection standards. Under the CCR Rule, DEC is required to file notices and reports[60], including annual

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[59] The exception being Riverbend because the CCR Rule does not apply to this site.

[60] *Available at* https://www.duke-energy.com/our-company/environment/compliance-and-reporting/ccr-rule-compliance-data (last visited February 6, 2020).

groundwater monitoring reports summarizing the detection and, if applicable, assessment monitoring activities and data. The Company has compiled a table quantifying 438 testing results from groundwater downgradient of the ash impoundments that have exceeded both the natural background levels and the groundwater protection standards for Appendix IV parameters. See **Junis Exhibit 16**.

Q. WHEN DID DEC BEGIN CONDUCTING GROUNDWATER MONITORING AND HAS THE COMPANY CONTINUED TO INSTALL ADDITIONAL GROUNDWATER MONITORING WELLS?

A. DEC installed groundwater wells and began monitoring on a site-specific basis. A majority of DEC's voluntarily monitoring wells were installed in the mid-2000s; however, a few were installed at Dan River as early as November of 1993.[61] In addition, exceedances of the groundwater quality standards were detected at monitoring wells installed at the direction of DEQ solid waste regulators near the on-site landfills at the Belews Creek and Marshall sites as early as 1989.[62]

DEC states the initial requirement by DEQ to monitor groundwater at each ash impoundment was in 2011 or 2012, with the exception of Dan River, which began in 1994, and the landfills at Belews Creek and Marshall. See

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[61] Exhibit 23, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

[62] Exhibit 24, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

Junis Exhibit 17. Despite the 1979 EMC adoption of the initial 2L rules and the publication of the 1982 EPRI Manual, which stated that the "monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of a safe disposal practice,"[63] DEC did not start monitoring groundwater quality at some of its sites until two decades later. Furthermore, DEC did not engage in comprehensive groundwater monitoring until even later, as quantitatively illustrated by the table in **Junis Exhibit 18**.

As noted by the EPA in the preamble to the CCR Rule, once monitoring wells are installed downgradient of unlined coal ash impoundments, exceedances of groundwater standards quickly become apparent.[64]

Q. WHAT ACTIONS DID DEC TAKE IN RESPONSE TO ITS GROUNDWATER MONITORING DATA?

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[63] Junis Exhibit 8 in Docket No. E-7, Sub 1146, pp 4-19.

[64] ". . . under many state programs existing impoundments are exempt from groundwater monitoring and once monitoring is put in place, new damage cases quickly emerge. This is illustrated by two lines of evidence: First, in the wake of the 2008 TVA Kingston CCR spill two states required utilities for the first time to install groundwater monitoring. Illinois required facilities to install groundwater monitoring down gradient from their surface impoundments. As a result, within only about two years, Illinois detected seven new instances of primary MCL exceedances and five additional instances with exceedances of SMCLs. The data for all twelve sites were gathered from onsite; it appears none of these facilities had been required to monitor groundwater off-site, so whether the contamination had migrated off-site is currently unknown. Similarly, North Caroline [sic] required facilities to install additional down gradient wells. In January 2012, officials from the North Carolina Department of Environment and Natural Resources disclosed that elevated levels of metals have been found in groundwater near surface impoundments at all of the State's 14 coal-fired power plants." 80 Fed. Reg. at 21455.

A. In response to a Public Staff data request seeking an explanation of the action taken by the Company in response to each exceedance, the Company stated the following:

> The actions taken by DEC are included in the response to PS DR 36-2. Since the PS DR 36-2 response in the Sub 1146 rate case was provided, operations of the Belews Creek groundwater extraction system began in March 2018. This system was installed per requirements of the September 29, 2015 settlement agreement between NCDEQ and Duke Energy to reduce groundwater migration of constituents off-site. Additionally, Corrective Action Plans (CAP) have been submitted to NCDEQ on December 31, 2019, for Allen, Belews Creek, Cliffside, and Marshall.

In response to the referenced Public Staff data request (DR 36-2) seeking in part what corrective action was taken and when it was taken with respect to each exceedance, the Company stated the following[65]:

> At the time DE Carolinas was engaged in voluntary groundwater monitoring, it did not have sufficient information to determine natural background levels. At some sites, the company did install background/upgradient wells, but the limited data generated were more appropriate for qualitative rather than quantitative comparisons. In other words, the limited data were not sufficient nor was it intended to support the kind of statistical analysis now required by NCDEQ to generate the PBTVs. During the voluntary monitoring period, NCDEQ never objected to the company's qualitative analysis or moved to set more explicit background levels. Although limited, the data, as compared to available North Carolina groundwater quality surveys, indicate that the constituents of concern were naturally occurring and could be due to background conditions. For example, at Allen, the constituents of concern beyond the compliance boundary were pH, iron, manganese, and vanadium, all of which can occur naturally in the Piedmont Region of North Carolina.

[65] Exhibit 23, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

> Subsequent analysis, which was not required by DEQ until 2016, has resulted in PBTVs above the default 2L standards for these parameters. Based on the more robust data set now available as a result of groundwater monitoring requirements in NPDES, it is possible that some exceedances identified in voluntary wells were due to naturally occurring conditions and some were affected by the ash basin. However, DE Carolinas does not have a comparison of voluntary well monitoring data against PBTVs to provide a well-by-well breakdown.
>
> Initial results appeared consistent with naturally occurring conditions, so between the installation of the voluntary monitoring wells and 2009, DE Carolinas continued monitoring the wells and submitting semi-annual reports to the NCDEQ. In 2009, DE Carolinas began to work with the department to relocate and install new wells at the ash basin compliance boundaries, as monitoring was added to NPDES permits. In 2011, the Department issued the Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements, whereafter DE Carolinas began to work through the assessment process detailed therein. The 2011 policy under which DE Carolinas had been operating was ultimately rescinded by NCDEQ in 2015; however, DE Carolinas has participated in CAMA's assessment and corrective provisions since 2014.

This is further evidence that DEC's groundwater monitoring prior to the 2010s was insufficient to provide convincing proof of a safe disposal practice. Moreover, in its reasoning for not taking further action with regard to detected exceedances, DEC relies in part on the absence of a DEQ directive to do more. For example, it states that "[d]uring the voluntary monitoring period, NCDEQ never objected to the company's qualitative analysis or moved to set more explicit background levels." However, silence by a regulator did not absolve DEC of its failure to take action when it detected groundwater exceedances at its unlined surface impoundments, nor did it absolve DEC of its failure to install a robust system of wells in the early 1980s, particularly where decades-worth of industry knowledge indicated that such impoundments were likely to cause groundwater contamination.[66]

When DEC detected exceedances at its unlined impoundments, it should have installed sufficient groundwater monitoring wells to determine to what extent those exceedances were attributable to the coal ash impoundments, to what extent they were attributable to other sources or natural background levels, and the extent and nature of potential groundwater degradation.

COSTS OF CCR-RELATED ENVIRONMENTAL IMPACTS

Q. FOR CCR MANAGEMENT, HAS DEC INCURRED COSTS RELATED TO NONCOMPLIANCE WITH ENVIRONMENTAL REGULATIONS?

A. Yes. The most publicized costs are the fines, mitigation payments, and cleanup costs noted in DEC's guilty plea to criminal negligence associated with the 2014 Dan River spill. In addition, there have been unpermitted discharges, violations of groundwater quality standards, and other violations of environmental regulations at all DEC CCR disposal sites. There have been and will continue to be substantial costs to remedy these CCR-related environmental violations and prevent risks of future violations,

[66] As stated in the 1982 EPRI Manual, "[p]otential deficiencies in utility waste disposal practices may be defined by two sets of standards," (1) "[t]he disposal practice does not comply with specific federal and/or state regulatory requirements," and (2) "[t]he site has the potential to contaminate the environment." Indeed, "[t]his seemingly redundant statement is important to any assessment of disposal site deficiencies. Identification and correction of regulatory deficiencies do not necessarily preclude the possibility of past or future environmental degradation by the site. Conversely, known degradation cannot be corrected by simply conforming to regulations." Pages 4-1 – 4-2.

particularly under the corrective action and closure requirements of the CCR Rule and CAMA. While the Company calls these “compliance” costs to meet the requirements of CAMA or the CCR Rule, they also reflect DEC’s non-compliance with longstanding environmental regulations. In my opinion, the evidence of violations shows DEC would have incurred substantial corrective action costs under the 2L rules even in the absence of the CCR Rule and CAMA. I believe this is relevant to DEC’s culpability and supports the recommendation of equitable sharing.

DEC DIRECT TESTIMONY ON COAL ASH PROJECTS

Q. PLEASE PROVIDE A SUMMARY OF THE COAL ASH COST RECOVERY DISCUSSION IN THE TESTIMONY OF DEC WITNESS JESSICA BEDNARCIK.

A. In her direct testimony and 17 exhibits filed on September 30, 2019, DEC witness Jessica Bednarcik discussed state and federal regulatory requirements, actions by DEQ, and coal ash related costs requested by DEC from January 1, 2018, through January 31, 2020. Witness Bednarcik provided actual costs from January 1, 2018, through June 30, 2019, and DEC has periodically provided updates for later months.

The costs in witness Bednarcik’s testimony are only those that DEC has booked for financial accounting purposes as Asset Retirement Obligations

(AROs).[67] Capital costs related to coal ash are not booked as AROs (and are thus termed by the Company as "non-ARO" costs) and are located in the testimony of DEC witness Steve Immel. In response to a Public Staff data request, DEC explained its method of separating ARO and capital costs as follows:

> If there is a project or work scope that is subject to the federal CCR regulations, CAMA, or other regulation/legislation that creates a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably estimated, the costs are recorded as ARO, e.g. basins/landfill closures. If there is a project that supports future ongoing operations and meets capitalization guidelines, these costs get recorded as Capital.

As of November 30, 2019, the total actual ARO coal ash costs expended in the period beginning January 1, 2018, and submitted for recovery in this case on a system basis were $491,002,217.

Q. PLEASE SUMMARIZE THE DISCUSSION IN THE TESTIMONY OF DEC WITNESS STEVE IMMEL REGARDING CAPITAL INVESTMENTS IN THE COMPANY'S COAL FLEET TO MEET ENVIRONMENTAL REGULATIONS.

A. In his direct testimony filed on September 30, 2019, DEC witness Steve Immel stated the following:

> [T]he Company has made significant investments within its coal fleet to meet environmental regulations to allow for the continued

[67] As noted in the testimony of Public Staff witness Maness, for North Carolina retail regulatory accounting and ratemaking purposes, as determined by this Commission, DEC is accounting for and recovering its impoundment closure costs through a deferral and amortization process, rather than a financial accounting ARO process.

> operation of active plants, including the Coal Combustion Residual ("CCR") Rule, the Coal Ash Management Act ("CAMA") and Effluent Limitations Guidelines ("ELG"), totaling approximately $689 million, largely driven by dry bottom ash conversions, wastewater treatment enhancements, and lined retention basins projects.

The Company did not provide any exhibits or additional direct testimony supporting the $689 million cost recovery request for capital investments in the Company's coal fleet.

Q. ARE THE COSTS IN WITNESS STEVE IMMEL'S TESTIMONY INCLUDED IN YOUR EQUITABLE SHARING RECOMMENDATION?

A. No. My testimony does not recommend a sharing of the costs for capital investments in the Company's coal fleet for compliance with environmental regulations in connection with the ongoing production of electricity (e.g., disposal of new waste materials). The Public Staff's equitable sharing recommendation only applies to the costs of disposing of ash a second time, where the initial disposal in unlined impoundments has caused environmental contamination and posed a risk of future environmental contamination, and associated remediation costs. It does not apply to the costs of disposal for future production ash.

Q. DID DEC PROVIDE ANY ADDITIONAL INFORMATION ON ITS COAL ASH RELATED COSTS?

A. In its E-1, Item 10, NC-1100, DEC provided its adjustments in this rate case for environmental-related costs. More specifically, NC-1103 provides the system spend ARO costs by month discussed in witness Bednarcik's testimony. NC-1105 provides the system spend capital costs by month discussed in witness Immel's testimony and further breaks down the costs by plant and account number. The two primary account numbers in NC-1105 are 311 (Structures and Improvements) and 312 (Boiler Plant Equipment) in Steam Production Plant. A small portion of capital costs is also booked as 315 (Accessory Electric Equipment) in Steam Production Plant and 341 (Structures and Improvements) in Other Production Plant.

Q. PLEASE PROVIDE A LIST OF COAL ASH RELATED PROJECTS THAT DEC BOOKED AS ARO.

A. **Confidential Junis Exhibit 19** is a list of projects that DEC booked as ARO.

Q. PLEASE PROVIDE A LIST OF COAL ASH RELATED PROJECTS THAT DEC BOOKED AS CAPITAL.

A. **Junis Exhibit 20** is a list of projects that DEC booked as capital.

GROUNDWATER EXTRACTION AND TREATMENT

Q. ARE YOU SPONSORING ANY ADDITIONAL TESTIMONY OR EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. My testimony incorporates by reference my testimony and exhibits filed on January 23, 2018, in Docket No. E-7, Sub 1146, describing groundwater quality at Belews Creek, groundwater extraction and treatment performed by DEC, and associated costs.[68]

Q. PLEASE BRIEFLY DESCRIBE DEC'S EXTRACTION AND TREATMENT OF GROUNDWATER AT BELEWS CREEK.

A. In summary, DEC contaminated the groundwater at the Belews Creek plant in violation of the 2L rules. DEQ issued a Notice of Violation, and in a settlement with DEQ for remediation[69], DEC agreed to extract and treat the contaminated groundwater. The settlement signed by the Company states in part: "data show constituents associated with the ash basins at concentrations over the 2L standards . . . have migrated off site," and "[e]xtraction wells will be used to pump the groundwater to arrest the offsite extent of the migration." DEC's own groundwater monitoring as reported to DEQ shows 2L violations at this site. DEC witness Wright further admitted during the 2017 DEC rate case that the extraction wells at Belews Creek would not have been necessary "if there had been no exceedances and no offsite groundwater impacts." (Docket No. E-7, Sub 1146, Tr. Vol. 13, pp 91-92).

[68] Page 73, line 12, through page 75, line 17, and Exhibit 29, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

[69] Settlement Agreement between DEQ and Duke Energy, executed as of September 29, 2015. Exhibit 29, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

Q. WHAT WAS THE PREMISE OF YOUR TESTIMONY IN DOCKET NO. E-7, SUB 1146, REGARDING GROUNDWATER EXTRACTION AND TREATMENT?

A. As stated on page 94 of my testimony in Docket No. E-7, Sub 1146, these costs should be disallowed "because they are costs due to environmental violations, and they exceed the amount of costs required for CAMA compliance in the absence of environmental violations."

Simply put, DEC is extracting and treating groundwater at the Belews Creek plant because it is responsible for contaminating the groundwater with coal ash constituents such as arsenic, boron, chromium, manganese, selenium, and others. The Public Staff's position in Docket No. E-7, Sub 1146, was that DEC should not place these costs on ratepayers. There is certainly no basis for DEC to extract and treat *clean* groundwater, or to extract groundwater because of natural background constituents.

Q. WHY DO YOU DISCUSS EXTRACTION WELLS AND TREATMENT SEPARATELY FROM DISCUSSION OF ENVIRONMENTAL VIOLATIONS IN GENERAL?

A. We can identify specific costs associated with extraction and treatment, and such costs are attributable solely to DEC's violation of groundwater standards. Those costs would not have been incurred if DEC had not violated the 2L rules.

Q. DID THE COMMISSION ALLOW DEC TO RECOVER COSTS FOR GROUNDWATER EXTRACTION AND TREATMENT IN DOCKET NO. E-7, SUB 1146?

A. Yes. In its Order, the Commission stated that it "declines to find that [DEQ's settlement agreement with DEC] evidences violation of environmental obligations."[70] The Commission further stated that "there is insufficient evidence that DEC would have had to engage in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule," and that "the assertion that DEC's 'violations' resulted in the DEQ Settlement Agreement and in groundwater extraction and treatment costs that would not otherwise have been incurred is incorrect and not supported by the evidence."[71]

The Public Staff asks that the Commission take a fresh look at the treatment of groundwater extraction and treatment costs. As of the last rate case, the Belews Creek plant had 1,926 groundwater violations.[72] No party, including DEC, contested the number of groundwater exceedances. As of this rate case investigation, there are cumulatively a total of 3,972 groundwater violations. From a factual standpoint, there was no reason for DEC to extract and treat groundwater unless DEC was responsible for that

[70] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146, p 297.

[71] *Id.* At 300.

[72] Exhibit 20, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

groundwater being contaminated, and the exceedance reports show that the groundwater was contaminated by DEC's coal ash impoundment. From a legal standpoint, counsel advises me that it is an error to conclude that CAMA or the CCR Rule would have required extraction and treatment of the groundwater at Belews Creek if there were no violations of groundwater quality standards.

SPECIFIC DISALLOWANCES

Q. PLEASE BRIEFLY DESCRIBE THE SPECIFIC DISALLOWANCES THAT YOU RECOMMEND.

A. The Public Staff recommends disallowance of specific costs associated with: (1) groundwater extraction and treatment at the Belews Creek Steam Station; (2) bottled water costs; (3) permanent alternative water supply connections for properties as required by CAMA; (4) permanent alternative water supply connections for ineligible properties; (5) water treatment systems as required by CAMA; and (6) fines and penalties, or the equivalent, for environmental violations.

1. I recommend that the expenditures for groundwater extraction and treatment at the Belews Creek plant not be included in DEC's pro forma adjustment set forth in the E-1, Item 10, NC-1103. This position is consistent with the Public Staff's position in the Sub 1146 rate case and the pending appeal before the North Carolina Supreme Court, and the reasoning is discussed in my testimony above. For

the period of January 2018 through November 2019, the extraction well and contaminated water treatment costs for Belews Creek amounted to $298,433 on a system basis. I recommend that these costs be disallowed because they are due solely to environmental violations and they exceed the amount of costs required for CAMA compliance in the absence of environmental violations.

2. The Public Staff has confirmed that the expenditures for bottled water, which include the bottled water itself, the delivery company, personnel associated with the delivery, and the consulting firm that managed the overall bottled water delivery program, provided to households in the vicinity of DEC plants have been excluded by DEC in its pro forma adjustment set forth in the E-1, Item 10, NC-1103. For the period of January 2018 through November 2019, the costs amounted to $856,034 on a system basis. This adjustment conforms to the precedent of the Commission's determination in the Sub 1146 rate case.[73]

3. The Company was required to connect eligible residential properties to permanent alternative water supplies per N.C. Gen. Stat. §130A-309.211(c1). I recommend these costs be disallowed by exclusion from DEC's pro forma adjustment set forth in the E-1, Item 10, NC-1103. For the period of January 2018 through November 2019, the

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[73] Page 302 of the Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction issued in Docket No. E-7, Sub 1146, on June 22, 2018.

costs amounted to $16,882,665 on a system basis. These permanent water supply costs and the bottled water costs discussed above are the direct result of the legislature deciding that coal ash constituents from DEC's impoundments created an unacceptable risk to people's groundwater wells in the vicinity of the coal ash impoundments. As noted in Commissioner Clodfelter's dissent in the Sub 1146 Order, there is no logical distinction between the permanent water supply costs and the bottled water costs that the Commission determined should be excluded in the last rate case.

