BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1187

DOCKET NO. E-2, SUB 1219

In the Matter of
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

DOCKET NO. E-7, SUB 1214

In the Matter of
Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

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 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

TESTIMONY OF
J. RANDALL WOOLRIDGE ON BEHALF OF THE
PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION
SUPPORTING SECOND PARTIAL STIPULATIONS

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2 SUB 1219

DOCKET NO. E-7, SUBS 1213, 1214, AND 1287

Testimony of J. Randall Woolridge

On Behalf of the Public Staff

North Carolina Utilities Commission

Supporting Second Partial Stipulations

July 31, 2020

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC.

Q. ARE YOU THE SAME J. RANDALL WOOLRIDGE WHO SUBMITTED DIRECT AND SUPPLEMENTAL TESTIMONY ON BEHALF OF THE PUBLIC STAFF-NORTH CAROLINA UTILITIES COMMISSION ("PUBLIC STAFF") IN DOCKET NO. E-7, SUB 1214 AND DIRECT TESTIMONY IN DOCKET NO. E-2, SUB 1219?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR CURRENT TESTIMONY?

A. The purpose of my testimony is to provide my comments on the cost of capital components of the Second Agreement and Stipulation of Partial Settlement filed on July 31, 2020, between Duke Energy Carolinas, LLC (DEC), and the Public Staff (DEC Second Partial Stipulation) and the Second Agreement and Stipulation of Partial Settlement filed on July 31, 2020, between Duke Energy Progress, LLC (DEP), and the Public Staff (DEP Second Partial Stipulation) (together "Second Partial Stipulations") in these proceedings.[1]

Q. WHAT IS YOUR UNDERSTANDING OF THE “TERMS” OF THE COST OF CAPITAL COMPONENTS OF THE PROPOSED SETTLEMENTS?

A. It is my understanding that the following items have been agreed to between DEC, DEP (together "Duke") and the Public Staff on the issues of cost of capital:

Capital Structure – 52% common equity and 48% long-term debt for both companies

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[1] An Agreement and Stipulation of Partial Settlement between DEC and the Public Staff was filed on March 25, 2020. An Agreement and Stipulation of Partial Settlement between DEP and the Public Staff was filed on June 2, 2020. These First Partial Stipulations do not involve cost of capital issues.

Cost of Common Equity – 9.6% for both companies

Cost of Long-Term Debt – 4.27% DEC, 4.04% DEP

Q. WHAT IS YOUR EXPERIENCE AND UNDERSTANDING OF SETTLEMENTS IN THE PUBLIC UTILITY PROCEEDINGS IN WHICH YOU HAVE BEEN INVOLVED IN OVER THE YEARS?

A. It is my experience that settlements are generally the result of good faith, "give-and-take," and compromise-related negotiations among the parties of utility rate proceedings, involving the utility, commission staff, and other parties. It is also my understanding that settlements, as well as the individual components of the settlements, are often achieved by the respective parties' agreements to accept otherwise unacceptable individual aspects of individual issues in order to focus on other issues.

Settlements are often the result of agreement on all or a significant portion of the issues that would otherwise be litigated in a rate proceeding; or sometimes are restricted to individual issues.

Q. BESIDES THE COST OF CAPITAL COMPONENTS, WHAT IS YOUR UNDERSTANDING OF THE NATURE OF THE SETTLEMENTS IN THESE PROCEEDINGS?

A. It is my understanding that the proposed settlements cover many of the issues including:

- a return of federal unprotected Excess Deferred Income Tax (EDIT) over five years, North Carolina EDIT over two years, and deferred revenues over two years.
- deferral accounting treatment for certain Grid Improvement programs and withdrawal of deferral requests for the remainder.
- updates of plant (including benefits and executive compensation) through May, but recognition of only 75% of revenues to recognize the uncertainty regarding effects of COVID-19.
- a $19.1 million disallowance for a portion of the costs of the Clemson Combined Heat and Power Project on a system basis.
- Amortization of coal ash capital projects over eight years.
- Acceptance of the Summer Coincident Peak cost of service allocation methodology for purposes of this case only with no precedential effect.
- Duke agreement to conduct a cost of service study.
- In addition to $6 million DEC and DEP have agreed to contribute in their settlement with the North Carolina Justice Center to the Helping Home Fund for energy efficiency , DEC and DEP agree to contribute $5 million each over two years to assist low income customers with payment of their bills.

- Reduction of DEP's annual funding of its Nuclear Decommissioning Fund by $8.7 million.
- There were also a number of accounting issues, including storm securitization, reductions to executive compensation, aviation costs, and employee incentives resolved in the first partial stipulations reached with each company.

The settlements explicitly exclude coal ash costs, depreciation rates, and an adjustment for Hydro Station sales in the DEC proceeding. Additionally, the settlements exclude any revenue or nonrevenue item that has not been specifically addressed in the First or Second Partial Stipulation between DEC and the Public Staff, the First or Second Partial Stipulation between DEP and the Public Staff, or agreed upon in the testimony of the Duke and the Public Staff.

Q. DID YOU PARTICIPATE IN THE NEGOTIATIONS LEADING UP TO THE PROPOSED SETTLEMENTS IN THIS PROCEEDING?

A. No, I was not involved in the negotiations leading up to the proposed settlements.

Q. DO YOU AGREE THAT THE COST OF CAPITAL COMPONENTS OF THE PROPOSED SETTLEMENTS ARE REASONABLE WITHIN THE CONTEXT OF THE OVERALL SETTLEMENTS?

A. Yes I do, for the reasons stated in this testimony. As I have indicated, the proposed settlements reflect the results of good faith negotiations and compromises.

I note that it remains my position that, should this be a fully litigated proceeding, I would continue to recommend as my primary recommendation for each company a capital structure with 50% common equity and 50% long-term debt and an ROE of 9.00%. However, given the benefits associated with entering settlements, it is my view that the cost of capital components of the proposed settlements are reasonable resolutions of otherwise contentious issues.

Q. HOW DO THE COST OF CAPITAL COMPONENTS OF THE PROPOSED SETTLEMENTS BETWEEN THE TWO COMPANIES AND THE PUBLIC STAFF COMPARE TO EACH COMPANY'S REQUESTS?

A. There are three components in the cost of capital issue of the proposed settlements.

The first component is the capital structure. Each company's proposed hypothetical capital structure was comprised of 53% common equity and 47% long-term debt. The proposed settlements utilize a slightly lower common equity ratio (52%) and a slightly higher long-term debt ratio (48%). The second cost of capital component is the cost of equity ("ROE"). Each company's ROE expert recommended an ROE of 10.50%,[2] whereas the proposed settlements contain a 9.6% ROE.

The third cost of capital component is the cost of long-term debt. DEC's proposed cost of long-term debt is 4.29%, as compared to the 4.27% cost of debt in the DEC proposed settlement. DEP's proposed cost of long-term debt is 4.11%, as compared to the 4.04% cost of debt in the DEP proposed settlement.

Q. DO YOU CONSIDER EACH OF THESE COST OF CAPITAL COMPONENTS IN THE PROPOSED SETTLEMENTS AS BEING "REASONABLE" IN THE CONTEXT OF A STIPULATED PROCEEDING?

A. Yes, I do. Each of these components can be considered as reasonable within the context of the proposed settlements. I note that Duke and the Public Staff, in their respective direct testimonies, proposed fundamentally different views on a number of issues, such as current market conditions and related current costs of common equity, as well as the appropriate capital structure. The proposed

[2] While each company found the ROE expert's 10.50% ROE recommendation to be a reasonable and appropriate estimate of its cost of equity capital, as a rate mitigation measure and in recognition of each company's ongoing efforts to keep rates affordable for customers, each company proposed rates to be set with an ROE of 10.30%.

settlements represent a compromise, or middle ground between their respective positions.

Further, the cost of capital components of the proposed settlements can be considered reasonable within a broad negotiation and resolution of most of the issues in this proceeding.

Q. PLEASE FIRST ADDRESS THE CAPITAL STRUCTURE COMPONENT OF THE PROPOSED SETTLEMENTS. WHY DO YOU CONSIDER THIS AS "REASONABLE"?

A. In each application, DEC and DEP both requested a hypothetical capital structure with a common equity ratio of 53% common equity and 47% long-term debt. This proposed capital structure in each case was sponsored by Duke witness Karl Newlin, who described it as the "optimal" capital structure in his direct testimony for each company and, in his rebuttal testimony for each company, described it as "consistent with the Company's financial objectives."

My direct testimony, in contrast, proposed for each company a capital structure with 50% common equity and 50% long-term debt. I note that both DEC's and DEP's actual capital structures were 52% equity / 48% debt as of December 31, 2019, according to discovery provided to the Public Staff.

The 52% common equity ratio in the proposed settlements is reflective of each company's current equity ratio and is also consistent with their currently authorized equity ratios.

Q. PLEASE NOW TURN TO THE COST OF COMMON EQUITY IN THE PROPOSED SETTLEMENTS AND INDICATE WHY THE 9.6% ROE IS REASONABLE FOR EACH COMPANY IN A SETTLEMENT CONTEXT.

A. Both companies requested an ROE of 10.30%, which I indicated in my direct testimony to be well above industry norms in recent years. I, in turn, proposed as my primary recommendation a 9.0% ROE. Whereas, I continue to believe my 9.0% ROE recommendation is appropriate at this time, a 9.6% ROE is 0.60% above my 9.0% recommendation and is 0.70% below Duke's 10.30% ROE requests and 0.90% below the ROEs recommended by each company's ROE expert. As a result, the 9.6% ROE in the proposed settlements is a "compromise" between Duke's and the Public Staff's respective proposals. The 9.6% ROE also reflects a reduction from the 9.9% authorized in each company's last rate proceeding. I also note that the 9.6% ROE is below the 9.67% average authorized ROE for vertically integrated electric utilities during the first half of 2020 as calculated by Regulatory Research Associates. In addition, it is my understanding that this is the lowest ROE for a vertically integrated investor-owned electric utility for at least the last 30 years in North Carolina.

Q. PLEASE NOW DISCUSS THE 4.27% COST OF LONG-TERM DEBT IN THE PROPOSED DEC SETTLEMENT.

A. DEC's application contained a cost of long-term debt of 4.51%. In my supplemental testimony, I proposed an updated cost of long-term debt (as of January 31, 2020) of 4.29%, and DEC updated its cost of debt to 4.29% in supplemental testimony filed July 6, 2020. The proposed settlement recognizes the updated 4.27% cost of long-term debt (i.e., updated cost of debt as of May 2020).

Q. PLEASE NOW DISCUSS THE 4.04% COST OF LONG-TERM DEBT IN THE PROPOSED DEP SETTLEMENT.

A. DEP's application contained a cost of long-term debt of 4.15%. In my testimony, I proposed a cost of long-term debt (as of December 31, 2019) of 4.11%, and DEP updated its cost of debt to 4.11% in second supplemental testimony filed July 10, 2020. The proposed settlement recognizes the updated 4.04% cost of long-term debt (i.e., updated cost of debt as of May 2020).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MS. DOWNEY: If this is the appropriate time, I would move the Public Staff excused witness testimony in, if this is the time to do that.

COMMISSIONER CLODFELTER: This is the time to do that, because the case is now with the Public Staff. So, Ms. Downey, make your motions.

MS. DOWNEY: Thank you, Commissioner. For the following witnesses, I move that the prefiled testimony be copied into the record as if given orally from the stand, and that the exhibits be identified as marked when filed and entered into evidence.

First, Mr. Scott Saillor, direct testimony and exhibits filed April 13, 2020, consisting of 12 pages, an Appendix A, and five exhibits; supplemental testimony and exhibits filed April 23, 2020, three pages and 5 exhibits; and second supplemental testimony and exhibits filed September 16, 2020, consisting of three pages and three exhibits.

Do you want to take this witness by witness, Commissioner Clodfelter?

COMMISSIONER CLODFELTER: I think that

may be cleanest, because that way, if we have any objections, we can -- I don't know that we will, but that way we can all deal with them discretely rather than have them all go out together.

All right. You've heard the motion as to witness Saillor. Are there any objections to the motion?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, the motion is granted.

(Saillor Exhibits 1 through 5, Saillor Supplemental Exhibits 1 through 5, and Saillor Second Supplemental Exhibits 1 through 3 were admitted into evidence.)

(Whereupon, the prefiled direct testimony and Appendix A, supplemental, and second supplemental testimony of Scott J. Saillor were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		TESTIMONY OF
Application of Duke Energy Progress,	)	SCOTT J. SAILLOR
LLC, for Adjustment of Rates and	)	PUBLIC STAFF – NORTH
Charges Applicable to Electric Utility	)	CAROLINA UTILITIES
Service in North Carolina	)	COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

TESTIMONY OF SCOTT J. SAILLOR
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

APRIL 13, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Scott J. Saillor. 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. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Commission my recommendations on annualizing revenue, weather normalization, customer growth and change in usage.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO ANNUALIZE RETAIL REVENUES FOR CURRENT RATES.

A. This adjustment annualizes revenue based on the rates in effect at the time of the application, revises the fuel component of base rates, and removes test period revenues recovered through the annual cost riders.

Q. DOES THE PUBLIC STAFF HAVE ANY CHANGES FOR THIS ADJUSTMENT?

A. No. The Public Staff reviewed this adjustment and does not have any recommended changes.

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION REVENUE ADJUSTMENT.

A. Monthly kilowatt-hour (kWh) adjustments are determined to weather normalize test period sales for the Residential, Small General Service (SGS), Medium General Service (MGS) and Large General Service (LGS) rate classes. The revenue adjustment is calculated by multiplying the total rate class kWh adjustment by the average customer class rates based on annualized revenues divided by per book sales.

Q. WHAT CHANGES DO YOU RECOMMEND FOR THIS ADJUSTMENT?

A. The annualized revenues used to calculate average rates include revenues generated from per-bill basic facilities charges. However, because the weather effect does not change the number of bills rendered during the test period, the weather normalization adjustment would not increase or decrease revenues from basic facilities charges. To account for this, I removed the basic facilities charge revenues from DEP's calculations for the average customer class rates.

In addition, I summed the monthly NC Retail kWh weather adjustments updated through December 2019, as provided to the Public Staff by DEP, for each month of the test period for each customer class. Each monthly adjustment is based on the monthly System weather adjustment and each month's NC sales to System sales ratio. This is in place of the method used in the E-1 Item 10 worksheet NC-0301 where the NC Retail kWh weather adjustment per class is calculated by multiplying the test period System kWh weather adjustment times the annual NC Retail to System sales ratio. I believe that summing the monthly NC Retail kWh adjustments more accurately reflects the normal weather adjustment being represented by DEP.

These changes, as shown in Saillor Exhibits 1 and 2, were provided to Public Staff witness Dorgan for incorporation into his schedules.

Q. DOES DEP AGREE WITH YOUR PROPOSED CHANGES TO THE WEATHER ADJUSTMENT?

A. Yes. In supplemental testimony, DEP Witness Pirro states that the Company agrees with these modifications.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO ANNUALIZE REVENUES FOR CUSTOMER GROWTH AND CHANGE IN USAGE.

A. The customer growth adjustment adjusts test period revenues and expenses by an amount that represents the growth in kWh sales due to the change in the number of customers. The adjustment estimates the change in kWh sales the Company would have booked had the end-of-period (EOP) level of customers been served for each of the twelve months of the test period.

The change in usage adjustment adjusts test period revenues and expenses by an amount that represents the difference in kWh usage per customer between each month of the test period and the corresponding month of the update period. The change in usage adjustment estimates the change in kWh sales the Company would have booked had the EOP usage profile per customer been exhibited by the EOP level of customers throughout the test period.

The adjustments are calculated by multiplying the total kWh adjustment by average customer class rates based on annualized revenues divided by per book sales.

Q. HOW DID THE COMPANY ADJUST FOR CUSTOMER GROWTH AND CHANGE IN USAGE AT THE END OF THE TEST PERIOD?

A. For the Residential, SGS, and Lighting rate classes, DEP used regression analysis to derive equations that best fit historic billing data ending December 31, 2018. The Company fit 12-, 24-, 36- and 48-month data to linear, exponential, power, logarithmic, quadratic, cubic and quartic equations. The equation with the highest adjusted r-square[1] value was used to calculate the representative EOP level of customers for each rate class. The change in the number of customers was determined by taking the difference between the calculated EOP level of customers and the actual bills for each month of the test period. The monthly average usage per customer for each month of the test period was multiplied by the corresponding change in number of customers for each month of the test period, and the results for each month were then summed to produce the total kWh

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[1] R-square measures the goodness of fit of the regression equations to the billing data.

usage adjustment for each customer class. Monthly average usage for the Residential class was weather normalized.

For the MGS and LGS customer classes, DEP applied a customer-by-customer approach whereby individual accounts were evaluated to identify customers that established new service or discontinued service during the test period. DEP determined the average monthly usage for each new customer using the months during the test period when the customer was on the system, and then multiplied the average usage by the number of months within the test period when the customer was not on the system. The initial month of usage for the new customers was not factored into the average usage calculation. These unrealized kWh sales were added to the adjustment. The kWh usage consumed by lost customers during the test period was removed from the adjustment.

There is no change in usage adjustment at the end of the test period.

Q. DOES THE COMPANY PROPOSE TO EXTEND THE CUSTOMER GROWTH AND CHANGE IN USAGE ADJUSTMENTS BEYOND THE TEST PERIOD?

A. Yes. The Company plans to update the adjustments to reflect customers and usage through February 29, 2020.

Q. DID THE COMPANY PROVIDE THE PUBLIC STAFF WITH AN EXAMPLE OF ITS METHOD FOR EXTENDING THE ADJUSTMENTS?

A. Yes. In a data request response, the Public Staff was provided with workpapers showing the Company's methodology for extending the adjustments, with actual customers and usage from the end of the test period through December 30, 2019 (Extended Period).

Q. PLEASE DESCRIBE DEP'S EXTENDED PERIOD CUSTOMER GROWTH AND CHANGE IN USAGE ADJUSTMENTS.

A. Regression analysis is performed using historical billing data ending December 30, 2019, to establish a new December 2019 EOP level of customers. The kWh adjustment was then calculated by multiplying the monthly per-customer usage for each month of the test period by the difference between the December 2019 EOP level of customers and the December 2018 EOP level.

DEP used the customer-by-customer approach to identify new and lost MGS and LGS customers from January 1, 2019, to December 30, 2019. The unrealized kWh sales added to the test period were calculated by determining the average monthly usage for each new customer and multiplying by 12. This added 12 months of unrealized sales to the test period for each new customer at the average usage rate. The kWh usage consumed during the test period for customers lost within the Extended Period was removed.

The change in usage was also determined for the Residential, SGS, and Lighting rate classes for the 12 months of the Extended Period. The adjustment was based on the difference in the monthly average usage per customer between the 12-month period ended December 2018 and the 12-month period ended December 2019. The average usage differences were summed and multiplied by the December 2019 EOP level of customers.

As with the test period adjustments, DEP replaced actual test period sales with weather-normalized sales for the Residential customer class.

The Company did not account for changes in usage for the MGS and LGS rate classes.

Q. DO YOU AGREE WITH DEP'S METHOD FOR DETERMINING THE CUSTOMER GROWTH AND CHANGE IN USAGE?

A. Yes, generally, except for the modifications I discuss below. This method for calculating customer growth and change in usage is consistent with the method approved by the Commission for use in the Company's last general rate case.

Q. WHAT MODIFICATIONS DO YOU PROPOSE TO THE END OF TEST PERIOD METHODOLOGY PROPOSED BY DEP?

A. For the MGS and LGS customer-by-customer approach, DEP determined the average monthly usage for each new customer using only the months during the test period when the customer was on the system, which could range from one to 11 months. For customers with two or more months of billing data, DEP removed the initial month of service from the usage calculation. I revised this calculation by summing the 12 months of billing data following initial month of service and dividing by 12. I believe including this additional usage data results in a more precise representation of the customer's average monthly usage.

For the SGS rate class, I replaced actual sales with weather-normalized sales in the adjustments.

Q. WHAT MODIFICATIONS DO YOU PROPOSE TO CUSTOMER GROWTH AND CHANGE IN USAGE FOR THE EXTENDED PERIOD?

A. For the MGS and LGS customer-by-customer approach, DEP determined the average monthly usage for new customers using each month of billing data during the Extended Period including the initial month of service. I revised this by removing the initial month of service from the average usage calculation to avoid using a partial month of usage.

For the change in usage calculations, I removed the basic facilities charge revenues. The increase or decrease in usage estimated by this adjustment would not change the number of bills included in the annualized revenues. This adjustment would therefore not change the revenues produced from basic facilities charges.

For the Traffic Signal and Street Lighting rate classes, I removed the change in usage revenue adjustment. These accounts are billed on a per-light basis, and revenues for this class would not change due to changes in usage.

To account for other changes in sales, I included a change in usage adjustment for the MGS and LGS rate classes. The adjustment was based on the difference in the monthly average weather-normalized usage per customer between the 12-month period ended December 2018 and the 12-month period ended December 2019. The average usage differences were summed and multiplied by the December 2019 EOP level of customers.

Q. DOES DEP AGREE WITH YOUR PROPOSED CHANGES TO THE CUSTOMER GROWTH AND CHANGE IN USAGE ADJUSTMENTS?

A. In supplemental testimony, DEP Witness Pirro states that the Company agrees with each of these modifications, except for the change to weather-normalized sales for the SGS rate class which was not addressed in his testimony.

Q. DID YOU CALCULATE ADJUSTMENTS FOR CUSTOMER GROWTH AND CHANGE IN USAGE USING THE PUBLIC STAFF'S PROPOSED METHODOLOGY?

A. Yes. I calculated customer growth and change in usage adjustments through the end of December 2019 to correspond with the update period considered by the Public Staff's Accounting Division.

This resulted in an overall kWh adjustment of 154,056,778 kWh, shown in Saillor Exhibit 3, for a total revenue adjustment of $17,685,132. The revenue adjustments for customer growth and usage, shown in Saillor Exhibits 4 and 5 respectively, were provided to Public Staff witness Dorgan for incorporation into his schedules.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

SCOTT J. SAILLOR

I graduated from North Carolina State University with a Bachelor of Science degree in Electrical Engineering. I was employed by the Communications Division of the Public Staff beginning in 1998, where I worked on issues associated with the quality of service offered by telephone and payphone service providers, arbitration proceedings, compliance reporting and certification filings. Since joining the Electric Division in 2011, my responsibilities have focused on the areas of demand side management and energy efficiency measures, renewable portfolio standards compliance, applications for resale of electric service and non-utility generating facilities, and revenue and customer growth analysis.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		
Application of Duke Energy Progress,	)	SUPPLEMENTAL
LLC, for an Adjustment of Rates and	)	TESTIMONY OF
Charges Applicable to Electric Utility	)	SCOTT J. SAILLOR
Service in North Carolina	)	PUBLIC STAFF – NORTH
	)	CAROLINA UTILITIES
	)	COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

SUPPLEMENTAL TESTIMONY OF SCOTT J. SAILLOR
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

APRIL 23, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Scott J. Saillor. 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. DID YOU FILE DIRECT TESTIMONY IN THIS CASE ON APRIL 13, 2020?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to update the weather normalization, customer growth and usage adjustments through February 2020.

Q. DO YOU HAVE ANY CHANGES TO THE METHOD DESCRIBED IN YOUR DIRECT TESTIMONY FOR UPDATING THE ADJUSTMENTS?

A. No. The methodology I used to calculate the adjustments through February 2020 is the same as described in my direct testimony.

Q. DID YOU CALCULATE FINAL ADJUSTMENTS FOR WEATHER, CUSTOMER GROWTH AND CHANGE IN USAGE THROUGH FEBRUARY 2020?

A. Yes. My adjustments are summarized in Saillor Exhibits 1 through 5.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1193 Application of Duke Energy Progress, 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-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	SECOND SUPPLEMENTAL TESTIMONY OF SCOTT J. SAILLOR PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUBS 1193 AND 1219

SECOND SUPPLEMENTAL TESTIMONY OF SCOTT J. SAILLOR

ON BEHALF OF THE PUBLIC STAFF

NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 16, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Scott J. Saillor. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS CASE?

A. Yes. I filed direct testimony on April 13, 2020, and supplemental testimony on April 23, 2020.

Q. WHAT IS THE PURPOSE OF YOUR SECOND SUPPLEMENTAL TESTIMONY?

A. The purpose of my second supplemental testimony is to update the customer growth and usage adjustments as described in the Second Agreement and Stipulation of Partial Settlement (Second Settlement) filed on July 31, 2020, between Duke Energy Progress, LLC, and the Public Staff.

Q. PLEASE EXPLAIN HOW THE ADJUSTMENTS WERE DETERMINED.

A. Per the Second Settlement, the adjustments were determined by taking 75% of the difference between the adjustments reflecting customer count and usage updated through May 2020 and the adjustments reflecting customers and usage updated through February 2020, and then adding the resulting difference to the February 2020 update. The February and May updates were calculated using the same methodology as described in my direct testimony filed on April 13, 2020. The adjustments are summarized in Saillor Exhibits 1 through 3.

Q. IS THE COMPANY IN AGREEMENT WITH THE ADJUSTMENTS?

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MS. DOWNEY: Thank you. And with respect to Shawn L. Dorgan, we would move that his direct testimony exhibits filed on April 13, 2020, consisting of 44 pages, Appendix A, and three exhibits; and supplemental testimony and exhibits filed on April 23, 2020, consisting of 11 pages and three exhibits be entered into the record.

COMMISSIONER CLODFELTER: I will entertain any objections to that motion.

(No response.)

COMMISSIONER CLODFELTER: Hearing none, the motion is allowed.

(Dorgan Exhibits 1 through 3 and Dorgan Supplemental Exhibits 1 through 3 were admitted into evidence.)

(Whereupon, the prefiled direct testimony and Appendix A, and supplemental testimony of Shawn L. Dorgan were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF SHAWN L. DORGAN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

TESTIMONY OF SHAWN L. DORGAN
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

APRIL 13, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Shawn L. Dorgan. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Staff Accountant with the Accounting 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. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the accounting and ratemaking adjustments I am recommending, as well as those recommended by other Public Staff witnesses, as a result of the Public Staff's investigation of the revenue, expenses, and rate base presented by Duke Energy Progress, LLC (DEP or the Company) in support of its October 30, 2019, request for $585,961,000 in additional North Carolina retail revenue.

Q. WHAT REVENUE INCREASE IS THE PUBLIC STAFF RECOMMENDING?

A. Based on the level of rate base, revenue, and expenses annualized for the test period ended December 31, 2018, with certain updates, the Public Staff is recommending an increase in annual operating revenue of $109,236,000.

Q. MR. DORGAN, PLEASE DESCRIBE THE SCOPE OF YOUR INVESTIGATION INTO THE COMPANY'S FILING.

A. My investigation included a review of the application, testimony, exhibits, and other data filed by the Company, an examination of the books and records for the test year, and a review of the Company's accounting, end-of-period, and after-period adjustments to test year revenue, expenses, and rate base. The Public Staff has also conducted extensive discovery in this matter, including the review of numerous data responses provided by the Company in response to data requests, participation in conference calls with the Company.

Q. PLEASE BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE ISSUES IN THIS CASE.

A. Each Public Staff witness will present testimony and exhibits supporting his or her position and recommend any appropriate adjustments to the Company's proposed rate base and cost of service. My exhibits reflect and summarize these adjustments, as well as the adjustments I recommend.

Q. PLEASE GIVE A MORE DETAILED DESCRIPTION OF THE ORGANIZATION OF YOUR EXHIBITS.

A. Schedule 1 of Dorgan Exhibit 1 presents a reconciliation of the difference between the Company's requested increase of $585,961,000 and the Public Staff's recommended increase of $109,236,000.

Schedule 2 presents the Public Staff's adjusted North Carolina retail original cost rate base. The adjustments made to the Company's proposed level of rate base are summarized on Schedule 2-1 and are detailed on backup schedules.

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. Schedule 3-1 summarizes the Public Staff's adjustments, which are detailed on backup schedules.

Schedule 4 presents the calculation of required net operating income, based on the rate base and cost of capital recommended by the Public Staff.

Schedule 5 presents the calculation of the required increase in operating revenue necessary to achieve the required net operating income. This revenue increase is equal to the Public Staff's recommended increase shown at the bottom of Schedule 1.

. Dorgan Exhibit 2 sets forth the calculation of an annual excess deferred income taxes (EDIT) Rider for unprotected taxes to be in effect for five years, the calculation of a one-year Rider to refund the provisional taxes, and the calculation of a one-year Rider to refund the recent decrease of state taxes.

Dorgan Exhibit 3 sets forth the reallocation of the Company's per books amounts and pro forma adjustments to reflect the Public Staff's recommended SWPA Cost of Service allocation methodology.

Q. WHAT ADJUSTMENTS TO THE COMPANY'S COST OF SERVICE DO YOU RECOMMEND?

A. I am recommending adjustments in the following areas:

1) Cost of service allocation to NC retail operations
2) Adjust Test Year Revenues

3) Updated Net Plant and Depreciation Expense
4) Update for New Depreciation Rates
5) Vanderbilt-W Asheville 115kV Distribution Line
6) Asheville CC Plant Deferral and Amortization
7) Updated Revenues and Non-Fuel Variable Operation and Maintenance (O&M) Expenses
8) Cash Working Capital Under Present Rates
9) Effect of Inflation on Non-Fuel O&M Expenses
10) Payroll
11) Executive Compensation
12) Board of Directors Expenses
13) Incentive Plans
14) Aviation Expenses
15) Outside Services
16) Lobbying Expenses
17) Decommissioning Expense
18) Credit Card Fees
19) End of Life Reserve for Nuclear Materials and Supplies
20) Asheville Coal Inventory
21) Storm Deferral and Normalization
22) Sponsorships and Donations
23) Rate Case Expense and Amortization
24) CertainTeed Payment Obligation
25) Severance
26) Non-fuel Variable O&M Displacement
27) Interest Synchronization
28) Cash Working Capital Effect of Increase
29) Excess Deferred Income Taxes (EDIT)

Q. WHAT ADJUSTMENTS RECOMMENDED BY OTHER PUBLIC STAFF WITNESSES DO YOUR EXHIBITS INCORPORATE?

A. My exhibits reflect the following adjustments recommended by other Public Staff witnesses:

1) The recommendations of Public Staff witness Woolridge regarding the capital structure, embedded cost of long-term debt, and return on common equity;

2) The recommendation of Public Staff witness McLawhorn regarding the Cost of Service Methodology;

3) The recommendations of Public Staff witness Metz regarding project costs included in plant in service and plant retirements, and materials and supply (M&S) inventory;

4) The recommendations of Public Staff witness McCullar of William Dunkel and Associates regarding the Company's depreciation study;

5) The recommendations of Public Staff witnesses Tommy Williamson and David Williamson regarding Vegetation Management and the Grid Improvement Plan (GIP);

6) The recommendations of Public Staff witness Maness regarding ARO and non-ARO environmental costs, reclassification of non-ARO deferred environmental costs, and GIP;

7) The recommendation of Public Staff witness Saillor regarding customer growth, usage, and weather normalization;

8) The recommendation of Public Staff witness Thomas regarding the GIP; and

9) The recommendation of Public Staff witness Hinton regarding decommissioning expense.

Q. PLEASE DESCRIBE ITEMS THE PUBLIC STAFF ACCOUNTING DIVISION REVIEWED BUT FOR WHICH IT DID NOT MAKE ADJUSTMENTS.

A. The Public Staff's investigation included procedures to evaluate and review all adjustments proposed by the Company in its initial application and filing. These procedures included a review of the Company's filing, prior Commission orders, and other Company data provided to the Public Staff. As discussed above, the Public Staff conducted extensive discovery of the Company's application including all of the E-1, Item 10 pro forma adjustments, as well as other areas identified by the Public Staff where the Company did not make an adjustment. Additionally, we looked at the fluctuations for rate base expenditures, and O&M expenses for one, three, and five-year periods to further review any anomalies that may have surfaced.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.

A. My adjustments are described below.

COST OF SERVICE ALLOCATION TO NC RETAIL OPERATIONS

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO THE ALLOCATION OF SYSTEM COSTS TO NC RETAIL OPERATIONS.

A. I have allocated total system amounts, as adjusted by the Company, to NC retail operations by using the jurisdictional cost of service study recommended by Public Staff witness McLawhorn. This reallocation of the Company's position is set forth in Dorgan Exhibit 3. Dorgan Exhibit 3 is presented in a format similar to the presentation of revenue, expenses, and rate base set forth in Smith Exhibit 1. My Exhibit 3 reflects the reallocation of all items, except investor funds advanced for operations. The investor funds advanced for operations will be reallocated by the Company as part of the overall cost of service allocation determination in this case.

In order to present the Company's position, in accordance with the Public Staff's recommended methodology, it was necessary to reallocate each of the Company's adjustments to revenue, expenses, and rate base by factors drawn from the study recommended by Mr. McLawhorn. The allocation factors used are of the same category as used by the Company in its adjustments in the NCUC Form E-1, Item 10.

All of the Public Staff's adjustments that flow through my exhibits have also been allocated to NC retail operations by use of factors drawn from Public Staff witness McLawhorn's recommended study. The net result of this process is a fully adjusted cost of service allocated to NC retail operations in accordance with the Public Staff's allocation methodology recommendation.

ADJUST TEST YEAR REVENUES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO TEST-YEAR REVENUES.

A. I have adjusted test-year revenues to reflect usage, customer growth, and weather normalization adjustments recommended by Public Staff witness Saillor. I have made a corresponding adjustment for the increase in customer-related O&M expenses to account for the additional customers related to the Company's adjustment to revenues. I have also made corresponding adjustments to fuel and energy-related non-fuel O&M expenses for the change in kilowatt hours resulting from the Company's and the Public Staff's adjustments to revenues.

UPDATED NET PLANT AND DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN HOW PLANT, ACCUMULATED DEPRECIATION, AND DEPRECIATION EXPENSE ARE RELATED.

A. As the Company places new plant into service, it increases its rate base. Upon being placed in service, the plant begins to depreciate, and depreciation expense is recorded each accounting period (and recovered from ratepayers) as the plant is used in providing service. The cumulative amount of depreciation expense is reflected on the balance sheet as accumulated depreciation, which is deducted from the original cost of the plant to determine net plant. Net plant (i.e., total plant, net of accumulated depreciation) is used to calculate the rate base on which the Company is allowed to earn a return, while depreciation expense is an input in the calculation of net operating income.

Q. PLEASE EXPLAIN THE COMPANY'S COMPUTATION OF NET PLANT.

A. The Company began its calculation of net plant with the plant and accumulated depreciation amounts recorded as of December 31, 2018, including the annual level of depreciation on the estimated plant additions as well as the matching amount of estimated accumulated depreciation through February 2020.

Q. PLEASE EXPLAIN HOW YOU HAVE COMPUTED NET PLANT.

A. My calculation begins with plant, accumulated depreciation, and net plant based on the Company's actual per books plant in service and accumulated depreciation amounts as of the update period ending December 31, 2019, which include rate base customer growth-related actual plant additions.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN YOUR AMOUNT OF NET PLANT AND THE COMPANY'S AMOUNT.

A. I have reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year (December 31, 2018) and December 31, 2019. Because I have updated plant and accumulated depreciation to reflect the Company's actual December 31, 2019, per books amounts, I have also considered the effect of normal retirements on the computation of depreciation expense. Pursuant to the FERC Uniform System of Accounts, normal retirements of plant reduce plant and accumulated depreciation by offsetting amounts, and, thus, do not affect the amount of net plant reflected as a component of rate base. If retirements are not properly reflected in the amount of plant used to compute depreciation expense, depreciation expense will be overstated.

Q. BY MAKING THIS ADJUSTMENT TO UPDATE ACCUMULATED DEPRECIATION FOR DEPRECIATION EXPENSE THAT HAS BEEN RECOVERED FROM RATEPAYERS SINCE THE END OF THE TEST PERIOD, IS THE PUBLIC STAFF CHANGING THE TEST PERIOD?

A. No. Consistent with N. C. Gen. Stat. § 62-133, we have used the historic test year to determine the cost of service for DEP. When justified, we have updated expenses, revenues, and investment to reflect the Company's most recent ongoing levels for these items, based on actual known and measurable changes occurring after the test year, just as DEP did in its initial testimony. The costs of the plant additions that the Company included are known and measurable, as are the plant retirements that have occurred and the depreciation that has been recovered from ratepayers, since the end of the test period. The Public Staff updated plant and accumulated depreciation to reflect actual per books amounts as of December 31, 2019, because that date represents the same point in time that the Public Staff used to update customer growth.

While the Public Staff's adjustment to accumulated depreciation is beyond the test year, it recognizes and maintains its relationship with plant and other cost of service items and is permitted by N.C. Gen. Stat. § 62-133(c) and (d). N.C. Gen. Stat. § 62-133(c) provides that the Commission shall consider evidence of changes in costs, revenues, or rate base after the test year, while N.C. Gen. Stat. § 62-133(d) requires the Commission to consider all material facts to allow it to set just and reasonable rates. The changes in plant, depreciation expense, and accumulated depreciation since the test year are exactly the type of changes and material facts that the Commission must consider pursuant to N.C. Gen. Stat. § 62-133(c) and (d).

The adjustment I recommend is consistent with the Commission's past treatment of comprehensive plant updates beyond the end of the test year. Adjustments like this have been consistently approved by the Commission in rate cases for natural gas utilities since the 1990's.[1]

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING PLANT?

A. Yes. In the process of our investigation, I noted the Company has a significant backlog in unitizing plant to the appropriate plant account for depreciation. Unitization is the process of closing plant projects into individual FERC plant accounts for appropriate depreciation. Plant retirements related to plant projects are normally handled

[1] Per Commission orders in Public Service Company of North Carolina, Inc., Docket No. G-5, Sub 565; Piedmont Natural Gas Company, Inc., Docket No. G-9, Sub 631; and Dominion North Carolina Power, Docket Nos. E-22, Sub 479 and Sub 532.

simultaneously with unitization of plant projects. My investigation revealed the Company is currently three to four years behind in unitizing plant projects to the appropriate plant accounts. Typically, unitization of plant occurs within three to nine months upon completion of plant, with larger plants comprising the longer time period to unitize. The delay in unitizing plant to the appropriate accounts misstates depreciation expense, because a general depreciation rate is utilized instead of the specific rate for the specific plant accounts. The Company stated it was working with accounting firm, Ernst & Young, to develop a plan for both the generation and power delivery plant categories to address the backlog. The Public Staff recommends the Company file with the Commission its plans to reduce the backlog, within 90 days of the Commission's Order in this case, and implement the proposed plans and procedures to decrease the lag in unitization.

UPDATE FOR NEW DEPRECIATION RATES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. Based on the recommendations of Public Staff witness McCullar, I have made an adjustment to depreciation expense to reflect her recommended depreciation rates.

Q. DOES THE PUBLIC STAFF HAVE ANY ADDITIONAL ADJUSTMENTS TO DEPRECIATION RATES?

A. Based on the Company's testimony, the Company has indicated that it is planning to retire its Roxboro generating plant Units 3 and 4 and the Mayo generating plant earlier than has been shown in DEP's 2018 Integrated Resource Plan (IRP) and the 2019 Update. The details regarding the retirements of these generating plants are further discussed in the testimony of Public Staff witness Metz. As a result of these retirements, the Company has recommended a retirement date of 2029 for the Mayo plant and Roxboro Units 3 and 4. I have recommended that Public Staff witness McCullar restore the depreciation rate of these units to the depreciation rate approved in the Company's last general rate case in Docket No. E-2, Sub 1142. I have recommended this rate change for the following reasons. First, the retirement of these generating units is extensively discussed in the testimony of Public Staff witness Metz. His concerns convey that the retirement of these units will have impacts for the DEP system. Second, although the Company has stated in its testimony that it intends to retire these plants, it has not presently done so. Third, the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, which is to be determined in a future general rate case. The Public Staff believes it is appropriate to continue this consistent treatment of retired plants in the present case.

W. ASHEVILLE - VANDERBILT 115Kv DISTRIBUTION LINE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE VANDERBILT - W. ASHEVILLE 115kV DISTRIBUTION LINE.

A. The Company recorded this project in the cost of service as a distribution project. Based on discussions with the Company, this project should have been recorded as a transmission project. As a result, based on the recommendation of Public Staff witness Metz, I have made an adjustment to reflect a change in the allocation percentage to NC retail to reflect that this project should have been recorded as transmission plant and not distribution plant..

ASHEVILLE COMBINED CYCLE (CC) PLANT PRO FORMA AND ASHEVILLE CC DEFERRAL AMORTIZATION

Q. PLEASE EXPLAIN THE COMPANY'S PRO FORMA ADJUSTMENTS TO INCLUDE THE ASHEVILLE (CC) PLANT AND THE ASHEVILLE CC DEFERRAL AMORTIZATION IN RATE BASE AND OPERATING REVENUE DEDUCTIONS IN THIS PROCEEDING.

A. The Company made a pro forma adjustment to include the amortization of deferred costs related to the Asheville CC Plant. This adjustment reflects an annual level of amortization of deferred costs, including a return on investment, over a three-year period. As part of this adjustment, DEP also included a separate pro forma adjustment to include a proxy for the ongoing O&M expenses and M&S inventory for the Asheville CC.

The Company also included a pro forma adjustment to reflect Power Block 1, including the common plant, and a combustion turbine (CT) from Power Block 2 in plant additions as of December 31, 2019. These additions represent the 480 MW of the 580 MW (nameplate capacity) Asheville CC facility that have been placed in service as of December 31, 2019. The Company's Supplemental Testimony will reflect the other plant additions associated with the Asheville CC, assuming that it has been successfully placed into service.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO THE ASHEVILLE CC PLANT PRO FORMA ADJUSTMENTS MADE BY THE COMPANY.

A. First, with regard to the pro forma adjustments made by the Company to reflect the ongoing level of O&M expenses and M&S inventory, I have made two adjustments. Based on the recommendations of Public Staff witness Metz, I have adjusted the annual operating expenses utilized by the Company to reflect a more accurate ongoing level of annual operating and maintenance (O&M) expenses for the Asheville CC. In its calculation, the Company utilized 2017 and 2018 annual O&M expenses for the Sutton CC and the H.F. Lee CC generating plants as a proxy for the ongoing annual Asheville CC O&M expenses. I have included the 2019 O&M expenses for each of the above referenced plants, as well as, the 2019 O&M costs for the W.S. Lee CC plant in calculating a proxy for the average of the annual operating expenses. It is our understanding that the Company accepts the Public Staff's methodology for calculating a proxy for the O&M expenses for the Asheville CC. Also, based on the recommendation of Public Staff witness Metz, the Public Staff accepts the Company's level of M&S inventory as reasonable for the Asheville CC. Second, in order to synchronize these adjustments with the amount of plant that is in service as of December 31, 2019, I have included only 83%[2] of the calculated level of O&M expenses and M&S inventory in my Exhibits. The Public Staff reserves the right to update these amounts to reflect actual M&S inventory as of the date the plant becomes operational,

[2] This percentage is calculated based on the ratio of 480 MW of plant in service at December 31, 2019, to 580 MW nameplate capacity of the Asheville CC expected to come online before the close of the hearing.

as well as, the O&M expenses to reflect an appropriate ongoing level as necessary.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE ASHEVILLE CC DEFERRAL AMORTIZTION.

A. I recommend that the deferred Asheville CC costs for North Carolina retail be recovered through a levelized amortization over a five-year period. I have calculated the levelized amortization amount based upon my recommended five-year period and the after-tax rate of return, using the capital structure, cost rates, and combined income tax rate recommended by the Public Staff in this proceeding. Both the five-year amortization period and the use of a levelized amortization calculation have historically been proposed by the Public Staff as a reasonable method for the Company to recover the deferred costs of adding a baseload plant. It is our understanding that as of April 5, 2020, all of Power Block 2 is now in service. The deferral amounts will thus need to be adjusted to reflect the actual in-service date for Power Block 2, including the appropriate amounts for O&M expenses and M&S Inventory, as well as, other calculations related to the deferral amounts, and adjustments to the balance for liquidated damages expected to be received by the Company, based on discussions with Company personnel. The Public Staff will file supplemental testimony to adjust and correct for all of these items in the deferral calculation.

UPDATED REVENUES AND NON-FUEL VARIABLE O&M EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UPDATE REVENUES AND VARIABLE NON-FUEL O&M EXPENSES.

A. As part of my update to plant and related items, I have updated revenues to reflect the effect of usage and customer growth adjustments as of December 31, 2019, based on the recommendation of Public Staff witness Saillor. I have made a corresponding adjustment for the increase in customer-related O&M expenses that result from the additional customers. I have also made corresponding adjustments to fuel and energy-related non-fuel O&M expenses for the additional kilowatt hours resulting from increased sales.

CASH WORKING CAPITAL UNDER PRESENT RATES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL UNDER PRESENT RATES.

A. The Company computed cash working capital using the lead-lag study method and then adjusted it to fully reflect all of the Company's proposed adjustments, before the amount of the proposed rate increase. I have likewise adjusted cash working capital under present rates to reflect all of the Public Staff's adjustments, in accordance with the Commission's Order in Docket No. M-100, Sub 137. Furthermore, through our investigation, the Public Staff discovered several errors in the new lead-lag study filed by the Company. I have incorporated the corrections to these errors in calculating the cash working capital under present rates. This cash working capital adjustment is reflected on Schedule 2-1 and incorporates the effect of the Public Staff's adjustments, before the rate increase, on the lead-lag study.

EFFECT OF INFLATION ON NON-FUEL O&M EXPENSES

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE COMPANY'S INFLATION ADJUSTMENT?

A. The Company adjusted annual non-labor, non-fuel O&M costs, to reflect the increase in costs during the test year that occurred due to the effect of inflation as of December 31, 2018. I have adjusted the amount to reflect the inflation factor through December 31, 2019, to coordinate with other items updated through that same point in time. I have also modified the Company's inflation adjustment to reflect the Public Staff's adjustment to include variable O&M expenses for changes in customer growth and the removal of aviation expenses, Board of Directors (BOD) expenses, outside services expenses, uncollectibles, sponsorships and donations, and advertising.

PAYROLL

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO PAYROLL.

A. I have adjusted the Company's payroll to include the updated payroll amounts and allocation factors through December 2019, as provided by the Company in response to a data request.

EXECUTIVE COMPENSATION AND BENEFITS

Q. WHAT ADJUSTMENT HAVE YOU MADE TO EXECUTIVE COMPENSATION AND BENEFITS?

A. The Company made an adjustment to remove 50 percent of the compensation of five Duke Energy executives with the highest level of compensation allocated to DEP in the test period. I made an additional adjustment to remove 50 percent of the benefits associated with these top five Duke Energy executives. This adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers. The Public Staff believes that it would be inconsistent to remove the compensation of these five executives without also removing the benefits related to that compensation.

Q. IS YOUR RECOMMENDATION BASED ON THE PREMISE THAT THE COMPENSATION AND BENEFITS OF THE EXECUTIVE OFFICERS YOU HAVE SELECTED ARE EXCESSIVE OR SHOULD BE REDUCED?

A. No. This recommendation is based on the Public Staff's belief that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests, which are not always the same as those of ratepayers. Officers have fiduciary duties of care and loyalty to shareholders, but not to customers. Consequently, the Company's executive officers are obligated to direct their efforts not only to minimizing the costs and maximizing the reliability of DEP's service to customers, but also to maximizing the Company's earnings and the value of its shares. It is reasonable to expect that management will serve the shareholders as well as the ratepayers; therefore, a portion of management salary and benefits should be borne by the shareholders.

BOARD OF DIRECTORS (BOD) EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO BOD EXPENSES.

A. I have made an adjustment to remove 50 percent of the expenses associated with the BOD of Duke Energy Corporation that have been allocated to DEP. The expenses allocated to DEP encompass the BOD's compensation, insurance, and other miscellaneous expenses. The premise of this adjustment is closely linked to the premise of the adjustment made by the Public Staff related to executive compensation. We believe that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating those individuals who have a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. Further, Directors' and Officers' liability insurance, while a necessary expense for a corporation, has been utilized to defend the BOD in suits brought by shareholders regarding issues such as coal ash. It is appropriate for shareholders to share the cost of the insurance with ratepayers.

INCENTIVE PLANS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR THE COMPANY'S LONG AND SHORT-TERM INCENTIVE PLANS.

A. DEP offers two incentive plans to its employees: the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). The STIP is offered to all employees, including executives. The LTIP is offered to employees at the Director level and above. Approximately 700 employees of Duke Energy Corporation qualify for the LTIP.

The STIP consists of goals set and approved by the BOD for a one-year term. In 2018, the test year in this case, the goals consisted of Earnings per Share (EPS), Operational Excellence, Customer Satisfaction, and Safety, as well as team and individual goals. The LTIP goals consist of Performance Shares, which are further categorized between EPS, Total Shareholder Return (TSR), and Safety, and Restricted Stock Units (RSU). Both offerings are set and approved by the BOD for a three-year period.

The Company's payout of STIP is based on the achievement of targets at minimum, target, and maximum levels. During the test year, the Company included an adjustment to reduce the STIP from the 2018 payout level to the 2018 target level. With regard to LTIP, the Company made an adjustment to remove the 2018 accruals and replace them with 2019 target accruals.

I have adjusted the allowable costs of STIP to exclude the incentive accruals that were based on the EPS metric. The Public Staff believes that the incentives related to EPS should be excluded, because they provide a direct benefit to shareholders rather than to ratepayers.

I have also adjusted the allowable LTIP costs to exclude the Performance Shares related to the EPS and TSR metrics. The Public Staff believes that the incentives related to EPS and TSR should be excluded, because they provide a direct benefit to shareholders rather than to ratepayers. The Company's BOD minutes depict a direct link and benefit between the Company's goals and shareholder's interests. Therefore, these costs should be borne by shareholders.

AVIATION EXPENSES

Q. WHAT ADJUSTMENT DO YOU RECOMMEND RELATED TO AVIATION EXPENSES?

A. The Company made an adjustment to O&M expenses to remove an amount for corporate aviation. The Public Staff made a further adjustment after investigating the aviation expenses charged to DEP during the test year. The aviation expenses are incurred by Duke Energy Corporation, and then a portion is allocated to DEP through the use of a corporate allocation factor. Based on the Public Staff's review of flight logs, the corporate aircraft are available for use by Duke Energy Corporation's Chief Executive Officer (CEO) and her staff. I recommend that certain expenses allocated to DEP be removed due to the nature of the flights involved. In the course of our investigation, the Public Staff determined that some of these flights appear to be unrelated to the provision of utility service. Additionally, I removed the DEP-allocated portion of commercial international flights due to the Public Staff's determination the international flights included appear to be unrelated to the provision of utility service.

OUTSIDE SERVICES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO OUTSIDE SERVICES.

A. The Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEP by DEBS as well as those incurred by DEP directly. Our investigation found certain expenses related to legal and non-legal invoices, which the Public Staff believes should not be charged to ratepayers.

LOBBYING EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSMTENT TO LOBBYING EXPENSES.

A. The Company assigned some lobbying expenses from the test year to below-the-line accounts, and, therefore, were not included in the cost of service. I have further adjusted O&M expenses to remove additional lobbying costs. In determining what costs should be removed, I applied the "but for" test for reporting lobbying costs as used in a Formal Advisory Opinion of the State Ethics Commission dated February 12, 2010. The Commission recognized at pages 70-71 of its 2012 Dominion North Carolina Power Order in Docket No. E-22, Sub 479, that lobbying included not only employees' direct contact with legislators, but also other activities preparing for or surrounding lobbying that would not have been conducted but for the lobbying itself. In applying this test, I removed O&M expenses associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line.

DECOMMISSIONING EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DECOMMISSIONING EXPENSES.

A. I have made an adjustment to remove decommissioning expenses based on the recommendation of Public Staff witness Hinton.

CREDIT CARD FEES

Q. WHAT ADJUSTMENT HAVE YOU MADE FOR CREDIT CARD FEES?

A. In the present case, the Company has made a pro forma adjustment to include credit card transaction fees for residential customers in its revenue requirement. The fees for other forms of payments such as checks, ACH payments[3], and bank drafts are currently included in the Company's cost of service. The Public Staff does not have an issue regarding the inclusion of credit card fees in the cost of service. However, in its adjustment, the Company did not calculate any impacts to late payments or uncollectibles associated with the request to include credit card fees. The Company included the 2019 credit card transactions in the adjustment, but has not removed the expenses related to the forms of payment that were utilized in the 2018 cost of service. I have made an adjustment to remove the O&M expenses included in the cost of service for 2018 associated with the increase in credit card transactions from the 2018 to 2019 period, to avoid a double counting of costs associated with the same payments.

END OF LIFE RESERVE FOR NUCLEAR M&S

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT FOR THE END OF LIFE RESRVE FOR M&S.

A. Based on the testimony of Public Staff witness Metz, I have made an adjustment to reflect his recommendation to remove certain items from inventory, as well as the application of a 10% salvage value to the end of life inventory.

[3] ACH payments are electronic payment that are created when the customer gives an originating institution, corporation, or other customer (originator) authorization to debit directly from the customer's checking or saving account for the purpose of bill payment.

ASHEVILLE COAL INVENTORY

Q. PLEASE EXPLAIN THE ADJUSTMENT TO ASHEVILLE COAL INVENTORY.

A. I have made an adjustment to Asheville coal inventory based on the recommendation of Public Staff witness Metz.

STORM EXPENSE AND DEFERRAL

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO THE COMPANY'S PROPOSED STORM DEFERRAL.

A. I have made an adjustment to remove all capital and O&M costs associated with Hurricane Florence, Hurricane Michael, and Winter Storm Diego in the present case; because the Company indicated it would seek to recover the costs of the foregoing storms through securitization if this method of financing were authorized by the North Carolina Legislature. Company witness DeMay stated in his initial testimony that, "If, however, North Carolina law is amended to allow for the securitization of these storm costs, the Company would pursue securitization if it provided a savings to its customers and would cease the recovery of the remaining storm costs in current rates and instead begin recovering the remaining unrecovered storm costs as provided for in a securitization financing order." On November 6, 2019, Senate Bill 559, which authorized a public utility to seek recovery of storm costs through securitization, was signed into law.

Q. ARE THE COSTS RELATED TO HURRICANE FLORENCE, HURRICANE MICHAEL, AND WINTER STORM DIEGO AS PRESENTED IN THE CURRENT CASE PRUDENTLY INCURRED?

A. Based upon our review of the costs the Company has included in this case, the Public Staff believes the costs associated with these storms were prudently incurred.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS RELATED TO STORM EXPENSE?

A. I have included an adjustment to reflect a 10-year normalized level of storm expense for storms, based on the premise that these storms would not otherwise be large enough for the Company to seek securitization of the costs.

RATE CASE EXPENSE AND AMORTIZATION

Q. WHAT ADJUSTMENT HAVE YOU MADE TO RATE CASE EXPENSE AND AMORTIZATION?

A. I have adjusted rate case expense to reflect the actual costs through the current update period of December 31, 2019. Furthermore, I have removed the Company's adjustment to include the unamortized portion of rate case expense in rate base. I have removed the Company's adjustment to include the unamortized balance in rate base, because the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on a historical average of the number of years between rate case filings. It is the Public Staff's position that rate case expense does not rise to the level of being extraordinary in nature, and, therefore, does not require rate base treatment.

CERTAINTEED PAYMENT OBLIGATION

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE CERTAINTEED PAYMENT OBLIGATION.

A. I have made an adjustment to remove the CertainTEED Gypsum payment obligation, because, on November 25, 2019, the Commission issued its *Order Approving Interim Fuel Clause Adjustment, Requiring Further Testimony, and Scheduling Hearing* in Docket No. E-2, Sub 1204 finding that these payments could be recovered as fuel-related costs in the Sub 1204 docket if found to be reasonable and prudent.

SPONSORSHIPS AND DONATIONS

Q. WHAT ADJUSTMENT HAVE YOU MADE FOR SPONSORSHIPS AND DONATIONS?

A. I have adjusted O&M expenses to remove amounts charged to O&M expense for sponsorships and charitable donations. Specifically, I have excluded from expenses amounts paid to the chambers of commerce, and other donations. These expenses should be disallowed because they do not represent actual costs of providing electric service to customers.

SEVERANCE

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S ADJUSTMENTS TO SEVERANCE COSTS.

A. The Company made an adjustment to remove atypical severance and retention costs included in the test period. The Company is also requesting to establish a regulatory asset and defer the NC retail amount and to amortize the regulatory asset over a three-year period.