4. The Company has voluntarily connected businesses and residential properties to permanent alternative water supplies that were otherwise not eligible under N.C. Gen. Stat. §130A-309.211(c1). The costs were not required by CAMA and, as described above, there is no logical distinction between them and the Company's bottled water costs that the Commission determined should be excluded in the last rate case. DEC has informed the Public Staff that it excluded the above costs from the rate request, and, therefore, no adjustments are necessary.

5. As an alternative to connections to permanent water supplies, the Company was able to install, operate, and maintain water treatment systems per N.C. Gen. Stat. §130A-309.211(c1). Where this alternative was chosen, I recommend the costs be disallowed. For the period of January 2018 through November 2019, the costs

amounted to $962,524 on a system basis. The water treatment system costs, similar to the permanent water supply and bottled water costs, are the direct result of the legislature deciding that DEC's coal ash management had created an unacceptable risk to people's groundwater wells in the vicinity of the coal ash impoundments. There is no logical distinction between the water treatment system costs and the bottled water costs that the Commission determined should be excluded in the last rate case.

6. Fines and penalties, or the equivalent, for environmental violations should be excluded from rate recovery. Included in this category are costs that must be excluded pursuant to the probation conditions of DEC's federal plea agreement. DEC has informed the Public Staff that it excluded the above costs from the rate request, and, therefore, no adjustments are necessary.

The above exclusions are in addition to the recommended disallowances presented in the testimony of witnesses Bernie Garrett and Vance Moore.

EQUITABLE SHARING

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE REMAINING CCR-RELATED COSTS?

A. Yes. Certain costs are so clearly and directly due to the Company's failure to comply with environmental regulations that none of those costs should be assigned to ratepayers. For most of the coal ash-related costs at issue in this rate case, the Company bears a great deal of culpability due to noncompliance with environmental regulations, but the Public Staff's view of culpability is different from traditional imprudence. The Public Staff did not conduct a prudence review of DEC decision-making at the time the ash basins were constructed, primarily due to the virtual impossibility of conducting a comprehensive review of Company records over the 1950s to 1980s timeframe. Instead, the Public Staff focused its investigation on the area where the Company's performance has been measured against its legal duty in recent years: groundwater and surface water compliance issues at ash basins. Even where some Company actions or omissions appear imprudent, such as failure to deploy a comprehensive groundwater monitoring system at a much earlier date, quantification of costs directly resulting from the acts or omissions would be speculative. Also, even where DEC's management was arguably prudent in light of the knowledge they had at the time, the Company bears some degree of responsibility for its extensive environmental violations. In this situation, an equitable sharing of those costs is reasonable and appropriate, both as a reflection of DEC's culpability for environmental violations and as a proxy for costs of violations that exist but cannot be precisely quantified.

An equitable sharing is particularly appropriate in light of the extent of the Company's failure to prevent environmental contamination from its CCR impoundments, in violation of state and federal laws. The nature and extent of some of the Company's CCR-related environmental problems found at earlier dates are addressed in the Joint Factual Statement[74] signed by Duke Energy as part of the DEC federal plea agreement.

Additionally, there is substantial evidence[75] of violations beyond those admitted in the federal criminal case. For example, there are violations of N.C. Gen. Stat. § 143-215.1 – unlawful surface water discharges such as seeps – some of which have led to penalties and some that will be corrected through dewatering and decanting of CCR basins as set out in the SOCs entered into by DEC. See **Junis Exhibits 7-9**. In addition, immediately following the Dan River Spill in 2014, and again two years later, DEQ found numerous dam safety issues at DEC's CCR impoundments. There is also evidence of numerous DEC groundwater violations. In general, DEC did not engage in comprehensive groundwater monitoring[76] until required to do so by their NPDES permits beginning in 2011.

The groundwater violations[77] currently reported to DEQ from DEC monitoring wells are a further indication of the breadth of environmental contamination caused by the Company. The 10,940 North Carolina groundwater violations listed in **Junis Exhibit 11**, exceeding the 2L

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[74] Exhibit 31, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

[75] Prior evidence of environmental impacts was presented in Exhibits 12, 18, 19, 20, and 25, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

[76] See the number of groundwater monitoring wells installed by decade in **Junis Exhibit 18**.

[77] This was affirmed by DEQ in a September 25, 2019 amicus brief filed at the North Carolina Supreme Court in State of North Carolina ex rel. Utilities Commission v. Attorney General, Docket Nos. 271A18 and 401A18.

standards or IMACs and PBTVs at or beyond the compliance boundary, are attributable to migration of contaminants from DEC's ash basins. The 1,280 South Carolina exceedances of the Federal MCLs and Secondary MCLs are listed in **Junis Exhibit 12**. The CCR Rule Appendix III Parameters 4,592 testing results determined to be statistically significant increases are listed in **Junis Exhibit 15**. The CCR Rule Appendix IV Parameters 438 testing results from groundwater downgradient of the ash impoundments that have exceeded both the natural background levels and the groundwater protection standards are listed in **Junis Exhibit 16**. It is notable that the number of 2L violations has increased by 7,849, or 254%, since my testimony in the last DEC rate case.

The failure of Duke Energy to comply with environmental regulations in its management of CCR was undoubtedly a contributing factor to the adoption of both the CCR Rule and CAMA, which in turn led to significant new compliance costs. In fact, the final CCR Rule cites environmental damage caused by Duke Energy facilities, and not just the Dan River plant[78], as part of the justification for the CCR Rule.[79] Furthermore, the Dan River spill

[78] "All CCR surface impoundments pose some risk of release—whether from a catastrophic failure or from a more limited structural failure, such as occurred at Duke Energy's Dan River plant." 80 Fed. Reg. at 21393. The EPA also referenced the Dan River Spill when it stated: "[a] recent CCR spill incident demonstrates that inactive surface impoundments that have not been properly decommissioned (i.e., by breaching, dewatering, and capping or by clean-closing) continue to pose a significant risk to human health and the environment." *Id.* at 21458-21459.

[79] "Certain states (*e.g.,* Indiana) consider surface impoundments as temporary storage facilities as long as they are dredged on a periodic basis (*e.g.,* annually). Under these states' rules, such impoundments are exempt from any solid waste regulations that would require groundwater monitoring, and from requirements for corrective action. Such requirements are likely to decrease

directly prompted the CAMA legislation – a strict schedule for impoundment closures that to the knowledge of the Public Staff is unmatched by any legislation in any other state. Moreover, DEC's non-compliance with its NPDES permits and the CWA and the DEQ 2L rules would undoubtedly have led to cleanup costs from environmental litigation or enforcement even if the CCR Rule and CAMA had never been adopted. Those cleanup costs largely overlap with CCR Rule and CAMA compliance costs because impoundment closure and other corrective action under CAMA became the required cleanup method. In the absence of CAMA, it is possible some other remedial action short of impoundment closure by excavation or extremely expensive beneficiation, such as cap in place, would have sufficed. The cost differential is speculative at best. However, given the existence of widespread environmental violations, we do know extensive corrective action would have been required to achieve compliance with pre-existing environmental laws and regulations even without CAMA and the CCR Rule.

In these circumstances, it would be unreasonable to charge ratepayers for all the CCR compliance costs above the specific and limited disallowances the Public Staff has recommended. Due to its environmental violations, DEC has a great deal of culpability for the compliance costs related to remediation and ash basin and storage unit closures, and would likely have

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the instances in which contamination above an MCL has migrated off-site will be detected." 80 Fed. Reg. at 21456. The EPA references Duke Energy's Gibson Generating Station in Indiana, a proven damage case, as an example. *Id*.

incurred substantial coal ash corrective action costs even without the CCR Rule and CAMA, whereas ratepayers are not culpable at all for those costs.

For the foregoing reasons, I believe the equitable sharing of CCR management costs, as further discussed and effectuated through the deferral and amortization approach recommended by Public Staff witness Maness, is reasonable in addition to the specific disallowances I have recommended.

INSURANCE COVERAGE FOR ENVIRONMENTAL LIABILITY

Q. DID THE COMMISSION ADDRESS DEC'S CLAIMS FOR INSURANCE COVERAGE IN DOCKET NO. E-7, SUB 1146?

A. Yes. In DEC's last rate case, the Commission determined that if any insurance proceeds are ultimately received or recovered for mitigation and remediation costs associated with CCR sites, DEC shall place all such insurance proceeds in a regulatory liability account to be disbursed back to ratepayers or to offset the costs to ratepayers of the Company's CCR costs.

Q. HAS DEC RECEIVED OR RECOVERED ANY INSURANCE PROCEEDS FOR ENVIRONMENTAL DAMAGES?

A. No. The Company is currently in active litigation against its insurance carriers for recovery of mitigation and remediation costs associated with CCR sites.

COMPARISON OF DUKE ENERGY AND DOMINION RATE CASES REGARDING CCR MANAGEMENT

Q. PLEASE DESCRIBE THE TREATMENT OF CCR-RELATED COSTS IN DOMINION'S 2016 RATE CASE.

A. In Docket No. E-22, Sub 532, the Dominion 2016 rate case, the resolution of CCR remediation costs was the result of an agreement and stipulation of settlement between the Public Staff and Dominion, which was accepted by the Commission.[80] The stipulation allowed for a five-year amortization period, with a return on the unamortized balance for coal ash costs in that case. The Public Staff supported this treatment of CCR-related costs because (1) the Public Staff was not aware of the extent of groundwater contamination and environmental degradation from Dominion's CCR, and (2) the magnitude of the costs at issue in that case was much lower than in subsequent cases. Importantly, the stipulation in the Dominion 2016 rate case did not have precedential value.[81]

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[80] "Based upon the entire evidence of record, the present Stipulation to allow the test year CCR costs to be recovered in this case by amortization over a five-year period with the unamortized balance to earn a return and the authorization to treat future CCR costs incurred through 2018 as a regulatory asset (which is the mechanism to facilitate the deferral of future CCR costs) is proper and in the public interest under the facts and circumstances of this case." Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions (Dominion 2016 Order), Docket No. E-22, Sub 532, at 62 (Dec. 12, 2016). *See also id.* at 10, 57-58.

[81] "This Stipulation shall not be cited as precedent by any of the Stipulating Parties with regard to any issue in any other proceeding or docket before this Commission or in any court." Agreement and Stipulation of Settlement, Docket No. E-22, Sub 532, at 16 (Oct. 3, 2016). See also, *id.* at 10-11 ("The Public Staff's agreement in this proceeding to the deferral and amortization of CCR expenditures incurred through June 30, 2016, shall not be construed as a recommendation that the Commission reach any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones to be

Q. PLEASE DESCRIBE THE TREATMENT OF CCR-RELATED COSTS IN DEC AND DEP'S 2017 RATE CASES.

A. In DEC and DEP's 2017 rate cases in Docket Nos. E-7, Sub 1146, and E-2, Sub 1142, respectively, the Public Staff found extensive environmental contamination and violations from ash impoundments. The Public Staff also noted the extraordinary amount of coal ash costs, resulting in no additional electric service for customers, as another factor. Accordingly, the Public Staff recommended that CCR-related costs of DEC and DEP be allocated equitably, with 50% paid by shareholders and 50% paid by customers. The equitable sharing recommendation applied to coal ash costs beyond the costs for which the Public Staff recommended a complete disallowance based on imprudence or unreasonableness, and was based upon DEC and DEP's culpability in creating adverse environmental impacts.

In those rate cases, the Commission allowed DEC and DEP to recover their CCR-related costs as requested, with the exception of management penalties of $70 million on DEC and $30 million on DEP. The Public Staff asks that the Commission take a fresh look at the coal ash costs in the present case, and adopt equitable sharing based on a review of the "other material facts of record" under N.C. Gen. Stat. § 62-133(d). The "other material facts of record" are the extensive environmental violations caused

recovered in this case."); Dominion 2016 Order at 63 (". . . the Commission's determination in this case shall not be construed as determining the prudence and reasonableness of the Company's overall CCR plan, or the prudence and reasonableness of any specific CCR expenditures other than the ones deferred and authorized to be recovered in this case.").

by DEC's coal ash and the extraordinary magnitude of costs that produce no new electricity as noted by Public Staff witness Maness.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE PUBLIC STAFF'S RECOMMENDATIONS FOR CCR COST RECOVERY IN THE DOMINION 2016 RATE CASE AND THE 2017 DEC AND DEP RATE CASES.

A. In my previous testimony[82], I discussed the Public Staff's investigation of Dominion's environmental compliance record in its 2016 rate case. In summary, I explained that Dominion's environmental compliance record at that time was better than DEC's, and therefore, DEC's cost recovery in its 2017 rate case should be treated differently.

Q. PLEASE DESCRIBE DEC'S TESTIMONY IN ITS 2017 RATE CASE COMPARING ITS CCR MANAGEMENT RECORD TO THAT OF DOMINION.

A. On pages 11 through 15 of his rebuttal testimony filed on February 6, 2018, in Docket No. E-7, Sub 1146, DEC witness Julius Wright responded to my testimony regarding Dominion's environmental compliance record by providing examples of CCR-related groundwater contamination[83] at Dominion's coal-fired power plants.

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[82] Page 107, line 1, through page 109, line 15, and Exhibits 17, and 27-32, Direct Testimony of Public Staff Engineer Charles Junis filed in Docket No. E-7, Sub 1146, on January 24, 2018.

[83] E.g., on pages 11 and 12 of his rebuttal, witness Wright states, "For example, in 2002 Dominion initiated a groundwater monitoring plan at is [sic] [Chesapeake Energy Center] to address

The extent of groundwater contamination at Dominion's plants, however, was not known to the Public Staff at the time of the Public Staff's Dominion testimony. In addition, Dominion's groundwater contamination remained far less extensive than that of DEC, and the finding of criminal negligence on the part of DEC was another differentiating factor.

Despite critical differences between the cases, witness Wright concluded that the Commission should apply the same standard to DEC in its 2017 rate case as it did in the Dominion 2016 rate case, in which it allowed Dominion to recover its CCR remediation costs.

Q. DID THE PUBLIC STAFF DISCOVER ANY NEW INFORMATION IN DOMINION'S SUBSEQUENT RATE CASE IN DOCKET NO. E-22, SUB 562?

A. Yes. In the most recent Dominion rate case in Docket No. E-22, Sub 562, Dominion's environmental compliance issues became more apparent than in the Dominion 2016 rate case. The extent of CCR-related environmental non-compliance is detailed in the testimony of Public Staff witness Jay Lucas in that case[84] and includes substantial groundwater exceedances and environmental contamination.

groundwater protection standard exceedances of arsenic attributed to wet ash from the unlined former ash settling basins."

[84] Page 68, line 1, through page 74, line 4, and Exhibits 1 and 12-14, Direct Testimony of Public Staff Engineer Jay Lucas filed in Docket No. E-22, Sub 562, on August 23, 2019.

Q. WHAT DOES THE PUBLIC STAFF CONCLUDE REGARDING ITS COMPARISON OF THE ENVIRONMENTAL COMPLIANCE RECORDS OF DEC AND DOMINION?

A. At the time of the Dominion 2016 rate case and the DEC 2017 rate case, the extent of Dominion's CCR-related noncompliance—as it was known to the Public Staff—paled in comparison to DEC's environmental noncompliance record. However, in 2019, the Public Staff found that Dominion had far greater environmental compliance problems than observed in 2016.

Based on its investigation in the Dominion 2019 rate case, the Public Staff believes that Dominion has a poor environmental compliance record, yet one that is better than that of DEC. One distinction is that Dominion did not cause the 2014 Dan River coal ash spill and did not plead guilty in a federal criminal case as DEC did. Another distinction is that the Public Staff has evidence of thousands of groundwater violations for DEC, whereas the number of Dominion groundwater exceedances is lower, and evidence of violations by Dominion is less clear due to a different state regulatory framework and poor recordkeeping on the part of Dominion.

The Public Staff recommended in the Dominion 2019 rate case that 40% of Dominion's CCR environmental remediation costs be paid for by shareholders. In its January 23, 2020 Notice of Decision, the Commission announced its decision of a 10-year amortization of Dominion's coal ash costs, with no return on the unamortized balance. This results in a sharing that allocates approximately 26% of the costs to shareholders, and 74% to ratepayers. The Public Staff recommends a 50%-50% equitable sharing in the present case. It is reasonable and appropriate to allocate a higher percentage of coal ash costs to DEC shareholders than was allocated to Dominion shareholders in the Notice of Decision because the environmental violations of DEC are far more extensive and far better documented.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Charles M. Junis

I graduated from North Carolina State University in 2011, earning a Bachelor of Science Degree in Civil Engineering. I have over 8 years of engineering experience, and since joining the Public Staff in April 2013, have worked on utility rate case proceedings, new franchise and transfer applications, emergency operations, customer complaints, general rate cases, and other aspects of utility regulation. Prior to joining the Public Staff, I worked for Farnsworth Group, an engineering and architectural consulting firm. I am a licensed Professional Engineer in North Carolina.

Summary of Testimony of Charles Junis

Docket Nos. E-7, Sub 1213, E-7, Sub 1214, and E-7, Sub 1187

The purpose of my testimony is to present background and recommendations related to coal ash cost recovery. Other Public Staff witnesses Maness, Garrett, and Moore also speak to coal ash cost recovery, and my testimony should be read in conjunction with theirs.

Duke Energy Carolinas, LLC, or the Company, now has 10,940 groundwater violations caused by its coal ash basins. That number is based on the Company's own data submitted to the North Carolina Department of Environmental Quality. Groundwater violations are indicated by groundwater samples that have contamination in exceedance of the state's 2L groundwater quality standards and natural background levels at or beyond the compliance boundary. There are also 1,280 groundwater exceedances at the W.S. Lee plant in South Carolina. This groundwater contamination is relevant to the sharing of coal ash costs between ratepayers and shareholders. The Company is asking customers to pay a second time for disposal of coal ash, without any added electric service.

Since 1979, Duke Energy Carolinas has had a duty under the 2L rules to prevent groundwater contamination. It failed to comply with that duty. Moreover, the Company unreasonably failed to assess the risk of groundwater contamination by not installing a comprehensive groundwater monitoring system at any of its coal ash sites for many years after the 2L rules had gone into effect. A proper allocation of risk and balancing of equities means that Duke Energy Carolinas should share in the costs to dispose of coal ash a second time when its initial disposal failed to protect the environment.