I have adjusted severance costs to reflect a normalized level over a five-year period. This is consistent with how the Public Staff has treated severance program costs in other utility rate cases.[4] The costs that the Company has incurred correlate with the savings reflected in the Company's update. There is a relationship between the savings generated by a severance program and the costs incurred for the severance program. The more employees who leave under a severance program, the greater the savings, and the greater the cost.

With regard to the Company's request to establish a regulatory asset, the Public Staff has established a normalized level to include in rates, and, as a result, has removed the Company's requested amount from rate base. The Company did not state a rationale for establishing a regulatory asset in its testimony. This is also consistent with how the Public Staff has treated severance program costs as stated above.

NON-FUEL VARIABLE O&M DISPLACEMENT ADJUSTMENT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR NON-FUEL VARIABLE O&M DISPLACEMENT.

A. The Company has made an adjustment to include 480 MW of the Asheville CC, a baseload generation unit, in plant in service at December 31, 2019. The Asheville CC has a nameplate capacity of

[4] Dominion Energy North Carolina Docket No. E-2, Subs 532 and 562.

580 MW, of which the remainder, or 100 MW, was placed in service as of April 5, 2020, based on our understanding. DEP made pro forma adjustments to include the full costs of this plant in the cost of service, including adding non-fuel O&M expenses to reflect a full year of operation. The Company also made an adjustment to remove rate base balances and expenses related to the Asheville coal plant, which has been retired since the end of the test year. The Public Staff estimates that the addition of the expenses related to the Asheville CC, offset by the expenses removed due to the retirement of the coal-fired plant, net to an increase in non-fuel variable O&M expenses associated with approximately 1,014,157 MWH of generation. With this net addition of kWh, other DEP resources will operate less frequently or at lower levels of output, and thus incur fewer non-fuel variable O&M expenses. In previous sections of my testimony, I discuss adjustments that I have made to increase non-fuel variable O&M expenses to reflect the total of such expenses needed to serve the Company's end-of-period level of kWh sales (at generation level). I have thus reduced non-fuel variable O&M expenses by a corresponding amount in this displacement adjustment to prevent the inclusion in cost of service of more than the end-of-period level of these types of expenses. In my opinion, inclusion of both (1) an annualized level of energy-related non-fuel variable O&M expenses via the adjustment to reflect the

annualized and normalized level of kilowatt-hour (kWh) sales after adjustments for changes in customer growth, usage, and weather normalization, and (2) annualized levels of incremental energy-related non-fuel variable O&M expenses specifically related to the addition of the Asheville CC and the retirement of the Asheville coal plant, would result in a total level of non-fuel energy-related O&M expense in this proceeding higher than the annual energy-related expense necessary to serve the end-of-period level of customers at the normalized level of generation.

This adjustment will need to be refined to reflect the addition of the 100 MW aforementioned that closed to plant in service on April 5, 2020, for the Asheville CC. The Public Staff reserves the right to adjust for this in its supplemental testimony.

INTEREST SYNCHRONIZATION ADJUSTMENT

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. The Company adjusted income tax expense to reflect interest synchronization with its proposed capital structure, cost of debt, and rate base. I have also adjusted income tax expense to reflect the deduction of the pro forma level of interest resulting from the application of the Public Staff's recommended return and capital structure to its recommended rate base.

CASH WORKING CAPITAL EFFECT OF INCREASE

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL FOR THE PROPOSED INCREASE.

A. The cash working capital lead-lag effect of the proposed revenue increase as recommended by the Public Staff has been calculated on Dorgan Exhibit 1.

EXCESS DEFERRED INCOME TAXES (EDIT)

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT RELATED TO EDIT.

A. In this case, the Company has proposed an EDIT Rider that contains the following categories of refunds for customers:

(1) Federal EDIT – Protected

(2) Federal EDIT – Unprotected (PP&E and non PP&E related)

(3) State EDIT

(4) Deferred Revenue from Tax Act Overcollections

DEP did not make an adjustment to exclude any EDIT from rate base, but instead proposes to handle each of the categories above in a single Rider, with rate changes occurring each year based on the proposed amortizations for these categories, which range from

39.6 years to 5 years. The Public Staff believes that the four categories of refunds listed above should be handled separately, due to the differing natures of the amounts and the amortization periods. We believe that this provides a more transparent means of tracking the Tax Act and state tax-related refunds to customers for each year.

Based upon the foregoing, I recommend several adjustments regarding federal EDIT.

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S RECOMMENDATIONS REGARDING EDIT.

The federal EDIT consists of two categories of amounts, protected and unprotected. The protected EDIT are deferred taxes related to timing differences arising from the utilization of accelerated depreciation for tax purposes and another depreciation method for book purposes. These deferred taxes are deemed protected because the Internal Revenue Service (IRS) does not permit regulators to flow back the excess to ratepayers immediately, but instead requires that the excess be flowed back to ratepayers ratably over the life of the timing difference that gave rise to the excess. Unprotected EDIT are those taxes that result from all other timing differences, and can be flowed back to ratepayers however quickly regulators deem reasonable.

Federal Protected EDIT

I have made an adjustment to remove the federal protected EDIT from the EDIT Rider proposed by the Company, and instead leave the amount in base rates. I recommend this treatment since the Company's calculation of the net remaining life of the timing differences (average rate assumption method or ARAM) results in an extremely long life due to the timing differences that gave rise to the excess. The Public Staff proposes to amortize the protected EDIT balance over 39.6 years in base rates and to remove the first year of amortization from the deferral amount for purposes of this proceeding.

Federal Unprotected EDIT

The Company has artificially created two categories of unprotected EDIT for purposes of its proposal: "unprotected PP&E" (Property Plant & Equipment) and "unprotected other," and has proposed to return EDIT to ratepayers over periods of 20 years and 5 years, respectively. The Company asserts that, since the unprotected PP&E EDIT is similar in nature to protected EDIT (which is also related to PP&E), it is reasonable to flow it back to the ratepayers over the same time period that it would have been paid to the IRS had the Tax Cuts and Jobs Act not been enacted. However, the Company acknowledges the Commission has the discretion to flow back all of the unprotected EDIT over any time period it finds appropriate.

The tax normalization rules are very clear - either EDIT is protected, or it is not. The EDIT that the Company designates as “PPE-related” is still clearly unprotected, a fact conceded by the Company. The Company’s assertion that it should only return this PP&E-related unprotected EDIT over the same period of time it would have paid the funds to the IRS had the tax law not been passed, is not supportable by any logical accounting or ratemaking principle and should not dictate this Commission’s decision as to what is a reasonable amount of time within which to return these funds to ratepayers. These funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible. It should be noted that the Company will continue to collect accumulated deferred income taxes (ADIT) at a tax rate sufficient to meet its tax obligations.

Based on the forgoing, for unprotected EDIT, I recommend removing the EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs. The immediate removal of unprotected EDIT from rate base increases the Company’s rate base, and mitigates regulatory lag that might occur from refunds of unprotected EDIT not contemporaneously reflected in rate base. Additionally, refunding the unprotected EDIT over five years allows the Company to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time. The Public Staff has provided the Company with the benefit of removing the total amount of the unprotected EDIT credit from rate base in the current case, thus providing the Company with an increase in rates to moderate any cash flow issues, to the extent they would exist. The financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

<u>Overcollection of Federal Taxes</u>

I have made an adjustment to remove, from the Company's single rider, the overcollection of federal taxes, which resulted from the reduction in tax rates from 35% to 21%, and placed it in a separate levelized rider to be amortized over a one-year period. Furthermore, I have removed the balance from the working capital schedules, since I am recommending a refund over one year. The one-year amortization period is consistent with the period approved by the Commission in the most recent rate cases of: Aqua North Carolina, Inc. in Docket No. W-218, Sub 497 (December 18, 2018), Carolina Water Service, Inc. of North Carolina in Docket No. W-354, Sub 360 (February 21, 2019), and Piedmont Natural Gas Company, Inc. in Docket No. G-9, Sub 743 (October 31, 2019).

State EDIT

I recommend removing the entire state EDIT balance from rate base, as the Company has in adjustment NC-0600, and placing it in a separate rider, and recommend a one-year levelized return on the balance. The change in the state tax rate represents one year's worth of tax difference, much like the over-collection of federal taxes, and, to avoid intergenerational issues, should be flowed back over the same time. This period is also consistent with the Commission's Order in Dominion Energy North Carolina, Docket No. E-22, Sub 532, in which the Commission approved a one-year flowback.

REGULATORY ASSETS AND REGULATORY LIABILITIES RIDER

Q. PLEASE DISCUSS YOUR COMMENTS TO THE REGULATORY ASSETS AND REGULATORY LIABILITIES RIDER.

A. Smith Exhibit 5 sets forth the Company's proposed Regulatory Assets and Regulatory Liabilities Rider. The Company proposes to refund the balance as of August 31, 2020, in a one-year Rider. The Public Staff has reviewed, and agrees with the Company's calculation of the Rider.

ADDITIONAL COMMENTS

Q. DO YOU HAVE ADDITIONAL COMMENTS?

A. Yes. I have additional comments with regard to the Company's March 13, 2020, supplemental filing.

Q. WHAT ARE YOUR ADDITIONAL COMMENTS REGARDING THE COMPANY'S MARCH 13, 2020, SUPPLEMENTAL FILING?

A. The Public Staff is aware of the supplemental filing; however, given the timing of the supplemental filing and the due date of the Public Staff's testimony, the Public Staff could not reasonably perform its investigation on the Company's updated information in the short amount of time before it was due to file testimony. The Public Staff plans to file its supplemental testimony related to the Company's March 13, 2020, supplemental filing by April 23, 2020.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

SHAWN L. DORGAN

Qualifications and Experience

I am a two-time accounting graduate of Appalachian State University, having earned a B.S.B.A. in Accountancy in 1988 and a Master's of Science in Accountancy (concentration in taxation; functional equivalent of an MST) in 1997. After graduation in August of that year I entered the public accounting industry, working first at the Charlotte practice office of Deloitte & Touche LLP, and later for several local and regional accounting firms in the metro-Charlotte, metro-Raleigh, and metro-Atlanta areas. I am a Certified Public Accountant, licensed in the State of North Carolina. My license number is 27030.

I joined the Public Staff in May 2016 and since have specialized in providing accounting support in conjunction with rider rate proceedings in both the Natural Gas and Electric Divisions, focusing primarily on program cost reviews of energy efficiency programs authorized for the state's electric utilities under N.C.G.S. § 62-133.9. In addition, I have provided accounting and testimonial support in general rate cases involving North Carolina's largest investor-owned electric and natural gas utilities, support focused primarily on applicant rate-base requests in the area of cash working capital.

In addition to serving as a Public Staff panel witness in annual gas cost review proceedings for Frontier Natural Gas Company, currently I serve as the lead technical accountant in the Duke Energy Progress general rate case filed on October 30, 2019 (Docket No. E-2, Sub 1219).

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))))	SUPPLEMENTAL TESTIMONY OF SHAWN L. DORGAN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

Supplemental Testimony of Shawn L. Dorgan

On Behalf of the Public Staff

North Carolina Utilities Commission

April 23, 2020

Q. MR. DORGAN, WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my supplemental testimony is to make updates and corrections recommended by other Public Staff witnesses, based on the Public Staff's investigation of the supplemental filing by DEP in this proceeding. On March 13, 2020, DEP filed its supplemental testimony and exhibits.

Q. WHAT UPDATED REVENUE INCREASE IS THE PUBLIC STAFF RECOMMENDING?

A. Based on the level of rate base, revenue, and expenses annualized at December 31, 2018, with certain updates, the Public Staff is recommending an increase in annual base rate operating revenue of $129,014,000.

Q. PLEASE GIVE A MORE DETAILED DESCRIPTION OF THE ORGANIZATION OF YOUR EXHIBITS.

A. Schedule 1 of Dorgan Supplemental Exhibit 1 presents a reconciliation of the difference between the Company's requested increase of $534,344,000, after the impacts of Company updates in its supplemental filing, and the Public Staff's recommended increase of $129,014,000.

Schedule 2 presents the Public Staff's adjusted North Carolina retail original cost rate base. The adjustments made to the Company's proposed level of rate base are summarized on Schedule 2-1 and are detailed on backup schedules.

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. Schedule 3-1 summarizes the Public Staff's adjustments, which are detailed on backup schedules.

Schedule 4 presents the calculation of required net operating income, based on the rate base and cost of capital recommended by the Public Staff.

Schedule 5 presents the calculation of the required increase in operating revenue necessary to achieve the required net operating income. This revenue increase is equal to the Public Staff's recommended increase shown at the bottom of Schedule 1.

Dorgan Supplemental Exhibit 2 sets forth the calculation of annual excess deferred income taxes (EDIT) Rider for all unprotected taxes to be in effect for five years, the calculation of a one-year Rider to refund the provisional taxes, and the calculation of a one-year Rider to refund the recent decrease of state taxes.

Dorgan Supplemental Exhibit 3 sets forth the calculation of the difference in allocation methodologies from the Company filed Summer CP (SCP) to Summer Winter Peak & Average (SWPA) based on the recommendation of Public Staff witness McLawhorn.

Q. MR. DORGAN, WHAT UPDATED OR CORRECTED ADJUSTMENTS TO THE COMPANY'S COST OF SERVICE DO YOU RECOMMEND?

A. I am recommending updated, corrected adjustments in the following areas:

1) Updated Net Plant and Depreciation Expense
2) Update for New Depreciation Rates
3) Asheville Combined Cycle Project
4) Non-Fuel O&M Displacement
5) Update Base Fuel Factors
6) Storm Costs
7) Inflation to February 29, 2020
8) Cash Working Capital under Present Rates
9) Interest Synchronization
10) Cash Working Capital Effect of Increase
11) Excess Deferred Income Taxes (EDIT)

Q. WHAT ADJUSTMENTS RECOMMENDED BY OTHER PUBLIC STAFF WITNESSES DO YOUR EXHIBITS INCORPORATE?

A. My exhibits reflect the following adjustments recommended by other Public Staff witnesses:

1) The recommendations of Public Staff witness Woolridge regarding the capital structure, embedded cost of long-term debt, and return on common equity;

2) The recommendations of Public Staff witness Maness regarding ARO and non-ARO environmental costs, as well as the reclassification of non-ARO deferred environmental costs and the Grid Improvement Plan (GIP);

3) The recommendation of Public Staff witness Metz regarding project costs included in plant in service and plant retirements and materials and supply (M&S) inventory;

4) The recommendation of Public Staff witness McLawhorn regarding the Cost of Service Methodology;

5) The recommendations of Public Staff witness McCullar of William Dunkel and Associates regarding the Company's depreciation study;

6) The recommendations of Public Staff witness Hinton regarding decommissioning expense;

7) The recommendations of Public Staff witnesses Tommy Williamson and David Williamson regarding Vegetation Management and the GIP;

8) The recommendation of Public Staff witness Thomas regarding the GIP; and

9) The recommendation of Public Staff witness Saillor regarding customer growth, usage, and weather normalization.

Q. WOULD YOU BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE REVENUE REQUIREMENT ASPECTS OF THE SUPPLEMENTAL TESTIMONY?

A. Yes. The attached Dorgan Supplemental Exhibit 1 sets forth the Public Staff's accounting and ratemaking adjustments.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.

A. My adjustments are described below.

UPDATE FOR PLANT AND ACCUMULATED DEPRCIATION

Q. PLEASE EXPLAIN HOW YOU HAVE COMPUTED NET PLANT.

A. My calculation begins with plant, accumulated depreciation, and net plant based on the Company's actual per books plant in service and accumulated depreciation amounts as of the update period ending February 29, 2020, which include rate base and customer growth-related actual plant additions.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN YOUR AMOUNT OF NET PLANT AND THE COMPANY'S AMOUNT.

A. I have reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year (December 31, 2018) and February 2020, utilizing the depreciation rates reflected in Public Staff witness McCullar's exhibits. The Company has reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year and February 29, 2020, utilizing the depreciation rates recommended by Company witnesses.

UPDATE FOR NEW DEPRECIATION RATES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. Based on the recommendations of Public Staff witness McCullar, I have adjusted depreciation expense to reflect her recommended depreciation rates.

ASHEVILLE COMBINED CYCLE (CC) PROJECT

Q. WHAT ADJUSTMENTS HAVE YOU MADE REGARDING THE ASHEVILLE CC PROJECT?

A. I have updated my adjustment to the Asheville CC to reflect the Company's actual costs at February 2020. I have also incorporated adjustments to the levelization calculation to reflect that Power Block 2 came on line April 5, 2020, and that the entire Asheville CC project can be economically dispatched, and is now able to provide power to the grid, in accordance with my understanding from Company personnel.

NON-FUEL O&M DISPLACEMENT ADJUSTMENT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE NON-FUEL DISPLACEMENT ADJUSTMENT.

A. I have adjusted the non-fuel O&M displacement adjustment to reflect that Power Block 2 came on line April 5, 2020. As a result, I have changed the amount of MW that needs to be displaced from 480 MW in my initial filing to 580 MW[1] in this supplemental filing.

[1] This is the nameplate capacity of the Asheville CC per Public Staff witness Metz.

UPDATE BASE FUEL FACTORS

Q. PLEASE DISUCSS YOUR UPDATE TO BASE FUEL FACTORS.

A. In Dorgan Supplemental Exhibit 1, I have reflected the most current base fuel factors as set forth and approved by the Commission in Docket No. E-2, Sub 1204.

STORM COSTS

Q. DO YOU HAVE ANY COMMENTS RELATED TO STORM COSTS?

A. In my original testimony, I indicate that the costs associated with Hurricane Florence, Hurricane Michael, and Winter Storm Diego were prudently incurred. In my initial testimony, I failed to include the costs associated with Hurricane Dorian. Dorgan Supplemental Exhibit 1 includes the costs for all these storms and, based upon our review of all the costs for each of the above named storms the Company has included in this case, the Public Staff believes the costs associated with each of the above named storms were prudently incurred.

CASH WORKING CAPITAL UNDER PRESENT RATES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL UNDER PRESENT RATES.

A. I have incorporated a few corrections related to Lead/Lag days in my original calculation of cash working capital under present rates, which are reflected on Schedule 2-1. This adjustment to cash working capital incorporates the effect of the Public Staff's adjustments updated through February 2020, on the lead-lag study, before the rate increase.

INTEREST SYNCHRONIZATION ADJUSTMENT

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. The Company adjusted income tax expense to reflect interest synchronization with its proposed capital structure, cost of debt, and rate base. I have also adjusted income tax expense to reflect the deduction of the pro forma level of interest resulting from the application of the Public Staff's recommended return and capital structure to its recommended rate base.

CASH WORKING CAPITAL EFFECT OF INCREASE

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL FOR THE PROPOSED INCREASE.

A. The cash working capital lead-lag effect of the proposed revenue increase as recommended by the Public Staff has been calculated on Dorgan Supplemental Exhibit 1, Schedule 2-1.

EXCESS DEFERRED INCOME TAXES (EDIT)

Q. PLEASE EXPLAIN THE ADJUSTMENTS RELATED TO EDIT.

A. I have updated the amount of each EDIT category to reflect the amounts on Smith Supplemental Exhibit 4, Line 8.

OTHER COMMENTS

Q. DO YOU HAVE ANY OTHER COMMENTS?

A. Yes. First, during the course of our investigation, the Public Staff has some concerns with certain aspects of the Company's capitalization policy with regard to hazard/danger tree removal. The Public Staff has no specific recommendation at this time, but plans to work with the Company to investigate this matter. The Public Staff will update the Commission as necessary with regard to the Public Staff's ongoing investigation of this matter.

Second, as of the filing date of our Supplemental Testimony in this case, the Engineering and Accounting Divisions of the Public Staff are still in the process of reviewing responses to data requests that were received yesterday morning. If our review reveals any items that warrant further adjustment, we will amend our Supplemental Testimony to reflect those adjustments.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. DOWNEY: With respect to Roxie McCullar, we would move that her direct testimony and exhibits filed on April 13, 2020, consisting of 32 pages, Appendix A, and three exhibits, some of which are confidential both in terms of the testimony and exhibits and should remain so, be entered into the record.

COMMISSIONER CLODFELTER: You heard the motion. Any objections?

(No response.)

COMMISSIONER CLODFELTER: Hearing no objections, the motion is granted with the appropriate preservation of confidentiality designations as made in the prefiled testimony.

(Exhibit RMM-1 and Confidential Exhibits RMM-2 and RMM-3 were admitted into evidence.)

(Whereupon, the prefiled direct testimony and Appendix A of Roxie McCullar was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))))	TESTIMONY OF ROXIE MCCULLAR ON BEHALF OF PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

TESTIMONY OF ROXIE MCCULLAR
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

April 13, 2020

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roxie McCullar. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. Since 1997, I have been employed as a consultant with the firm of William Dunkel and Associates and have regularly provided consulting services in regulatory proceedings throughout the country.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have 20 years of experience consulting in regulatory rate cases and have addressed depreciation rate issues in numerous jurisdictions nationwide. I am a Certified Public Accountant licensed in the state of Illinois. I am a Certified Depreciation Professional through the

Society of Depreciation Professionals. I received my Master of Arts degree in Accounting from the University of Illinois in Springfield. I received my Bachelor of Science degree in Mathematics from Illinois State University in Normal.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES YOUR QUALIFICATIONS?

A. Yes. My qualifications and previous experiences are shown in the attached Appendix A.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Public Staff of the North Carolina Utilities Commission ("Public Staff").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the depreciation rates proposed to be used by Duke Energy Progress, LLC ("DEP" or "Company") in North Carolina. On October 30, 2019, DEP witness John Spanos filed direct testimony in this proceeding supporting DEP's proposed depreciation rates, based on the "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018" that was included as Spanos Exhibit 1 ("2018 Depreciation Study").

Q. DID YOU PARTICIPATE IN A FIELD VISIT OF DEP'S FACILITIES IN NORTH CAROLINA?

A. Yes. During my review of the depreciation study utilized in DEP's prior rate case in Docket No. E-2, Sub 1142 ("Sub 1142 Proceeding"), I participated in field visits of several different DEP facilities or project locations on October 9-13, 2017.[1] At each location, Company personnel or outside contractors discussed the facilities and ongoing projects with me.

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S POSITION ON DEP'S PROPOSED DEPRECIATION ANNUAL ACCRUAL.

A. DEP is proposing a depreciation annual accrual increase of $145.0 million based on December 31, 2018, investments.[2] The Public Staff's adjustments to DEP's filed depreciation rates result in a $66.4 million reduction to DEP's filed depreciation annual accrual, or an increase of $78.6 million to the depreciation annual accrual compared to the depreciation rates that were approved in the Commission's February 23, 2018, Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase in the Sub 1142 Proceeding ("Sub 1142 Order").

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[1] Site visits included the Archers Lodge Substation, the Harris Plant, the Mayo Plant, the Smith Energy Complex, and the Tillery Plant. I also visited two sites where active aerial and underground projects were underway.

[2] Page 1 of NC-2601 of the October 30, 2019, Rate Case Information Report. These amounts are prior to any jurisdictional allocations.

Q. PLEASE PROVIDE A COMPARISON OF THE ANNUAL DEPRECIATION RATE PROPOSALS.

A. The Public Staff's proposed depreciation rates compared to DEP's proposed depreciation rates are summarized below:

Table 1: Comparison of Depreciation Accrual Rates

Functional Category	12/31/18 Investment	Current Approved Depreciation Rate	DEP Proposed Depreciation Rate	Public Staff Proposed Depreciation Rate
A	B	C	D	E
Steam Production Plant	$3,978,949,911	3.75%	5.33%	4.13%
Nuclear Production Plant	8,840,958,166	2.80%	3.31%	3.31%
Hydraulic Production Plant	140,864,659	3.47%	3.70%	3.65%
Other Production Plant	3,126,769,437	4.50%	5.08%	5.03%
Transmission Plant	2,555,572,839	1.90%	2.23%	2.23%
Distribution Plant	6,869,268,718	2.50%	2.44%	2.32%
General Plant	620,468,150	5.16%	5.74%	4.39%
Land Rights	265,099,637	1.18%	1.18%	1.18%
Total Depreciable Plant	**$26,397,951,517**	**3.06%**	**3.60%**	**3.35%**

The annualized accrual based on December 31, 2018, investments reflected in the 2018 Depreciation Study using the Public Staff's proposed depreciation rates compared to DEP's proposed depreciation rates is summarized below:

Table 2: Comparison of Annual Depreciation Accrual Amount

Functional Category	12/31/18 Investment	DEP Proposed Accrual Amount	Public Staff Proposed Accrual Amount
A	B	C	D
Steam Production Plant	$3,978,949,911	$212,170,895	$164,169,204
Nuclear Production Plant	8,840,958,166	292,257,258	292,257,258
Hydraulic Production Plant	140,864,659	5,213,027	5,148,380
Other Production Plant	3,126,769,437	158,732,404	157,217,103
Transmission Plant	2,555,572,839	57,110,744	57,110,744
Distribution Plant	6,869,268,718	167,607,654	159,311,890
General Plant	620,468,150	35,638,485	27,229,682
Land Rights	265,099,637	3,123,751	3,123,751
General Plant Res. Amort.		18,529,294	18,529,294
Total Depreciable Plant	**$26,397,951,517**	**$950,383,512**	**$884,097,306**

Q. PLEASE DESCRIBE EXHIBIT RMM-1.

A. Exhibit RMM-1 contains the calculations of the Public Staff's proposed depreciation rates for DEP's Electric Plant in North Carolina.

II. <u>Definition of Depreciation</u>

Q. COULD YOU PLEASE PROVIDE THE DEFINITION OF DEPRECIATION?

A. Yes. The Federal Energy Regulatory Commission ("FERC") definitions contained in the FERC Uniform System of Accounts ("FERC USOA") state:

> 12. *Depreciation,* as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility

> is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[3]

The FERC USOA definition of "depreciation" specifically states depreciation is a "loss in service value." FERC defines "service value" as "the difference between original cost and net salvage value of electric plant."[4]

Since this is a utility regulation proceeding, I rely on the FERC USOA definition of "depreciation," which focuses on the "loss of service value."

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF HOW REMAINING LIFE DEPRECIATION RATES ARE CALCULATED.

A. The remaining life depreciation rate formula is:

$$\text{Depreciation Rate} = \frac{(100\% - \text{Book Reserve \%} - \text{Future Net Salvage \%})}{\text{Average Remaining Life}}$$

In the formula above, the book reserve percent is the actual reserve on the Company's books divided by the actual plant in service investment on the Company's books. The book reserve percent is

[3] FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, as currently embodied in the United States Code of Federal Regulations, Title 18, Part 101.

[4] FERC USOA Definition 37.

based on actual data from the Company's books and is not estimated in a depreciation study.

The future net salvage percent and the average remaining life are future estimates proposed in a depreciation study. A depreciation study estimates the projected average service life of the assets, the retirement pattern of those assets, and the cost of removing or retiring those assets less any expected salvage from the sale, scrap, insurance, reimbursements, etc., of those assets. These estimates are referred to as depreciation parameters.

The projected average service life and retirement pattern (survivor curve) are used to calculate the average remaining life.

The estimated future net salvage percent is the estimated future cost of removing or retiring less any estimated future salvage from sale, scrap, insurance, reimbursements, etc.

Q. PLEASE EXPLAIN WHAT IS MEANT BY NET SALVAGE.

A. The National Association of Regulatory Commissioners ("NARUC") publication *Public Utility Depreciation Practices* defines net salvage as "the gross salvage for the property retired less its cost of removal."[5] Gross salvage is defined as "the amount recorded for the property retired due to the sale, reimbursement, or reuse of the

[5] *Public Utility Depreciation Practices*, published by NARUC, at p. 322 (1996).

property."[6] Cost of removal is defined as "the costs incurred in connection with the retirement from service and the disposition of depreciable plant. Cost of removal may be incurred for plant that is retired in place."[7]

Q. WHY IS THE ESTIMATED FUTURE NET SALVAGE COSTS SHOWN AS A PERCENT?

A. The depreciation rates resulting from a depreciation study are applied to the investment amounts as of the date of the test year in the rate proceeding. Since a depreciation study produces a depreciation rate, the estimated future net salvage is incorporated into the depreciation rate formula as a percent of the investment.

Q. WHAT IMPACT DOES THE ESTIMATED FUTURE NET SALVAGE HAVE ON DEPRECIATION RATES?

A. Estimated positive future net salvage results in a lower depreciation rate, all other things being equal. Estimated negative future net salvage results in a higher depreciation rate, all other things being equal.

As explained in NARUC's *Public Utility Depreciation Practices*:

> Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage

[6] *Id.* at p. 320.
[7] *Id.* at p. 317.