In addition to the 10,940 groundwater violations and the federal criminal charges to which Duke Energy Carolinas pled guilty—the costs of which are not part of this case—the Company has had additional compliance failures. In particular, the Company had unlawful discharges in the form of constructed and non-constructed seeps from coal ash basins to surface waters in violation of G.S. 143-215.1. Some of these unlawful discharges have led to penalties and some will be addressed through decanting and dewatering of coal ash basins as set out in DEQ Special Orders by Consent to correct the Company's regulatory noncompliance.

I have been able to quantify certain costs directly resulting from coal ash environmental violations. Those costs are unreasonable to charge to customers. Therefore, I recommend exclusion of the following costs from rate recovery:

- First, the Company's costs for the installation, operation, and maintenance of groundwater extraction and treatment at the Belews Creek plant. These costs, in the amount of $298,433, are due solely to environmental violations and are above and beyond the amount the Company would have paid for CAMA compliance in the absence of environmental violations.
- Second, bottled water costs, including the bottled water itself, the delivery company, personnel associated with the delivery, and the consulting firm that managed the bottled water delivery program. These costs, in the amount of $856,034, should be excluded from rate recovery as ordered by the Commission in the previous rate case, and were properly excluded by the Company.

- Third, costs to connect eligible residential properties to permanent alternative water supplies and, alternatively, the installation, operation, and maintenance of water treatment systems, as required by CAMA. These costs, in the amount of $17,845,189, are the direct result of the legislature deciding that Duke Energy Carolinas' coal ash management had created an unacceptable risk to people's groundwater wells in the vicinity of the impoundments. The permanent alternative water supplies serve the same purpose as bottled water—protecting neighbors surrounding the coal ash impoundments from contamination risks—and therefore should be excluded from cost recovery just as bottled water costs have been excluded.

For deferred coal ash-related costs not otherwise disallowed as unreasonable, the Public Staff recommends that the Commission create a sharing between ratepayers and shareholders. While the Public Staff has been able to quantify a small part of the coal ash costs as unreasonable to charge to customers, we have primarily focused on equitable sharing as the way to achieve reasonable and just rates where quantification is not feasible. We recommend equitable sharing only for costs related to coal ash that is in effect being disposed of a second time by corrective action and closure of leaking ash impoundments. We do not oppose cost recovery for prudent costs incurred only to dispose of new production ash in dry, lined sites.

The Company should bear an equitable portion of the burden for deferred coal ash costs because it had a duty to comply with the state’s 2L rules and other environmental requirements, and the Company failed to do so. The Company’s failure to comply with environmental regulations is compounded by its disregard for the need to conduct appropriate groundwater monitoring for many years. The material facts of record in this case are the extensive environmental violations caused by Duke Energy Carolinas’ coal ash impoundments and the extraordinary magnitude of costs that produce no new electricity. Public Staff witness Maness discusses additional reasons for equitable sharing.

This completes my summary.

MS. LUHR: And my colleague Mr. Grantmyre will be presenting Mr. Maness.

MR. GRANTMYRE: Good morning. This is William Grantmyre, Public Staff attorney. I will be sponsoring Mike Maness. He has already prefiled testimony in the consolidated docket.

DIRECT EXAMINATION BY MR. GRANTMYRE:

Q. But, Mr. Maness, would you please state your name, business address, current position for the record.

A. (Michael C. Maness) Michael C. Maness, 430 North Salisbury Street, Raleigh, North Carolina. I am director of the accounting division of the Public Staff.

Q. Now, did you cause to be prefiled on September 9, 2020, your third supplemental testimony consisting of 12 pages of testimony and Exhibits 1 and 2?

A. Yes, I did.

Q. Now, you noticed some corrections to your testimony, and there was a late-filed correction, but it was not filed until today.

And you would agree that those corrections are not controversial in any way?

A. I would agree.

Q. Now, other than that, did you file a summary of your testimony?

A. Yes, I did.

Q. And there was one minor correction to the -- or two minor corrections that were noncontroversial?

A. Yes.

Q. Okay. Now, other than that, would you have any other changes or corrections to your testimony or exhibits?

A. No, I do not.

Q. And if I were to ask you the same questions today, would your answers be the same?

A. Yes.

MR. GRANTMYRE: Chair Mitchell, I move at this time that Mr. Maness' third supplemental testimony and the summary of his testimony be entered into the record as if given orally from the stand. And that his third supplemental exhibits be marked for identification as premarked.

CHAIR MITCHELL: All right. Hearing no objection to that motion, Mr. Grantmyre, it is allowed.

(Public Staff Maness Direct Exhibits I

and II, Public Staff Maness Exhibit III, Public Staff Maness Exhibit I Revised and Exhibit II Revised, Public Staff Maness Second Revised and Second Stipulation Exhibits I and II were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony and Appendix A, first supplemental, second supplemental, and third supplemental testimony and summary and errata of the testimony of Michael C. Maness were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

February 18, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present certain accounting and ratemaking adjustments related to 2018-2019 coal ash clean-up, disposal, and remediation that I am recommending be adopted by the North Carolina Utilities Commission (Commission) for purposes of determining the revenue requirement to be approved for Duke Energy Carolinas, LLC (DEC or the Company), in this proceeding. I am also taking coal-ash related adjustments recommended by other members of the Public Staff and flowing them through my schedules so that they can be incorporated into the Public Staff's recommended revenue requirement. Finally, I am commenting on the ratemaking treatment of the 2015-2017 costs of DEC's ARO–related coal ash compliance and cleanup activities, first considered by the Commission in Docket No. E-7, Sub 1146, with regard to those aspects that are still on appeal to the North Carolina Supreme Court, as well as presenting certain comments regarding deferral of 2020 through 2022 costs related to the Company's proposed Grid Improvement Plan (GIP).

Q. HOW ARE YOUR RECOMMENDED ADJUSTMENTS, AS WELL AS THOSE YOU ARE FLOWING THROUGH, BEING INCORPORATED INTO THE PUBLIC STAFF'S RECOMMENDED REVENUE REQUIREMENT?

A. I have provided the impact of all the adjustments I am recommending to Public Staff witness Michelle M. Boswell for inclusion in her Exhibit 1, in which she calculates the overall change in the Company's revenue requirement recommended by the Public Staff, which is then used to determine the recommended rate change.

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Q. IN WHAT AREAS ARE YOU RECOMMENDING ADJUSTMENTS OR INCORPORATING ADJUSTMENTS RECOMMENDED BY OTHER MEMBERS OF THE PUBLIC STAFF?

A. I am recommending or incorporating adjustments in the following areas:

1. The ratemaking treatment of the January 2018 – November 2019 costs of DEC's Asset Retirement Obligation (ARO) – related coal ash compliance and cleanup activities;
2. The appropriate classification within the rate base of the regulatory assets associated with the ARO-related coal ash compliance and cleanup; and
3. The amortization period for the Company's proposed deferred non-ARO-related costs.

<u>COSTS OF DEC'S ARO-RELATED 2018-2019 COAL ASH MANAGEMENT ACTIVITIES</u>

Q. PLEASE BRIEFLY DESCRIBE THE BACKGROUND OF DEC'S ARO-RELATED COAL ASH MANAGEMENT ACTIVITIES.

A. The background related to these activities is described in the testimony of Public Staff witnesses Garrett, Moore, and Junis. Briefly, DEC's coal ash, or coal combustion residual (CCR) management activities are today being conducted because DEC must conduct corrective action for its environmental contamination from coal ash, and because of new legal requirements for closure of coal ash disposal sites. Some of DEC's coal ash remediation and

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non-ARO (capital projects) are pursuant to several federal and state statutes and regulations, including, but not limited to the Environmental Protection Agency's (EPA) CCR Rule (CCR Rule), the federal Clean Water Act and the related EPA Steam Electric Power Generating Effluent Guidelines and Standards (ELG Rule), the North Carolina Coal Ash Management Act (CAMA), and the 2L rules[1].

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED ADJUSTMENTS RELATED TO CCR EXPENDITURES.

A. The Company has made adjustments intended to result in the recording of a regulatory asset to reflect expenditures it has incurred to remediate coal ash storage areas and to comply with the above-described federal and state governmental requirements imposed to provide for the safe disposal of coal ash. These adjustments include (1) the implicit elimination of the CCR-related accounting entries made to the Company's books and records during 2018 or before for financial accounting purposes, (2) a pro forma adjustment to increase rate base to defer as a regulatory asset the CCR expenditures incurred between January 1, 2018, and January 31, 2020 (the Deferral Period), and (3) a pro forma adjustment to

[1] Groundwater Classification and Standards, 15A N.C. Admin. Code 2L.

increase depreciation and amortization expenses to reflect a five-year amortization of those costs.

FINANCIAL AND REGULATORY ACCOUNTING FOR DEC'S ARO-RELATED CCR COSTS

Q. HOW HAS THE COMPANY TREATED ITS ARO-RELATED OBLIGATIONS FOR FINANCIAL ACCOUNTING PURPOSES?

A. For financial accounting purposes, the Company has recorded the current fair value of its entire projected level of ARO-related CCR expenditures, with adjustments for market influences and probability-weighted cash flows, as an ARO liability, based on the requirements of Topic 410 (Asset Retirement and Environmental Obligations) of the Accounting Standards Codification (ASC 410) promulgated and maintained by the Financial Accounting Standards Board (FASB).

Upon initial establishment, the ARO liability is offset in the financial statements by one or both of two separate amounts. The first is a balance sheet asset, the Asset Retirement Cost (ARC), which represents amounts related to the future useful life of still operating assets; the ARC is depreciated over those remaining useful lives. The second is an immediate write-off to expense of ARO amounts that are related to assets that have already been retired or are no longer reflected in the financial statements (such as those written off as financially impaired).[2]

Q. FOR RATEMAKING PURPOSES IN THIS PROCEEDING, IS THE COMPANY PROPOSING TO UTILIZE ARO ACCOUNTING AS PRESCRIBED BY THE FASB?

A. No. In this proceeding, the Company has at least implicitly and effectively reversed all of the entries made on its books in association with the establishment of the FASB-mandated CCR ARO liability, and is instead proposing the deferral and amortization of actual expenditures during the Deferral Period. (A similar procedure was followed in the Sub 1146 case for the expenditures made between January 1, 2015, and December 31, 2017.)

The Company bases its proposal not to adopt ARO treatment for North Carolina retail ratemaking purposes on both its deferral request filed in 2016 in Docket No. E-7, Sub 1110, and a 2003 Commission Order in Docket No. E-7, Sub 723, which focused on the relationship between the Commission's long-standing treatment of nuclear decommissioning costs and the FASB's required

[2] The FERC has adopted a similar method of accounting for use in accordance with its Uniform System of Accounts (USOA); however, both the FERC and this Commission provide for departures from the USOA for purposes of state jurisdictional accounting and ratemaking purposes (through the use of regulatory assets and liabilities). CFR Title 18, Chapter I, Subchapter C Part 101 - Accounts 182.3 and 254; Rules and Regulations of the North Carolina Utilities Commission – Rule R8-27.

treatment of AROs pursuant to Statement of Financial Accounting Standards No. 143 (SFAS 143), now codified within ASC 410. These Orders essentially allowed DEC to replace ASC 410 accounting treatment of a legal retirement obligation with a treatment that has been approved by the Commission. In this case, as in the Sub 1146 rate case, the Company is asking the Commission to replace ASC 410 treatment with its own proposed ratemaking treatment.

Q. HOW IS THE COMPANY PROPOSING TO TREAT CCR EXPENDITURES AND OBLIGATIONS FOR RATEMAKING PURPOSES?

A. As noted previously, and as also requested in the Sub 1146 case, the Company proposes to establish a regulatory asset for actual CCR expenditures made during the Deferral Period, and to amortize that regulatory asset over a five-year period beginning with the effective date of the rates approved in this proceeding. This is fundamentally different from the FASB's ARO approach, in that it focuses on the recording and future recovery of actual costs spent, rather than the determination of a liability for future expenditures and the assignment of that liability to both past and future accounting periods for earnings recognition purposes.

Q. DOES THE PUBLIC STAFF AGREE WITH THIS APPROACH?

A. The Public Staff agrees with the concept proposed by the Company of deferring the costs incurred during the period in question and amortizing them over some multi-year period (but does not agree with the amortization period proposed by the Company in this case, nor with the allowance of a return on the unamortized balance, as will be discussed later). The use of the Company's deferral approach results in a more straightforward tracking of the monies expended and awaiting future recovery than does the FASB's ARO approach, although it starts from a presumption that all of the costs should be eligible for consideration of recovery, not rejected simply because they are related to service in prior years. In this particular instance, I believe that the presumption is reasonable in this case, although it certainly is not so in all instances. The reason deferrals are not always appropriate is because North Carolina is a historical test year jurisdiction: retroactive ratemaking is generally unlawful, so deferral of past costs for purposes of future rate recovery should be a strictly limited exception to the retroactive ratemaking prohibition. Legal counsel advises that deferral is authorized under N.C. Gen. Stat. § 62-133(d) as a matter of limited Commission discretion to depart from the ratemaking formula of N.C. Gen. Stat. § 62-133(b) where necessary to achieve "reasonable and just rates" due to extraordinary circumstances.

Q. WHAT IS THE EFFECTIVE RESULT OF THE COMPANY'S APPROACH?

A. The effective result of the Company's approach is to replace, for ratemaking purposes, the ARO approach required by the FASB for financial accounting purposes with the Company's proposed approach of deferring actual cash expenditures and then recovering them through amortization. On the Company's books, the regulatory asset and liability entries effectuating its approach may take the form of overlaying the financial accounting entries; however, their effect, when added to the financial accounting entries, should be, consistent with the Sub 723 Order. Under the Sub 723 approach, the FASB's ARO financial accounting approach is replaced with deferral of the costs to a regulatory asset for North Carolina retail ratemaking purpose.

Q. CAN YOU EXPLAIN WHY THERE IS A DEFERRED BALANCE OF COAL ASH MANAGEMENT EXPENDITURES THAT DEC IS PROPOSING TO AMORTIZE FOR RATE RECOVERY BEGINNING WITH THIS PROCEEDING?

A. Yes. On December 21, 2015, Duke Energy Corporation (Duke Energy) filed a letter with the Commission indicating that DEC had established a regulatory asset account for purposes of accounting for costs related to its coal ash-related AROs. Subsequently, on December 30, 2016, in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, DEC and Duke Energy Progress, LLC (DEP), jointly filed a petition requesting that the Commission authorize each utility to defer certain costs related to compliance with state and federal environmental requirements associated with coal combustion residuals. On January 6, 2017, the Commission issued an order requesting comments on DEC's and DEP's petition.

Several parties, including the Public Staff, filed comments in response to the Commission's order. In its comments, filed on March 15, 2017, the Public Staff stated that in this particular case, it believed that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfied the criteria for deferral for regulatory accounting purposes, subject to (a) the normal provision that this decision would be entered without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings; (b) recognition of the fact that given the complex task of determining what portion, if any, of these very unique deferred expenses should ultimately be approved for rate recovery in a general rate proceeding, any assumptions regarding such rate recovery should be especially discouraged; (c) the possibility that given the unusual circumstances of these costs, the Commission might determine that some sharing of the costs between ratepayers and shareholders is necessary to ensure that rates charged to customers are limited to an appropriate and reasonable amount; and (d) the determination of the method and length of amortization of any deferred costs.

In addition to not objecting to deferral of these expenses, the Public Staff indicated that the unique nature of the costs and the complexity of the issues surrounding the determination of ultimate rate recovery justified a limited delay in determining the beginning date of any amortization of the deferred expenses until the next respective general rate proceeding, which was expected to be filed sometime in 2017.

With regard to the deferral of a return on capitalized items, as well as deferral of carrying charges on the deferred expenses themselves, the Public Staff did not object to such a deferral. However, the comments indicated that the ultimate recoverability of those deferred returns in rates should be considered to be subject to the provisions generally set forth therein.

The Public Staff also identified several items unique to the topic of coal ash management that would need to be considered as part of the process of determining the appropriate amount of CCR costs that should be recovered from ratepayers, as well as the timing of that recovery. Those items included, but were not limited to, the prudence and reasonableness of the costs incurred; any fines, penalties, or other costs of resolving and/or remediating violations of law and regulations; any costs of settling legal disputes, or of resolving and/or remediating issues as part of a settlement; issues of jurisdictional allocation; whether the setting of fair and reasonable rates demands a sharing of costs between ratepayers and shareholders; and the appropriate and reasonable amortization period for any costs ultimately determined to be prudently incurred and reasonable for recovery from the ratepayers.

On April 19, 2017, DEC and DEP filed reply comments in the subdockets. On July 10, 2017, the Commission issued an order consolidating Docket No. E-7, Sub 1110, with the Sub 1146 general rate case proceeding. On June 22, 2018, the Commission issued its Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in Sub 1110 and Sub 1146 (Sub 1146 Order), which approved the Company's deferral petition until its next general rate case.

Q. IF THE COMPANY HAD CHOSEN TO USE THE FASB ARO METHOD OF TRACKING EXPENSE INSTEAD OF THE "SPEND AND DEFER" METHOD IT CHOSE TO UTILIZE, WOULD IT STILL HAVE BEEN NECESSARY FOR THE COMPANY TO FILE A DEFERRAL REQUEST?

A. Most likely, yes. Following either method of tracking expenses would have exposed the Company to very significant charges, either through dollars spent and not included in rates, or asset retirement cost write-offs related to closed generating stations, which also would not have been recovered in rates. In either case, in the absence of deferral, DEC would have had to write substantial ARO-related costs off to expense and would not have been able to recover them in rates.

Q. ARE THERE CERTAIN RATEMAKING APPROACHES TAKEN IN THIS PROCEEDING WITH WHICH YOU AGREE, GIVEN THE PUBLIC STAFF'S COMMENTS IN SUB 1110 AND THE COMMISSION'S SUB 1146 ORDER?

A. Yes. Consistent with its comments and the Commission's Sub 1146 Order, the Public Staff does not object for purposes of this proceeding to the deferral of a return for the period January 2018 through July 2020 on deferred ARO-related coal ash expenditures. Additionally, due to the magnitude and very unique nature of these costs, the Public Staff does not object to the beginning of the amortization being delayed until the effective date of the rates approved in this proceeding.[3]

Q. IN GENERAL, WHAT ADJUSTMENTS HAVE YOU MADE TO THE COMPANY'S ARO-RELATED COSTS OF COAL ASH MANAGEMENT?

A. I have made the following adjustments:

1. Adjustments to the ARO-related coal ash management expenditures as of the end of November 2019 to reach a prudent and reasonable level of coal ash expenditures, as recommended by Public Staff witnesses Vance F. Moore, L. Bernard Garrett, and Charles Junis;

2. Amortization of the balance of ARO-related deferred coal ash expenditures at the beginning of August 2020 over a 26-year period, rather than the 5-year period proposed by the Company; and

3. Reversal of the Company's inclusion of the unamortized balance of ARO-related coal ash expenditures in rate base; this reversal, in conjunction with the 26-year amortization

[3] For many types of deferred costs, the Public Staff typically recommends that amortization begin in the month of or the month following the incurrence of the costs.

period, produces an equitable and reasonable sharing of the burden of coal ash expenditures between the Company's ratepayers and its shareholders.