> occurs when cost of retirement exceeds gross salvage.[8]

In that same section of the text, NARUC concludes that:

> Cost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate.[9]

The estimated future net salvage is part of the annual depreciation accrual, which is credited to the depreciation reserve to cover the estimated future net salvage costs the company may incur in the future associated with plant asset retirements.

III. <u>Estimated Terminal Net Salvage Costs (Decommissioning or Dismantlement Costs)</u>

Q. WHAT ARE ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS?

A. Estimated future terminal net salvage costs are estimated future costs that are associated with the closure and assumed demolition of a production plant that is no longer in service. These costs are also referred to as decommissioning or dismantlement costs.

[8] *Id.* at p. 18.
[9] *Id.* at p. 19.

Q. DID DEP INCLUDE ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS FOR POWER PRODUCTION PLANTS IN THE PROPOSED DEPRECIATION RATES?

A. Yes. The estimated future terminal net salvage costs for power production plants included in DEP's proposed depreciation rates are supported by the Burns & McDonnell *Decommissioning Cost Estimate Study* ("DEP Decommissioning Cost Estimate Study") provided as Doss Exhibit 5 in the Sub 1142 proceeding.[10]

DEP's estimated future terminal net salvage costs for power production plants assume **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**.[11]

Q. IS IT CERTAIN THAT DEP WILL DEMOLISH THE STRUCTURES AND OTHER ASSETS WHEN A PRODUCTION PLANT RETIRES FROM SERVICE?

A. No. There are other alternatives that may not result in the demolition of the structures at the production plant site. One alternative is to convert a coal power production plant to a natural gas power production plant, which would not require the demolition of all the structures owned by DEP. Another alternative would be to sell the

[10] DEP Decommissioning Cost Estimate Study, provided as Confidential Attachment in response to Public Staff Data Request 17-18, attached as Confidential Exhibit RMM-2.
[11] *Id.* at p. 18.

production plant, which would not require the demolition of all the structures owned by DEP.

Q. ARE YOU PROPOSING ADJUSTMENTS TO DEP'S ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS?

A. Yes. I am proposing to continue the use of the current approved 10% contingency for future "unknowns" included in DEP's estimated future terminal net salvage costs.

Q. WHAT IS THE CURRENT APPROVED CONTINGENCY FACTOR?

A. In its Sub 1142 Order, the Commission approved the 10% contingency factor included in the stipulation, instead of the 20% contingency factor included in the DEP Decommissioning Cost Estimate Study conducted by Burns and McDonnell filed as Doss Exhibit 5 in that docket.[12]

Q. HAS THE COMMISSION REVIEWED THE CONTINGENCY FACTOR USED IN BURNS AND MCDONNELL DECOMMISSIONING COST ESTIMATE STUDY IN ANOTHER PROCEEDING?

Yes. Regarding the contingency factor used a Decommissioning Cost Estimate Study conducted by Burns and McDonnell for Duke Energy Carolinas, LLC, the Commission found:

[12] Sub 1142 Order at pp. 43-44.

> The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e. increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.[13]

Q. WHAT CONTINGENCY FACTOR DID DEP ASSUME IN THE FUTURE ESTIMATED TERMINAL NET SALVAGE COSTS IN THIS PROCEEDING?

A. In this proceeding, DEP's proposed future terminal net salvage costs are again supported by the same DEP Decommissioning Cost Estimate Study reviewed in the Sub 1142 Proceeding.[14]

DEP proposed to return to the original 20% contingency factor included in the DEP Decommissioning Cost Estimate Study "to cover unknowns," which escalates the estimated terminal net salvage costs in the depreciation rate calculation.

[13] June 22, 2018, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in Docket No. E-7, Sub 1146 at pp. 172-173.

[14] DEP Decommissioning Cost Estimate Study, provided as confidential attachment in response to Public Staff Data Request 17-18, attached as Confidential Exhibit RMM-2.

Q. WHAT DO YOU RECOMMEND REGARDING THE CONTINGENCY FACTOR?

A. I recommend the continued use of the current approved 10% contingency factor for the future estimated terminal net salvage costs included in the calculation of the depreciation rate.

IV. <u>Advanced Metering Infrastructure ("AMI") Meter Service Life</u>

Q. WHAT SERVICE LIFE DOES DEP RECOMMEND FOR THE AMI METERS?

A. DEP is proposing a 15-year average service life for AMI Meters.

Q. WHAT IS THE LIFE RANGE INDICATED BY THE MANUFACTURER OF THE AMI METERS?

A. In response to discovery, DEP stated that the manufacturer expected a service life of 15-20 years for AMI meters.[15] DEP is proposing to use the low end of that range. DEP's proposal to use the low end of the life range increases the depreciation expense, all other things being equal.

Q. WHAT LIFE DO YOU RECOMMEND FOR AMI METERS?

A. Since DEP's deployment of AMI meters occurred primarily in the past three years, it has limited historic data on the service lives of AMI

[15] DEP Confidential response to Public Staff Data Request 17-10, attached as Confidential Exhibit RMM-3. In correspondence to Public Staff dated March 19, 2020, counsel for DEP indicated that it would waive the confidentiality of the information related to the expected service life information provided by the manufacturer of the AMI meters.

meters.[16] I therefore recommend a 17-year life that is in the middle of the manufacturer's range. Using a life in the middle of the range is a reasonable estimate based on the manufacturer's expected life of the AMI meters and is fair to both the Company and the ratepayer.

V. Mass Property Future Net Salvage

Q. DID YOU REVIEW THE REASONABLENESS OF DEP'S PROPOSED FUTURE NET SALVAGE FOR A MASS PROPERTY ACCOUNT?

A. Yes. For Mass Property Distribution Accounts 364, 366, and 369, I recommend future net salvage percentages that differ from DEP's proposal as shown in Table 3 below:

Table 3: Comparison of Distribution Plant Future Net Salvage ("FNS") Percent Proposals

Account	Current Approved FNS %	DEP's Proposed FNS %	Public Staff's Proposed FNS %
Account 364, Poles, Towers, & Fixtures	-100%	-100%	-75%
Account 366, Underground Conduit	-10%	-15%	-10%
Account 369, Services	-10%	-20%	-15%

[16] Spanos Exhibit 1 (2018 Depreciation Study) at p. 303.

Q. PLEASE EXPLAIN WHAT FACTORS DEP CONSIDERED IN THE ESTIMATION OF THE PROPOSED FUTURE NET SALVAGE PERCENTS.

A. Mr. Spanos included the historic net salvage ratios calculated in the 2018 Depreciation Study as part of his analysis. In his direct testimony, Mr. Spanos states:

> The net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided to me by the Company's operating personnel, general knowledge and experience of industry practices; and trends in the industry in general. The statistical net salvage analyses incorporate the Company's actual historical data for the period 1979 through 2018, and considers the cost of removal and gross salvage ratios to the associated retirements during the 40-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.[17]

The DEP 2018 Depreciation Study included the analysis of the historic data of incurred net salvage and related retirements. Regarding historic net salvage, the 2018 Depreciation Study states:

> The estimates of net salvage by account were based in part on historical data compiled through 2018. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account

[17] Direct Testimony of John J. Spanos at p. 12, line 20 through p. 13, line 6.

> are expressed as a percent of the original cost of plant retired.[18]

Q. WHAT IS A CONCERN REGARDING THE HISTORIC NET SALVAGE RATIOS CALCULATED IN THE 2018 DEPRECIATION STUDY?

A. As pointed out in Wolf and Fitch's *Depreciation Systems*:

> Salvage ratios are a function of inflation.[19]

Additionally, *Depreciation Systems* points out that a historic net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator is a ratio using different units, stating:

> One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels.[20]

The calculation of the historic net salvage ratio includes the impact of high historic inflation rates since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic

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[18] Spanos Exhibit 1 (2018 Depreciation Study) at p. 42.

[19] Wolf, Frank K. and Fitch, W. Chester *Depreciation Systems* (Iowa State University Press, 1994) at p. 267.

[20] *Id.* at p. 53.

dollars. In other words, due to inflation, the amounts in numerator and denominator of the net salvage ratio are at different price levels.

Q. IS THE FACT THAT HISTORIC INFLATION IS INCLUDED IN THE NET SALVAGE RATIO RECOGNIZED IN ANOTHER AUTHORITATIVE DEPRECIATION TEXT?

A. Yes. Regarding inflation, NARUC's *Public Utility Depreciation Practices* states:

> The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices.[21]

As stated earlier in this testimony, NARUC also points out that careful consideration should be given to the net salvage estimate, stating:

> Cost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate"[22]

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE IMPACT OF INFLATION IN THE SETTING OF THE FUTURE NET SALVAGE PERCENT?

A. Yes. I am aware of several jurisdictions that have adopted future net salvage percents that recognized the inflated dollars included in the

[21] Page 19, *Public Utilities Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[22] *Id.* at p. 19.

historic net salvage ratio and adopted future net salvage percent that recognizes the time value of the cost of removal due to inflation.

- The Connecticut Public Utilities Regulatory Authority, in its December 14, 2016 Decision in Docket No. 16-06-04 the Commission accepted net salvage depreciation rates that produced "an annual accrual that is 1.2 times the annual incurred distribution plant net salvage costs" stating that the "distribution net salvage depreciation rates still comfortably cover the actual incurred net salvage costs."[23]

- The Public Service Commission of the District of Columbia Order No. 15710 stated: "Fairness and equity require that the Commission adopt a methodology that, to the extent possible, balances the interest of current and future ratepayers," and went on to state:

> Pepco should not be allowed to charge current customers for future inflation, nor should Pepco be allowed to charge current customers in higher-value current dollars for a future cost of removal amount that is calculated in lower-value future dollars.[24]

- The Public Service Commission of Maryland in its Order No. 81517 stated:

[23] Connecticut Public Utilities Regulatory Authority Docket No. 16-06-04, December 14, 2016 Decision at p. 46.

[24] Public Service Commission of the District of Columbia Formal Case No. 1076, paragraph 252 of March 2, 2010, Order No. 15710.

> The Commission has carefully reviewed the record and finds that the Present Value Method should be adopted for the recovery of removal costs. The Straight Line Method recovers the same annual cost in nominal dollars from ratepayers today as it does at the time plant is removed from service. However, a dollar is worth substantially more today than it will be 20 to 40 years from now. Consequently, today's ratepayers would pay more in "real" dollars under the Straight Line Method for the recovery costs of the plant they consume than would future ratepayers when net salvage is negative, as everyone projects.[25]

- The New Jersey Board of Public Utilities found:

> As a result of this data and the underlying concept of FASB 143 as discussed in this matter, the Board FINDS it appropriate to revisit the concept of including estimated future net salvage in current depreciation rates. The Board HEREBY FINDS the recommendation of the Ratepayer Advocate and Staff to exclude estimated net salvage from depreciation rates to be appropriate. The Board FURTHER FINDS that the Ratepayer Advocate and Staff's proposed utilization of a five-year average of actual salvage expense in depreciation expense is reasonable as it more closely aligns the amount recovered in base rates with the historical level of expenses incurred. The Board concurs with Staff that the ten-year window of actual experience rather than the five-year rolling average proposed by the Ratepayer Advocate is appropriate.[26]

- The Pennsylvania Superior Court found:

> Negative salvage attributed to existing plant is purely prospective; it is a cost which has not yet been incurred; it is uncertain when and if it will be incurred; and it is not a part of the original cost of construction of the facilities when first devoted to public service. To permit the recovery of

[25] Public Service Commission of Maryland Case No. 9092 page 30 of July 9, 2007 Order No. 81517.

[26] New Jersey Docket No. ER02080506, Final Order at pp. 129-30 (May 14, 2004).

> prospective negative salvage is to permit the recovery of a total amount in excess of the original cost of construction prior to the actual expenditure of those costs and, in our opinion, represents the recovery of something in the nature of a future reproduction cost. The established law in this Commonwealth does not permit the recovery by annual depreciation of any such prospective excess. It is therefore the prospective nature of future negative salvage that prevents it from being considered either in accrued depreciation or in the allowance for annual depreciation; they must have a consistent basis under our law.[27]

Q. IS THE DEP PROPOSED FUTURE NET SALVAGE PERCENT BASED SOLELY ON HISTORIC NET SALVAGE RATIOS CALCULATED IN THE 2018 DEPRECIATION STUDY?

A. No. Using Account 369, Services as an example, the calculated historic net salvage ratios for Account 369, Services are included in the 2018 Depreciation Study.[28]

DEP's proposed -20% future net salvage percent is not one of the historic net salvage ratios calculated in the 2018 Depreciation Study. Based on the calculations in the 2018 Depreciation Study, the overall historic net salvage ratio is -38%, the five-year average historic net salvage ratio is -23%, and the three-year average historic net salvage ratios range from -161% to -1%. So DEP's proposed -20% is not based solely on the calculated historic net salvage ratios.

[27] Pennsylvania, Superior Court of Pennsylvania in Penn Sheraton Hotel v. Pennsylvania Public Utility Commission, 184 A.2d 324, 329 (Pa. Super. Ct. 1962).
[28] Spanos Exhibit 1 (2018 Depreciation Study) at pp. 409-411.

Q. HAVE YOU REVIEWED THE RECOVERY OF FUTURE NET SALVAGE COSTS INCLUDED IN DEP'S PROPOSED DEPRECIATION RATES AND THE ACTUAL NET SALVAGE COSTS DEP HAS INCURRED IN THE RECENT PAST?

A. Yes. Instead of relying solely on the historic net salvage ratios, which are influenced by historic inflation levels, I also reviewed the future net salvage costs included in DEP's proposed depreciation accrual and the actual net salvage costs incurred by DEP on average over the recent five-year period.

Q. PLEASE PROVIDE THE COMPARISON OF DEP'S ACTUAL NET SALVAGE INCURRED AND PROPOSED ANNUAL ACCRUAL FOR FUTURE NET SALVAGE.

A. Table 4 below is a comparison of the actual net salvage costs incurred by DEP on average over the recent five-year period to future net salvage costs included in DEP's and the Public Staff's proposed depreciation accruals.

Table 4: Comparison of Actually Incurred Net Salvage and Net Salvage in Proposed Depreciation Rates as of December 31, 2018 Investments[29]

Account	Description	Five Year Net Salvage Actually Incurred	Net Salvage Recovery included in DEP's Proposed Depr Rates	DEP Proposed / Actually Incurred	Net Salvage Recovery included in Public Staff's Proposed Depr Rates	Public Staff Proposed / Actually Incurred
		A	B	C=B/A	D	E=D/A
	DISTRIBUTION PLANT					
361.00	Structures & Improvements	$ 71,828	$ 263,656	3.7	$ 263,656	3.7
362.00	Station Equipment	1,231,386	1,999,844	1.6	1,999,844	1.6
364.00	**Poles, Towers, & Fixtures**	**567,257**	**16,778,097**	**29.6**	**11,558,347**	**20.4**
365.00	Overhead Conductors & Dev	1,396,464	5,751,241	4.1	5,751,241	4.1
366.00	**Underground Conduit**	**44,902**	**616,405**	**13.7**	**402,170**	**9.0**
367.00	Undgrd Conductors & Dev	281,705	876,716	3.1	876,716	3.1
368.00	Line Transformers	616,069	1,324,123	2.1	1,324,123	2.1
369.00	**Services**	**344,410**	**1,811,464**	**5.3**	**1,308,069**	**3.8**
370.00	Metering Equip & Meters	705,739	430,396	0.6	430,396	0.6
370.02	Meters - Utility of the Future	0	0		0	
371.00	Installations on Cust.' Premises	115,608	400,523	3.5	400,523	3.5
373.00	Street Lighting & Signal Systems	518,231	1,167,357	2.3	1,167,357	2.3
	TOTAL DISTRIBUTION PLANT	**$ 5,893,597**	**$ 31,419,823**	**5.3**	**$ 25,482,442**	**4.3**

Q. ARE YOUR PROPOSED FUTURE NET SALVAGE PERCENTS BASED ONLY ON THE HISTORICAL ANALYSIS SHOWN IN TABLE 4 ABOVE?

A. No, which is supported by the fact that my proposed future net salvage accrual amounts are not equal to the average annual historical amount as shown in Table 4 above. Table 4 provides a reasonableness check of the proposed future net salvage percents.

[29] This table is based on the December 31, 2018 investment levels used in the 2018 Depreciation Study.

My proposed future net salvage accrual amounts consider DEP's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience.

Q. PLEASE EXPLAIN HOW YOUR FUTURE NET SALVAGE BUILDS THE RESERVE FOR FUTURE NET SALVAGE COSTS.

A. Using Account 364, Poles, Towers, and Fixtures for discussion, as shown on Table 4 above, DEP actually incurred $567,257 in net salvage costs on average per year, however, DEP proposes to collect a $16,778,097 net salvage annual accrual.[30] The annual accrual amount is an expense to be recovered from ratepayers in customer charges.[31] The annual accrual DEP is proposing for net salvage is about 29.6 times the average annual amount DEP has actually recently incurred for net salvage.

Under my recommendation, the annual accrual for Account 364, Poles, Towers, and Fixtures net salvage would still be $11,558,347, which is about 20.4 times the average annual amount DEP actually incurred.[32] My recommendation provides recovery of the expected

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[30] Annual accrual amount based on investments as of December 31, 2018.

[31] The exact amount to be recovered from ratepayers will vary when calculated on investments other than the investment as of December 31, 2018.

[32] Annual accrual amount based on investments as of December 31, 2018. I am not recommending or implying a change from the "accrual" basis to the "cash" basis for the recovery of future net salvage costs. In other words, I am not recommending or implying

cost of removal in the near future and builds the reserve for future cost of removal associated with future retirements.

VI. Continue Use of Current Approved Amortization Period for General Plant Accounts

Q. WHAT CHANGE DEP IS PROPOSING TO THE AMORTIZATION PERIOD FOR TWO GENERAL PLANT ACCOUNTS?

A. DEP is proposing to change the current approved 20-year amortization period for Account 391, Office Furniture and Equipment to a 15-year amortization and the current approved 20-year amortization period for Account 397, Communication Equipment to a 10-year amortization period.

Q. WHAT CHANGES WERE MADE TO ACCOUNT 391, OFFICE FURNITURE AND EQUIPMENT AND ACCOUNT 397, COMMUNICATION EQUIPMENT IN THE PREVIOUS DOCKET?

A. In the Sub 1142 Proceeding, the Commission approved DEP's proposed change from depreciation accounting to amortization accounting using a 20-year amortization period for Account 391, Office Furniture and Equipment and Account 397, Communication Equipment. The Sub 1142 Order stated:

> The Stipulating Parties have agreed as part of the settlement to the 20-year amortization period for Accounts 391 and 397. In light of all of the evidence, the Commission finds and concludes that a 20-year

that the depreciation accrual no longer be credited to the Accumulated Provision for Depreciation or that the net salvage costs be "expensed".

> amortization period for Accounts 391 and 397 proposed by the Stipulating Parties is reasonable in this case.[33]

Q, WHAT CHANGE IS DEP PROPOSING TO THE AMORTIZATION PERIODS FOR ACCOUNT 391, OFFICE FURNITURE AND EQUIPMENT AND ACCOUNT 397, COMMUNICATION EQUIPMENT IN THIS PROCEEDING?

A. DEP is proposing the same amortization periods for these accounts that it initially proposed in the Sub 1142 Proceeding. For Account 391, Office Furniture and Equipment DEP is again proposing a 15-year amortization period and for Account 397, Communication DEP is again proposing a 10-year amortization period.

Q. DID THE DEP 2018 DEPRECIATION STUDY PROVIDE ANY DATA SUPPORTING THE PROPOSED CHANGE IN THE AMORTIZATION PERIOD FOR THESE ACCOUNTS?

A. No. The 2018 Depreciation Study did not provide any life data for Account 391, Office Furniture and Equipment and Account 397, Communication Equipment. The lack of life data is not uncommon for amortized accounts due to the change in the record-keeping for an amortized account.

[33] Sub 1142 Order at p. 49.

Q. PLEASE EXPLAIN THE DIFFERENCE IN RECORD KEEPING BETWEEN DEPRECIATION ACCOUNTING AND AMORTIZATION ACCOUNTING.

A. Under depreciation accounting, the Company keeps track of the installation date and retirement date of each asset in the depreciable account. These detailed historical records are then used to populate the original life tables for each account, as shown in Section VII of the 2018 Depreciation Study.

Under amortization accounting, DEP no longer keeps the detailed records needed to populate the original life tables. DEP tracks the installation year, but the asset will be retired off the books when it reaches the approved average service life, whether or not that asset is still in service. The use of amortization accounting for these smaller value general plant accounts is used to minimize the accounting expense involved in keeping the detailed records used in depreciation accounting.

Q. HOW DID DEP DETERMINE THE AMORTIZATION PERIODS TO BE USED?

A. The 2018 Depreciation Study states:

> The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives

> used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.[34]

Q. ARE THE AMORTIZATION PERIODS PROPOSED BY DEP BASED ON THE "SERVICE LIFE ESTIMATES PREVIOUSLY USED FOR THE ASSET UNDER DEPRECIATION ACCOUNTING"?

A. No. The current approved amortization period for both Account 391, Office Furniture and Equipment and Account 397, Communication Equipment is 20 years. Prior to the switch to amortization accounting in the Sub 1142 Proceeding the approved service life for Account 391, Office Furniture and Equipment was 20 years and the approved service life for Account 397, Communication Equipment was 27 years.

Q. DID YOU FILE TESTIMONY IN THE SUB 1142 PROCEEDING REGARDING THE SERVICE LIFE ESTIMATES FOR BOTH ACCOUNT 391, OFFICE FURNITURE AND EQUIPMENT AND ACCOUNT 397, COMMUNICATION EQUIPMENT?

A. Yes. Pages 33-37 of my Direct Testimony in the Sub 1142 Proceeding discussed the previously approved 20-year service life for Account 391, Office Furniture and Equipment and the previously

[34] Spanos Exhibit 1 (2018 Depreciation Study) at p. 50.

approved 27-year service life for Account 397, Communication Equipment based on the data provided in Docket No. E-2, Sub 1025.

Q. WHAT AMORTIZATION PERIOD DO YOU RECOMMEND FOR ACCOUNT 391, OFFICE FURNITURE AND EQUIPMENT AND ACCOUNT 397, COMMUNICATION EQUIPMENT?

A. Based on the analysis I provided in the Sub 1142 Proceeding and since DEP did not provide any information supporting the change in the current approved amortization period for these accounts. I recommend the continued use of the currently approved 20-year amortization period for these accounts.

VII. <u>Mayo Unit 1 and Roxboro Units 3 and 4 Final Retirement Year</u>

Q. WHAT FINAL RETIREMENT YEAR ARE INCLUDED IN THE CALCULATED DEPRECIATION RATES FOR MAYO UNIT 1 AND ROXBORO UNITS 3 AND 4?

A. At the request of Public Staff, I have used the expected final retirement dates of June 2035 for Mayo Unit 1 and June 2033 for Roxboro Units 3 and 4 in the calculation of the Public Staff proposed depreciation rates, consistent with the retirement dates used in the Sub 1142 Proceeding, rather than the earlier retirement date of June 2029 for all three units proposed in this proceeding by DEP. This analysis, and the Public Staff's proposed adjustment to the depreciation expense, are discussed further in the testimony of Public Staff witnesses Shawn Dorgan and Dustin Metz.

VIII. Composite Distribution Depreciation Rate Excluding AMR Meters

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE 2.26% DISTRIBUTION PLANT COMPOSITE DEPRECIATION RATE EXCLUDING AMR METERS?

A. At the request of Public Staff, I calculated the distribution plant composite depreciation rate excluding AMR Meters based on my proposed depreciation rates shown in my attached Exhibit RMM-1.

Table 5: Composite Depreciation Rate Excluding AMR Meters[35]

Amounts from Exhibit RMM-1	12/31/2018 Investment	Public Staff Proposed Annual Depr	Public Staff Proposed Depr Rate
Total Distribution Plant	6,869,268,718	159,311,890	2.32%
AMR Meters	142,517,522	7,007,351	
Distribution Composite w/o AMR Meters	6,726,751,196	152,304,529	**2.26%**

This adjustment is discussed further in the testimony of Public Staff witness Shawn Dorgan.

IX. Conclusion

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. For the reasons stated above, I recommend that the Public Staff's proposed depreciation rates shown on Exhibit RMM-1 be approved for DEP.

[35] Exhibit RMM-1 at p. 12.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Roxie McCullar, CPA, CDP
8625 Farmington Cemetery Road
Pleasant Plains, IL

Roxie McCullar is a regulatory consultant, licensed Certified Public Accountant in the state of Illinois, and a Certified Depreciation Professional through the Society of Depreciation Professionals. She is a member of the American Institute of Certified Public Accountants, the Illinois CPA Society, and the Society of Depreciation Professionals. Ms. McCullar has received her Master of Arts degree in Accounting from the University of Illinois-Springfield as well as her Bachelor of Science degree in Mathematics from Illinois State University. Ms. McCullar has 20 years of experience as a regulatory consultant for William Dunkel and Associates. In that time, she has filed testimony in over 50 state regulatory proceedings on depreciation issues and cost allocation for universal service and has assisted Mr. Dunkel in numerous other proceedings.

Education

Master of Arts in Accounting from the University of Illinois-Springfield, Springfield, Illinois

12 hours of Business and Management classes at Benedictine University-Springfield College in Illinois, Springfield, Illinois

27 hours of Graduate Studies in Mathematics at Illinois State University, Normal, Illinois

Completed Depreciation Fundamentals training course offered by the Society of Depreciation Professionals

Relevant Coursework:

- Calculus
- Number Theory
- Linear Programming
- Finite Sampling
- Introduction to Micro Economics
- Principles of MIS
- Introduction to Managerial Accounting
- Intermediate Financial Accounting I
- Advanced Financial Accounting
- Accounting Information Systems
- Fraud Forensic Accounting
- Commercial Law
- Advanced Auditing
- Discrete Mathematics
- Mathematical Statistics
- Differential Equations
- Statistics for Business and Economics
- Introduction to Macro Economics
- Introduction to Financial Accounting
- Intermediate Managerial Accounting
- Intermediate Financial Accounting II
- Auditing Concepts/Responsibilities
- Federal Income Tax
- Accounting for Government & Non-Profit
- Advanced Utilities Regulation
- Advanced Corp & Partnership Taxation

Current Position: Consultant at William Dunkel and Associates

Participation in the proceedings below included some or all of the following:

> Developing analyses, preparing data requests, analyzing issues, writing draft testimony, preparing data responses, preparing draft questions for cross examination, drafting briefs, and developing various quantitative models.