Q. PLEASE DISCUSS YOUR ADJUSTMENTS TO THE COMPANY'S RECOMMENDED LEVEL OF DEFERRED COAL ASH MANAGEMENT EXPENDITURES.

A. The first adjustment I am making is to reduce the coal ash management costs subject to deferral, based on the recommendations of Public Staff witnesses Moore, Garrett, and Junis. The rationales for these adjustments are fully set forth in the testimonies of those witnesses, but they can be briefly described as follows:

1. Adjustments recommended by witness Garrett with regard to (a) a fulfillment fee paid to Charah, Inc., related to the disposal of ash from Riverbend Station at the Brickhaven structural fill project, and (b) management of activities at the Dan River Station – approximately $46.1 million and $29.2 million, respectively, on a system basis;

2. An adjustment recommended by witness Moore with regard to coal ash costs associated with beneficiation activities at the Buck Station - approximately $67.8 million, on a system basis; and

3. Adjustments recommended by witness Junis (a) to remove the costs of extraction and treatment of groundwater at the Belews Creek Station and (b) to provide for permanent

alternative water supplies or water treatment – approximately $0.3 million and $17.8 million, respectively, on a system basis.

I have accumulated these costs and spread them in a reasonable manner throughout the January 2018 through November 2019 period, pursuant to guidance received from the applicable witnesses. This accumulation is set forth on Maness Exhibit I, Schedule 1-2. The adjustments have then been used to reduce the monthly deferral of system-level costs set forth on Maness Exhibit I, Schedule 1-1.

Q. PLEASE EXPLAIN YOUR SECOND AND THIRD ADJUSTMENTS, THE RECOMMENDATION TO AMORTIZE THE DEFERRED BALANCE OF JANUARY 2018 THROUGH NOVEMBER 2019 COAL ASH COSTS OVER 26 YEARS, AND THE RECOMMENDATION TO REVERSE THE COMPANY'S INCLUSION OF THE UNAMORTIZED COSTS IN RATE BASE.

A. The Company has recommended that the ARO-related costs of 2018-2019 coal ash management be amortized over five years for ratemaking purposes in this proceeding. In my opinion, that is simply too short an amortization period for costs of the magnitude and nature of these. Instead, the Public Staff has been guided in its choice of amortization period for these costs in this proceeding by its belief that it is most reasonable and appropriate for coal ash costs, after specific imprudently incurred or otherwise unreasonable amounts have been identified and disallowed for recovery, to be shared equitably between the ratepayers and the Company's shareholders.

Q. WHY DOES THE PUBLIC STAFF BELIEVE COAL ASH COSTS, AFTER REMOVAL OF SPECIFICALLY DISALLOWABLE AMOUNTS, SHOULD BE SHARED BETWEEN THE RATEPAYERS AND SHAREHOLDERS?

A. There are two general reasons why the sharing of costs for coal ash management is reasonable and appropriate for ratemaking purposes. First, as discussed in more detail by Public Staff witness Junis, the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws, supports ratemaking that leaves a large share of the costs for DEC shareholders to pay. Furthermore, he testifies that DEC's original disposal practices pose an ongoing contamination risk that requires expensive remediation – which includes closure of the impoundments - without any additional electric service benefit to its ratepayers. However, Mr. Junis also testifies that it is very difficult to quantify the costs for such actions, as the costs of taking an alternative course of action in the past would be speculative to some degree. He also indicates that apart from traditional imprudence, there is Company culpability for years of extensive groundwater contamination, and other environmental non-compliance, that justifies a sharing of the remediation and closure costs in accord with N.C. Gen. Stat. § 62-133(d). Therefore, he is of the opinion that some degree of equitable sharing is appropriate on the facts of this case.

Second, there is a history of approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. Such sharing between ratepayers and shareholders has been approved for costs of abandoned nuclear construction and for environmental cleanup of manufactured gas plant facilities. Even if the reasons for equitable sharing set forth by Mr. Junis were not present, the Public Staff still believes that some level of sharing, perhaps comparable to that previously used for abandonment losses on cancelled nuclear generation facilities, would be appropriate and reasonable for DEC's coal ash costs.

Q. IS THE TYPE OF EQUITABLE SHARING YOU AND MR. JUNIS DESCRIBE APPROPRIATE EVEN FOR COSTS FOR WHICH THERE HAVE BEEN NO SPECIFIC IMPRUDENCE OR UNREASONABLENESS FINDINGS?

A. Yes. Under N.C. Gen. Stat. § 62-133(b), imprudently incurred or otherwise unreasonable costs must be excluded 100% from rate recovery. In addition, there can be circumstances where the traditional imprudence framework is not applicable, but an equitable sharing of costs – short of a 100% disallowance - is still appropriate to consider. The lack of any finding of specific imprudence or unreasonableness does not invalidate consideration of whether or not a sharing adjustment is appropriate and reasonable. There may well be reasons, such as the ones discussed in this testimony, that make equitable sharing appropriate and reasonable for purposes of achieving reasonable and just rates, independent of prudence conclusions.

Q. WHY DO YOU BELIEVE THAT THE MAGNITUDE AND GENERAL NATURE OF THE CCR COSTS PRESENTED FOR AMORTIZATION IN THIS PROCEEDING MAKES IT APPROPRIATE TO IMPLEMENT EQUITABLE SHARING?

A. First, the total amount of costs incurred during the Deferral Period ($329,656,000, on a system basis, after removal of the adjustments recommended by other Public Staff witnesses) is extraordinarily large. Indeed, this was a basis for the Company's deferral petition. The N.C. retail amount presented for amortization ($243,042,000, including carrying costs) amounts to an average of approximately $104 per N.C. retail customer, using a proforma balance of 2,334,590 customers at November 30, 2019. Requiring the N.C. retail customers to bear the cost of a five-year amortization period for these costs would burden them to the tune of almost $21 per year, on average, even before considering the impact of including the unamortized amount in rate base. (In fact, even without the removal of the unamortized amount from rate base that enables an equitable sharing adjustment, I believe that a five-year amortization period would be much too short for an expense of this magnitude.) Second, it must be remembered that DEC will be incurring significant additional costs in the future, in the billions of dollars. Therefore, the costs incurred during the Deferral Period do not come close to the total CCR costs the Company expects in total. Third, much like the equitable sharings that have been approved by the Commission with regard to plant abandonments over the years, the incurrence of these costs will not provide any benefits to customers in terms of additional electric service or improvements in service. Fourth, unlike some situations in recent years in which plants have been retired early due to economic reasons, the incurrence of CCR costs has not been the result of an economic analysis that pointed toward an action that would be economically advantageous to ratepayers. Finally, equitable sharing helps mitigate the intergenerational inequity of present and future customers paying for costs caused by service to customers in past decades.

Q. HOW DOES THE PUBLIC STAFF ACHIEVE THIS RECOMMENDED EQUITABLE SHARING?

A. The first step in achieving a sharing is to exclude the unamortized amount of the deferred expenses from rate base. As a result of taking this step, the Company will not be allowed to earn a return from the ratepayers on the unamortized balance while the deferred costs are being amortized. The second step is to choose an amortization period that will result in a reasonable and appropriate sharing of the costs.

Q. IS EXCLUDING DEFERRED EXPENSES FROM RATE BASE LEGAL UNDER THE NORTH CAROLINA GENERAL STATUTES?

A. Yes, according to advice of Public Staff counsel. Pursuant to N.C. Gen. Stat. § 62-133(b)(1), the only costs that the Commission is required to include in rate base are (1) the "reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period . . . ," and (2) in some circumstances, the costs of construction work in progress. I am advised by counsel that beyond those requirements, what is and what is not allowed in rate base is within the legal discretion of the Commission to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers. Moreover, N.C. Gen. Stat. § 62-133(d) requires the Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates." According to counsel, N.C. Gen. Stat. § 62-133(d) operates separately from N.C. Gen. Stat. § 62-133(b), and provides the Commission with discretion to authorize equitable sharing of utility costs, beyond the ratemaking formula of N.C. Gen. Stat. § 62-133(b), where appropriate to achieve reasonable and just rates.

The Commission has taken this approach several times in past cases, most often in the cases of nuclear and coal plants abandoned prior to commencing commercial operation, including, specifically for DEC, the abandonment loss related to the Cherokee Plant (Units 1, 2, and 3). In DEC's 1983 general rate case, Docket No. E-7, Sub 358, the Commission outlined its policy regarding the treatment of plant abandonment losses:

> The proper ratemaking treatment of abandonment losses related to electric generating plants has been before the Commission in several cases and will continue to arise in future cases. The Commission has, therefore, undertaken to reexamine this important issue in order to develop a more consistent and equitable approach to it. The Commission's ultimate responsibility with respect to ratemaking is to fix rates for the service provided which are fair and reasonable both to the utility and to the consumer. G.S. 62-133(a); <u>State ex rel. Utilities Commission v. Morgan</u>, 277 N.C. 255, 177 S.E. 2d 405 (1970); <u>State ex rel. Utilities Commission v. Area Development, Inc</u>., 257 N.C. 560, 126 S.E. 2d 325 (1962).

> Although the parties to this proceeding may disagree as to the proper amortization period, they generally agree that the Company should be allowed to recover the prudently invested cost of its abandonment losses through amortization over some period of time. The Commission, based upon the evidence presented, must determine what is a fair amortization period in order to fairly allocate the loss between the utility and the consumer. With regard to the Cherokee Units 1, 2, and 3, the Commission concludes that utilization of a 10-year amortization period is proper and fair in this proceeding for the reason that such an amortization period, particularly when considered in conjunction with the Commission's decision, as subsequently discussed, to allow Duke no return on the unamortized balance, will service to more reasonably and equitably share the burden of such plant cancellations between the Company's shareholders and its present and future ratepayers.
>
> Furthermore, the Commission has determined that it is neither fair nor reasonable to include any portion of the unamortized balance of the prudently incurred abandonment losses associated with the Cherokee units in rate base and that no adjustment should be allowed which would in fact have the effect of allowing the Company to earn a return on the unamortized balance. The Commission has concluded that this treatment provides the most equitable allocation of the loss between the utility and the consumer.

Seventy-Third Report of the North Carolina Utilities Commission, pp. 255 ff.

The policy of exclusion from rate base was applied consistently from 1983 forward during the rash of nuclear plant cancellations by the large electric utilities of this State, and also in Sub 1146 for the Lee Nuclear project cancellation costs.

This specific issue has also come before the North Carolina courts. While I am not an attorney, it is my understanding that equitable sharing of prudently incurred utility costs has been ruled to be lawful in past cases. A memorandum from Public Staff counsel addressed this question in the last Duke Energy Carolinas rate case, Docket No. E-7, Sub 1146. That memorandum was attached to my testimony in that docket as Appendix B, and was allowed by the Commission since it was the foundation underlying my recommendation on equitable sharing. Any recommendation the Public Staff makes on equitable sharing will depend on the facts and circumstances of each case, but the legal foundation is the same. Therefore, in response to this question I incorporate by reference the memorandum labeled as Appendix B to my testimony in Docket No. E-7, Sub 1146.

As discussed in that memorandum, in 1989 the North Carolina Supreme Court affirmed the Commission's decision that reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs. In State ex rel. Utilities Com. v. Thornburg, 325 N.C. 463 (1989), the Attorney General had sought exclusion of all abandonment costs related to the Harris Nuclear Plant. However, the Commission allowed amortization of the abandonment costs, with no return on the unamortized balance. The Court ruled that the Commission was acting within its discretion:

> [T]he Commission's order does not err as a matter of law in authorizing CP&L to continue to recover a portion of the cancellation costs of the abandoned Harris Plant as operating expenses through amortization. The Commission's determination was supported by several findings and conclusions. First, the Commission found that although "[t]his case must of course be decided on the basis of North Carolina statutes" the "majority of courts and commissions that have dealt with this issue have allowed ratemaking treatment of abandonment losses, usually as operating expenses." Second, the Commission concluded "that a liberal interpretation of the operating expense element of ratemaking so as to include the Harris abandonment losses is appropriate herein." Last, the Commission found further support for its conclusion was provided by N.C.G.S. § 62-133(d), which allows the Commission to consider all material facts in the record in determining rates.
>
> . . . .
>
> Last, we disagree with the Attorney General's contention "that strong policy considerations support the disallowance of [cancellation] expenses." We note that jurisdictions have generally dealt with the allocation of cancelled plant costs in one of the following three ways:
>
> (1) recovery of all of the costs from ratepayers, by allowing amortization of the investment plus a return on the unamortized balance;
>
> (2) recovery of all costs from shareholders through a total disallowance of recovery in rates, instead requiring the utility to write off the entire amount in a single year; or
>
> (3) recovery from ratepayers and shareholders through amortization of costs in rates over a period of years, with no return on the unamortized balance.
>
> . . . Strong policy considerations support the Commission and commentators who have concluded that method three is the best of the three alternatives in that it promotes "an equitable sharing of the loss between ratepayers and the utility stockholders."
>
> . . . .

> On this record, the Commission's continued use of method three is within the Commission's discretion, and this Court will not disturb that decision.

Similarly, an equitable sharing of costs was approved in the Commission’s October 7, 1994, *Order Granting a Partial Rate Increase* in Docket No. G-5, Sub 327 (1994 Order). In that case, Public Service Company of North Carolina (PSNC) owned several sites that were previously operated as manufactured gas plants (MGPs). The MGPs had ceased operations in the early 1950s. At the time of the rate case, the MGP sites were the subject of “investigations under environmental laws.” 1994 Order at 6. In its Order, the Commission concluded that deferral and amortization of MGP clean-up costs in a general rate case, rather than through a tracker, would result in more stable rates than otherwise. Furthermore, the Commission concluded that the unamortized balance of MGP costs should not be included in rate base, resulting in a sharing of clean-up costs between ratepayers and shareholders that would provide PSNC with motivation to minimize its costs or seek contributions from others.

Q. ARE THE CCR COSTS THAT DEC IS SEEKING TO RECOVER IN THIS CASE “USED AND USEFUL,” THUS IMPLYING THAT THEY MUST BE INCLUDED IN RATE BASE?

A. No. In North Carolina utility regulation, the term "used and useful" only applies to the public utility's property (including cash working capital, as discussed below, and materials and supplies), not the <u>expenses</u> it incurs in the operation, maintenance, or disposal of that property. Some might claim that since the costs deferred for coal ash clean-up are associated with property that is or once was used and useful, the costs themselves should be considered "used and useful," and therefore should be included in rate base, to the extent they remain unamortized, pursuant to N.C. Gen. Stat. § 62-133(b)(1). In my opinion as a regulatory accountant, and in the opinion of Public Staff counsel, this argument is incorrect and is an inappropriate application of the term "used and useful." It is appropriate to state that the actual costs <u>capitalized</u> by a utility as the costs of used and useful property itself may be included in rate base and thereby earn a return, as long as those costs are reasonable and prudently incurred, and are intended to provide utility service in the present or in the future; however, the expenses of operating and maintaining that property in the present or in the future do not get capitalized as part of the cost of the property. Instead, they are allowed to be recovered from the ratepayers on an ongoing basis as operating expenses, if they themselves are determined by the Commission to be reasonable and prudently incurred. This recovery is provided for under N.C. Gen. Stat. § 62-133(b)(3), an entirely different portion of the statute, and there is no "used and useful" provision applicable to operating expenses. If, however, there are expenses that were incurred in the past, but for some reason the Commission decides that they can be deferred for recovery in the future, the Commission can approve a regulatory asset to capture such expenses, and even provide for a return on them due to the deferral of their recovery (by including them in rate base or otherwise providing for carrying costs). This treatment is within the discretion of the Commission (counsel advises that the discretion is authorized under N.C. Gen. Stat. § 62-133(d), but it does not transform the Commission-created regulatory asset into capitalized property cost, such as the cost of a generating plant. The two types of costs are fundamentally different from one another; one is the actual cost of property intended to provide service in the present or future; the other is a past expense deferred for future recovery. The first, if reasonable and prudently incurred, is appropriate to include in rate base pursuant to N.C. Gen. Stat. § 62-133(b)(1)[4]; the second carries no such return requirement.

Q. IN WHICH CATEGORY DO THE ARO-RELATED DEFERRED COSTS PROPOSED IN THIS CASE BY DEC FOR AMORTIZATION FALL?

[4] Again, counsel advises that N.C. Gen. Stat. § 62-133(d) may override the return or otherwise adjust rates beyond the formula in N.C. Gen. Stat. § 62-133(b), where justified by exceptional circumstances.

A. I believe that the costs should fall into the category of a deferred expense for the following reasons:

(1) The Company has itself chosen to request a regulatory accounting and ratemaking method that does not explicitly account for any ARO-related coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as ongoing expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past, expenses that but for the Commission's approval of the deferral request, would be immediately written off. Although the Company could have chosen to propose following the method prescribed by generally accepted accounting principles (GAAP) for non-regulated companies, which does provide for the recording of at least a portion of asset retirement costs as a depreciable asset (albeit one that might be offset in rate base by unspent asset retirement obligations), it did not. Instead, the Company has used an accounting and ratemaking model that accounts for and recovers the ARO-related coal ash cleanup costs as expenses on an "as-spent" or "as-accrued" basis, without specific identification of or accounting for any costs as plant in service or other property. It has chosen a totally different route than the one typically followed for utility property.

(2) The ARO-related costs proposed for deferral and amortization themselves are not in any manner costs related to present or future operations; instead they are costs that, but for Commission approval of the deferral and amortization, will be immediately written off as expenses related to the past. There may be some form of capital assets underlying some portion of the ARO-related activities undertaken by DEC to meet its coal ash compliance obligations; however, the particular costs requested for deferral related to such assets, if they exist, are themselves expenses related to past operations. The Company itself stated, in its Petition for Deferral filed on December 30, 2016:

> The Companies are requesting to defer to a regulatory asset, until the effective date of new rates from the next base rate case, all non-capital costs as well as the depreciation expense and cost of capital at the weighted average cost of capital for all capital costs related to activities required under the legislative and regulatory mandates … <u>(Petition, page 14)</u>

All of the costs identified in the quote above are expenses related to periods that will be in the past when the rates requested in this case become effective; they are not forward-looking capital costs related to future operations, which are characteristic of the assets recorded as used and useful property and included in rate base.

Q. DOES THE FACT THAT THE COMPANY HAS CLASSIFIED THE PROPOSED COAL ASH DEFERRED COST BALANCE IN ITS FILING AS "WORKING CAPITAL" MEAN THAT THE REGULATORY ASSET MUST BE INCLUDED IN RATE BASE?

A. No, it does not, because in my opinion, this classification is just a matter of convenience. For working capital to qualify as rate base, it should be the investment made in materials and supplies, cash, and other similar items to finance and provide for the Company's present and future operations; in other words, to "do the work" of providing ongoing utility service. The proposed deferred coal ash compliance costs are expenses incurred in the past that the Company proposes to recover in the future; they have nothing to do with the Company's forward-looking obligation to provide utility service. Normally, it does no harm for the Company to group many disparate items under the heading of working capital; however, one should not mistake the inclusion of past coal ash costs in this group for actual evidence that such costs are in fact "working capital" needed to fund future operations.

The late Charles F. Phillips, Jr., Ph.D., former Professor of Economics at Washington and Lee University, described working capital in this manner:

> Working capital – the funds representing necessary investment in materials and supplies, and the cash required to meet current obligations and to maintain minimum bank balances – is included in the rate base so that investors are compensated for capital they have supplied to a utility.

Charles F. Phillips, Jr., <u>The Regulation of Public Utilities, Third Edition</u> (1993), p 348.

It is very important to note that the items of working capital described by Dr. Phillips – materials and supplies, minimum cash balances, and the cash necessary to meet current obligations (which is typically determined for large utilities through the use of a lead-lag study) – are all focused on doing the current and future work of the utility. Working capital is not like deferred CCR costs, which are expenditures made in the past that the Commission, if it approves the Company's amortization expense proposal, would allow the utility recover in the future. Thus, no matter how it is categorized on paper by a utility filing a general rate case, the CCR deferred costs neither enable or facilitate the provision of current or future utility service, and cannot be classified in substance as "working capital" for purposes of inclusion in rate base.

In summary, DEC's accrued coal ash management costs may qualify as regulatory assets, but they are not utility plant or another form of utility "property." They may have been prudently incurred expenses in support of utility plant (or former utility plant), but they themselves are not utility plant, and the N.C. Gen. Stat. § 62-133(b)(1) requirement of "used and useful" has no applicability to such costs. The Commission is under no obligation to include them in rate base or to otherwise allow a return on them to be recovered or accrued.

Q. PLEASE DESCRIBE HOW THE SECOND STEP YOU DESCRIBED PREVIOUSLY, THE CHOICE OF AN AMORTIZATION PERIOD, CAN BE USED TO ACHIEVE A SHARING OF COSTS BETWEEN THE UTILITY AND ITS RATEPAYERS.

A. Once it has been determined that the unamortized balance of the coal ash costs will not be included in rate base, the ability of the utility to recover those costs at a 100% level becomes entirely dependent upon the speed at which recovery can be achieved. The utility has already spent the money represented by the deferred costs in question; therefore, it will be required to borrow money or use equity to finance the spent costs until it can recover them from the ratepayers. If the utility was able to recover the total cost immediately, it would recover all of the costs at a 100% level; however, the ratepayers would also lose all of the time value of money that could be provided to them by a reasonable amortization period. Another way to look at this financing process is that in that immediate recovery circumstance, the utility recovers 100% of the present value of the deferred costs at the time of deferral, and the ratepayers bear 100% of that cost. However, as the delay in utility recovery (i.e., the amortization period) increases, the utility's financing costs increase, and the burden of the loss of the time value of money on the ratepayers decreases. The utility recovers a lesser amount and lesser percentage of the present value of the underlying cost, and thus the ratepayers bear less of the burden. Considering the magnitude and inherent nature of the CCR costs themselves, as well as the extensive environmental contamination and violations resulting from DEC's coal ash management in North Carolina as articulated by Public Staff witness Junis, it is inappropriate to ask ratepayers to bear 100% of the risk or fund a return to shareholders on these expenses.

Q. WHAT AMORTIZATION PERIOD DOES THE PUBLIC STAFF RECOMMEND IN THIS CASE FOR THE COMPANY'S COAL ASH COSTS AS ADJUSTED BY THE PUBLIC STAFF?

A. As shown on Maness Exhibit I, Schedule 1, the Public Staff recommends an amortization period of 26 years beginning on the date the rates approved in this proceeding become effective.

Q. WHAT SHARING PERCENTAGE DOES A 26-YEAR AMORTIZATION PERIOD PRODUCE?

A. At the net-of-tax overall rate of return recommended by the Public Staff, a 26-year amortization period results in the ratepayers bearing approximately 50.4% of the present value of the January 2018 – November 2019 deferred costs at August 1, 2020 (with a return accrued to that point).[5] The Public Staff believes that this level of sharing is reasonable and appropriate for the reasons discussed above. The specific sharing ratio of 50% of the costs to be borne by ratepayers, and 50% of the costs to be borne by shareholders, is a qualitative judgment. The large magnitude of costs that do not contribute to additional electric service is part of the judgment; another part is the available evidence on the extent of DEC's culpability for coal ash environmental contamination. An important consideration is that the extent of environmental contamination and violations, most notably the number of groundwater violations documented by witness Junis, is much greater than in the Sub 1146 rate case.

Q. ARE THERE OTHER FACTORS THAT SUPPORT A SHARING OF ARO-RELATED COAL ASH MANAGEMENT COSTS BETWEEN DEC'S RATEPAYERS AND SHAREHOLDERS?

[5] If the Commission were to approve a rate of return different from that recommended by the Public Staff, the amortization period necessary to achieve a 50%-50% sharing would possibly change. A lower rate of return would tend to produce a higher ratepayer burden; a higher rate of return would produce a lower ratepayer burden.

A. Yes. In Dominion Energy North Carolina's (DENC) most recent general rate case, Docket No. E-22, Sub 562, the Public Staff recommended an equitable sharing adjustment for CCR costs similar to what it is recommending in this proceeding. On January 23, 2020, the Commission issued its *Notice of Decision* in that proceeding, ordering that the Company amortize its deferred CCR costs over ten years, with the unamortized balance not being allowed to earn a return during the amortization period. Although the ratepayer share associated with a ten-year amortization is greater than what the Public Staff recommended in that case, the result still appears to reflect a 74%-26% sharing of costs between the ratepayers and the shareholders, respectively. While each case must be decided on its merits, it is noteworthy that the Commission has recognized the denial of a return on coal ash costs is appropriate in given circumstances. It is also noteworthy that the extent of environmental violations, and thus utility culpability, is much greater for DEC than the evidence showed in the most recent DENC case.

Q. WHERE DO YOU PRESENT YOUR ADJUSTMENT?

A. My adjustment, which has a total revenue requirement impact of approximately $86 million, is set forth in Maness Exhibit I, and has been incorporated by Public Staff witness Boswell.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING ARO-RELATED COAL ASH COSTS?

A. Yes. The Public Staff is aware that Duke Energy has filed suit against certain of its insurers to recover coal ash management costs under its policies with those insurers. Duke Energy has stated that if it does recover on any of those claims, that recovery will be credited against coal ash management costs to be recovered from its ratepayers. The Public Staff believes that ratepayers should be credited the full amount of any recovery from those policies and that Duke Energy should vigorously prosecute those lawsuits on behalf of ratepayers.

RATE BASE CLASSIFICATION OF REGULATORY ASSETS ASSOCIATED WITH ARO-RELATED <u>COAL ASH COMPLIANCE AND CLEANUP</u>

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING WITH REGARD TO THE CLASSIFICATION OF COAL ASH ARO-RELATED REGULATORY ASSETS?

A. As noted above, I do not believe that the ARO-related regulatory assets associated with coal ash clean-up and remediation activities, representing funds that have already been spent, and that are not being maintained in association with the provision of current or future service, truly qualify in substance as working capital. Therefore, I have recommended to Public Staff witness Boswell that she reclassify the Company-proposed unamortized balances of these regulatory assets from a working capital classification to a separate classification outside of working capital.

There may well be other items that the Company has classified as working capital in its filed cost of service that truly should instead be classified as rate base items outside of working capital. I did not have time during my investigation to fully determine which items those might be. However, because it was clear that the regulatory assets associated with ARO-related coal ash clean-up, disposal, and remediation activities do not qualify as true working capital, I am recommending their particular reclassification.

AMORTIZATION PERIOD FOR NON-ARO-RELATED <u>DEFERRED COAL ASH CAPITAL COSTS</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE AMORTIZATION PERIOD FOR NON-ARO-RELATED DEFERRED COAL ASH CAPITAL COSTS.

A. Pursuant to the Commission's approval of the 2016 request for deferral filed in Docket No. E-7, Sub 1110, the Company is proposing to defer and amortize certain depreciation and return requirements related to certain capital projects placed into plant in service since its most recent rate proceeding. These projects are not classified by the Company as legal obligations associated with the retirement of coal ash facilities or the generating plants with which those facilities are associated; instead, they are intended to address coal ash issues related to the continuing operation of the applicable generating plants. Although they are not part of the legal obligation that gives rise to DEC's coal ash ARO, the Company nonetheless maintains that they are eligible for deferral pursuant to the terms of the Sub 1110 deferral accounting request, because they are needed to fulfill the Company's responsibilities under CAMA and the EPA's CCR Rule. The Public Staff agrees.

The Company has deferred or is deferring the return requirements and depreciation expenses incurred between the dates that the projects (or components thereof) were placed in service and the expected effective date of the rates in this case going into effect. The Public Staff does not oppose deferral in this particular case.

Although I do not oppose deferral of the capital (return and depreciation) costs of the projects in this case, I do not agree with the five-year period proposed by the Company over which to amortize the deferred costs. The return on the deferred costs and the annual amortization expense proposed by the Company would increase the revenue requirement in this proceeding by approximately $25 million (using the Public Staff's recommended cost of capital), a not insubstantial amount. Increasing the amortization period to ten years (even with the offset of a smaller first-year reduction to rate base) would decrease this $25 million revenue requirement by approximately $9 million. Given the fact that this reduction would substantially ease the annual impact of the deferral and amortization on the ratepayer, and that the reduction would not directly harm the Company in that the unamortized amount would earn a return through being included in rate base, I am recommending that the deferred costs be amortized over ten years, instead of five. This adjustment is set forth on Maness Exhibit II, and has been incorporated by Public Staff witness Boswell.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THE DEFERRAL AND AMORTIZATION OF NON-ARO-RELATED CAPITAL COSTS?

A. Yes. Although the Public Staff agrees that the Company is authorized to defer the capital costs of non-ARO-related coal ash remediation projects it has presented in this proceeding, we were frankly surprised at the number and cost magnitude of these projects. At the time the Company made its Sub 1110 deferral request in late 2016, and until it filed its application in this case, the Public Staff believed that the capital costs mentioned in the Sub 1110 request would be ARO-related, not related instead to projects associated with the continuing operation of the generating plants. The ARO was the focus of the petition, and it certainly seemed to be where the highest magnitude risk of loss to the Company resided.

Given the unexpected nature of the non-ARO-related projects proposed for deferral, and the fact that the non-ARO-related deferral requested in this case is more similar in nature to other requests that have been brought forth frequently in the past related to new generation projects than it is to the unique situation presented by the incurrence of ARO-related costs associated with the retirement of its existing coal ash facilities at an extraordinarily high-cost, the Public Staff believes that the automatic right to defer capital costs associated with CAMA or the CCR Rule should not continue. Therefore, the Public Staff recommends that any further authorization to defer CCR-related costs should be restricted to those costs that qualify for the ARO.

ARO-RELATED COSTS DEFERRED AND AMORTIZED PURSUANT TO DOCKET NO. E-7, SUB 1146

Q. PLEASE EXPLAIN HOW THE ARO-RELATED DEFERRED COSTS AND AMORTIZATION EXPENSE APPROVED BY THE COMMISSION IN DOCKET NO. E-7, SUB 1146, IMPACT THIS PROCEEDING.

A. In the Company's most recent general rate case, it proposed to defer and amortize ARO-related coal ash remediation costs incurred during 2015 and 2016 over a five-year period, with the unamortized balance included in rate base. The Public Staff recommended instead that the costs, net of certain recommended prudence and reasonableness adjustments, be equitably shared between ratepayers and shareholders, proposing a 25-year amortization with the unamortized balance excluded from rate base, which would result in an approximately 50% sharing between ratepayers and shareholders. Ultimately, the Commission agreed with the Company's position, except that it imposed a $14 million annual penalty on the Company for each of the five years. As a result, in this proceeding the Company has proposed to include in its North Carolina retail cost of service an annualized amount of approximately $97 million in amortization expense related to the 2015-2017 incurred costs, and in its North Carolina retail rate base an annualized end-of period level of unamortized deferred 2015-2017 costs of approximately $297 million, net of accumulated deferred income taxes (ADIT).

Q. WHAT IS THE CURRENT LEGAL STATUS OF THE ISSUES RELATED TO 2015-2017 ARO-RELATED DEFERRED COSTS?

A. Several parties have appealed the Commission's Sub 1146 Order to the North Carolina Supreme Court. In particular, the Public Staff appealed the Commission's decisions regarding equitable sharing and the Public Staff's recommended disallowance related to groundwater extraction and treatment. The outcome of the appeals remains pending at the Supreme Court.

Q. IF THE SUPREME COURT WERE TO RULE IN THE PUBLIC STAFF'S FAVOR IN THE APPEAL, AND THE PUBLIC STAFF'S POSITIONS WERE APPROVED BY THE COMMISSION ON REMAND, WHAT WOULD BE THE APPROPRIATE IMPACT ON THE SUB 1146 COSTS INCLUDED IN THIS CASE, DOCKET NO. E-7, SUB 1214?

A. If the Public Staff prevailed on its positions at both the appellate level and on remand to the Commission, not only would it be mandatory for customers' rates effective during the period covered by the Sub 1146 Order to be reduced to match the positions on which the Public Staff prevailed, but it would also only be appropriate for the revenue requirement impact of the Public Staff's successfully appealed Sub 1146 adjustments to be flowed through to the Sub 1146 costs as included in the Sub 1214 case. Also, if the case were remanded and the Commission chose some equitable sharing other than the percentage recommended by the Public Staff, there would still be a need to flow the effect of the remand decision through to the Sub 1146 costs included in the Sub 1214 case.

Q. WHAT WOULD BE THE EFFECT OF THE PUBLIC STAFF'S APPEALED POSITIONS ON THE SUB 1146 COSTS AS INCLUDED IN THIS CASE?

A. The effect in this case would be to reduce annual Sub 1146 coal ash amortization expense from approximately $97 million to approximately $22 million, and reduce the associated net-of-ADIT Sub 1146 rate base amount from approximately $297 million to $0. The revenue requirement impact in the current case of these changes would be an annual reduction of approximately $99 million.

Q. HAS THE PUBLIC STAFF ROLLED THIS ADJUSTMENT INTO ITS RECOMMENDED REVENUE REQUIREMENT IN THIS PROCEEDING?

A. No, we have not, although it would not be wholly inappropriate to do so, if only to show the Public Staff's position regarding the very costs that are the subject of a pending appellate decision. However, the Public Staff has instead chosen to highlight this issue for the Commission, and recommend that the Commission take whatever steps are necessary to ensure that the outcome of this issue is flowed into each case on which it would have an effect.

DEFERRAL OF GRID IMPROVEMENT PLAN (GIP) COSTS

Q. WHAT IS THE GRID IMPROVEMENT PLAN (GIP)?

A. The GIP is explained in the testimony of Company witness Jay W. Oliver, and is analyzed in great detail in the joint testimony of Public Staff witnesses David Williamson and Tommy Williamson, Jr., and in the testimony of Public Staff witness Jeff Thomas. Briefly, however, according to Company witness Oliver's testimony, the GIP is a list of projects and programs, to be implemented over the time period 2020-2022, to meet certain large, emerging trends that affect the grid ("Megatrends"), with the intent of protecting and modernizing the grid, as well as optimizing customer experience.

Q. WHAT REGULATORY TREATMENT IS THE COMPANY PROPOSING THAT THE COMMISSION APPROVE IN THIS RATE CASE FOR GIP COSTS?

A. As set forth in the testimony of Company witness Jane L. McManeus, DEC is requesting permission to defer costs incurred during the period 2020 through 2022 as part of its GIP. The costs requested to be deferred include both capital costs (return on rate base, depreciation expense, and property taxes) and operations and maintenance (O&M) expenses, as well as carrying costs on the deferred balance. Ms. McManeus testifies that the incurrence of these costs meets the tests typically applied by the Commission to requests for deferral; namely, the costs are "major, non-routine investments, that produce substantial customer benefits," and if deferral is not approved, the Company will "experience a significant adverse earnings impact." Ms. McManeus also testifies that deferral can be applied in a flexible way that rates are just and reasonable and set in a manner that balances Company and customer interests.

Q. PLEASE DESCRIBE THE PROCESS FOLLOWED BY THE PUBLIC STAFF TO DETERMINE WHETHER IT IS APPROPRIATE TO APPROVE DEFERRAL OF GIP COSTS.

A. As alluded to by Company witness McManeus, in many situations deferral accounting is justifiable before this Commission only by meeting both "prongs" of a two-prong test: the costs must be qualitatively very unusual, even extraordinary, in type, and they must be very significant, even extraordinary, in magnitude; significant enough that the Commission can reasonably conclude that they are clearly not being recovered in then-current customer rates. It must be noted when conducting an analysis of whether costs can be reasonably deferred that different types of costs can be in existence at utilities at different times, and that costs of various categories (as well as revenues) can be relatively higher or lower at various points in time. Therefore, for example, one cannot assume that just because a certain category of costs increases, another has not decreased in a manner that wholly or partially offsets the increased costs. This leads to the conclusion that when assessing the reasonableness of deferral of a category of costs, one must not only consider the absolute size of a particular cost, but also the state of the utility's overall earnings. If overall earnings remain relatively healthy in relation to the utility's last approved rate of return, or even, if enough time has passed, to what is a currently reasonable rate of return, then deferral of even a high level of cost may not be appropriate.[6]

In this case, Public Staff witnesses Tommy and David Williamson undertook a comprehensive and very detailed analysis of the proposed GIP programs to determine which, if any of the programs should be considered extraordinary in type and outside the scope of DEC's normal course of business. To do so, as explained in their testimony, they followed a two-step approach, first reviewing each program to determine if it "exhibited" the characteristics of a grid modernization program, and then evaluating each program through applying a matrix in which they ranked each program on various metrics. They used the results of these two types of evaluations to help determine which of the programs was of an "extraordinary type," and thus met that prong of the deferral test.