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2020	North Carolina	North Carolina Utilities Commission	E-7, SUB 1214	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2019	Kansas	Kansas Corporation Commission	20-UTAT-032-KSF	United Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2019	Kansas	Kansas Corporation Commission	19-ATMG-525-RTS	Atmos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2019	Kansas	Kansas Corporation Commission	19-GNBT-505-KSF	Golden Belt Telephone Association	Cost Study Issues, Support Fund Adjustments	Kansas Corporation Commission Staff
2019	Arizona	Arizona Corporation Commission	E-01933A-19-0028	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2019	North Carolina	North Carolina Utilities Commission	E-22, SUB 562	Dominion Energy North Carolina	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2019	Utah	Public Service Commission of Utah	19-057-03	Dominion Energy Utah	Natural Gas Depreciation Issues	Division of Public Utilities
2019	Kansas	Kansas Corporation Commission	19-EPDE-223-RTS	Empire District Electric Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2019	Arizona	Arizona Corporation Commission	T-03214A-17-0305	Citizens Telecommunications Company	Arizona Universal Service Fund	The Utilities Division Staff Arizona Corporation Commission
2018	Kansas	Kansas Corporation Commission	18-KGSG-560-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2018	Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4800	SUEZ Water	Water Depreciation Issues	Division of Public Utilities and Carriers

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4770	Narragansett Electric Company	Electric & Natural Gas Depreciation Issues	Division of Public Utilities and Carriers
2018	North Carolina	North Carolina Utilities Commission	E-7, SUB 1146	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	DC	District of Columbia Public Service Commission	FC1150	Potomac Electric Power Company	Electric Depreciation Issues	District of Columbia Public Service Commission
2017	North Carolina	North Carolina Utilities Commission	E-2, SUB 1142	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	Washington	Washington Utilities & Transportation Commission	UE-170033 & UG-170034	Puget Sound Energy	Electric & Natural Gas Depreciation Issues	Washington State Office of the Attorney General, Public Council Unit
2017	Florida	Florida Public Service Commission	160186-EI & 160170-EI	Gulf Power Company	Electric Depreciation Issues	The Citizens of the State of Florida
2016	Kansas	Kansas Corporation Commission	16-KGSG-491-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2016	DC	District of Columbia Public Service Commission	FC1139	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2016	Arizona	Arizona Corporation Commission	E-01933A-15-0239 & E-01933A-15-0322	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2016	Georgia	Georgia Public Service Commission	40161	Georgia Power Company	Addressed Depreciation Issues	Georgia Public Service Commission Public Interest Advocacy Staff
2016	DC	District of Columbia Public Service Commission	FC1137	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2015	Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Amos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2015	Kansas	Kansas Corporation Commission	15-TWVT-213-AUD	Twin Valley Telephone, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-MRGT-097-AUD	Moundridge Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-S&TT-525-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-WTCT-142-KSF	Wamego Telecommunications Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-PLTT-678-KSF	Peoples Telecommunications, LLC	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	New Jersey	State of New Jersey Board of Public Utilities	BPU ER12121071	Atlantic City Electric Company	Electric Depreciation Issues	New Jersey Rate Counsel
2013	Kansas	Kansas Corporation Commission	13-JBNT-437-KSF	J.B.N. Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-ZENT-065-AUD	Zenda Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	DC	District of Columbia Public Service Commission	FC1103	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2012	Kansas	Kansas Corporation Commission	12-LHPT-875-AUD	LaHarpe Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-GRHT-633-KSF	Gorham Telephone Company	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-S&TT-234-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2011	DC	District of Columbia Public Service Commission	FC1093	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2011	Kansas	Kansas Corporation Commission	11-CNHT-659-KSF	Cunningham Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2011	Kansas	Kansas Corporation Commission	11-PNRT-315-KSF	Pioneer Telephone Association	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2010	Kansas	Kansas Corporation Commission	10-HVDT-288-KSF	Haviland Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2009	Kansas	Kansas Corporation Commission	09-BLVT-913-KSF	Blue Valley Tele-Communications, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2009	DC	District of Columbia Public Service Commission	FC1076	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2008	Kansas	Kansas Corporation Commission	09-MTLT-091-KSF	Mutual Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2007	Kansas	Kansas Corporation Commission	08-MRGT-221-KSF	Moundridge Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-PLTT-1289-AUD	Peoples Telecommunications, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-MDTT-195-AUD	Madison Telephone, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	06-RNBT-1322-AUD	Rainbow Telecommunications Assn., Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-WCTC-1020-AUD	Wamego Telecommunications Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-H&BT-1007-AUD	H&B Communications, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-ELKT-365-AUD	Elkhart Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-SCNT-1048-AUD	South Central Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Utah	Public Service Commission of Utah	05-2302-01	Carbon/Emery Telecom, Inc.	Cost Study Issues & Depreciation Issues	Utah Committee of Consumer Services
2005	Kansas	Kansas Corporation Commission	05-TTHT-895-AUD	Totah Communications, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Maine	Public Utilities Commission of the State of Maine	2005-155	Verizon	Depreciation Issues	Office of Public Advocate

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2005	Kansas	Kansas Corporation Commission	05-TRCT-607-KSF	Tri-County Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-CNHT-020-AUD	Cunningham Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-KOKT-060-AUD	KanOkla Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-UTAT-690-AUD	United Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-CGTT-679-RTS	Council Grove Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-GNBT-130-AUD	Golden Belt Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	03-TWVT-1031-AUD	Twin Valley Telephone, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-HVDT-664-RTS	Haviland Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-WHST-503-AUD	Wheat State Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-S&AT-160-AUD	S&A Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-JBNT-846-AUD	JBN Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-S&TT-390-AUD	S&T Telephone Cooperative Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2002	Kansas	Kansas Corporation Commission	02-BLVT-377-AUD	Blue Valley Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-PNRT-929-AUD	Pioneer Telephone Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-BSST-878-AUD	Bluestem Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SFLT-879-AUD	Sunflower Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-CRKT-713-AUD	Craw-Kan Telephone Cooperative, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	11-RNBT-608-KSF	Rainbow Telecommunications Association	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SNKT-544-AUD	Southern Kansas Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-RRLT-518-KSF	Rural Telephone Service Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2000	Illinois	Illinois Commerce Commission	98-0252	Ameritech	Cost Study Issues	Government and Consumer Intervenors

MS. DOWNEY: Thank you, Commissioner. Finally, Dustin R. Metz, direct testimony and exhibits [sic] filed on April 13, 2020, consisting of 36 pages, Appendix A, which contains confidential information, the testimony does; and supplemental testimony filed September 15, 2020, consisting of four pages.

COMMISSIONER CLODFELTER: All right. You've heard the motion, any objections?

(No response.)

COMMISSIONER CLODFELTER: Hearing no objections, the motion is granted.

(Whereupon, the prefiled direct testimony and Appendix and supplemental testimony of Dustin R. Metz were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	CORRECTED TESTIMONY OF DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

CORRECTED TESTIMONY OF DUSTIN R. METZ
ON BEHALF OF THE PUBLIC STAFF NORTH
CAROLINA UTILITIES COMMISSION

APRIL 13, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Dustin Ray Metz. 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. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the results of my investigation into Duke Energy Progress LLC's (DEP or the Company) request for a general rate increase in this proceeding.

Q. WHAT WERE YOUR AREAS OF INVESTIGATIVE RESPONSIBILITY IN THIS CASE?

A. I participated in and contributed to a number of components of the Public Staff's investigation in this case, but I specifically reviewed or supervised the review of the following:

- General capital additions to nuclear, hydro, solar, and certain aspects of the fossil generation fleet, including the following:
  - Asheville Combined Cycle Plant
  - Roxboro Waste Water Treatment Facility
  - Harris Nuclear Power Plant Reactor Vessel Head
  - Robinson Nuclear Power Plant Low Pressure Turbine Blade Replacement
- Accelerated retirement of Roxboro Station Units 3 and 4 and Mayo Steam Station
- Materials and Supplies (M&S) inventory
- Legal and non-legal invoices related to Outside Services
- E-1, Item 10 NC-1500 Adjustment to levelize nuclear refueling outage costs
- E-1, Item 10 NC-2400 Adjustment to coal inventory
- E-1, Item 10 NC-2800 Adjustment to end of life nuclear costs
- E-1, Item 10 NC-3400 Asheville Combined Cycle
- E-1, Item 10 NC-3500 Power Purchase Agreements
- Staffing levels for specific work groups
- Vanderbilt to West Asheville 115 kV Transmission Line

- o Darlington Combustion Turbine retirements
- o Base fuel factor

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

A. I recommend the following adjustments in this case:

- M&S Inventory - remove costs associated with unusable inventory
- NC-2400 minor modifications to account for updates in fuel commodity pricing and retirement of the Asheville Steam Plant (coal).
- NC-2800 minor modifications related to the inclusion of salvage value for inventory.
- NC-3400 minor modifications to adjust the estimated Operations and Maintenance expense for Asheville Combined Cycle

In addition, I address several general concerns that I have for the Commission's consideration.

Capital Additions to Generating Plants

Q. PLEASE DESCRIBE THE SPECIFIC CAPITAL ADDITIONS TO THE COMPANY'S GENERATION FLEET THAT YOU REVIEWED IN THIS CASE.

A. DEP witnesses Turner and Henderson, in their prefiled direct testimonies, discuss the addition of approximately $2.8 billion of capital plant investments either placed in service, or expected to be placed in service by February 29, 2020.[1] As part of the Public Staff's investigation, I looked at multiple aspects of capital spend to evaluate for reasonableness and prudence, as well as whether the underlying asset(s) or result of the capital investment is currently used and useful.

My investigation included the following: (1) a review of the prefiled direct testimony of DEP witnesses Turner and Henderson; (2) an audit of specific expenditures (i.e., sampling of specific costs); (3) initial and follow-up discovery; (4) teleconferences between the Company and Public Staff; (5) interviews with Company witnesses and staff, including detailed discussions on specific aspects of certain projects; (6) site visits; and (7) a review of the overall projects with Company management.

[1] Direct Testimony of DEP witness Julie Turner, at 6, and Direct Testimony of DEP witness Kelvin Henderson, at 7.

Asheville Combined Cycle Plant

Q. HAS THE NEW ASHEVILLE COMBINED CYCLE PLANT (ASHEVILLE CC) BEEN PLACED IN SERVICE?

A. Partially. Three of the four generating units are online and have been called on and are available for economic dispatch.[2]

Q. WHY IS THE ASHEVILLE CC PLANT ONLY PARTIALLY IN SERVICE?

A. During testing, unexpected events occurred on one of the steam turbines (STs). These unexpected events have led to repairs and further testing, which I discuss below.

Q. PLEASE ELABORATE ON THE UNEXPECTED EVENTS.

A. There were **[BEGIN CONFIDENTIAL]** [redacted]

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[2] The new Asheville CC is comprised of two power blocks (PB). Each PB consists of one combustion turbine (CT) and one steam turbine (ST). The combination of a CT and ST make up each combined cycle PB. A CT and ST are both capable of generating electricity. While the CT can operate independently of its corresponding ST (often referred to as bypass mode), a ST cannot operate without its CT. A ST utilizes the exhaust heat (energy) from the CT to generate electricity.

[redacted] **[END CONFIDENTIAL]**

Q. WAS THE COMPANY AT FAULT FOR ANY OF THE EVENTS?

A. Based on my investigation, I do not believe so. The first event **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. DO YOU RECOMMEND ANY COST DISALLOWANCE IN THIS CASE?

A. No.

Q. DO YOU HAVE ANY RELATED RECOMMENDATIONS?

A. Yes. First, I encourage the Company to continue negotiations with the OEM to obtain a "no cost" extended warranty on at least the ST and its associated generator that experienced the damage events. An extended warranty would help minimize the risk to ratepayers from the potential of an embedded flaw or deficiency in the repair while also ensuring that the equipment will serve its intended purpose and life expectancy.

My second recommendation deals with reporting on and cost recovery of the Asheville CC in this rate case.

Q. PLEASE PROVIDE MORE DETAILS ON YOUR SECOND RECOMMENDATION.

A. Based on extensive review and discussions with the Company regarding the associated delays for the repairs of the Asheville CC discussed above, it is anticipated that the ST in question will be completed, placed in service, and be available for economic dispatch before the close of the hearing in this case.

As of the writing of my testimony, approximately three quarters of the total plant has been placed into rate base.

I recommend that the Commission require the Company to file a letter in this docket as soon as the repair to the PB2 ST is completed (i.e., commercially operational), has passed testing, has been connected to the electrical grid, has operated at approximately 100 percent of nameplate rating for at least 24 continuous hours without interruption, has supplied all generated energy to the "grid," and is available for full economic dispatch by the Company's Energy Control Center. In addition, the filing should provide hourly generation profiles showing the hourly megawatts (MW) delivered to the grid, along with realized heat rates and/or steam usage with incoming pressures for the minimum continuous 24 hour period identified above.

Other Areas of Concern Regarding Generating Plant Additions

Q. WHAT OTHER AREAS DID YOU IDENTIFY IN YOUR INVESTIGATION THAT YOU WISH TO HIGHLIGHT FOR THE COMMISSION?

A. My concerns are identical to those recently included in my testimony in the Duke Energy Carolinas, LLC rate case (Docket No. E-7, Sub 1214). To reiterate those concerns, I believe it is important for the Public Staff and the Commission to be able to evaluate the soundness of the Company's decisions to make significant capital investments in its electrical system that is both aging and expanding. For example, coal and nuclear generation assets are nearing the end of their useful lives. As an asset approaches the end of its useful remaining life, less time is available for continued capital investments to prove cost-effective for ratepayers. It is important to understand the cost impacts of both individual and multiple projects on both a capacity and energy basis.

Faced with a dynamic landscape of technological and regulatory changes, utilities must balance the operation of the electrical grid with the contemporaneous requirement of meeting supply and demand requirements in real time. These dual requirements affect the decision whether to retire a generation asset and build a new asset or invest capital to prolong the life of the existing generation asset.

Q. CAN YOU PROVIDE AN EXAMPLE IN THIS CURRENT RATE CASE THAT IS ILLUSTRATIVE?

Yes. DEP's H.B. Robinson Nuclear Power Plant (Robinson), a single unit generating plant, is currently scheduled to retire in 2030. Robinson has a nameplate capacity of just under 800 MW and operates at an average annual capacity factor in excess of 80%. The Company has indicated that it is moving forward with evaluation and the potential submittal of a second license renewal (SLR). An approved SLR would allow the Company to operate Robinson for up to an additional 20 years, for a total operating life of 80 years. As the Company evaluates capital projects for Robinson based on its current expected operating life through 2030, as well as additional capital costs necessary if a 20-year SLR were granted, such costs should be evaluated based on the cost effectiveness of continued plant operation and the resulting increase (or decrease) of both capacity and energy costs (kilowatt (kW) and kilowatt-hour (kWh) costs, respectively). It is also important to note that if the SLR is granted, while the unit will be certified to operate *up to* an additional 20 years, 20 years of additional operation is not guaranteed.

Also, at this time, the economics of evaluating whether obtaining an SLR is cost effective should be completed on a plant by plant basis and not on a portfolio basis. Absent an established carbon policy or a solidified plan on carbon reduction goals, cost estimations and sensitivities require a high degree of speculation. To the extent that the economics support a SLR, the Public Staff would encourage continued operation of the plant as it would be in ratepayer interest. Ultimately, if the generation output of older plants can be replaced with more economical resources, then older, less economical plants should be retired at their current license expiration date.

While the Public Staff agrees that the Company must operate its nuclear fleet in a safe manner while meeting all regulatory compliance requirements, it must also make sound capital investments, and those investments should be benchmarked and evaluated with results available for audit and verification by the Commission and Public Staff. This is also true for all generation assets in the Company's fleet and is not just specific to nuclear generation.

Q. DO YOU HAVE ANY RECOMMENDATIONS?

A. Yes. As I stated above, the Public Staff and Commission must be able to fully evaluate the Company's decisions to make significant capital investments in its electric system, including the consideration of alternative investments considered and not chosen. The Public Staff recommends that the Commission order the Company to begin collaboration with the Public Staff, within three months following conclusion of issuance of an Order in this rate case, to evaluate the necessity for modifications to internal Company policies and procedures to clarify the expectations for project evaluation and selection and document creation and retention, this would pertain to all additions to the electrical system, not only additions to generation plants, but also transmission and distribution groups. This will enable both the Company and Public Staff to be more efficient in requesting and reviewing project specific documentation going forward. This evaluation can be done in tandem with the evaluation recommended for Duke Energy Carolinas, LLC (DEC) in my recent testimony in DEC's pending general rate case (Docket No. E-7, Sub 1214; hereinafter, Sub 1214).

At this time, I am not proposing specific recommendations or changes to Company procedures, as I believe a collaborative effort will better enable the Company and Public Staff to identify the issues and craft solutions to address project evaluation and documentation concerns going forward. This will also ensure that Public Staff recommendations do not unintentionally impose unwarranted costs to ratepayers without providing a commensurate benefit. Finally, I will note that resolving these issues as soon as possible following the issuance of an Order in this rate case will ensure that we do not encounter similar issues with projects going forward.

Q. IN HIS TESTIMONY, COMPANY WITNESS DEMAY STATES THAT THE COMPANY IS ACTIVELY WORKING TOWARDS ACHIEVING A LOWER CARBON FUTURE. HAS THE COMPANY ANNOUNCED ITS CORPORATE NET CARBON GOAL, OR HAD THE NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY (NCDEQ) ISSUED ITS DRAFT OF THE CARBON REDUCTION PLAN AT THE TIME THAT DEP FILED ITS RATE CASE SEEKING RECOVERY OF CAPITAL INVESTMENTS?

A. While I do not have the exact percentage of projects that were planned and completed since Duke Energy Corporation (Duke) made its initial public announcement of a net carbon reduction goal in the summer of 2019, large capital projects of this nature take many years to plan, achieve funding approval, procure long lead time equipment, manage, construct, and commission. It is likely that the majority of these capital projects in question were approved by management well in advance of Duke's 2019 net carbon goals public announcement. NC DEQ issued its report in the fall of 2019, but the specifics to meet a recommended target have not been fully vetted nor developed. At this time, the DEQ stakeholder process is still ongoing and subject to continued stakeholder input; the exact plan for the electric utilities has not been solidified.

Q. HAS THE PUBLIC STAFF REVIEWED DUKE'S PROPOSED NET CARBON GOALS OR PLANS TO ACHIEVE SAID GOALS?

A. No. As of this date, DEP has not released a plan for achieving those goals.

<u>Accelerated Retirement of Coal Plants</u>

Q. DID THE COMPANY REQUEST TO ACCELERATE RETIREMENT OF CERTAIN COAL-FIRED GENERATION UNITS?

A. Yes. In this rate case, DEP indicated that it plans to retire Mayo Unit 1 and all four units of the Roxboro Plant in 2030. The retirement dates for Roxboro Units 3 and 4 and Mayo are now several years earlier than shown in DEP's 2018 Integrated Resource Plan (IRP)[3] filed on September 5, 2018, and the 2019 IRP Update[4] filed on September 3, 2019.

Q. DO YOU BELIEVE THAT A GENERAL RATE CASE IS THE MOST APPROPRIATE PROCEEDING FOR EVALUATING EARLY RETIREMENTS?

A. No. The Company's Integrated Resource Plan (IRP) proceeding is the appropriate venue for a thorough evaluation of early, or any, generation retirements. The IRP optimizes future generation additions and minimizes production costs across a robust variety of portfolios generated by the Company's capacity expansion model. The IRP modeling process seeks the optimal expansion plan for meeting customer needs given the load, planned unit retirements and uprates, inputs to the electrical system, and imposed constraints. While the IRP does not solely focus on the economics of retiring an asset early, it does evaluate various scenarios in more detail than is possible in the context of a general rate case.

[3] Docket No. E-100, Sub 157, at 91. – The retirement date shown for Mayo is December 2035; the retirement date shown for Roxboro Units 1 and 2 is 12/2028; the retirement date shown for Roxboro Units 3 and 4 is December 2033.

[4] Id.

Additionally, the decision to retire a generating asset requires an analysis of power flows and transmission impacts to the electrical system. This analysis should incorporate required or deferred transmission-related costs, replacement generation, load growth projections, and other system impacts.

Q. DO YOU AGREE WITH THE COMPANY'S DECISIONS TO ACCELERATE THE RETIREMENT OF ROXBORO AND MAYO?

A. No.

Q. CAN YOU DESCRIBE WHY YOU DO NOT AGREE WITH ACCELERATED RETIREMENT OF ROXBORO AND MAYO?

A. I have several topics that I will discuss, as well as minor critiques of the analysis used to support the early retirement decisions.

I reviewed: (1) the cost analysis performed and used by the Company to support accelerated retirement, that in my opinion, is too narrow and not sufficient to support the decision to accelerate retirement; (2) the potential impacts of early retirement on the Company's electrical system, including assumptions made regarding replacement generation, and the costs of necessary transmission upgrades resulting from the retirement of these units, which I believe are not adequately captured by the analysis; and (3) the magnitude of the aggregate generation that will be taken offline in one given year and the need to have replacement generation built prior to retirement.

Cost Analysis

My review of the Company's cost analysis used to support the cost benefit of early retirement revealed that the Company performed multiple scenarios/sensitivities of low, medium, and high natural gas fuel costs coupled with no, low, and high carbon pricing. In other words, the Company's analysis compared the savings resulting from early retirement (ultimately deferring any future costs of coal commodity prices, variable and fixed O&M costs, continued capital investments, carbon costs, etc.) to the costs associated with building new generation assets to replace the retired capacity and the respective associated costs for the same categories mentioned above.

Table 1 below provides a summary of the cost analysis. A negative value equates to savings associated with early retirement of the coal generation assets given the scenario/sensitivity completed. As shown, only **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**. Absent State or federal legislation or Commission determination, a **BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** dollar value assigned to generation is not appropriate at this time. While I agree it is a valuable data point to consider from a "what if" standpoint, it requires too much speculation at this time to either: (1) assign an absolute dollar value or (2) determine a reasonable escalation rate.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

At this time, I do not have any overarching concerns with the cost analyses performed by Duke. There are, however, finer points to these analyses that should be evaluated in future IRPs and supporting cost analyses for retirement of these coal units, as well as an evaluation of transmission upgrades and interconnection costs, costs of natural gas infrastructure, and advanced studies of increased renewable penetration and distributed energy resources.

Transmission System Impacts

As I discussed in my testimony in the pending DEC Sub 1214 proceeding, impacts to the transmission system must be evaluated when adding new generation to the electrical system, as well as when existing generation is being removed. In addition, there should be coordination within the utility when bringing new generation online that will ultimately usurp an older generation asset.

Based on the response to a Public Staff data request, the Company completed a study simulating the removal of the approximately 3,000 MW combined generation of Mayo and Roxboro coal plants in 2030. The study included **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** I believe this analysis and revelation is particularly noteworthy because it demonstrates that power plants, regardless of their technology and fuel source, cannot be merely "turned off" (retired) overnight, nor can new sources of generation be connected to the grid in any location without considering other impacts. In other words, the laws of physics must be satisfied to maintain a stable grid, and sound, strategic long term planning is necessary in advance of decisions to retire or build major capital investments, now that the generation fleet is both aging and growing.

7,000 MW of generating capacity needs to be built or sourced by 2030

The Carolinas' service territories of DEP and DEC are currently experiencing decreasing costs for renewable generation technologies (particularly solar PV), historically low natural gas prices, technology innovation, and low load growth. New electrical generation and concomitant interconnections take multiple years to plan, study, build, interconnect, and commission. It is essential for project timing and success to factor in an appropriate lead time for equipment purchases, solicitation of bids or proposals, consideration of policy initiatives, analysis of weather patterns, time value of money, position within the transmission queue, and other potential project delays (to name a few) when reverse time line planning the year to begin a particular project build process.

Looking at the Company's recently filed 2019 IRP Update,[5] the Company already has placeholders for two new combined cycle plants (aggregate capacity of 2,700 MW mentioned above) and five new combustion turbine plants (aggregate capacity of 2,300 MW) for a grand total of approximately 5,000 MW to be placed in service and

[5] Docket No. E-100, Sub 157, *2018 Biennial Integrated Resource Plan*, DEP's 2019 IRP Update (Table 9A), September 3, 2019.

used and useful by winter of 2029.[6] In addition to generating unit retirements, approximately 1,100 MW of current short term market purchases are set to expire and roll off between 2025 and 2030. The previously cited proposed generation would also replace these market purchases. Based on the expected retirement dates from the 2018 IRP, this 5,000 MW of proposed generation does not account for the accelerated retirement of Mayo and Roxboro requested in this docket. If the Commission were to approve the Company's request for early retirement of Roxboro Units 3 and 4 and Mayo in this proceeding, approximately 2,000 MW of additional dependable capacity[7] would need to be built by 2030 on top of the already estimated 5,000 MW of dependable capacity, for a total of 7,000 MW.[8] The sheer magnitude of this quantity of new and replacement generation that must be built over the next 10 years is staggering for

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[6] For a generating plant to be ready to be available for dispatch by winter of 2029, the generating asset must be completed no later than late fall of 2028 and perhaps even during the summer of 2028.

[7] Dependable capacity is not the same as nameplate rating. For some generation types, dependable capacity and nameplate rating are the same, but in others cases they are different. For example, a combustion turbine's dependable capacity would be the same as the nameplate rating, but a wind turbine's nameplate rating would not be 1:1 to the dependable capacity. Dependable capacity, at a high level, must align with the estimated output of the facility at the time of the utility's coincident peak load. If the dependable capacity coincident to peak is 3%, then significantly more nameplate capacity must be installed (i.e., 7000 MW / 0.03 = 233,333 MW of nameplate capacity), or with a coincident peak of 25%, (7000 MW / 0.25 = 28,000 MW) a lesser amount of nameplate capacity must be installed. One could further derive the land (total acreage) requirements given the technology.

[8] IRP assumptions related to reserve margins, load growth, second license renewal of nuclear power plants, DSM and EE impacts, etc., all stay at currently assumed values.

a system with a 2018 test year system peak of approximately 15,000 MW. This level of new generation investment, coupled with ongoing capital investments in the Company's Grid Improvement Program, typical capital investments in the surviving generation fleet and other utility operations, and coal ash and other environmental costs, will have a significant impact on future rates, and exacerbate the issue of affordability raised by the Commission and discussed in the testimony of Public Staff witness Jack Floyd.

I also recommend that the Commission deny any future requests for accelerated generating unit retirements in a general rate case, and instead find that retirement dates should be evaluated in the Company's IRP filings where complexities can be more appropriately and thoroughly evaluated.

Q. MR. METZ, SHOULD THE COMPANY CONDUCT AN ALL SOURCE BID OR OTHER MARKET ACQUISITION APPROACH TO REPLACE RETIRING ASSETS OR TO MEET OTHER SYSTEM CAPACITY NEEDS?

A. Yes. Given the magnitude of potential generation needs by DEP over the next decade, a capacity solicitation process should be immediately initiated in order to ensure ratepayers are served with the most cost effective resources. Public Staff witness Bob Hinton discusses this further in his testimony.

Materials and Supplies Inventory

Q. BRIEFLY DESCRIBE MATERIALS AND SUPPLIES INVENTORY.

A. For purposes of my testimony in this case, I define Materials and Supplies (M&S) Inventory as spare parts to maintain the reliability and serviceability of generating plants. M&S Inventory can also include costs associated with future projects, as the Company needs to procure parts in advance of the time they will be physically installed.

Q. HAVE YOU PROVIDED TESTIMONY ON THIS ISSUE IN PREVIOUS RATE CASES?

A. Yes, I provided detailed testimony describing M&S Inventory and the different categories of it in DEP's last general rate case,[9] In addition, I would also like to reference the South Carolina Office of Regulatory Staff (ORS) witness Willie J. Morgan's[10] direct testimony and DEP witness Kelvin Henderson's[11] rebuttal testimony in DEP's 2018 rate case filed in South Carolina. (Docket No. 2018-318-E). Together,

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[9] Docket No. E-2, Sub 1142, *Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, Testimony of Evan D. Lawrence and Dustin R. Metz, p. 11-18, December 6, 2019.

[10] Docket No. 2018-318-E, *Application of Duke Energy Progress, LLC for Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order*, Direct Testimony and Exhibits of Willie J. Morgan, P.E., p. 7-9, March 4 2019.

[11] Docket No. 2018-318-E, *Application of Duke Energy Progress, LLC for Adjustments in Electric Rate Schedules and Tariffs and Request for an Accounting Order*, Direct Testimony and Exhibits of Kelvin Henderson for Duke Energy Progress, LLC, p. 8-11, April 1, 2019.

their testimonies provide additional detail and perspective on M&S Inventory.

Q. ARE THE CONCERNS YOU HAVE NOW SIMILAR TO THE CONCERNS YOU RAISED IN DEP'S PREVIOUS RATE CASE, DOCKET NO. E-2, SUB 1142?

A. Yes. As I stated in my testimony in the Sub 1142 proceeding, if the inventory, and its associated cost, cannot be used for extended time periods, those parts (inventory) are unavailable for use, and ratepayers should not be burdened with these costs. In its Order in that proceeding, the Commission agreed with my recommended adjustment based on the supporting evidence.

Q. HAS THE COMPANY'S TOTAL DOLLAR VALUE BOOKED TO M&S INVENTORY HOLD "IMPROVED" SINCE THE LAST RATE CASE?

A. The answer to this question is indeterminate at this time. The following table, Table 2, compares the "hold" category of costs for both the 2016 and 2018 test years.[12]

[12] Docket No. E-2, Sub 1142 utilized a 2016 test year; Docket No. E-2, Sub 1218 is utilizing a 2018 test year.

M&S Inventory												
Hold Category	Repair Hold			QA Hold			EC Hold			Hold Sum		
Years on Hold ≥	2	4	6	2	4	6	2	4	6	2	4	6
Test Year 2016 ($M)		1.6	0.9		8.0	1.0		7.1	0.9	27.2	19.5	2.8
Test Year 2018 ($M)	7.5	3.2	1.9	8.0	5.7	4.8	15.3	13.7	10.5	30.8	22.6	17.2
Delta ($M)		1.6	1.0		(2.3)	3.8	15.3	6.6	9.6	3.6	3.1	14.4
Percent Change		100%	111%		-29%	380%		93%	1067%	13%	16%	514%

Table 2: M&S Inventory

As can be seen in Table 2, for Year 4, the Repair Hold (RH) category increased in value, the QA Hold (QH) category decreased in value, and the EC Hold (EH) category increased in value. I caution in drawing absolute conclusions based on the dollar values reported, as there is a possibility of some reporting/coding nuances that may skew the overall values;[13] nevertheless, this information represents what is best known at this time. Given these nuances, it is difficult to determine whether a direct improvement occurred or not.