[6] There can be other circumstances that justify deferral, such as to stay in sync with an already established method or process of ratemaking, to reconcile the recognition of costs and rates for a large generating plant coming into service very close to a rate case intended to match up with the in-service date, or to match the way in which costs are already being recognized in the ratemaking process. However, in the case of the GIP, utilizing the prongs of "extraordinary in type and magnitude" seems most appropriate.

As a result of their evaluation, witnesses Tommy and David Williamson identified the programs that they considered extraordinary in type and appropriate to be considered for deferral:

1. Self-Optimizing Grid (SOG) – Automation;
2. SOG - Advanced Distribution Management System (ADMS);
3. Integrated Volt/Var Control (IVVC);
4. Transmission System Intelligence;
5. Underground Automation; and
6. Integrated System Operation Planning (ISOP).

After making this determination, the Public Staff Electric Division forwarded their choices to the Accounting Division, so that we could determine if the estimated costs of the identified programs are substantial enough in magnitude to justify deferral.

Q. HAVE YOU COMPLETED YOUR EVALUATION OF THE MAGNITUDE OF THE PACKAGE OF PROGRAMS?

A. Not as of the date of the filing of this testimony. During the course of evaluating the magnitude of the programs, I discovered that certain tax-related information appeared to not have been included in the data that the Company had supplied to the Public Staff in response to a data request. At this time, the Accounting Division is continuing to work with the Company to determine the impact of the proposed deferral. In supplemental testimony, I will discuss the magnitude of the costs and recommend whether special ratemaking treatment is appropriate.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

MICHAEL C. MANESS

I am a graduate of the University of North Carolina at Chapel Hill with a Bachelor of Science degree in Business Administration with Accounting. I am a Certified Public Accountant and a member of both the North Carolina Association of Certified Public Accountants and the American Institute of Certified Public Accountants.

As Director of the Accounting Division of the Public Staff. I am responsible for the performance, supervision, and management of the following activities: (1) the examination and analysis of 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) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings. I have been employed by the Public Staff since July 12, 1982.

Since joining the Public Staff, I have filed testimony or affidavits in several general, fuel, and demand-side management/energy efficiency rate cases of the utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC., and Virginia Electric and Power Company (Dominion Energy North Carolina) as well as in several water and sewer general rate cases. I have also filed testimony or affidavits in other proceedings, including applications for certificates of public convenience and necessity for the construction of generating facilities, applications for approval of self-generation deferral rates, applications for approval of cost and incentive recovery mechanisms for electric utility demand-side management and energy efficiency (DSM/EE) efforts, and applications for approval of cost and incentive recovery pursuant to those mechanisms.

I have also been involved in several other matters that have come before this Commission, including the investigation undertaken by the Public Staff into the operations of the Brunswick Nuclear Plant as part of the 1993 Carolina Power & Light Company fuel rate case (Docket No. E-2, Sub 644), the Public Staff's investigation of Duke Power's relationship with its affiliates (Docket No. E-7, Sub 557), and several applications for business combinations involving electric utilities regulated by this Commission. Additionally, I was responsible for performing an examination of Carolina Power & Light Company's accounting for the cost of Harris Unit 1 in conjunction with the prudence audit performed by the Public Staff and its consultants in 1986 and 1987.

I have had supervisory or management responsibility over the Electric Section of the Accounting Division since 1986, and also was assigned management duties over the Water Section of the Accounting Division during the 2009-2012 time frame. I was promoted to Director of the Accounting Division in late December 2016.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

First Supplemental Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

February 25, 2020

Q. MR. MANESS, WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to present my and the Public Staff's conclusions regarding the deferral of the six Grid Improvement Plan (GIP) programs forwarded to the Accounting Division so that we could determine if the estimated costs of the identified programs are substantial enough in magnitude to justify deferral.

Q. AGAIN, WHAT ARE THE SIX PROGRAMS?

A. The six programs are as follows:

1. Self-Optimizing Grid (SOG) – Automation;
2. SOG - Advanced Distribution Management System (ADMS);

3. Integrated Volt/Var Control (IVVC);
4. Transmission System Intelligence;
5. Underground Automation; and
6. Integrated System Operation Planning (ISOP).

Q. IN YOUR TESTIMONY FILED ON FEBRUARY 18, 2020, YOU STATED THAT YOU HAD NOT COMPLETED YOUR EVALUATION OF THE MAGNITUDE OF THE PACKAGE OF GIP PROGRAMS, DUE TO THE FACT THAT CERTAIN TAX-RELATED INFORMATION APPEARED TO NOT HAVE BEEN INCLUDED IN THE DATA THAT THE COMPANY HAD SUPPLIED TO THE PUBLIC STAFF IN RESPONSE TO A DATA REQUEST. HAVE YOU NOW RECEIVED THAT DATA?

A. Yes, I have.

Q. BASED ON THE DATA YOU HAVE RECEIVED, WHAT IS THE TOTAL AMOUNT OF CAPITAL INVESTMENT ESTIMATED FOR THE SIX PROGRAMS OVER THE YEARS 2020 THROUGH 2022?

A. The total amount of capital expenditure estimated by the Company for the six programs is approximately $445 million.

Q. DID YOU INCLUDE THE ENTIRETY OF THIS $445 MILLION IN YOUR ANALYSIS OF MAGNITUDE?

A. Yes. However, the analysis I have performed, with the assistance of other members of the Accounting Division, has focused on the basis point impact on earned return on equity (ROE) of the investment, plus certain estimated operations and maintenance (O&M), depreciation, and property tax expenses (expenses) over the three-year period (Deferral Period). Therefore, the rate base analysis also included impacts of estimated accumulated depreciation and accumulated deferred income tax (ADIT) changes to the rate base, as well as annual changes in gross plant in service investment, all calculated to reflect average investment during each year (using a 13-month average).

Q. WHAT WAS THE BASELINE FOR YOUR BASIS POINT IMPACT ANALYSIS?

A. The baseline is the Public Staff's recommended capital structure, cost rates (including ROE), rate base, and net operating income in this proceeding.

Q. ARE THERE ANY NORMAL ELEMENTS OF A BASIS POINT IMPACT ANALYSIS THAT YOU HAVE NOT CONSIDERED?

A. Yes. Normally, in conducting an analysis of this type, the Public Staff would consider the actual earnings of the Company during the year, as compared to the most recently approved ROE approved by the

Commission. However, in this case, since the request is to preapprove a deferral coming right out of a general rate case, I have not attempted to project Company actual earnings over the 2020-2022 proceeding, and have instead used the Public Staff's recommended earnings and ROE as a reasonable proxy for actual earnings during the Deferral Period. Additionally, the Public Staff believes it is reasonable, due to the programmatic nature of the GIP, to consider, at this time, deferral of the applicable amounts during the entire three-year (excluding January 2020, assuming he Company's proposed updates, with appropriate and reasonable Public Staff adjustments, are approved). However, the prudence and reasonableness of actual amounts spent and deferred should remain subject to Commission review in future Company general rate cases.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS?

A. The results of my analysis, as calculated and set forth on Maness Exhibit III attached to this testimony, are as follows:

Year	ROE Basis Point Impact
2020	(4)
2021	(19)
2022	(38)

A single basis point represents one-one hundredth of a percentage point of an ROE. The annual impacts can increase not only because of higher incremental investments in each year, but also because of the continued annual impact of investments made in prior years.

Q. GIVEN THESE RESULTS, DOES THE PUBLIC STAFF RECOMMEND DEFERRAL?

A. The average basis point impact of the results averages out to only approximately 20.33 basis points per year. Under normal circumstances, the Public Staff would not recommend deferral of an investment with basis point impacts so small. However, in this case, the Public Staff takes special notice of relevant language in the Commission's Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, issued in the Company's most recent general rate case, Docket No. E-7, Sub 1146, on June 22, 2018 (Sub 1146 Order). In the Evidence and Conclusions for Findings of Fact Nos. 42-44 in the Sub 1146 Order, which addressed the Company's request for a rate rider for the costs of the precursor to the GIP, the Power Forward program, the Commission denied the request for a rate rider, but also stated, with regard to alternatively approving deferral:

> [T]he Commission finds and concludes that DEC has not satisfied the criteria for deferral accounting treatment of Power Forward costs. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral.

> . . .
>
> With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside of the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during a test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside a test year and meet the test of economic harm, the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs. Should a collaborative undertaking with stakeholders as addressed herein produce a list of Power Forward projects, such designation would greatly assist the Commission in addressing a requested deferral. Were the Company to demonstrate that the costs can be properly classified as Power Forward and grid modernization, the Commission would seek to expeditiously address the request and to determine that the Company would meet the "extraordinary expenditure" test and conceptually authorize deferral for subsequent consideration for recovery in a general rate case.
>
> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the "extraordinary expenditure" test.

With this language, the Commission appears to offer to consider being "lenient" regarding the magnitude of costs or financial impacts necessary to justify deferral, although the Commission did not identify in the Sub 1146 Order the limits to the leniency it would consider. For this reason, and this reason only, I do not object to the

Commission allowing deferral of the capital costs of the six programs, along with associated incremental expenses (net of quantifiable operational benefits in operating revenues or expenses), incurred over the February 2020 through December 2022 time period, as long as the Commission determines that the estimated amount of basis point impacts falls within the range of leniency that it is willing to grant in this particular circumstance. I have not attempted to quantify what this range may be, but will leave it in the hands of the Commission. However, the Public Staff does recommend that the Commission find that any deferral it approves in this case should be considered specific only to this case, and not precedential with regard to any future general rate case proceeding or deferral request for the GIP or for any other costs.

Q. ARE THERE OTHER RESTRICTIONS THAT THE PUBLIC STAFF RECOMMENDS BE APPLIED TO ANY DEFERRAL OF GIP COSTS THE COMMISSION APPROVES IN THIS PROCEEDING?

A. Yes. The Public Staff recommends the following restrictions:

1. Deferral should be restricted to incremental capital costs (return and depreciation) related to plant in service and incremental expenses (offset by incremental operating benefits) incurred between February 1, 2020 and the earlier

of December 31, 2022, or the effective date of the rates set in the Company's next general rate case.

2. No allocated overheads or administrative and general costs shall be included in the allowable deferred amount.

3. The prudence and reasonableness of all costs incurred shall remain subject to review in the Company's next general rate case.

4. The Company shall make annual reports setting forth the cost amounts incurred and deferred by project, with a description of each significant cost amount included in plant in service or expenses. Such reports shall be filed with the Commission by the 60th day following the end of each calendar year.

Q. DO YOU HAVE ANY RECOMMENDATION TO MAKE AT THIS TIME REGARDING THE APPROPRIATE AND REASONABLE AMORTIZATION PERIOD FOR ANY COSTS THE COMMISSION MIGHT CHOOSE TO DEFER?

A. No. I recommend that the choice of an amortization period or periods be left to the Company's next general rate case.

Q. DOES THIS COMPLETE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

AND

DOCKET NO. E-7, SUB 1214

Second Supplemental Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

March 25, 2020

Q. MR. MANESS, WHAT IS THE PURPOSE OF YOUR SECOND SUPPLEMENTAL TESTIMONY?

A. The purpose of my Second Supplemental Testimony is to present revisions to the accounting and ratemaking adjustments I am recommending in this proceeding to the coal ash clean-up, disposal, and remediation cost amounts proposed for recovery by Duke Energy Carolinas, LLC (DEC). These revisions affect my adjustments to the Company-proposed amortization expenses and unamortized balances associated with both (a) DEC's Asset Retirement Obligation (ARO) – related coal ash activities, and (b) its non-ARO-related coal ash projects. I have provided my revised adjustments to Public Staff witness Michelle M. Boswell for inclusion in her Supplemental and Stipulation Exhibit 1, in which she calculates the revised overall change recommended by the Public Staff to the Company's updated proposed base rate revenue increase.

Q. WHAT REVISIONS ARE YOU MAKING TO YOUR RECOMMENDED ADJUSTMENTS?

A. With regard to my recommended adjustment to the amortization expense and unamortized balance of deferred ARO costs (set forth on Maness Exhibit I – Revised), I have made the following revisions:

1. I have added to the balance of deferred costs to be amortized the actual ARO-related coal ash expenditures for December 2019 and January 2020.

2. I have redistributed the adjustment recommended by Public Staff witness Junis to remove costs of extraction and treatment of contaminated groundwater to reflect direct assignment to specific months, rather than the proportionate allocation I utilized in my initial Maness Exhibit I.

3. I have proportionately reallocated the Dan River excavation and Buck Beneficiation adjustments recommended by Public Staff witnesses Garrett and Moore, respectively, to reflect the addition to the allocation base of the December 2019 and January 2020 ARO-related coal ash expenditures.

4. I have increased the Public Staff's recommended amortization period for the deferred costs from 26 to 27 years.

With regard to the amortization expense and unamortized balance of deferred non-ARO coal ash costs (set forth on Maness Exhibit II – Revised), I have made the following revisions:

1. I have added to the balance of deferred costs to be amortized the monthly capital cost impacts through July 2020 of the actual non-ARO-related additions to coal ash project plant in service for December 2019 and January 2020.

2. To be consistent with the allocation methodology recommendation of Public Staff witness Mclawhorn and the corrected implementation of that recommendation by witness Boswell, I have corrected the allocation of the Company's adjustment and my recommended adjustment to reflect the Summer/Winter Peak and Average allocation method.

Q. WHY HAVE YOU INCREASED THE RECOMMENDED AMORTIZATION PERIOD FOR ARO-RELATED COAL ASH DEFERRED COSTS TO 27 YEARS?

A. As noted in the initial testimony of witness Junis, the Public Staff is recommending that 50 percent of the costs for CCR remediation and closure should be paid by the Company's shareholders and the remaining 50 percent be paid by the Company's customers. I noted in my initial testimony that the 26-year amortization produced a ratepayer sharing ratio of approximately 50.4% of the costs (based on a present value analysis), which the Public Staff considered sufficiently close to 50%. However, in our set of supplemental testimony, the Public Staff is recommending a decrease in the embedded cost of debt from 4.51% to 4.29%. This decrease, via its influence on the present value analysis, increases the ratepayer sharing ratio resulting from a 26-year amortization period from approximately 50.4% to approximately 50.8%. If, on the other hand, the amortization period is increased to 27 years, the resulting ratepayer sharing ratio is approximately 49.7%, which is closer to 50% than is 50.8%. Therefore, the Public Staff believes that given its revised cost of capital recommendation, a 27-year amortization period is more appropriate than a 26-year period.[1]

Q. HAS THE ADDITION OF DECEMBER 2019 AND JANUARY 2020 COAL ASH COSTS TO THE BALANCE AVAILABLE FOR DEFERRAL CHANGED THE IMPACT OF THESE COSTS ON NORTH CAROLINA RETAIL RATEPAYERS?

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[1] If the Commission were to approve a rate of return different from that recommended by the Public Staff, the amortization period necessary to achieve a 50%-50% sharing would possibly change. A lower rate of return would tend to necessitate a longer amortization period; a higher rate of return, a shorter one.

A. Yes. In my initially filed testimony, I indicated that the Public Staff-adjusted N.C. retail amount presented for amortization (through November 2019) amounted to an average of approximately $104 per N.C. retail customer, and that the cost of a five-year amortization period for these costs would burden N.C. retail customers by almost $21 per year, on average, even before considering the rate base impact of the deferred costs.

With the addition of December 2019 and January 2020 costs, the measurements of these impacts have increased. Now, the N.C. retail amount presented for amortization ($261,242,000), including carrying costs) amounts to an average of approximately $112 per N.C. retail customer, using a pro forma balance of 2,337,291 customers at January 31, 2020. Requiring the N.C. retail customers to bear the cost of a five-year amortization period for these updated costs would burden them by approximately $22 per year, on average, even before considering the impact of including the unamortized amount in rate base.

Q. DO YOU HAVE ANY FURTHER COMMENTS?

A. Yes. I would like to note that, although not explicitly stated in my initial testimony, the Public Staff recommends that the Company be allowed to continue, for regulatory accounting purposes, to defer ARO-related coal ash clean-up, disposal, and remediation costs from

February 1, 2020, through the effective end-of-period date in the Company's next general rate case. The amount of those costs actually allowed for recovery would be subject to review by the Commission, presumably in that case.

As in past cases, this recommendation is based on the magnitude and unique nature of the costs. Additionally, allowance of a carrying charge on new costs incurred between general rate cases (before the Commission has reached a decision regarding the ultimate recovery of those specific costs) reduces the incentive for the Company to make more frequent general rate case filings. The degree to which this reduced incentive to file new rate cases is material will vary depending on such circumstances as how long the Company goes between rate cases, the weighted average cost of capital, and the amount of deferred coal ash costs. In any event, the Public Staff recommends that the Commission take the allowance of between-case carrying costs into account when determining, in that next proceeding, the appropriateness of including the deferred costs in rate base and the appropriate amortization period.

Q. DOES THIS COMPLETE YOUR SECOND SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUBS 1187, 1213, AND 1214

Third Supplemental and Settlement Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

September 8, 2020

Q. MR. MANESS, WHAT IS THE PURPOSE OF YOUR THIRD SUPPLEMENTAL AND SETTLEMENT TESTIMONY?

A. The primary purpose of my Third Supplemental and Settlement Testimony is to present revisions to the accounting and ratemaking adjustments I am recommending in this proceeding to the coal ash clean-up, disposal, and remediation cost amounts proposed for recovery by Duke Energy Carolinas, LLC (DEC). These revisions affect my adjustments to the Company-proposed amortization expenses and unamortized balances associated with both (a) DEC's Asset Retirement Obligation (ARO) – related coal ash activities, and (b) its non-ARO-related coal ash projects. I have provided my revised adjustments to Public Staff witness Michelle M. Boswell for inclusion in her Second Supplemental and Stipulation Exhibit 1, in which she calculates the revised overall change recommended by the Public Staff to the Company's updated proposed base rate revenue increase.

Secondarily, I am also making certain comments with regard to both (a) the Joint Testimony of Jay W. Oliver and Jane L. McManeus in Compliance with Commission Order Requesting GIP Information, filed by DEC in this proceeding on August 5, 2020 (Additional GIP Testimony), and (b) the Supplemental Testimony and Exhibit of David L. Doss, Jr., filed by DEC in this proceeding on August 28, 2020 (Supplemental Doss CCR Testimony).

Q. WHAT COMPANY FILINGS OR COMMISSION ORDERS HAVE LED TO THE FILING OF YOUR THIRD SUPPLEMENTAL AND SETTLEMENT TESTIMONY?

A. On July 31, 2020, the Company filed with the Commission the Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation) between it and the Public Staff (Stipulating Parties) regarding certain issues related to this rate proceeding. Among the issues settled were the following:

1. The period to be utilized to amortize the deferred costs associated with non-asset retirement obligation-related (non-ARO-related) deferred coal ash capital costs. The Stipulating Parties agreed to an eight-year amortization period, different than either party initially proposed in the proceeding.