Q. WHAT M&S INVENTORY COST CATEGORIES ARE YOU RECOMMENDING FOR DISALLOWANCE?

A. Similar to my testimony in DEP's Sub 1142 proceeding, I recommend disallowance of RH and QH costs associated with inventory that has been in a hold (unusable) status for four years or greater ($3.2 M +

[13] It is my understanding that the Company continues to refine its internal reporting/coding of items in the inventory system. There is also a possibility that the EH category may have been incorrectly reported for the 2016 test year, as there are multiple sub categories that "roll up" (aggregated) into the overall EH designation, and were interpreted by the Company based on particular year thresholds established through Public Staff discovery.

$5.7 M = $8.9 M). I have provided this adjustment to Public Staff witness Dorgan for incorporation in his schedules.

Q. MR. METZ CAN YOU ELABORATE MORE ON WHY YOU ARE NOT DISALLOWING THE EH CATEGORY IN THIS RATE CASE?

A. Yes. In DEP's previous rate case, I made the following statement,

> "Having worked in the nuclear industry and participated in engineering change packages, I understand that delays may occur for certain plant projects due to the need to balance and minimize the overall outage schedule. Thus, I did not include the costs associated with Engineering Change Hold category in my adjustment".[14]

That statement is still true today, and a degree of flexibility is required for project planning. The Public Staff will continue to evaluate these costs and categories in future cases.[15]

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS BASED ON YOUR REVIEW OF MATERIALS AND SUPPLIES?

A. Yes. Similar to my testimony in DEC's Sub 1214 proceeding, I recommend that the Company have an independent third party perform a review and audit of the Company's nuclear, fossil, and hydro materials and supplies (M&S) inventory and program controls.

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[14] *Id.*

[15] The EH category at six years or greater is starting to become alarming. While at this time I do not propose an adjustment, I will re-evaluate this category and the Company's actions to reduce the EH category cost in future rate cases.

The independent audit of M&S Inventory shall be, at a minimum, for at least one nuclear station, one fossil station, and one hydro station by the time of its next general rate case filing, or within the next three years, whichever is sooner, and establish a long term schedule for a continuous independent audit cycle (e.g. a three to five year rotational cycle).

Coal Inventory NC-1500

Q. WHAT IS THE COMPANY'S PROPOSED COAL INVENTORY ADJUSTMENT IN THIS CASE?

A. The Company's proposed adjustment for coal inventory, is reflected in its Form E-1, Item 10, Adjustment NC-2400, establishing the coal inventory balance at 35 days of 100 percent full load burn.

Q. PLEASE DEFINE THE PHRASE "FULL LOAD BURN".

A. "Full load burn" (FLB) refers to the physical quantity of coal needed for full generation output for each facility for a continuous 24-hour period. The aggregate FLB of each plant is the total quantity of coal inventory requested by the Company in its proposed adjustment. FLB is a common designation to quantify coal inventory on hand. This designation helps to evaluate the inventory available during critical demand periods on the utility's system (e.g., extreme weather periods in winter and summer months) to ensure that the Company can meet resupply constraints associated with delivery of the coal inventory.

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S 35 DAY FLB REQUEST?

A. No. During the last rate case, the Commission approved a provision of the stipulation between the Company and the Public Staff requiring a study to evaluate the appropriate inventory. The Company's requested inventory adjustment aligns with the findings of the study.

Q. DO YOU HAVE ANY RECOMMENDATIONS OR ADJUSTMENTS TO THE COMPANY'S PROPOSED COAL INVENTORY ADJUSTMENT?

A. Yes, but I would first like to note that the Company is aware of the identified issues, but due to the nature of misalignment of update periods between the Public Staff's filing and Company updates, this adjustment is necessary.

Following are my required adjustments to NC-2400: (1) The estimated full load burn should be adjusted to 32,017 tons, which removes the burn associated with the now retired Asheville Coal

Plant,[16] and (2) the projected average delivered coal cost per ton should be revised to $65.43/ton. Other parts of the NC-2400 adjustment will change when these two inputs are revised. I have provided this adjustment to Public Staff witness Dorgan.

Reserve End of Life for Nuclear, NC-2800

Q. CAN YOU BRIEFLY DESCRIBE THE PURPOSE OF THIS ADJUSTMENT?

A. This adjustment calculates the cost and value of certain elements of a nuclear power plant, including the unused energy of the last nuclear fuel bundle and material and supplies inventory (spare parts).

Q. PLEASE DISCUSS YOUR ADJUSTMENT.

A. From a review of the Company's workpapers for adjustment NC-2800, I propose two major edits. These edits will have subsequent impacts to the overall adjustment calculation.

NC-2803 will have two adjustments. First, the end of life inventory (the M&S Inventory) should be reduced on a pro-rata share across all of the nuclear generation assets as per my previously proposed M&S Inventory adjustment. I recommend the pro-rata share be

[16] The Asheville Coal Plant was retired January 2020.

based on the MW ratings of the plants. This adjustment will result in an overall reduction of the total amount of M&S Inventory for this line item. Second, I propose a positive salvage value be assigned to the M&S Inventory. In DEP's prior rate case, 20% salvage value was used, but in this case, the Company has reduced that value to 0%.

Q. IS 20% STILL A REASONABLE ESTIMATE OF THE SALVAGE VALUE OF THE INVENTORY AT THE END OF THE PLANT'S LIFE?

A. In the Sub 1142 proceeding, the Company and the Public Staff agreed that the inventory at end of life would be valued at 20 percent. A significant portion of the inventory is uniquely suited to a specific nuclear plant design, other nuclear facilities, or in some cases, even coal-fueled power plants. As these older plants are retired, the demand for items in inventory will decline. The Company, in the previous rate case stated that "[it] has no reason to believe that 20% percent transferability and salvage value established in the prior case would have increased".[17]

[17] Docket No. E-2 Sub, 1142, *Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, Rebuttal Testimony of T. Preston Gillespie, Jr. for Duke Energy Progress, LLC, November 16, 2017.

As the nuclear fleet continues to age, be upgraded, and retire, the 20% value will likely decline due to declining demand for spare parts. I recommend an overall reduction of the salvage value to 10% in this case. I agree with DEP witness Gillespie's statement that "[as] older plants are retired, the demand for items will decline."[18] As the nuclear fleet ages, the overall salvage value will decrease and should be continuously adjusted in future filings. Part of the salvage value will be dependent upon SLR and the number of plants that will continue to operate into the future, the magnitude of older systems that are replaced with newer technologies, and whether the plants will operate during the entire period in which they have a license to operate.

I have provided this adjustment to Public Staff witness Dorgan.

Asheville Combined Cycle NC-3400

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR ADJUSTMENT.

A. This adjustment is primarily an accounting adjustment to account for the time delay between the Company's request in this case and the time rates will actually go into effect and a establish an estimated amount of expected plant expenses.

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[18] *Id*.

Q. WHAT IS YOUR PROPOSED ADJUSTMENT?

A. The Asheville Combined Cycle Operations and Maintenance (O&M) estimated expense, shown as E-1, Item 10 adjustment NC-3406, should be adjusted to reflect a revised cost and change in the cost calculation methodology. The Asheville CC estimated annual O&M expense should be $4,266,720 (system amount). I have provided this adjustment to Public Staff witness Dorgan.

Q. BRIEFLY DESCRIBE HOW YOU CALCULATED THIS ADJUSTMENT.

A. Similar to the Company's initial proposed adjustment, I used an average of O&M expenses from other recently built combined cycle plants in Duke Energy's fleet (e.g., H.F. Lee, L.V. Sutton, and W.S. Lee[19]). In so doing, I took a three year average of the O&M expenses at these three plants, then determined a base $/MW expense. I weighted the base $/MW expense against the nameplate capacity of each plant in this sample and arrived at a weighted $/MW expense across the fleet. The weighted $/MW expense was then multiplied by Asheville CC's expected nameplate capacity to arrive at my adjustment. The Company's original filing used a simple average, whereas I have proposed a weighted average. My overall adjustment

[19] W.S. Lee CC is a Duke Energy Carolinas plant.

also removed certain costs that were found to be duplicative or incorrectly charged to the plants in the sample.

<u>Vanderbilt to West Asheville 115 kV Transmission Project</u>

Q. WHAT IS THIS PROJECT?

A. This project involved reconductoring approximately two miles of the existing Vanderbilt to West Asheville 115 kV transmission line in order to accommodate power flows associated with generation additions in the Asheville area.

Q. DID YOU IDENTIFY ANY CONCERNS WITH THIS PROJECT?

A. Yes. During the course of my review, I discovered that the Company had inadvertently categorized and booked this project as distribution plant, rather than transmission plant. The Company should reclassify and rebook this Project as transmission plant, and reallocate the costs accordingly. I have provided this finding to Public Staff witness Dorgan for incorporation in his testimony and schedules.

<u>Darlington Combustion Turbine Units</u>

Q. DID THE COMPANY RECENTLY ANNOUNCE PLANS TO RETIRE COMBUSTION TURBINES AT THE DARLINGTON CT SITE?

A. Yes, the Company filed a letter on March 17, 2020, in Docket No. E-100, Sub 157 stating its intent to retire Darlington CT Units 1-4, 6-8, and 10, effective March 31, 2020.

Q. ARE THE DARLINGTON UNIT RETIREMENTS REFLECTED IN THE CURRENT RATE CASE IN THIS DOCKET?

A. Not at this time. Due to the timing of the filing of these specific retirements, it was not possible to conduct discovery in this case prior to the filing of this testimony. Therefore, I reserve the right to file supplemental testimony in this case addressing the impacts of these retirements on DEP's revenue requirement.

<u>Base Fuel Factor</u>

Q. DID YOU REVIEW THE BASE FUEL FACTOR PROPOSED BY THE COMPANY?

A. Yes. The base fuel factor in the Company's application reflected the rates that were in effect at the time of the filing. Therefore, the base fuel factor is appropriate for the Company's initial filing. However, the base fuel rate approved by the Commission in Docket No. E-2, Sub 1204, the Company's previous annual fuel proceeding, went into effect December 1, 2019. Due to the time misalignment, Docket No. E-2, Sub 1204 rates will have to be refined in future Public Staff filings in this proceeding. Also, a future update will need to reflect the refinement of catalyst deprecation being shifted from fuel rates to base rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I am currently enrolled at North Carolina State University, working toward a Masters of Engineering degree.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion and an additional six years of employment with an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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<tr><td>DOCKET NO. E-2, SUB 1193

Application of Duke Energy Progress, 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-2, SUB 1219

In the Matter of
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina</td><td>)
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TESTIMONY OF
DUSTIN R. METZ
PUBLIC STAFF – NORTH
CAROLINA UTILITIES
COMMISSION</td></tr>
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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUBS 1193 AND 1219

SUPPLEMENTAL TESTIMONY OF DUSTIN R. METZ
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 15, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Dustin Ray Metz. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. ARE YOU THE SAME DUSTIN METZ WHO FILED TESTIMONY IN THIS DOCKET ON APRIL 13, 2020?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide to the Commission the results of my investigation into certain plant-related capital costs included in Duke Energy Progress LLC's (DEP or the Company) second supplemental testimony filed on July 2, 2020 for the purpose of updating certain known and measurable changes to rate base through May 31, 2020 (May 2020 Update) in Docket No. E-2, Sub 1219.

Q. PLEASE SUMMARIZE YOUR ADDITIONAL SUPPLEMENTAL TESTIMONY.

A. I recommend removing certain capital costs associated with Project Focal Point from rate base.

Q. WHAT IS PROJECT FOCAL POINT?

A. This project is a corporate-wide initiative to replace and upgrade older monitoring and recording equipment (e.g., cameras) with modern, state of the art equipment. This project, once completed, is intended to be an overall upgrade to Duke Energy Corporation's security system.

Q. WHY YOU ARE RECOMMENDING COST DISALLOWANCE OF THIS PROJECT?

A. The May 2020 Update costs for Project Focal Point included in rate base in this proceeding are largely for the purchase of equipment that has yet to be fully installed and operational. After discussions with the Company on this particular project, the Company agrees to withdraw its request to recover costs for this project in this case.

Q. WHAT AMOUNT OF PROJECT FOCAL POINT ARE YOU RECOMMENDING FOR DISALLOWANCE IN THIS CASE?

A. I recommend that $3,021,933.96 (system) be removed at this time. Once the project, and any subparts of the project, are successfully installed, tested, commissioned and working per their designed criteria, the Company may seek cost recovery at that time. The Public Staff will also review the reasonableness and prudence of the project in more detail at that time. I have provided this adjustment to Public Staff witness Maness for incorporation in his exhibits and schedules.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. DOWNEY: And again, there is confidential testimony in his April 13th testimony.

COMMISSIONER CLODFELTER: The confidentiality designations will be preserved in the record as marked.

MS. DOWNEY: I believe that's all of the Public Staff testimony for witnesses that have been excused.

COMMISSIONER CLODFELTER: Ms. Downey, with your permission, we have Mr. Quinn now, and I don't want to hold him any longer than we have to any further. So with your permission, may I interrupt your presentation at this point?

MS. DOWNEY: Of course.

COMMISSIONER CLODFELTER: Thank you. All right. Mr. Quinn, we're back with you. You're on mute.

MR. QUINN: I apologize for that. And I appreciate the Public Staff's allowing me to make this motion. Commissioner Clodfelter, NC WARN sponsored witness William Powers. His prefiled direct testimony was filed on July 16th of 2020 in this docket. I'm sorry, April 13th of 2020 in this docket, and it consisted of 25 pages, no exhibits, and we would move that testimony into the record, please.

COMMISSIONER CLODFELTER: Any objection to the motion?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, motion is allowed.

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

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1219

In the Matter of: Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Services in North Carolina.	)))))	DIRECT TESTIMONY OF WILLIAM E. POWERS ON BEHALF OF NC WARN

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William E. Powers, P.E. My business address is Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, CA 92116.

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

A. My employer is Powers Engineering. I am the founder and principal of the company.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am a consulting and environmental engineer with over 35 years of experience in the fields of power plant operations and environmental engineering. I have worked on the permitting of numerous combined cycle, peaking gas turbine, micro-turbine, and engine cogeneration plants, and am involved in siting of distributed solar photovoltaic (PV) and battery storage projects. I have been an expert witness is high voltage transmission application proceedings in California, Missouri, and Wisconsin, and have evaluated the impact of rooftop solar and battery storage on electric distribution systems for multiple clients. I began my career converting Navy and Marine Corps shore installation projects from oil firing to domestic waste, including wood waste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo in the 1970's.

I authored "San Diego Smart Energy 2020" (2007) and "(San Francisco) Bay Area Smart Energy 2020" (2012), and have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources. I have a B.S. in mechanical engineering from Duke University, an M.P.H. in environmental sciences from UNC – Chapel Hill, and am a registered professional engineer in California and Missouri.

Q. HAVE YOU EVER TESTIFIED BEFORE THE N.C. UTILITIES COMMISSION (THE "COMMISSION") OR ANY OTHER REGULATORY BODIES IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified on behalf of NC WARN in Docket No. E-7, SUB 1214, Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Services in North Carolina. I testified on behalf of NC WARN in Docket No. EMP-92, SUB 0, Application of NTE Carolinas II, LLC for a Certificate of Public Convenience and Necessity to Construct a Natural Gas-Fueled Electric Generation Facility in Rockingham County, North Carolina. I have also offered affidavit testimony and reports to this Commission in prior dockets, such as Docket No. E-2, Sub 1089. Further, I have offered testimony before other utilities commissions across the country, such as the commissions in California, Missouri, and Wisconsin.

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

A. The purpose of my testimony is: 1) to address the need for the Commission to reject the proposed Duke Energy Progress LLC ("DEP") Grid Improvement Plan ("GIP") capital investment program as unreasonable, and 2) to contest cost recovery by DEP for the Asheville natural gas combined-cycle power plant project.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony consists of two parts. Part I will address the reasons why the Commission should reject the GIP as unreasonable. Part II will discuss the reasons why the Commission should reject cost recovery for the Asheville natural gas combined-cycle power plant project.

I. THE GIP SHOULD BE REJECTED

Q. WHY ARE YOU ADVOCATING THE COMMISSION REJECT COST RECOVERY OF THE GIP?

A. DEP has proposed to spend approximately $1.1 billion over three years on its GIP capital projects – many of which Duke Energy Carolinas LLC ("DEC") and the Commission have identified as indistinguishable from traditional spend transmission and distribution (T&D) projects[1] – with no formal application(s) or

[1] DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, pp. 127-150.

associated evidentiary processes to evaluate the reasonableness of the proposed expenditures or potential alternatives that negate the need for these proposed expenditures.

Q. WHAT IS THE SCOPE OF THE GIP?

A. DEP and DEC (collectively, "Duke Energy") list eighteen separate elements to the GIP, as shown in Table 1, totaling $2,319.2 million, of which DEP's portion is $1,085.8 million. The most expensive single cost element is "Self-Optimizing Grid," with a capital expenditure of $722.5 million shared between DEP and DEC. Ten of these eighteen GIP elements, combined among DEC and DEP, have capital budgets in excess of $100 million. DEP itself proposes three GIP projects with capital budgets in excess of $100 million.

Table 1. Elements and Budgets for 2020-2022 GIP Programs[2]

GIP Program	DEC Budget, $ millions	DEP Budget, $ millions	Total Expenditure, $ millions
Physical & Cyber Security	65.1	68.7	133.8
Self-Optimizing Grid	420.1	302.4	722.5
Integrated Volt/VAR Control	206.7	10.0	216.7
Hardening & Resiliency	102.5	31.3	133.8
Targeted Undergrounding	59.8	54.7	114.5
Energy Storage[3]	56.5	72.5	129.0
Transformer Retrofit	8.3	109.7	118.0
Long Duration Interruptions	11.3	15.8	27.1
Transformer Bank Replacement	33.7	82.7	116.4
Oil Breaker Replacement	115.6	84.7	200.3
Enterprise Communications	103.7	108.1	211.8
Distribution Automation	115.4	78.9	194.3
System Intelligence	62.7	23.7	86.4
Enterprise Applications	17.0	10.8	27.8
ISOP	4.1	2.5	6.6
DER Dispatch	4.5	2.9	7.4

[2] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC, Jay Oliver Direct Testimony, October 30, 2019, Exhibit 10, pdf p. 154.
[3] Duke Energy excludes Energy Storage and Electric Transportation projects from the GIP total.

Electric Transportation	38.2	25.3	63.5
Power Electronics	0.7	1.1	1.8
Total	1,233.4	1,085.8	2,319.2

Q. OTHER THAN DUKE ENERGY'S OWN INTERNAL ANALYSIS AND STAKEHOLDER WORKSHOPS, HAS MORE FORMAL VETTING OF THE GIP OCCURRED?

A. No. DEP witness Oliver stated "DE Progress' Grid Improvement Plan was developed through a comprehensive analysis of the trends affecting our business in the state and the tools to best address those trends in a cost-effective and timely manner."[4] The stakeholder workshops are essentially sales presentations by Duke Energy to stakeholders, many of whom have no technical background in the provision of electric power, on the benefits of the GIP. There has been no formal Commission process to probe whether the alleged benefits are real, whether the benefits justify the costs, or whether alternatives could achieve the same objectives at less cost.

Q. IS IT YOUR POSITION THAT THE STAKEHOLDER WORKSHOPS SPONSORED BY DUKE ENERGY AT THE DIRECTION OF THE COMMISSION ARE AN INSUFFICIENT REVIEW OF THE SCOPE AND COST OF THE GIP?

A. Yes. The high cost of the GIP alone, about $2.3 billion in capital expenditures over three years between DEP and DEC,[5] is sufficient by itself to mandate an additional rigorous review to protect ratepayers. The GIP as proposed also

[4] Direct Testimony of Jay W. Oliver for Duke Energy Progress, LLC, p. 9.
[5] Ibid, Exhibit 10, pdf p. 154. Approximately $1.1 billion is attributable to DEP. See Table 1.

presumes that there is only one pathway to grid modernization and grid hardening, with no assessment of alternatives that may be much less costly and achieve the stated goals more effectively.

Q. DOES DEP INDICATE ITS TRANSMISSION AND DISTRIBUTION GRID IN NORTH CAROLINA IS SAFE AND RELIABLE WITHOUT GIP EXPENDITURES?

A. Yes. DEP Witness Oliver states that "Our (transmission and distribution) system has performed well, and we have continued to provide safe, reliable, and affordable electric service to our customers."[6] He includes a graphic in his testimony showing a DEP Interruption Frequency Index ("SAIFI") that is improving steadily over time. The DEP SAIFI declined about 17 percent between 2011 and 2018.[7] The Interruption Duration Index ("SAIDI") was relatively unchanged from 2015 to 2018.[8] However, Mr. Oliver makes no mention of the SAIFI graphic in his testimony, which undercuts his argument that the GIP is necessary to improve reliability. Mr. Oliver only addresses the SAIDI graphic, saying that "Over the past ten years however, SAIDI shows an unfavorable trend."[9] He ignores the fact that the DEP SAIDI has been relatively unchanged over the last several years (since 2015). The DEP SAIFI and SAIDI trend data presented by Mr. Oliver makes the case that DEP's traditional expenditure levels

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[6] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC, Jay Oliver Direct Testimony, October 30, 2019, p. 20.
[7] Ibid, Figure 1, p. 21. SAIFI 2011 = 1.62. SAIFI 2018 = 1.34. (1.62 – 1.34)/1.62 = 0.173 (17.3 percent)
[8] Ibid, Figures 1 and 2, p. 21. The SAIDI and SAIFI figures do not include 2019 data.
[9] Ibid, p. 20.

on transmission and distribution, without GIP, are adequate to provide safe and reliable transmission and distribution service.

Q. CAN YOU GIVE AN EXAMPLE OF WHERE DEP PRESUMES WITHOUT ANALYSIS THAT THERE IS ONLY ONE APPROACH AVAILABLE TO THE IDENTIFIED DEFICIENCY THAT GIP IS INTENDED TO RESOLVE?

A. Yes. An example is the presumption by DEP that targeted undergrounding is the only solution to further reduce outages caused by conductor contact with vegetation. DEP identifies the benefits of targeted undergrounding as: significantly reduce outages, minimize momentary interruptions, restore power faster, eliminate tree trimming in hard-to-access areas.[10]

DEP acknowledges that vegetation contact is responsible for 20 to 30 percent of outages.[11] However, the company implies that its vegetation management program is as good as it can be, and therefore presumptively no further vegetation management improvement is possible: "For the outages that occur because of trees inside the right-of-way, even a perfectly executed integrated vegetation management plan will not bring this number down to zero but instead will only help minimize vegetation outages."[12] DEP also asserts that 50 percent of the vegetation outages are caused by trees located on private

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[10] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC Jay Oliver Direct Testimony, October 30, 2019, pdf p. 562.
[11] Ibid, p. 7. "This work seeks to improve overall reliability, harden the grid against severe weather, and reduce the impact of vegetation which currently accounts for 20 to 30 percent of outages across the system."
[12] Ibid, p. 24.

property outside its right-of-way and that it does not have the ability to address these trees.[13] Based on this information, DEP makes the conclusory statement that "Drastic clear cutting and going onto customer property and cutting down live trees via condemnation or negotiating with customers for rights on their property is also impractical and not cost effective."[14] This assertion then introduces the alleged benefits of targeted undergrounding with the statement that "programs such as Targeted Undergrounding . . . can be effectively used to address vegetation outages caused by trees outside of the right-of-way."[15] DEP and DEC collectively propose to spend $114.5 million on targeted undergrounding projects, of which DEP's portion is $54.7 million.[16]

Q. IS DEP'S CONCLUSORY STATEMENT ABOUT THE IMPRACTICALITY OF MORE EFFECTIVE VEGETATION MANAGEMENT A SUFFICIENT BASIS TO JUSTIFY A $114.5 MILLION TARGETED UNDERGROUNDING CAPITAL EXPENDITURE?

A. No. Duke Energy has made clear that a primary objective of the GIP is to increase shareholder value by accelerating the tempo of capital projects.[17] In this context, Duke Energy proposes a combined total of $114.5 million in capital expenditure on targeted undergrounding. The estimated cost of a distribution line overhead-to-

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[13] Ibid, p. 24.
[14] Ibid, p. 24.
[15] Ibid. p. 25.
[16] See, *supra*, Table 1. DEP = $54.7 million, DEC = $59.8 million.
[17] DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, p. 129. Duke Energy Witness Fountain also admitted that Power / Forward is part of Duke Energy's corporate policy intended, as quoted in a Duke investor earnings call, "to drive 4 to 6 percent earnings growth."

underground conversion is more than $2 million per mile in urban and suburban areas.[18] Based on this undergrounding cost-per-mile, Duke Energy will underground about 60 miles of distribution line in this general rate case cycle, between DEP and DEC targeted undergrounding projects.

Vegetation management is also a tool used by Duke Energy to minimize outages on overhead lines. As noted by Witness Oliver:[19]

> In 2018, the Vegetation Management Plan implemented the seven-year trim cycle for non-urban miles, which had previously been set at six years. The change was based on the result of the Distribution Vegetation Management Species Frequency and Re-Growth Study completed in 2015 conducted to help determine an optimal vegetation maintenance cycle. The study did not result in a change from the three-year trim cycle set for urban miles.

DEP relaxed its non-urban trim cycle from every six years to every seven years in 2018, and left its urban trim cycle unchanged at three years. This is not a situation where DEP has increased the frequency of vegetation trimming in an effort to reduce the 20 to 30 percent of outages caused by vegetation contact. An improved vegetation management program - more frequent than the current non-urban and urban trimming cycles - on about 30 miles of overhead distribution lines that would otherwise be undergrounded by DEP may be able to achieve the same level of outage reduction projected for undergrounding at a fraction of the cost.[20] An improved vegetation management program option should have been

[18] Pacific Northwest National Laboratory, *Electricity Distribution System Baseline Report*, July 2016, p. 40. See: https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf.
[19] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC, Jay Oliver Direct Testimony, September 30, 2019, p. 23.
[20] ($54.7 million ÷ $114.5 million) × 60 miles = 28.7 miles.

considered to assure that any expenditures on targeted undergrounding are just and reasonable for ratepayers.

Q. ARE THERE REASONABLE AND PRACTICAL ALTERNATIVES TO DEP'S UNDERGROUNDING PLAN BEYOND ENHANCED VEGETATION MANAGEMENT?

A. Yes. It would be practical and less costly to put battery storage in every home along a proposed distribution line undergrounding route. Green Mountain Power ("GMP"), a Vermont investor-owned utility, implemented a virtual power plant ("VPP") in 2017, approved by the Vermont Public Utility Commission, consisting of aggregating and dispatching up to 2,000 residential Tesla Powerwall™ battery storage units.[21,22] GMP customers participating in this program have the option to purchase the Powerwall™ for a one-time cost of $1,500 or $15 per month over ten years.[23] The first phase of this project, consisting of 500 Powerwall™ units, saved GMP more than $500,000 over several days during a 2018 summer heat wave.[24] Assuming the presence of a comparable program in Duke Energy North Carolina territory, whether DEP or DEC service territory, it would cost about $300,000 per mile to equip every home in a North Carolina neighborhood with a

[21] The Tesla Powerwall™ has a discharge capacity of 5 kilowatts (kW) continuous and a storage capacity of 13.5 kW-hours. See: https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf.

[22] Green Mountain Power, *Notification - Tesla Powerwall Grid Transformation Innovative Pilot*, submitted to Vermont Public Utility Commission, July 31, 2017. See: http://apps.psc.wi.gov/pages/viewdoc.htm?docid=364977.

[23] Ibid, p. 2.

[24] Utility Dive, *Tesla batteries save $500K for Green Mountain Power through hot-weather peak shaving*, July 23, 2018. See: https://www.utilitydive.com/news/tesla-batteries-save-500k-for-green-mountain-power-through-hot-weather-pea/528419/.

Tesla Powerwall™.[25] $300,000 per mile to assure reliability during outages in every home along a distribution line pathway is a small fraction of the more than $2 million per mile for an overhead-to-underground distribution line conversion along the same route. The home battery storage option is an example of alternatives to the undergrounding capital budget that have not been examined or deployed by DEP.

Q. DUKE ENERGY PROPOSES CAPITAL EXPENDITURES OF $133.8 MILLION FOR "HARDENING AND RESILIENCY," OF WHICH $31.3 MILLION IS RELATED SPECIFICALLY TO DEP. WHAT IS HARDENING AND RESILIENCY?

A. The company defines transmission and distribution hardening and resiliency capital projects as: alternate power feeds for substations in flood-prone areas, hardening distribution line river crossings, improved guying for at-risk structures within flood zones, 44-kV system upgrades, targeted line rebuild for extreme weather, networking radially served substations, and substation flood mitigation.[26] However, DEP also acknowledges that ". . . energy storage solutions may offer more cost-effective solution(s) for improving reliability and managing costs."[27] Witness Oliver includes a description of the Hot Springs, NC microgrid project as an example of Duke Energy using battery storage and solar power to substitute for

[25] Assume each home has a street-front property length of 50 feet. Therefore, there are about 100 homes per mile on each side of the street (5,280 feet per mile ÷ 50 feet per home = 105.6 homes per mile per side of street), or about 200 homes per mile total. 200 homes/mile × $1,500/home = $300,000 per mile. This cost does not include homeowner investment in an associated solar power system.
[26] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC Jay Oliver Direct Testimony, October 30, 2019, Exhibit 12, p. 66 and p. 78.
[27] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC Jay Oliver Direct Testimony, October 30, 2019, pdf p. 105.

building a redundant line to provide back feed capability to a vulnerable community.[28] Notably, DEP filed an application in 2018 for a certificate of public convenience and necessity to build the Hot Springs microgrid project.[29] However, there is no discussion in Witness Oliver's testimony as to whether the battery storage microgrid approach is less costly than building redundant lines to serve vulnerable communities, and therefore should be the preferred method of protecting these vulnerable communities.

Q. DUKE ENERGY PROPOSES CAPITAL EXPENDITURES OF $722.5 MILLION ON THE "SELF-OPTIMIZING GRID." WHAT IS A SELF-OPTIMIZING GRID?

A. Duke Energy proposes to spend $722.5 million, $302.4 million by DEP and $420.1 million by DEC, on Self-Optimizing Grid technologies.[30] Witness Oliver states that "the Self-Optimizing Grid, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that ensures many issues on the grid can be isolated and customer impacts are limited to hundreds versus thousands. These grid capabilities are enabled by installing automated switching devices to divide circuits into switchable segments that will serve to isolate faults and automatically reroute power around trouble areas which call for expanding line and substation

[28] Id., pdf p. 270.
[29] Duke Energy Progress, LLC, *Application for Certificate of Public Convenience and Necessity - Hot Springs Microgrid Solar and Battery Storage Facility*, Docket No. E-2, Sub 1185, October 8, 2018, p. 7. Hot Springs is a remote town of 500 people in the Appalachian Mountains served by a single distribution line that is subject to frequent outages. DEP plans to install approximately 3 MW of solar power and 4 megawatt-hours (MWh) of lithium battery storage and configure circuits to allow Hot Springs to isolate from the grid as needed, known as "islanding," when grid power is unavailable.
[30] See Table 1.

capacity to allow for two-way power flow and creating tie points between circuits."[31] In a single sentence, DEP mixes talk of switching devices to isolate faults with expanding line and substation capacity to allow for two-way power flow. There is no analysis of alternatives that might achieve the same distribution grid reliability improvement at less cost to ratepayers. DEP also implies that the impact of outages will be reduced by 90 percent or more ("limited to hundreds versus thousands") by deploying the Self-Optimizing Grid, but no evidence is offered to support or clarify what DEP means by "impact of outages" or how it calculated the precipitous decline in impacts.

Q. IS EXPANSION OF LINE AND SUBSTATION CAPACITY NECESSARY TO ENABLE TWO-WAY POWER FLOW CAUSED BY HIGH LEVELS OF DISTRIBUTED ENERGY RESOURCES (AKA ROOFTOP SOLAR)?

A. No. Installing rooftop solar with battery storage in homes and businesses can achieve the same purpose. An October 2017 study commissioned by the California Public Utilities Commission ("CPUC"), *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*,[32] examined the degree to which grid upgrades would be necessary to absorb rooftop solar flows in neighborhoods where all homes have rooftop solar. The context of the 2017 study is the California mandate that all new residences built in 2020 or later are zero net energy homes with rooftop

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[31] Direct Testimony of Jay W. Oliver, p. 35.
[32] DNV NL, *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*, prepared for CPUC, October 2017. "This study was conducted to inform the next CPUC net-energy metering (NEM) policy revisit (now anticipated for summer 2020)," p. vii.

solar.[33] The study was in effect a "worst case" assessment of the existing grid's ability to absorb distributed solar inflows when all homes on a circuit are generating solar power and potentially exporting some or all of that solar power to the grid at the same time.

Q. IS IT YOUR POSITION THAT ADDING SOLAR AND BATTERY STORAGE AT HOMES AND BUSINESSES ACHIEVES THE SAME END WITHOUT THE POTENTIAL FOR STRANDED INVESTMENTS IN GRID OPTIMIZATION?

A Yes. Distribution circuits are typically designed to accommodate double or more of the expected peak load on the circuit.[34] The basis for this is to provide sufficient capacity to ensure each circuit can serve as a backup source of power to an adjacent circuit in case of an outage on the adjacent circuit. In this context, the 2017 California study examined rooftop solar inflows (i.e. two-way flow) up to 160 percent of the base case peak load of the distribution circuit being analyzed. The study determined that simple steps, such as use of "smart" solar inverters and good distribution of the solar systems along the circuit, could substantially increase the capacity of the circuit to absorb solar inflows with little or no cost.

The 2017 study also determined that, without battery storage, incrementally more extensive grid upgrades would potentially be necessary, including regulator control upgrades, re-close blocking, reconductoring of overloaded circuit sections, and/or additional voltage regulators, to address grid

[33] New York Times, *California Will Require Solar Power for New Homes*, May 9, 2018: https://www.nytimes.com/2018/05/09/business/energy-environment/california-solar-power.html.
[34] The thermal rating of the conductors determines the maximum power flow.

reliability issues. However, the addition of battery storage with the rooftop solar would negate the need for progressively more expensive grid optimization upgrades. The report states that ". . . energy storage could be deployed to mitigate all violations on the circuit rather than deploying other measures at lower penetrations that would later become redundant."[35] In this case, DEP is proposing grid optimization measures that will become redundant if battery storage is integrated with rooftop solar. The deployment of battery storage with rooftop solar systems is projected to rapidly become a standard industry practice.[36]

The 2017 study concludes its assessment of the grid reliability value of battery storage stating ". . . (battery storage) could prove much more cost-effective in the long run particularly given the other functions that are available from distributed energy storage systems. If energy storage was implemented at the buildings or circuits . . . then the associated integration costs identified in this study would be negated." In sum, if an appropriate capacity of battery storage is included with solar installations in neighborhoods where 100 percent of the homes have rooftop solar, no additional "grid optimization" would be necessary to the existing distribution grid.

Q. IS ANOTHER STATE EXPECTING TO ADD ABOUT 3,000 MW OF RESIDENTIAL AND COMMERCIAL BATTERY STORAGE FOR

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[35] DNV NL, *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*, prepared for CPUC, October 2017, p. xv. "This study was conducted to inform the next CPUC net-energy metering (NEM) policy revisit (now anticipated for summer 2020)," p. vii.

[36] Greentech Media, *10 Rooftop Solar and Storage Predictions for the Next Decade*, January 3, 2020: https://www.greentechmedia.com/articles/read/10-rooftop-solar-and-storage-predictions-for-the-next-decade.

ABOUT THE SAME COST AS DUKE ENERGY'S $722.5 MILLION SELF-OPTIMIZING GRID CAPITAL BUDGET?

A. Yes. California Senate Bill SB 700 was signed into law in late September 2018 and is expected to add, with an incentive budget of $830 million, up to 3,000 MW of behind-the-meter residential and commercial storage in California by 2026.[37]

Q. IS THE CONSERVATIVE DEFAULT SOLAR CAPACITY OF DEC AND DEP DISTRIBUTION FEEDERS ALREADY SIX TIMES HIGHER THAN THE GIP SMART GRID OPTIMIZATION TARGET OF 835 MW?[38]

Yes. According to the National Renewable Energy Laboratory, the default rule-of-thumb for solar capacity on a distribution feeder - without any need for study - is 15 percent of peak load.[39] The summer peak loads in DEP and DEC service territories in 2018 were 12,841MW and 17,632 MW, respectively, or approximately 30,500 MW.[40,41] Using this rule-of-thumb, the total default "as is" solar hosting capacity of the DEC and DEP's North Carolina distribution feeders is in the range of 30,500 MW × 0.15 = 4,575 MW. This is more than five times higher than the stated GIP Smart Grid Optimization solar capacity goal of 835 MW. There is no justification for a Smart Grid Optimization solar capacity goal

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[37] Greentech Media, *California Passes Bill to Extend $800M in Incentives for Behind-the-Meter Batteries*, August 31, 2018, https://www.greentechmedia.com/articles/read/california-passes-bill-to-extend-incentives-for-behind-the-meter-batteries#gs.6cxCMs0.

[38] Opening Testimony of Jay W. Oliver, pdf p. 470. "SOG increases hosting capacity from approximately 496 MW to 835 MW."

[39] National Renewable Energy Laboratory (NREL), *Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders*, July 2012, p. 1. See: https://www.nrel.gov/docs/fy12osti/55094.pdf. "A commonly used rule of thumb in the U.S. allows distributed PV systems with peak powers up to 15% of the peak load on a feeder (or section thereof) to be permitted without a detailed impact study [4]. This necessarily conservative rule has been a useful way to allow many distributed PV systems to be installed without costly and time-consuming distribution system impact studies."

[40] 2018 DEP FERC Form 1, April 12, 2019, p. 401b (12,841 MW, June 19, 2018).

[41] 2018 DEC FERC Form 1, May 29, 2018, p. 401b (17,632 MW, June 19, 2018).

of 835 MW, as far more than 835 MW is already available, and any capital expense justified as necessary to achieve this goal is unreasonable.

Q. IS THE SELF-OPTIMIZING GRID NECESSARY TO ACHIEVE A CUSTOMER SOLAR CAPACITY OF 835 MW?

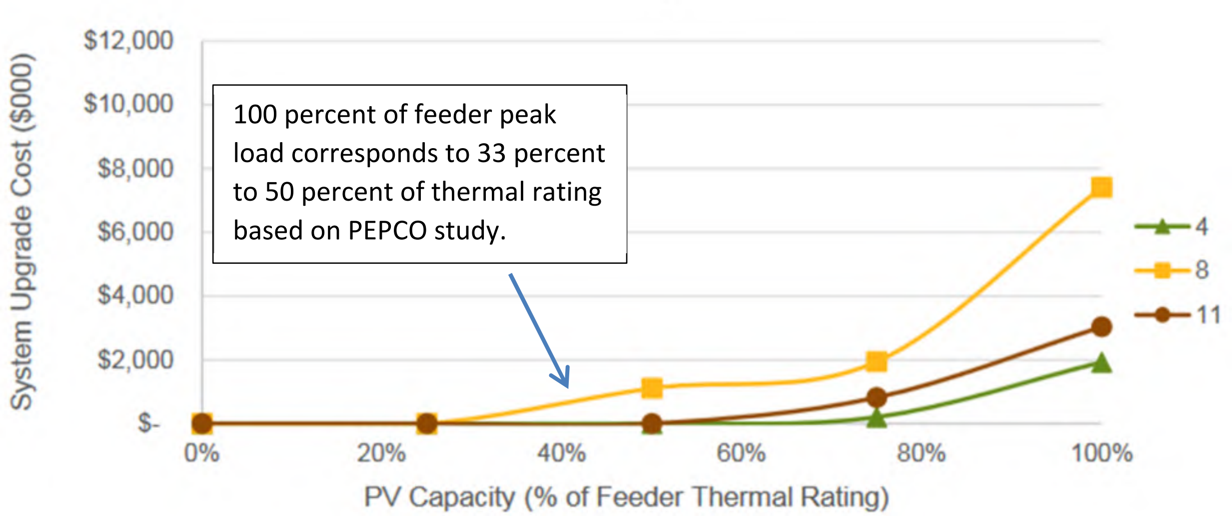
A. No. In addition to the rule-of-thumb identified by the National Renewable Energy Laboratory, the Department of Energy has sponsored numerous studies to estimate the solar capacity of utility distribution systems. One study involved the Dominion Virginia Power (DVP) distribution system.[42] DVP evaluated 14 representative distribution feeders from an overall distribution feeder population of 1,813 in its service territory.[43] The DVP summer peak load of 15,570 MW is comparable to the 2018 DEP and DEC peak loads of 12,841 MW and 17,632 MW,[44] respectively. DVP evaluated the percentage of thermal rating of the feeder available for solar hosting as upgrades were added. This necessitates understanding the relationship between peak load on the feeder and the thermal rating of the feeder.

The feeder thermal rating, meaning the point at which overhead feeders sag excessively due to the high temperature of the conductor or at which underground feeders approach the temperature where the insulation could begin to melt, is typically 2 to 3 times the peak load on the feeder.[45] Conversely, 100

[42] An affiliated company of DVP, Dominion North Carolina, is regulated by NCUC.
[43] B. Powers, *North Carolina Clean Path 2025*, August 2017, pp. 73-74, filed by NC WARN in the 2017 IRP docket, E-100, Sub 147.
[44] DEP 2018 FERC Form 1, April 12, 2019, p. 401b.
[45] Ibid., B. Powers, *North Carolina Clean Path 2025*, August 2017, Table 30a Increase in Solar Hosting Capacity and Upgrade Cost for Top 12 of 20 PEPCO Feeders Evaluated, p. 72. The 2015 PEPCO study sponsored by DOE evaluated feeder upgrades necessary to increase distribution feeder solar hosting capacity to up to 300 percent of the actual feeder peak load. See: DOE, *Model-Based Integrated High*

percent of peak load is approximately 33 to 50 percent of the feeder thermal rating, depending on the individual feeder. This is an important relationship to understand to interpret the DVP results. The results shown in Figure 1 are for the three feeders selected by DVP for presentation, and assume that smart solar inverters – without battery storage – are utilized to optimize voltage at the point of interconnection between the solar array and the feeder.

Figure 1. Cost Versus Improvement in Solar Hosting Capacity for Selected DVP Feeders Assuming Use of Advanced Solar Inverters
(source: Navigant)[46]



The most representative feeder among the three shown in Figure 1, in the opinion of Powers Engineering, is Feeder 11. This feeder serves a predominantly residential load, as do most of the fourteen representative feeders included in the DVP study. In contrast, Feeder 8 serves a predominantly commercial load and is representative of only about 1 percent of the 1,813 feeders in the DVP service

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Penetration Renewables Planning and Control Analysis for PEPCO Holdings - Final Report, December 10, 2015 (https://www.osti.gov/servlets/purl/1229729).

[46] B. Powers, *North Carolina Clean Path 2025*, August 2017, Figure 14, p. 74, filed by NC WARN in the 2017 IRP docket, E-100, Sub 147.

territory. Feeder 4 is somewhat of an outlier, representing low voltage (4.16 kV) and very short (3 miles) feeders. No significant solar hosting upgrade costs are encountered on Feeder 11 until about 67 percent of the thermal rating is reached, which equates to 133 to 200 percent of feeder peak load.[47] This data implies that the Duke Energy North Carolina distribution grid, including DEP and DEC service territories, with a summer peak load of approximately 30,500 MW, could meet that peak load with distributed solar power – and without battery storage – with little or no upgrading. In contrast DEP presumes, with no analysis, that its base case distributed solar hosting capacity without the Self-Optimizing Grid program is only 496 MW.

Q. HAS ANY OTHER STATE UTILITY COMMISSION RULED ON THE REASONABLENESS OF SELF-OPTIMIZING GRID EXPENDITURES?

A. Yes. Virginia's State Corporation Commission rejected Dominion's self-healing grid proposal in March 2020 saying that the utility failed to provide evidence of reliability improvements.[48]

[47] DOE, *Model-Based Integrated High Penetration Renewables Planning and Control Analysis for PEPCO Holdings - Final Report*, December 10, 2015 (https://www.osti.gov/servlets/purl/1229729). The 2015 PEPCO study sponsored by DOE evaluated feeder upgrades necessary to increase distribution feeder solar hosting capacity to up to 300 percent of the actual feeder peak load.

[48] GreenTech Media, *Virginia Regulators Reject Key Parts of Dominion's Smart Meter, Grid Upgrade Plan*, March 27, 2020: https://www.greentechmedia.com/articles/read/virginia-regulators-reject-most-expensive-parts-of-dominions-grid-modernization-smart-meter-plan. "The SCC also rejected Dominion's plan for 'self-healing grid' automation technologies, expected to cost $241.5 million in the first phase and $2.1 billion over 10 years, stating that the utility failed to provide evidence of the reliability improvements that could come from such an 'expensive and sweeping' deployment. . . Also rejected was one of the most expensive parts of Dominion's grid-hardening plan, which would have directed $70 million in its first phase and $1.2 billion over the next 10 years to perform 'proactive' upgrades of substation and service transformers identified as being at risk of failure or overloading."

II. ASHEVILLE COMBINED CYCLE POWER PLANT

Q. WHAT IS THE CAPITAL COST AND SCOPE OF THE ASHEVILLE NATURAL GAS COMBINED CYCLE POWER PLANT?

A. DEP requests approximately $770 million in recovery in this rate case for the Ashville combined cycle power plant.[49] DEP announced the Western Carolinas Modernization Plan in November 2015, which included retirement of the existing Asheville coal-fired plant and the construction of two 280 MW combined-cycle natural gas plants having dual-fuel capability.[50] DEP estimated a capital cost of $893 million for the Asheville combined cycle project in its March 2018 progress report to the Commission.[51] Both phases of the combined cycle project were online as of April 5, 2020.[52,53]

Q. WHAT IS THE PRODUCTION COST OF A COMPARABLE COMBINED CYCLE UNIT?

A. No actual production costs have yet been reported for the Asheville combined cycle project. Production costs are available for other DEP combined cycle projects. The most recently constructed combined cycle power plant in DEP's system, prior to the Asheville plant, was the H. F. Lee combined cycle plant in

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[49] *See generally* Direct Testimony of Julie K. Turner, a pp. 6-7.
[50] DEP FERC Form 1, April 12, 2019, pdf p. 80.
[51] Ibid.
[52] Duke Energy Progress, LLC, *Western Carolinas Modernization Project Annual Progress Report Docket No. E-2, Sub 1089*, March 30, 2020. "As noted in the report, DEP continues to work with the original equipment manufacturer to repair a manufacturing defect in the Unit 8 Steam Turbine Generator of Power Block 2 and currently expects to place the Unit 8 Steam Turbine Generator into commercial operation in April 2020."
[53] Duke Energy Progress, LLC, *Western Carolinas Modernization Project Status Update - Docket No. E-2, Sub 1089*, April 6, 2020. "On April 5, 2020, the Unit 8 Steam Turbine Generator of Power Block 2 of the Asheville Combined Cycle Project went into commercial operation."

Wayne County, North Carolina. This 920 MW combined cycle project came online in December 2012.[54] The production cost in 2018 of DEP's 920 MW H. S. Lee combined cycle project was $36/MWh in 2018.[55]

Q. IS IT REASONABLE TO ASSUME THAT THE ASHEVILLE COMBINED CYCLE POWER PLANT WOULD HAVE A PRODUCTION COST COMPARABLE TO THE W.S. LEE COMBINED CYCLE PROJECT?

A. Yes. The two combined cycle plants are the same design and similar combustion efficiency, either new or recently constructed, and use the same fuel with presumably a similar cost.

Q. WHAT IS THE PRODUCTION COST OF HYDROELECTRIC UNITS?

A. About $13/MWh, or one-half to one-third the expected production cost of the Asheville combined cycle units.[56]

Q. ARE EXISTING REGIONAL MERCHANT COMBINED CYCLE AND HYDROELECTRIC PLANTS AVAILABLE TO SUPPLY DEP WITH LOWER-COST POWER THAN POWER FROM THE ASHEVILLE COMBINED CYCLE POWER PLANT?

A. Yes. I addressed this issue in July 2016 in DOCKET NO. E-2, SUB 1089, "Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752 MW Natural Gas-Fueled

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[54] Duke Energy, H.F. Lee Plant, webpage accessed March 31, 2020: https://www.duke-energy.com/our-company/about-us/power-plants/h-f-lee-plant.
[55] Ibid, p. 403.3 (920 MW H.F. Lee combined cycle plant, expenses per net kWh = $0.0357/kWh – line 35).
[56] DEC FERC Form 1, May 29, 2019, p. 406.1 (Cowans Ford hydro plant, 350 MW, expenses per net kWh = $0.0129/kWh – line 35).

Electric Generation Facility in Buncombe County Near the City of Asheville."[57] The affidavit filed by NC WARN on my behalf in DOCKET NO. E-2, SUB 1089, which affidavit remains both accurate and pertinent today, stated that "DEP West has available off-the-shelf hydropower and combined cycle gas turbine options in the region to supply capacity if additional capacity is needed . . . Four Smoky Mountain Hydro units near the North Carolina-Tennessee border have a capacity of 378 MW and produce 1.4 million MWh annually. These units are in the TVA system, which is connected to DEP West by a single 161 KV line from TVA to the substation at the Walters Hydro Plant in DEP West. The power produced by these units is not currently contracted for purchase. . ." This is an example of a lower-cost regional power supply that could have been contracted to avoid the substantial DEP capital expenditures to build the 560 MW Asheville combined cycle plant. There is also currently nearly 50,000 MW of low-cost merchant combined cycle capacity in the PJM Interconnection regional market,[58] adjacent to DEP territory, potentially available for contracting by DEP at or below the production cost of the Asheville combined cycle plant.[59] Relying on these existing

[57] DOCKET NO. E-2, SUB 1089 - Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752 MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville, *Affidavit of William E. Powers for NC WARN and The Climate Times*, June 27, 2016.

[58] Monitoring Analytics, LLC, *2019 Quarterly State of the Market Report for PJM: January through March*, May 9, 2019, p. 65. See: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019q1-som-pjm.pdf. As of March 31, 2019, there was 47,591.6 MW of operational combined cycle capacity in PJM.

[59] U.S. Energy Information Administration, *Natural gas-fired power plants are being added and used more in PJM Interconnection*, October 17, 2018. See: https://www.eia.gov/todayinenergy/detail.php?id=37293. Combined cycle units in PJM generated about 200 million MWh in 2017, at an average capacity factor of about 60 percent.

regional combined cycle and/or hydroelectric resources would avoid DEP ratepayers having to pay the capital cost of the Asheville combined cycle plant.

Q. IS BATTERY STORAGE ALREADY CAPABLE OF PRODUCING POWER FOR LESS THAN A $20/MWH PRODUCTION COST, WELL BELOW THE PRODUCTION COST OF THE ASHEVILLE COMBINED CYCLE PROJECT?

A. Yes. Los Angeles Department of Water and Power signed a 25-year contract for the 300 MW Eland solar and battery storage project in September 2019.[60] The production cost of the battery storage component of the project is approximately $0.02/kWh.[61] The project includes four hours of battery storage at rated capacity.[62] The cost of battery storage capacity continues to decline at a rapid rate.[63]

Q. COULD THE ADDITION OF BATTERY STORAGE TO THE NEARLY 6,000 MW OF UTILITY-SCALE SOLAR IN NORTH CAROLINA ACHIEVE THE SAME PURPOSE AS THE ASHEVILLE COMBINED CYCLE PROJECT?

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[60] PV Magazine USA, *Los Angeles says "Yes" to the cheapest solar plus storage in the USA*, September 10, 2019. See: https://pv-magazine-usa.com/2019/09/10/los-angeles-commission-says-yes-to-cheapest-solar-plus-storage-in-the-usa/.

[61] Ibid. "The final version of the project delivered will in fact be a 300 MW / 1.2 GWh energy storage installation – with an aggregate pricing of 3.962¢/kWh. The project was originally offered at a record US price of 1.997¢/kWh for solar power alone." The incremental cost of the battery storage = 3.962¢/kWh - 1.997¢/kWh = 1.965¢/kWh (~$0.01965/kWh).

[62] Ibid.

[63] CNBC, *The battery decade: How energy storage could revolutionize industries in the next 10 years*, December 30, 2019. See: https://www.cnbc.com/2019/12/30/battery-developments-in-the-last-decade-created-a-seismic-shift-that-will-play-out-in-the-next-10-years.html.

A. Yes. This approach could be used on the nearly 6,000 MW of solar farms in North Carolina[64] to smooth-out solar generation and provide dispatchable peaking power.

Q. WOULD THIS APPROACH IMPOSE ANY CAPITAL COST BURDEN ON DEP RATEPAYERS?

A. No. The cost of battery storage additions would be borne by the third-party owners of the solar facilities. However, Duke Energy has opposed allowing solar facility owners to add battery storage. As noted by NCSEA Witness Tyler Harris, "Duke Energy is proposing unjust and unreasonable barriers to market entry for energy storage resources – particularly with respect to power purchase terms and conditions and interconnection standards – that will wholly obstruct the addition of such resources to the vast majority of installed renewable generating facilities in North Carolina."[65] Duke Energy has spent approximately $820 million building the Asheville combined cycle power plant – resulting in the DEP request in this general rate case to recover approximately $770 million – that could have been avoided by simply allowing existing solar facilities in North Carolina to add battery storage at their own expense in return for reasonable payment for the added value of the storage capacity.

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[64] Solar Energy Industries Association, *State Solar Spotlight: North Carolina*, at https://www.seia.org/sites/default/files/2019-12/North%20Carolina.pdf.
[65] Docket No. E-100, Sub 158, Direct Testimony of Tyler H. Norris on behalf of NCSEA, July 3, 2019, p. 8.

Q. IN LIGHT OF THE ABOVE, SHOULD DEP RATEPAYERS HAVE TO PAY FOR THE CONSTRUCTION OF THE ASHEVILLE COMBINED CYCLE PROJECT JUST BECAUSE IT IS ALREADY BUILT?

A. No. As described above, DEP's investment in the Asheville combined cycle project was not needed. Moreover, both phases of the Asheville combined cycle project were not online until April 5, 2020. Hence, the project cannot be considered "used and useful." Moreover, for the reasons described above, the Asheville combined cycle project was not the least-cost mix of generation. For all of these, among others, the significant expense of the Asheville combined cycle project was not reasonably and prudently incurred. Accordingly, DEP should not be reimbursed by ratepayers for the Asheville combined cycle project.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MR. QUINN: Thank you very much.

COMMISSIONER CLODFELTER: Thank you. Ms. Downey, with your indulgence, let me just ask again. Ms. Medlyn, if you are here and if you have any matters we need to take up with the Department of Defense.

(No response.)

COMMISSIONER CLODFELTER: Ms. Downey, thank you for your patience and indulgence. We're back with you.

MS. DOWNEY: No problem, Commissioner Clodfelter. Public Staff calls James McLawhorn and Jack Floyd. And I believe they're both there.

Whereupon,

JAMES S. MCLAWHORN AND JACK L. FLOYD,

having first been duly affirmed, were examined

and testified as follows:

COMMISSIONER CLODFELTER: Ms. Downey.

MS. DOWNEY: I'll start with Mr. McLawhorn.

DIRECT EXAMINATION BY MS. DOWNEY:

Q. Please state your name, business address, and present position.

A. (James S. McLawhorn) My name is James McLawhorn. My business address is 430 North Salisbury Street, Raleigh, and I am the director of the Public Staff's energy division.

Q. Mr. McLawhorn, did you prepare and cause to be filed on April 13, 2020, direct testimony in this case consisting of 38 pages, an appendix, and two exhibits?

A. Yes, I did.

Q. And did you further cause to be filed on July 31, 2020, testimony supporting the second partial stipulation between the Public Staff and the Company consisting of seven pages?

A. Yes.

Q. Do you have any corrections or changes to either your direct testimony or your second partial stipulation supporting testimony at this time?

A. No.

Q. If the same questions were asked of you today, would your answers be the same?

A. Yes.

MS. DOWNEY: Commission Clodfelter, I would move that Mr. McLawhorn's direct testimony and testimony supporting the second partial stipulation be copied into the record as if given orally from the stand, and that his exhibits to his direct testimony be marked as prefiled.