2. The cost of service methodology to be utilized to allocate system costs for jurisdictional and retail class purposes. The Stipulating Parties agreed to utilize the Summer Coincident Peak (SCP) methodology (on a non-precedential basis), instead of the Summer/Winter Peak and Average (SWPA) methodology initially recommended by the Public Staff.

3. The cost of capital to be utilized for purposes of this proceeding. The Stipulating Parties agreed to utilize a capital structure of 52% equity and 48% debt, a debt cost rate of 4.27%, and a rate of return on equity of 9.60%. These factors were all different than the factors initially recommended by the Public Staff.

The Second Partial Stipulation also provided that that the Stipulating Parties agreed that the Public Staff shall have until September 8, 2020 to audit DEC's updates of revenues and certain expenses to May 31, 2020, and file testimony or affidavits, with schedules, addressing the updates.

On July 31, 2020, DEC filed the Second Settlement Testimony and Exhibits (Second Settlement Testimony) of witness Jane L. McManeus, which presented the Company's revised proposed revenue requirement pursuant to the terms of the First and Second Partial Stipulations.

Also on July 31, 2020, Public Staff witnesses J. Randall Woolridge, James S. McLawhorn, and Michelle M. Boswell each filed Testimony Supporting Second Partial Stipulation, stating that the Second Partial Stipulation is in the public interest and should be approved. Ms. Boswell further testified that once the Public Staff had completed the audit of all revenue, rate base, and expense updates through May 31, 2020, the Public Staff would file schedules supporting the Public Staff's recommended revenue requirement.

On September 4, 2020, the Commission issued an Order (September 4 Order) granting the Public Staff leave to file testimony and exhibits regarding the Company's Second Supplemental Testimony.

Q. WHY DOES THE SECOND PARTIAL STIPULATION AND THE COMPANY'S SECOND SETTLEMENT TESTIMONY NECESSITATE THE FILING OF YOUR THIRD SUPPLEMENTAL AND SETTLEMENT TESTIMONY?

A. Although the Second Partial Stipulation did not provide for an update of system-level ARO-related or non-ARO-related costs for purposes of this proceeding, each of the stipulated items I have listed herein has a revenue requirement effect on one or the other of the categories of coal ash disposal/remediation costs presented as part of the proceeding.

Q. PLEASE DESCRIBE THE EFFECT THAT THE SECOND PARTIAL STIPULATION HAS ON THE AMORTIZATION OF NON-ARO-RELATED DEFERRED CAPITAL COSTS RECOMMENDED BY THE PUBLIC STAFF.

A. First, the non-ARO-related deferred capital costs are allocated to N.C. retail operations by the production plant-related allocation factor. That factor is numerically different under the SCP methodology than it is under the SWPA methodology. The application of the SCP factor changes the N.C. retail amount of deferred costs to be amortized from the amount initially recommended by the Public Staff.

Second, the Public Staff initially recommended a five-year amortization period for the deferred costs, while the Company proposed a ten-year amortization period. Pursuant to the Second Partial Stipulation, the Stipulating Parties have agreed to an eight-year amortization period. Therefore, the Public Staff's recommended amortization expense has been increased, and the Company's proposed amortization period has been decreased.

The Public Staff's revised recommended amortization expense and rate base impact are set forth on Maness Second Revised and Second Stipulation Exhibit II, filed with this testimony. No difference now exists between the amount recommended by the Public Staff and that recommended by the Company.

Q. PLEASE DESCRIBE THE EFFECT THAT THE SECOND PARTIAL STIPULATION HAS ON THE AMORTIZATION OF ARO-RELATED DEFERRED COSTS RECOMMENDED BY THE PUBLIC STAFF.

A. Because of the changes in the Public Staff's recommended cost of capital, as agreed to in the Second Partial Stipulation, I have decreased the Public Staff's recommended amortization period for the deferred costs from 27 to 25 years.

Q. WHY HAVE YOU DECREASED THE RECOMMENDED AMORTIZATION PERIOD FOR ARO-RELATED COAL ASH DEFERRED COSTS TO 25 YEARS?

A. As noted in the initial testimony of witness Junis, the Public Staff is recommending that 50 percent of the costs for coal combustion residual (CCR) remediation and closure should be paid by the Company's shareholders and the remaining 50 percent be paid by the Company's customers. In my second supplemental testimony filed on March 25, 2020, I recommended an amortization period of 27 years, which I testified produced a ratepayer sharing ratio of approximately 49.7% of the costs (based on a present value analysis), which the Public Staff considered sufficiently close to 50%. However, pursuant to the Second Partial Stipulation, the Public Staff is agreeing to capital structure, debt cost and return on equity changes that have the effect of increasing the Public Staff's proposed weighted net-of-tax overall rate of return from 6.144% to 6.563%.

This increase, via its influence on the present value analysis, decreases the ratepayer sharing ratio resulting from a 27-year amortization period from approximately 49.7% to approximately 47.8%. If, on the other hand, the amortization period is decreased to 25 years, the resulting ratepayer sharing ratio is approximately 50.1%. Therefore, the Public Staff believes that given its revised cost of capital recommendation, a 25-year amortization period is more appropriate than a 27-year period.[1]

My revised recommended ARO-related coal ash cost amortization expense and rate base impact is set forth on Maness Second Revised and Second Stipulation Exhibit I, filed with this testimony. As I have testified to previously, I continue to recommend that the unamortized balance of these costs be excluded from rate base. I also continue to recommend that any unamortized balance of ARO-related coal ash costs that the Commission does decide to include in rate base be presented separately as a regulatory asset outside of working capital.

[1] If the Commission were to approve a rate of return different from that recommended by the Public Staff, the amortization period necessary to achieve a 50%-50% sharing would possibly change. A lower rate of return would tend to necessitate a longer amortization period; a higher rate of return, a shorter one.

SUPPLEMENTAL DOSS CCR TESTIMONY

Q. DO YOU HAVE ANY COMMENTS TO MAKE REGARDING THE SUPPLEMENTAL CCR TESTIMONY FILED BY COMPANY WITNESS DAVID L. DOSS, JR. IN THIS PROCEEDING ON AUGUST 28, 2020?

A. Yes. On page 4 of his Supplemental CCR Testimony, Company witness Doss, states:

> Witness Bednarcik's Supplemental Testimony notes that the activities identified in Supplemental Exhibit 1 were charged to "ARO," meaning that under the charging guidelines they were classified as Asset 10 Retirement Obligations ("ARO"). As such, the costs incurred in connection with the activities I reviewed would properly be capitalized costs. As I explained in my Rebuttal Testimony, under Financial Accounting Standards Board ("FASB") and Federal Energy Regulatory Commission ("FERC") guidance, ARO costs are an integral part of the plant asset that gives rise to the ARO, and therefore must be capitalized as part of such asset when the ARO liability is recognized.

Although Mr. Doss is correct with regard to the requirements of the FASB's standards (commonly referred to as GAAP) for financial accounting purposes and the guidance set forth in the FERC Uniform System of Accounts (FERC USOA), in the absence of regulatory assets and liabilities recorded due to regulatory commission rate-setting actions, he fails to acknowledge that this Commission has chosen not to set rates on the basis of expenses calculated and recorded pursuant to GAAP and the FERC USOA (which in their default mode are determined on the basis of a complex process of estimating future costs, determining their present value, and depreciating that present value over time, all the while re-estimating and truing up the costs), but instead on the basis of deferring actual costs for ratemaking purposes as they are incurred, and amortizing those actual costs over time. He also fails to acknowledge that this Commission's use of a different ratemaking methodology itself justifies the recording of regulatory expense on the books in a manner that synchronizes the recognition of expenses for GAAP and FERC USOA purposes with this Commission's ratemaking actions. Therefore, for N.C. retail jurisdictional accounting and ratemaking purposes, the fact that the default GAAP and FERC USOA practices require capitalization of an ARO asset is essentially rendered moot. The GAAP/FERC ARO asset recorded on the books of the Company is not included in rate base, and the depreciation and accretion expenses related to the ARO are reversed for regulatory purposes and deferred to a regulatory asset that is only proposed by the Company for rate base inclusion as cash is actually spent.[2] In fact, the Company's own workpapers submitted in the general rate case to calculate its proposed deferral and amortization amounts pay no

[2] It is interesting, and perhaps important for the Commission's analysis, to note that the deferred costs being proposed for rate base treatment by the Company are not a portion of the ARO asset itself at the time of proposed rate base inclusion, but instead represent a portion of the costs that would have otherwise already been written off to expense absent the Commission's approval of deferral.

attention whatsoever to the recording or reversal of GAAP/FASB ARO assets and expenses; they simply start in the most direct manner possible for determining the expenses to be recognized for ratemaking purposes: with the actual dollars spent.

This approach is thoroughly consistent with the Commission's August 8, 2003 Order in Docket No. E-7, Sub 723, which the Company used to justify its 2016 petition for deferral of coal ash costs in Docket No. E-7, Sub 1110. In the Sub 723 Order, the Commission directly stated, in ordering subparagraph 2.b:

> That the adoption of SFAS 143 shall have no impact on Duke's operating results or return on rate base for North Carolina retail regulatory purposes and that the net effect of the deferral accounting allowed shall be to reset Duke's North Carolina retail rate base, net operating income, and regulatory return on common equity to the same levels as would have existed had SFAS 143 not been implemented.

ADDITIONAL GIP TESTIMONY

Q. MR. MANESS, HAVE YOU REVIEWED THE ADDITIONAL GIP TESTIMONY AND EXHIBIT FILED BY DEC WITNESSES OLIVER AND MCMANEUS ON AUGUST 5, 2020?

A. I have read the testimony and performed a general overview of the attached exhibits. I have not performed a detailed analysis of the calculations and input amounts utilized in the exhibits.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE TESTIMONY OR EXHIBITS?

A. I have one comment regarding the exhibits, which is that they do not appear to reflect the impact of any accumulated deferred income taxes (ADIT) related to incremental Grid Improvement Plan (GIP) investment. In my opinion, in order to present a complete picture of the impacts of GIP investment on the revenue requirement, the impacts of ADIT on rate base should be included.

Additionally, I would like to reiterate the recommendation made in my previous testimony in this proceeding that no amortization period be decided in this case. Given that (a) there is no “natural” amortization period that suggests itself, as there is with the sale of hydro facilities, for example, and (b) we do not at this time know what the complete facts and circumstances of the Company’s situation will be at the time of the first rate case proceeding in which deferred GIP costs are presented for amortization, it makes better sense to wait to decide on the reasonable period until the facts and circumstances are clearer.

Q. DOES THIS COMPLETE YOUR THIRD SUPPLEMENTAL AND SETTLEMENT TESTIMONY?

A. Yes, it does.

Summary of the Testimony of Michael C. Maness Related to Coal Combustion Residual Costs, for the Remote Unconsolidated Hearing in Docket No. E-7, Subs 1187, 1213, and 1214

This summary addresses the coal combustion residual (CCR) portions of my initial Testimony (as corrected), Second Supplemental Testimony, and Third Supplemental and Settlement Testimony, filed (with accompanying Exhibits) in Docket No. E-7, Subs 1187, 1213, and 1214 (collectively, Sub 1214), on February 18, 2020, March 25, 2020, and September 8, 2020, respectively. My testimony, along with that of Public Staff witnesses Garrett, Moore, and Junis, presents the Public Staff's recommendations regarding the deferral and amortization of the Duke Energy Carolinas, LLC's (DEC or the Company) asset retirement obligation related (ARO-related) and non-ARO-related CCR costs incurred between January 1, 2018 and January 31, 2020 (Deferral Period).

I am recommending or incorporating adjustments in the following areas:

1. The ratemaking treatment of the costs of DEC's Asset Retirement Obligation (ARO) – related coal ash compliance and cleanup activities;
2. The appropriate classification within the rate base of the regulatory assets associated with the ARO-related coal ash compliance and cleanup; and
3. The amortization period for the Company's proposed deferred non-ARO-related costs.

With regard to ARO-related CCR costs, the Company proposes to establish a regulatory asset for actual CCR expenditures made during the Deferral Period, and to amortize that regulatory asset over a five-year period beginning with the effective date of the rates approved in this proceeding, while including the unamortized balance in rate base.

The Public Staff has made the following adjustments to the Company's proposed revenue requirement associated with ARO-related CCR costs:

1. Adjustments to reach a prudent and reasonable level of coal ash expenditures, as recommended by Public Staff witnesses Vance F. Moore, L. Bernard Garrett, and Charles Junis;
2. Amortization of the prudent and reasonable balance of ARO-related deferred coal ash expenditures over a 25-year period; and
3. Reversal of the Company's inclusion of the unamortized balance of ARO-related coal ash expenditures in rate base; this reversal, in conjunction with the 26-year amortization period, produces an equitable and reasonable sharing of the burden of coal ash expenditures between the Company's ratepayers and its shareholders.

The Public Staff has been guided in its choice of amortization period for these costs in this proceeding by its belief that it is most reasonable and appropriate for coal ash costs, after specific imprudently incurred or otherwise unreasonable amounts have been identified and disallowed for recovery, to be shared equitably between the ratepayers and the Company's shareholders. In this case, the Public Staff believes that equitable sharing should amount to DEC's shareholders being required to bear approximately 50% of the present value of the January 2018 – January 2020 deferred costs (with carrying costs allowed on the costs up to the point that rates have been estimated to go into effect). The 50% sharing is accomplished by choosing an appropriate amortization period and excluding the unamortized balance from rate base during the amortization period.

The Public Staff believes that a 50% sharing percentage is appropriate and reasonable due to the reasons for such set forth by witness Junis, and because there is a history of approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. Such sharing between ratepayers and shareholders has been approved for costs of abandoned nuclear construction and for environmental cleanup of manufactured gas plant facilities. Even if the reasons for equitable sharing set forth by Mr. Junis were not present, the Public Staff still believes that some level of sharing, perhaps comparable to that previously used for abandonment losses on cancelled nuclear generation facilities, would be appropriate and reasonable for DEC's coal ash costs. The Public Staff believes that a five-year amortization period is simply too short an amortization period for costs of the magnitude and nature of these. The Public Staff believes that the totality of the circumstances surrounding the ARO-related CCR costs deferred in this proceeding make equitable sharing appropriate and reasonable for purposes of achieving reasonable and just rates, independent of prudence conclusions.

According to advice of Public Staff counsel, the inclusion in rate base of these deferred ARO-related regulatory assets is left to the discretion of the Commission. Pursuant to N.C. Gen. Stat. § 62-133(b)(1), the only costs that the Commission is required to include in rate base are (1) the "reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period . . . ," and (2) in some circumstances, the costs of construction work in progress. I am advised by counsel that beyond those requirements, what is and what is not allowed in rate base is within the legal discretion of the Commission to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers. Moreover, N.C. Gen. Stat. § 62-133(d) requires the Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates." The Commission has taken this approach several times in past cases.

With regard to the classification of ARO-related CCR regulatory assets in rate base before taking into account the Public Staff's removal adjustment, I recommend that these assets be reclassified from a working capital classification to a separate classification outside of working capital. This recommendation is based on my opinion that the regulatory assets associated with ARO-related coal ash clean-up, disposal, and remediation activities do not qualify as true working capital.

With regard to the amortization of deferred non-ARO CCR costs, the Company and the Public Staff have agreed to both the cost of service allocation of these costs and an eight-year amortization period. Therefore, there is no longer any difference between the two parties as to the revenue requirement associated with this category of costs. However, the Public Staff does recommend that given the unexpected nature of the non-ARO-related projects proposed for deferral, and the fact that the non-ARO-related deferral requested in this case is more similar in nature to other requests that have been brought forth frequently in the past related to new generation projects than it is to the unique situation presented by the incurrence of ARO-related costs associated with the retirement of its existing coal ash facilities at an extraordinarily high-cost, the automatic right to defer capital costs associated with these non-ARO projects should not continue.

With regard to ARO-related CCR costs that were approved for a five-year amortization period and rate base inclusion in Docket No. E-7, Sub 1146, I note that these adjustments are still on appeal from that case. Although it would not be wholly inappropriate to make an adjustment to reflect the Public Staff's position on the Sub 1146 costs as they are reflected in this proceeding, the Public Staff has instead chosen to highlight this issue for the Commission, and recommend that the Commission take whatever steps are necessary to ensure that the outcome of this issue on appeal is flowed into each case on which it would have an effect.

This concludes my summary.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1187 In the Matter of Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	CORRECTIONS TO THE THIRD SUPPLEMENTAL AND SETTLEMENT TESTIMONY AND ACCOMPANYING SUMMARY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1213 In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program	CORRECTIONS TO THE SUMMARY OF THE TESTIMONY OF MICHAEL C. MANESS RELATED TO COAL COMBUSTION RESIDUAL COSTS, FOR THE REMOTE UNCONSOLIDATED HEARING
DOCKET NO. E-7, SUB 1214 In the Matter of Application of Duke Energy Carolinas, LLC, for an Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	

<u>CORRECTIONS TO THE THIRD SUPPLEMENTAL AND SETTLEMENT TESTIMONY OF MICHAEL C. MANESS</u>

Mr. Maness's third supplemental and settlement testimony should be corrected as follows:

1. On Page 6, Line 12, the hyphenated term "five-year" should be changed to "ten-year."
2. On Page 6, Line 14, the hyphenated term "ten-year" should be changed to "five-year."
3. On Page 6, Line 18, the word "period" should be changed to "expense."
4. On Page 9, Line 7, the comma should be deleted.

CORRECTIONS TO THE SUMMARY OF MICHAEL C. MANESS RELATED TO COAL COMBUSTION RESIDUAL COSTS, FOR THE REMOTE UNCONSOLIDATED HEARING

Mr. Maness's summary of his testimony related to coal combustion residual costs, for the remote unconsolidated hearing, should be corrected as follows:

1. On the eighth line of Page 1, the word "the" immediately preceding the word "Duke" should be deleted.
2. On Page 2, the enumerated item 3, the third line, the number "26" should be changed to "25."

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

CHAIR MITCHELL: All right. We will proceed. Mr. Mehta, you are up.

MR. MEHTA: Thank you, Chair Mitchell. And I am hearing some feedback, I think it might be from Mr. Grantmyre, but I'm not sure.

MR. GRANTMYRE: We will get -- okay. I'll make sure I mute.

MR. MEHTA: Yeah, it was just like papers rustling.

CROSS EXAMINATION BY MR. MEHTA:

Q. Mr. Maness, I think we'll start with you. In this case, Mr. Maness, the Public Staff is again proposing a 50/50 sharing between customers and shareholders of even prudently incurred coal ash costs like it did in the last Duke Energy Carolinas case and like it did in the last Duke Energy Progress case; is that right?

A. (Michael C. Maness) Yes, for those that are related to the ARO.

Q. So when you say "for those related to the ARO," what do you mean by that?

A. Well, that would be the same costs that we recommended in the last case, the same category. There are costs in this case also that are related to coal ash but not related to the ARO.

Q. Understood.

A. Our position here, which has been settled with the Company, is a new position for this case.

Q. All right. Understood. And when you're talking about ones not related to the ARO, I guess those are the ones that are called the non-ARO coal costs or something like that? The capital costs associated with reconfiguring plants and things of that nature, correct?

A. Yes, that's correct.

Q. Okay. And I guess, to be totally technically accurate, in the last -- the last DEC case, the split was 51 percent that you assigned to the Company and its shareholders and 49 percent that you assigned to customers, correct?

A. Yes. That's because we tried to make things a little administratively simpler to pick an even number of years and not years, and a certain number of months. So we try to get as close to 50 percent as we can, and so that's the reason it was slightly off, 51/49 or approximately thereabouts in the last case.

Q. Now, the Commission actually rejected the Public Staff's sharing proposal in both of the preceding cases, the DEC case and the DEP case, correct?

A. Yes. And they are both still on appeal to the North Carolina Supreme Court.

Q. And in the prior cases, you testified that the 50/50 sharing or 51/49 sharing splits came about simply as a result of the judgment of the Public Staff, correct?

A. Yes, that's generally correct. There's significant testimony in the cases which give the reasons for that judgment, but it was a judgmental decision on the part of the Public Staff.

Q. And in this case, the Public Staff has again provided a judgmental split, which in your judgment, the appropriate split is 50/50 with respect to even prudently incurred coal ash costs in the ARO?

A. Yes. Well, I guess I would phrase that for only the prudently incurred coal ash costs. For those that we consider unreasonable or imprudently incurred, we've recommend that they be entirely disallowed.

Q. So, for example, the costs that Garrett and Moore believe are imprudently incurred, those are

removed from the equation off the top; is that right?
A. Yes.
Q. And then whatever is left, the Public Staff does not believe were imprudently incurred, but the Public Staff advocates that they be split 50/50, correct?
A. I think Mr. Junis could probably give more detail, but we're not making a conclusion that they were not imprudently incurred, we have just not been able, for various reasons, to develop the evidence of imprudence. But even though we are not making a case for them being imprudently incurred, we still believe that the Company has the ultimate responsibility for those costs being too high to be borne by the North Carolina retail ratepayers.
Q. Now, in the recently concluded -- I guess, recently is probably an elastic term. Probably back in February the Commission decided the latest Dominion North Carolina rate case, correct?
A. Yes, that's correct. I will take the date subject to check. You're right, it seems forever.
Q. And in that case, the Public Staff -- the judgment of the Public Staff was that the proper sharing would be 60/40 with shareholders bearing

40 percent and customers bearing 60 percent, correct?
A. Yes, that's correct.
Q. Well, which one of you can explain to me why Dominion's shareholders get assigned a smaller percentage of coal ash costs than Duke's shareholders?
A. Well, I can give you a general explanation, and Mr. Junis would have to address the details. I think that the biggest difference between the two cases is the fact that Duke was subject to a criminal complaint. But there's more than that, and I would relay your question to Mr. Junis for further details.
A. (Charles Junis) Yes, sir. And that's detailed in my testimony, a comparison of the records that were under consideration by the Commission both in the DENC rate case and then the Duke Energy rate cases. Clearly there's a difference in that Duke had the federal criminal plea. Duke has a much more considerable record of groundwater violations. And so those are the two key differences. And I'm happy to go into the testimony if necessary.
Q. Sure. Well, let's -- Mr. Junis, I'm just looking at page 7 of your testimony. Tell me when you're there.
A. I'm there. I'm ready.

Q. And you indicate, line 5:

"DEC has accumulated a record of significant environmental violations"; do you see that?

A. Yes.

Q. And you indicate on line 8:

"These violations include unauthorized seeps"; do you see that?

A. That's correct.

Q. Dominion has unauthorized seeps; does it not?

A. Yes, I believe so.

Q. In fact, Mr. Junis, if you would look at what was previously marked as DEC Exhibit 22 and 23.

MR. MEHTA: And, Chair Mitchell, I would like to go ahead and mark -- identify these exhibits for the record. And we will call DEC Exhibit 22, DEC Junis/Maness Cross Examination Exhibit 1.

CHAIR MITCHELL: All right. Mr. Mehta, just to make sure we're all looking at the same document, will you identify the -- describe the document for me.

MR. MEHTA: Yes. It is a complaint filed in the United States District Court for the Eastern District of Virginia with the plaintiffs being the United States of America and the Commonwealth of Virginia, and the defendant being Virginia Electric and Power Company dba Dominion Energy.

CHAIR MITCHELL: Okay. Thank you, Mr. Mehta. The document will be marked DEC Junis/Maness Cross Examination Exhibit Number 1.

(DEC Junis/Maness Cross Examination Exhibit Number 1 was marked for identification.)

MR. MEHTA: And, Chair Mitchell, DEC Exhibit 23, if we could have that one marked for identification as DEC Junis/Maness Cross Examination Exhibit Number 2, that would be great. And for purposes of the record, this is the consent decree in the case in which Exhibit 1 is the complaint.

CHAIR MITCHELL: All right. The document will be so marked.

(DEC Junis/Maness Cross Examination Exhibit Number 2 marked for identification.)

MR. MEHTA: And the -- both documents reflect that each one of them was filed with the

Eastern District of Virginia on the same day, March 13, 2020.

Q. And, Mr. Junis, if you would look at what we've marked as Cross Exhibit -- excuse me, DEC Junis/Maness Cross Examination Exhibit Number 1.

A. Yes, sir, I have that open.

Q. So on the very first page of the complaint, it's alleged that Dominion had violated the Federal Clean Water Act and a Virginia state statute called the State Water Control Act, correct?

A. Yes, sir.

Q. And the Federal Clean Water Act allegation relates to violations of Dominion's NPDES permits, correct?

A. Yes.

Q. And the violation of the state Water Control Act of involves specifically seeps, correct?

A. Yes, sir.

Q. And the complaint further alleges that Dominion had additional violations with respect to release notifications of hazardous substances under the Emergency Planning and Community Right-to-Know Act and the Superfund law, correct?

A. Yes, sir, that's under item C.

Q. And Duke Energy Carolinas had no such hazardous substance release notification violations, did it?
A. I am not familiar with a similar charge against Duke Energy.
Q. Does that mean that you think they might have had one and you just don't know about it, or that they didn't have one?
A. I would say I'm not aware of one. I'm not claiming that I suspect they did or didn't have one.
Q. Well, Mr. Junis, if they have had one, you probably would be aware of it, wouldn't you?
A. Yes, sir. But like I said, I'm just not aware of one.
Q. And in the consent decree, which is DEC Junis/Maness Cross Examination Exhibit 2, Dominion agreed to pay a civil penalty of a million -- I guess $1,400,000, correct?
A. Are you referring to page 11 of that document?
Q. Yes.
A. Let me scroll there real quick. Do you know where the total amount is listed? Is that on page 11?
Q. I believe so. Let me go there too.

A. And what was the amount you stated?

Q. It's on page 11, paragraph 10:

"Within 30 days after the effective date of this consent decree, defendant," meaning Dominion, "shall pay a total of $1,400,000 as a civil penalty to the United States and the Commonwealth of Virginia," correct?

A. Yes, sir, I see that.

Q. And if you keep scrolling down, there's a number of -- I guess go all the way down to page 15. There's a section called "Injunctive Relief"; do you see that?

A. Yes, sir.

Q. And in that section, the consent decree, once issued by the court, would require Dominion to do a number of things, correct?

A. It appears so. But I'm not overly familiar with this document, so I don't know exactly what they were required to do.

Q. Well, you can just scan. The first thing they're required to do is what's called an EMS audit, correct? That's paragraph 24, 25.

A. Yes.

Q. A few paragraphs down.

And an EMS audit is essentially an environmental management audit, correct?

A. Yes.

Q. And they were going to select an auditor to perform that audit, correct?

A. Yes.

Q. And on page 17, you can see that that audit was really to conduct -- was to investigate management practices at Dominion's power generation business, correct?

A. Yes, sir.

Q. And if you go on down to page 19, Mr. Junis, Dominion was further ordered to undergo a third-party environmental audit; do you see that?

A. Yes, sir. And I would just like to note, as you stated, that these documents were filed in March of 2020, well after the completion of the most recent Dominion Energy rate cases. So this is not in the evidence for consideration by the Public Staff or the Commission.

Q. Well, did the Public Staff investigate Dominion as to whether or not the factual bases of the complaint and the consent decree were in existence as of the time of the last Dominion case?

A. We certainly did a thorough investigation. As I said, I'm not overly familiar with these documents, so I'm not sure if -- who knew what, in terms of the actual claims.

Q. Well, if you go back up to page 3, Mr. Junis, of the consent decree. So that would be Cross Exhibit 2.

A. Yes, sir.

Q. The last sentence on the page, this is dealing with seeps, it says:

"In addition" -- well, actually we'll just take a look at the entire paragraph H; do you see that?

"On July 21, 2017, a Virginia agency identified an area of groundwater seepage along the James River in the vicinity of Dominion's Chesterfield power station"; do you see that?

A. Yes, sir.

Q. And the last sentence says:

"On May 11, 2018, Dominion self-reported to the Virginia Department of Environmental Quality its observation of groundwater seepage."

Again, in the vicinity of the Chesterfield power station, correct?

A. Yes, sir.

Q. The Dominion rate case that was decided in February of 2020 began when?

A. I don't recall the exact date, but in 2019.

Q. Somewhere in 2019. July 21, 2017, is before it began, correct?

A. Yes, sir. And while Mr. Lucas was the witness in that case, I certainly helped in that investigation. I do not recall seeing information regarding this issue. We rely heavily both on the regulators and the Company to provide such information. Like I said, I do not recall seeing this.

Q. Did you ask Dominion about seeps?

A. We certainly asked Dominion about seeps, environmental compliance, their groundwater monitoring data. It was exhaustive and very much replicated our investigation of Duke in their prior rate cases.

Q. Well, did they not tell you about these two seeps?

A. Without diving into all those records, like I said, I do not recall seeing information regarding these seeps.

Q. And if you go on down, I think we were around page 19, go back there.

A. Okay.

Q. Page 19, just above the third-party environmental audit section. The consent decree in paragraph 28 said that the -- Dominion would complete full implementation of any recommendations of the EMS audit, essentially nine months after receiving those recommendations, correct?

A. Yes, sir. And I would just add that this evidence would be appropriately considered in Dominion's next rate case when they continue to seek recovery of coal ash costs.

Q. So, Mr. Junis, is it your testimony, then, that when you're comparing the environmental records of two utilities that the Public Staff, in part, regulates, that -- that look a lot alike that somehow, just because you don't happen to know something, that that would factor into an allocation of responsibility that the Public Staff makes as between those two utilities?

A. Certainly. The Public Staff and the Commission is reliant on the facts that are available in the case. We cannot all of a sudden materialize information that is not given to us either through discovery through the Company, which is the primary source -- they are supposed to have the burden of proof to justify their costs -- and then from regulators as sometimes a double check, or as a secondary source.

So -- and as G.S. 62-133(d) states:

"The Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates."

And that is the basis of our equitable sharing. So we only know what we know, and that's the same for the Commission. If -- and I'm not suggesting that information was intentionally hidden, but if that happens, how could we be aware of it if it was never seen?

Q. All right. Well, Mr. Junis, we don't need to go through all of the -- all of the parts of the injunctive relief, but they go on for pages, and pages, and pages; do they not?

A. It appears so. This document is 60 pages, so like I said, I've only scanned what we've talked about here.

Q. And if you go back to page 7 of your testimony, Mr. Junis, you also indicate in that numbered paragraph 1 that DEC had groundwater exceedances with respect to the operation of its coal ash basins, correct?

A. That's correct, sir.

Q. And when you say "groundwater exceedances," I assume what you mean is that there were exceedances of the two state -- North Carolina 2L standards in the groundwater sampled at various points in time, and that's how you come up with an exceedance, correct?

A. Yes, sir. Those are exceedances both of the standard and background levels, and would therefore be considered a violation as confirmed by the amicus brief in the appeal proceeding.

Q. Now, Mr. Junis, Dominion had groundwater exceedances in connection with its ash basin sites; did it not?

A. Yes, sir.

Q. You just didn't count as many as you found for Duke, correct?

A. That's correct. And part of the issue there was some of the historic data with the procedure that those analysis were conducted, it would not be apples-to-apples comparison.

Q. Mr. Junis, while you were conducting this investigation of Dominion as part of its last rate case, did you consult with the Virginia environmental regulators to see if you could get information from them?

A. Yes, I believe so.

Q. You believe so or you know so?

A. Yes.

Q. And did you not get information from the Virginia environmental regulators as to the number or quantity or frequency of groundwater monitoring evaluations done in connection with Dominion's ash basins?

A. We certainly -- I apologize, my phone rang, and I thought I had hung it up, that it was silenced. I apologize to the Chair, and the Commission, and all parties. Regarding your question of Dominion's -- holy moly. Sorry. I'm going to unplug the thing. Sorry.

Mr. Mehta, would you mind repeating the question?

Q. I think it was more or less, did you, in the course of your investigation of the Dominion in its prior rate case, did you ask the Virginia environmental regulatory authorities for information that the Virginia environmental regulatory authorities would have had on Dominion's ash basins, and in particular, groundwater exceedances in connection with those ash basins?

A. Yeah. So, I mean, in the Dominion -- in that testimony, Mr. Lucas' testimony, we lay out the observed exceedances. So I'm not sure -- there is historic data that, again, is not comparable to today's standard.

Q. Well, do you know how far along Dominion was in its investigation of groundwater at its ash basins in comparison to how far along Duke Energy Carolinas was in connection with its investigation of ash basins?

A. Yes, sir. So both Dominion and Duke are subject to the CCR rule, so they had detection and assessment monitoring requirements. And that's where we got a considerable amount of groundwater exceedances. And they have state laws comparable to North Carolina, while different. And so we did look at that and accumulate as much information as we could.

Q. In fact, while you say "comparable," Mr. Junis, they're comparable in the sense that they say thou shalt not pollute the groundwater, but they're quite different in terms of the rigor and robustness of the standards that relate to the "thou shalt not pollute groundwater" direction, correct?

A. Yes, sir. I did not mean to insinuate that the programs were the same, but only that they could be compared.

Q. So let me get this straight, then, Mr. Junis.

Duke Energy Carolinas has seeps; Dominion has seeps, correct?

A. Yes, sir.

Q. Duke Energy Carolinas had groundwater exceedances; and Dominion had groundwater exceedances, correct?

A. Yes, sir.

Q. And the -- at least the federal complaint about Dominion indicates that Dominion was also fined in connection with NPDES permit violations and violations of hazardous waste reporting issues, correct?

A. Yes, sir. But as we said, that consent decree was filed here in March of 2020 after the Commission's decision in the Dominion rate case. And as I stated, this evidence would duly -- be duly considered in its next rate case.

Q. So if I'm understanding it -- and basically I think, Mr. Junis, I believe that the Public Staff, in the Dominion case, expressed a fair amount of frustration that the in investigation -- in its investigation of Dominion that it was not able to obtain a number of documents that it had requested, correct?

A. We did express frustration. We even -- at one point there was an agreement pertaining to some of the data, and its availability, and the appropriateness of its comparison to present-day data.

Q. So, Mr. Junis, is Duke Energy Carolinas being penalized by the Public Staff because it has better records and it's operating under an environmental regime that is a whole lot more robust than the one in Virginia?

A. I would not characterize it as being penalized. As I said, these bodies can only make a decision based on the evidence before them.

Q. Well, you're applying a different standard.

The judgment of the Public Staff is that Dominion has a better environmental record than Duke Energy Carolinas; is that basically correct?

A. Yes. Based on the available evidence. There is some adjustment for environmental compliance, and Mr. Maness can attribute this, that the equitable sharing is based -- a majority of it is based on the magnitude of the cost and the comparable treatment of canceled nuclear plants and manufactured gas plants.

But then there is also a component tied to environmental costs.

Q. Well, the sharing percentage that you used for Dominion has nothing to do with the magnitude of the costs, does it?

A. It absolutely does, and I'm happy for Mr. Maness to expand on that.

Q. You mean the difference between the sharing percentage, 60/40 for Dominion, 50/50 for Duke Energy Carolinas, has something to do with the magnitude of the costs?

A. Oh, no. I misunderstood the question. I'm sorry. No, that difference is not tied to magnitude.

Q. Okay. And you mentioned the criminal -- criminal proceedings with respect to Duke Energy Carolinas. And that is certainly a distinction between Duke Energy Carolinas and Dominion.

But the criminal proceeding didn't, in fact -- there was no guilty plea, for example, with respect to a violation of the state 2L standards, was there?

A. No, there was not.

Q. In fact, the criminal process and proceeding occurred as a result of or flowed from the Dan River incident, which was there but for the grace of God go I, any utility would be subject to that kind of scrutiny if it happened to them, correct?

A. The plea agreement did not only cover the 39,000 tons of coal ash that was released into the Dan River.

Q. Thank you for reminding us of the tonnage, Mr. Junis, I really appreciate.

Yes, it did not only deal with that, but that was the impetus behind it, correct?

A. Certainly that would prompt further scrutiny.

Q. And if Dominion, by misfortune, had a pipe break under one of its coal ash basins and had 39,000 tons of coal ash flow into the Roanoke River, for example, they might have had the same problem, right?

A. I would not agree with that characterization of misfortune as there was negligence shown in that case.

Q. Well, in the case of Dominion, if they had a pipe break in the same way that the Dan River pond had a pipe break, would that also not be negligence?

A. Depending on the circumstances. I'm not going to speculate on a hypothetical, but I will agree that such an event would warrant additional scrutiny.

Q. Now, Mr. It Junis, you mentioned also --

MR. MEHTA: And actually, Chair Mitchell, I'm about to run into a completely -- not completely different, but a different subject. I don't know if you want -- it's a couple minutes before 1:00. If you want to stop here, that would be fine. It will take me longer than a couple of minutes to go through the next subject.

CHAIR MITCHELL: All right. Mr. Mehta, let's go ahead and call it a day. We will go off the record. We will be in recess until 9:00 on Monday morning. Thank you very much.

(The hearing was adjourned at 12:56 p.m. and set to reconvene at 9:00 a.m. on Monday, September 14, 2020.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly affirmed; that the testimony of said witnesses were taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 15th day of September, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112