COMMISSIONER CLODFELTER: Are there any objections to the motion as made?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, motion is allowed.

(McLawhorn Exhibits 1 and 2 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony and Appendix A and testimony supporting the second partial stipulation of James S. McLawhorn was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		TESTIMONY OF JAMES S. MCLAWHORN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

TESTIMONY OF JAMES S. MCLAWHORN

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

APRIL 13, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of 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. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations concerning the cost-of-service (COS) methodology to be used in establishing rates for Duke Energy Progress, LLC (DEP or the Company) in this case. The Public Staff's recommendations are based on a review of the application; the testimony and exhibits (direct) of DEP's witnesses; DEP's responses to numerous data requests; and prior general rate cases of DEP and Dominion Energy North Carolina (DENC), including the 2019 general rate case of DENC in Docket No. E-22, Sub 562. In addition, I will address the Commission's January 23, 2020 Order (January 23 Order) in this docket, directing the Public Staff to include information similar to that included in Public Staff witness Jack Floyd's testimony in Docket No. E-7, Sub 1146, regarding the differences between the COS methodologies specified in the January 23 Order. I will also offer testimony on additional COS methodologies for the Commission's consideration.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. General Discussion of Cost-of-Service

II. Discussion of Various COS Study Methodologies

III. Adjustments to Test Year Data

IV. Allocation of Transmission and Distribution Plant

V. Recommendations to the Commission

I. General Discussion of Cost-of-Service

Q. WHY IS THE COST-OF-SERVICE STUDY (COSS) IMPORTANT IN A GENERAL RATE CASE?

A. The cost-of-service study (COSS) is illustrative of how the utility incurs costs to provide all of its customers with safe, reliable, economical, and continuous electric utility service. It is important that all costs are considered in the COSS to ensure that the utility is reasonably able to recover its full costs to serve all of its customers, while also ensuring that all jurisdictions and customer classes bear the appropriate responsibility for the costs they impose upon the system.

Q. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF A COST-OF-SERVICE STUDY, HOW IT IS DEVELOPED, AND HOW IT IS USED IN ESTABLISHING RATES.

A. Utilities use a COSS to determine how to allocate overall costs among jurisdictions and customer classes to establish rates based on an analysis of cost causation. Through an analysis of load characteristics, the COSS allocates or assigns the Company's rate base, expenses, and revenues to the appropriate jurisdictions and customer classes.

Data used in a COSS is based on the official accounting books and records of the utility. This data is obtained through load research and direct measurement and includes the number of customers and meters, the demand (kilowatts or kW) recorded during peak load periods, and the total energy (kilowatt-hours or kWh) used to serve each customer class. This cost causation analysis determines the costs each jurisdiction and customer class impose on the utility system. As explained by Company witness Hager on page 6 of her testimony, costs in a COSS are grouped according to function, then classified according to cost causation, then allocated or directly assigned to the appropriate jurisdiction or rate class.

The general principle underlying COS is that each jurisdiction, customer class, or, in some cases, individual customer should be responsible for an appropriate share of the costs that are planned for and incurred in order to serve it. Some costs can and should be directly assigned. Costs that cannot be directly assigned should be allocated using the methodology that most accurately and equitably reflects this underlying cost causation principle. Specifically with respect to production plant, the COS allocation methodology should account for the uses for which generation is planned and costs are incurred.

II. Discussion of Various COSS Methodologies

Q. WHAT COST–OF–SERVICE METHODOLOGY HAS DEP PROPOSED FOR USE IN THIS PROCEEDING?

A. DEP has proposed using the summer coincident peak (SCP) methodology to determine both jurisdictional and customer class cost responsibility in this case.

Q. IS THE SCP METHODOLOGY UTILIZED TO ALLOCATE ALL COSTS IN THIS CASE?

A. No. SCP is utilized only for the allocation of both production and transmission plant and related costs. Other costs are allocated on the basis of, among other things, non-coincident peak, energy, customer count, and revenues.

Q. DOES THE PUBLIC STAFF AGREE WITH DEP'S USE OF THE SCP COST-OF-SERVICE METHODOLOGY IN THIS PROCEEDING?

A. No. As explained below, the Public Staff recommends the use of the summer/winter coincident peak and average demand (SWPA) methodology for allocating production plant and production plant-related costs because it more accurately reflects actual generation planning and customer usage than does SCP.

Q. HOW ARE PRODUCTION PLANT COSTS ALLOCATED UNDER SCP?

A. Under the SCP methodology, production plant and related costs, such as depreciation and accumulated depreciation, purchased power capacity costs, and certain production operation and maintenance (O&M) costs are allocated based on the loads (that is, the level of demand) of a jurisdiction and its customers that occur during just one specific hour of the year -- the summer system peak. The remaining 8,759 hours of energy consumption are not recognized under this methodology for the purpose of allocating production plant cost responsibility of the North Carolina jurisdiction and its customer classes. In other words, the SCP looks at the summer system peak, and compares it to the peak loads of all jurisdictions and customer classes at that same single hour, and allocates all production plant, regardless of type and use of plant, based on a direct ratio of the jurisdiction and customer class loads to that single hour summer peak load.

Q. WHAT IS THE SIGNIFICANCE OF FOCUSING ONLY ON ONE SYSTEM PEAK HOUR RATHER THAN ALL HOURS?

A. In response to a Public Staff data request, the Company stated that its 2018 SCP was 12,619 MW, which occurred on June 19, 2018 at the hour ending 5:00 p.m.; however, that was not the system peak for 2018. The 2018 system peak was 15,022 MW, which occurred on January 7, 2018 at the hour ending 8:00 a.m.[1] The winter peak was the annual system peak in eight of the ten years between 2009 and 2018, including the last six. In four of the last five years, the winter peak exceeded the summer peak by between 14% and 22%.

As observed in the Company's 2018 IRP[2] and in the 2019 IRP update,[3] DEP's annual coincident peak has moved to the winter from the summer season. In fact, in response to an intervenor data

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[1] On page 9 of her testimony filed in this case, witness Hager identified the DEP summer peak as 12,841 MWs; on page 10, witness Hager identified the DEP winter peak as 15,322 MWs. In response to the Public Staff's data request, the Company stated that certain specific loads were excluded, for cost of service purposes, from the peaks identified by witness Hager in her testimony.

[2] Filed in Docket No. E-100, Sub 157.

[3] Also filed in Docket No. E-100, Sub 157.

request, the Company identified that the peak load forecasts used in the 2019 IRP show the annual system peak occurring in January of every year for the period 2020-2029. Also, in response to another intervenor data request, the Company identified that for IRP planning purposes, it had forecast the 2018 annual peak to occur in the winter, but by only 283 MW over the summer peak; in actuality, as shown above, the 2018 winter peak exceeded the 2018 summer peak by over 2,400 MW.

Further, DEP has shifted its generation planning to a winter-planning approach, beginning with its 2016 IRP. Winter peaks have a much different character than the summer peak. Winter peaks tend to occur in the morning and ramp up and down quickly over a few short hours. Summer peaks tend to occur in the late afternoon with a more gradual ramp up and down over several hours.

By focusing solely on the one single coincident peak hour (winter or summer), the COSS can inappropriately assign costs to jurisdictions and particularly to the customer classes. Focusing on one single peak hour can result in certain customer classes not being allocated any production plant costs at all. Also, certain customer classes can be allocated much more of the production plant costs because they cannot avoid consumption during that single peak demand hour. While SCP, or any peak allocation, is a very simple COS methodology to comprehend, simplicity is not necessarily an appropriate goal for such a critical and important task of assigning the costs of production built for a variety of purposes.

Q. WHAT COST–OF–SERVICE METHODOLOGY DOES THE PUBLIC STAFF PROPOSE FOR USE IN THIS PROCEEDING?

A. As stated above, the Public Staff proposes using the SWPA methodology for allocating production plant and production plant-related costs in this case.

Q. HOW ARE PRODUCTION PLANT COSTS ALLOCATED UNDER SWPA?

A. Under the SWPA methodology, the fixed costs of production plant and production plant-related costs are allocated among jurisdictions and customer classes on the basis of a formula that contains two components. The first component, the "summer/winter peak" component, is based on the demands of the jurisdictions or customer classes in question at the time of the utility's summer[4] <u>and</u> winter peak demands. This component takes into account the hour when the load on the system is highest during both the summer months and the winter months. The second component, the "average" component, takes into account the energy consumed during all hours of the year and is calculated by dividing the total kilowatt-hour (kWh)

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[4] As noted above, the summer peak demand is the sole basis for allocating production plant under the SCP methodology advocated by Company witness Hager.

sales for the year by the number of hours in a year to arrive at the average demand. This component recognizes that there is a load being served by the system over the course of all hours during the year. In other words, the first component is based on the peak demands at a particular time, and the second component is based on the average demand over an entire year. The two components are then weighted as explained below before determining the appropriate allocation factor.

Q. WHY ARE THESE TWO COMPONENTS USED IN THE ALLOCATION OF COSTS UNDER SWPA?

A. The SWPA methodology recognizes that some production plant costs are incurred primarily to provide sufficient capacity during peak periods, while other production plant costs are incurred because of the need to provide the lowest cost energy to customers during all hours. When there is a need for new capacity, generally three types of generation resources are considered: peaking units, intermediate or cycling units, and base load units. The selection of the type of unit is an economic decision based on the amount of energy required to meet customer load or the number of hours a unit is expected to need to operate each year. If the amount of energy required is low, peaking units are cost-justified due to their lower capital cost as compared to large base load units. However, if the amount of energy required is high enough, the lower energy cost (in cents/kWh) of capital-intensive base load units makes them more appropriate. Therefore, the magnitude of production plant costs incurred by the utility are not only a result of the one-hour summer and winter peaks, but also a result of the energy or hours-of-use requirement for which the plant was built. Unlike the SCP methodology proposed by Company witness Hager, which allocates all of the Company's production plant costs based on the single coincident peak, the SWPA methodology recognizes that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements and not solely to meet peak demand. Without an average component in the allocation factor, all production plant would be allocated based on the jurisdictional and customer class contribution to demands at the peak hour. Such an approach assumes that the Company's total production plant investment was made **only** to serve the peak load that occurs during one hour on a single day during the year. While serving peak load is clearly a driver of the Company's generation resource planning, another important component is the need to invest in new baseload generation that can serve customers' electricity needs throughout the year. For example, the Company's recent construction of the Asheville Combined Cycle Plant, as is the case with other advanced combined cycle facilities and historical investments in baseload nuclear, will operate throughout the year to provide baseload energy to the Company's customers. This recent generating plant investment supports the view that DEP's resource planning is driven by both the need to serve load at the peak hour as well as throughout the year. As such, this recent plant decision aligns with the SWPA's approach of allocating plant costs and related expenses considering both the peak demand component and the average demand component of service.

Q. WHAT WEIGHTINGS ARE GIVEN TO THE TWO COMPONENTS UNDER THE SWPA METHODOLOGY?

A. The "summer/winter coincident peak" component is weighted by 1 minus the system load factor for the jurisdiction or class in question. The "average" component is weighted by the system load factor for the jurisdiction or class in question. For purposes of my testimony, "load factor" is defined as the ratio of total energy (kWh) usage for the year divided by the total usage that would have occurred if the demand of the jurisdiction or class had remained continuously at the average of the summer and winter peaks level throughout the entire year [total energy / (summer/winter average system peak times 8,760 hours)].

Q. WHY ARE THESE PARTICULAR WEIGHTINGS ASSIGNED TO THE TWO COMPONENTS UNDER SWPA?

A. The load factor is used as an estimate of the portion of production plant costs incurred primarily to meet the need for low-cost energy at all hours of the day and year, as distinguished from the need for sufficient capacity during peak periods. As a jurisdiction, or customer class, uses more energy during non-peak hours,[5] its load factor increases, and the proportion of production plant costs needed for base load capacity rather than for peaking capacity will increase correspondingly. It is thus appropriate to use the load factor as the weighting for the “average” component of the allocation and to use one minus the load factor as the weighting for the “summer/winter peak” component. Together, these two components result in a factor that appropriately allocates fixed production plant costs based on actual planning and usage.

Q. WHY IS THE SWPA METHODOLOGY SUPERIOR TO METHODOLOGIES USING A SINGLE COINCIDENT PEAK?

A. The SWPA methodology addresses the distribution of production plant costs more accurately and equitably than other methodologies using only a single coincident peak. As I have previously described, the SWPA methodology addresses two of the main factors considered by a utility when selecting the appropriate type of plant to build when new capacity is required. The first is the quantity of energy the plant must supply, and second is the peak demand the

[5] For purposes of this description, “non-peak hours” means any hours other than the single hour of the summer peak and the single hour of the winter peak. A significant number of these hours would still qualify as “peak” hours in many of the Company’s rate designs.

plant must meet. A single coincident peak methodology (like SCP) addresses the peak requirement of the plant selection process but places no value on the need to produce energy at any time other than one peak hour in the summer. The SWPA methodology, however, addresses both the peaks the utility must meet in the summer and winter seasons and, importantly, the energy the utility must supply its customers during the other 8,759 hours of the year. In addition, SWPA more closely matches the Company's actual production planning process, which determines the type and mix of resources that meet, at least cost, the customers' electricity needs during all hours of the year. DEP's 2018 Integrated Resource Plan (IRP) filed with this Commission on September 5, 2018, in Docket No. E-100, Sub 157, and updated on September 3, 2019, identifies future capacity needs for natural gas-fired combined cycle and natural gas-fired combustion turbine production plants over the identified planning cycle.[6] The decisions leading to the identification of these specific least cost combinations of plant were not based solely on the one hour highest peak in the summer. Without a doubt, the amount of annual energy that these resources would be required to provide to the system was a major consideration in their selection.

[6] DEP 2019 IRP Update Report, Docket No. E-100, Sub 157, p. 70 and p. 74.

Q. CAN YOU IDENTIFY OTHER SHORTCOMINGS OF THE SCP METHODOLOGY VERSUS THE SWPA METHODOLOGY?

A. Yes. One illogical outcome of the SCP methodology is that a customer class can avoid responsibility for <u>any</u> production plant cost if it has no consumption during the one-hour summer peak. In this case, the Company's Area Lighting and Street Lighting customer classes are allocated <u>zero</u> production plant costs under SCP, even though they consume significant amounts of energy from the Company's base load plants during other hours of the year. Under a strict coincident peak allocation, these classes would not pay any fixed costs associated with production plant resources that are obviously used to power the lights throughout the year. Other customer classes also have significant energy needs, but have the ability through various options to manage those needs during certain times so as not to coincide with the system peak. For example, the Company has a request pending before this Commission in Docket No. E-2, Sub 1197 to provide incentives to customers for the purchase of various types of electric vehicles (EV), as well as other EV infrastructure. Clearly, the Company intends to not only serve EV load, but to drive the development of it. The Company has said that it plans to limit on-peak charging through active load management and other specifically designed EV time of use rates. Under the SCP methodology, none of the energy needs for EV load that is managed at the time of the summer peak would be used to allocate production plant to that class, even though the load will be present during the remainder of the year. As a result, responsibility for the cost of production plant that was built and is used to meet the significant needs of EV customers year round falls on other customer classes that do not have the same ability or options to manage their electricity needs during the one summer peak hour. In short, EV customers would receive the energy associated with the load that was avoided for one single hour out of the entire year, but is present during the other 8,759 hours of the year, by paying only for the cost of fuel and variable O&M. The SWPA methodology, through its use of the average demand, would allocate some portion of system production plant costs to these customers, even though they place no, or a reduced, demand on the system during the respective summer and winter peak hours. These EV customers will use and receive the benefit of the significant investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours, and as these loads grow, they will be driving the construction of other energy intensive generation resources.

Another shortcoming of the SCP methodology is that cost allocation studies are highly dependent on the year in which they are conducted and are particularly susceptible to weather anomalies in a given year. This often results in swings in the magnitude and occurrence of the one-hour peak, which in turn can significantly alter the production plant cost allocation responsibility for certain jurisdictions and customer classes, depending on the test year chosen. For example, in 2014, 2015, 2017, and 2018, the differences between the summer and winter peaks were 1,940 MW, 2,809 MW, 1,817 MW, and 2,403 MW respectively. Weather was more extreme in 2014, 2015, and 2018, than the other years, and as DEP witness Jay Oliver states on page 26 of his direct testimony in this case, “[t]he number, severity and impact of weather events on DE Progress customers have been increasing significantly.” By employing an average demand component based on total annual energy usage, which is less likely than single hour peak loads to vary significantly from year to year, the SWPA methodology is much less susceptible to these anomalies and resulting allocation swings.

Finally, an integrated system with economic dispatch that serves diversified loads with a least cost mix of diverse generating resources benefits all customers through lower average fuel costs than would be possible if the system were built to serve the individual, discrete load components. Such a system benefit requires that <u>all</u> customers be responsible for the fixed costs that make it possible. The SWPA methodology recognizes this benefit more accurately than the SCP methodology and allocates the production plant and related costs accordingly.

Q. WHY IS IT IMPORTANT TO USE BOTH THE SUMMER AND WINTER PEAKS?

A. Not only have DEP's winter peaks been greater than its summer peaks in recent history, the Company is also forecasting the winter peak to be greater than the summer peak for every year from 2020-2029 by approximately 1,200 MW – 1,300 MW. In fact, as noted above in my testimony, the Company's test year winter peak is greater than its summer peak (15,022 MWs versus 12,619 MWs). Nevertheless, the annual summer peak is both real and significant, representing 91% or more of the annual winter peak in DEP's IRP forecasts for 2020-2029. In addition, in some years, certain jurisdictions (North Carolina Wholesale, South Carolina Retail, South Carolina Total) and some customer classes within a jurisdiction may have higher summer peaks than winter peaks and vice versa. As discussed previously, if only a single, one-hour peak is used to determine peak responsibility for cost allocation, jurisdictions or customer classes that are able to reduce a significant portion of their load at that one hour will be able to avoid paying for a significant portion of plant, even though their loads are present for other high demand periods of the year, including other very significant seasonal peaks. Averaging the summer and winter peaks together decreases the likelihood that a jurisdiction or class can shift load away from a single hour of the year and avoid any peak cost responsibility, notwithstanding its energy needs over the rest of the hours of the year. Thus, a more accurate cost allocation results from using SWPA.

Q. HAS THIS COMMISSION APPROVED SWPA AS THE APPROPRIATE COST ALLOCATION METHODOLOGY IN PAST GENERAL RATE CASE PROCEEDINGS?

A. Yes. This Commission has found SWPA to be the appropriate cost-of-service allocation methodology for Carolina Power & Light Company (now DEP) in prior general rate case proceedings: Docket No. E-2, Subs 461, 481, 526, and 537. In finding that SWPA is the most appropriate cost of service methodology for DEP,[7] the Commission said the following in its Order:

> Without base load plants, CP&L [now DEP] would simply not be able to serve its high load factor customers. It is only appropriate that high load factor customers pay their share of the cost of these base load plants built primarily to serve them. The Commission is reluctant to shift the costs of these production facilities to further burden lower load factor customers, thereby reducing their load factors and ultimately, CP&L's system load factor still further.
> 78 N.C.U.C. 238, 367 (1988).

Q. WHAT HAS THIS COMMISSION RECENTLY HAD TO SAY ABOUT SWPA AS COMPARED TO OTHER COST ALLOCATION METHODOLOGIES?

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[7] See Finding of Fact No. 14 of the Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 537, issued August 5, 1988.

A. In its DENC rate case Order, dated February 24, 2020, in Docket No. E-22, Sub 562, this Commission in approving SWPA as the appropriate cost-of-service methodology for DENC, stated the following at page 72:

> …<u>a methodology that does not properly consider the effect of overall energy consumption</u>, but focuses mainly on peak responsibility, such as the 1-CP methodology, <u>would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service</u>. The Commission is not persuaded that either the S/W CP methodology or the 1-CP methodology is appropriate for the Company in this proceeding… The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DENC's customer classes in this case. …the Commission finds that the SWPA method is not unreasonable or flawed… [Emphasis added]

In its Dominion North Carolina Power (now DENC) rate case Order, dated December 22, 2016, in Docket No. E-22, Sub 532, this Commission, in approving SWPA as the appropriate cost-of-service methodology for DNCP (now DENC), stated the following at page 114:

> The Commission finds and concludes that DNCP has carried its burden of proof to show that the <u>SWPA</u> methodology is the <u>most appropriate cost of service methodology</u> to use in this proceeding to assign cost responsibility for production plant to the North Carolina jurisdiction and the Company's customer classes. … The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique

> characteristics of each class's peak demands and overall energy consumption. Company witness Haynes testified extensively that the Company's investment in generating plant, including the recently placed in service Warren County and Brunswick County CC, are designed to meet the Company's system peaks and to deliver low cost energy throughout the year. Witness Haynes explained that the SWPA methodology appropriately recognizes that DNCP's system planning is designed to meet both the Company's peak and average system demands and energy needs of customers throughout the year. Both Company witness Haynes and Public Staff witness Floyd testified that the SWPA method appropriately matches allocation of production plant with DNCP's generation planning and operations. The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DNCP plans and operates its generating plants to provide utility service to customers in North Carolina. [Emphasis added]
>
> Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service.
>
> The Commission is not persuaded that either the S/W CP methodology or the 1CP methodology is appropriate for the Company in this proceeding. Company witness Haynes and Nucor witness Goins provided calculations to compare the rates of return associated with the cost of service methodologies they advocated. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DNCP's customer classes in this case.

In its rate case Order, dated December 21, 2012, in Docket No. E-22, Sub 479, this Commission, in approving SWPA as the appropriate cost-of-service methodology for DNCP (now DENC), stated the following at page 23:

> The cost of service methodology is a crucial component in establishing an electric utility's general rates. The methodology employed should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class's peak demands and overall energy consumption. Based on the facts in this case, a methodology that does not properly consider the effect of <u>overall energy consumption</u>, but focuses mainly on peak responsibility would not properly represent the way in which [DNCP] plans for and provides its utility service and the way customers use that service. [Emphasis added]

The Commission further stated the following at page 24:

> In addition, the Commission is not persuaded that…any…cost of service methodology that only considers the jurisdictional and customer class peak demands is appropriate for the Company in this proceeding. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the <u>SWPA</u> resulting in the <u>most equitable sharing</u> of the rate of return among DNCP's customer classes. [Emphasis added]

Thus, what the Commission has found in past rate cases for DEP and DENC holds true today – the appropriate cost-of-service methodology must consider both overall energy consumption and peak demand. SWPA takes both into account; SCP does not.

Q. DOES THE PUBLIC STAFF CONSIDER A UTILITY'S IRP IN SELECTING THE APPROPRIATE COSS METHODOLOGY?

A. Yes. The Public Staff has historically taken the position that the cost-of-service methodology associated with any utility should be based on how that utility plans, builds, and operates its utility system. The best view of how a utility does this comes from the utility's integrated resource plan (IRP). Based on my review of DEP's 2018 IRP,[8] I believe the Company plans its system on the basis of meeting the peak demand plus a reserve margin at the peak hour of the year, <u>and</u> on the basis of satisfying the demand for energy at all other hours of the year. In other words, DEP plans and operates its utility system to provide the least-cost mix of generation resources to provide electric service for all hours of the year. Therefore, the methodology employed for a COSS should be based on the utility's efforts to provide electric utility service for all hours of the test year period, not a few hours of the year, and certainly not one single hour. Moreover, as stated above, DEP, beginning in 2016, considers itself to be winter peaking, and for generation planning purposes, winter planning.

Q. WHAT IN DEP'S 2018 IRP SUGGESTS THAT THE UTILITY PLANS ITS SYSTEM TO MEET THE DEMANDS OF ALL HOURS OF THE YEAR AT LEAST-COST?

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[8] The 2018 IRP filed in Docket No. E-100, Sub 157 was used because it was the last full IRP available.

A. The first piece of evidence can be found on page 72 of the 2018 IRP Update. Chart 9-A identifies the forecast capacity of the utility system in 2020 and 2034. Approximately 52% of the capacity in 2020 comes from nuclear, coal, and combined-cycle (natural gas) resources. These resources are typically considered baseload capacity resources and are intended to operate at least 50% to 60% of the hours of the year (50% times 8,760 hours is 4,380 hours).

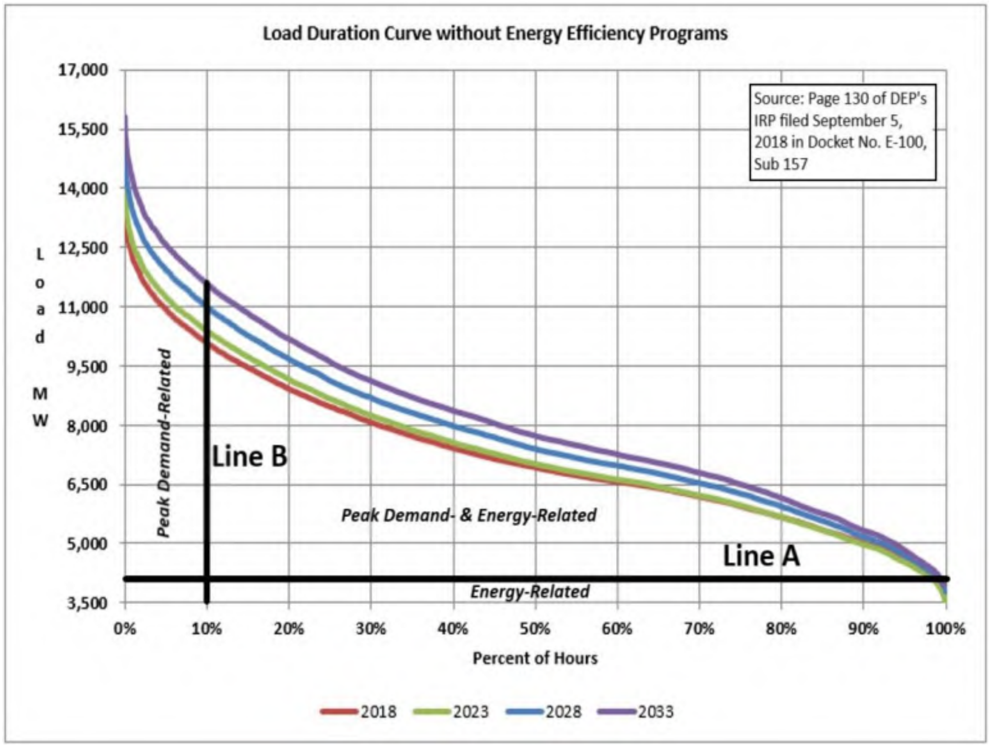
The second piece of evidence can be found on page 73 of the 2018 IRP Update. Chart 9-B[9] identifies the energy generated by fuel type, and clearly shows that for 2020 approximately 85% of the fuel used to produce energy comes from nuclear, coal, and combined-cycle resources.

The quantitative analysis that is in Appendix A of the 2018 IRP and the load duration curves in Appendix C of the 2018 IRP discuss the inputs (peak demand and energy load forecasts, existing resources, fuel prices, capital costs, and environmental constraints) used by the IRP model to determine the least-cost mix of generation resources for the next 15 years.

The load duration curve identifies the demand for resources needed over all hours of the year. For example, the graph below is taken from DEP's 2018 IRP. In general terms, all demand below line A is

[9] Chart 9-B shows a combined DEC/DEP energy production by technology type.

satisfied with baseload generation resources, which operate many hours of the year. This area is considered to be "energy-related." Demand to the left of line B is typically satisfied with peaking resources, which are usually combustion turbines that operate fewer than 10% of the hours in a year. This area is typically considered to be "demand-related." Everything else beneath the load duration curve is typically satisfied with a mix of baseload, intermediate, and peaking resources, and is considered to be <u>both</u> peak demand- and energy-related. Furthermore, the slope of the lines also informs how likely the model is to consider an energy resource versus a peak demand resource. In general terms, a flatter slope tends to lean more toward the selection of a baseload or more energy-intensive resource. A steeper slope tends toward the selection of a peaking resource. The IRP model will select the appropriate type of resource at least cost.



As a final point, both the quantitative analysis and development of the load duration curves are part of a technical and economic analysis that weighs the need to meet the one single peak demand hour, but also to satisfy the energy and demand requirements for every other hour of the year. The IRP model attempts to resolve this analysis by picking the least-cost mix of generation resources. In other words, it is the single peak demand that determines the total quantity of generation capacity needed by the system plus a reserve margin, but the type of generation resource (baseload, intermediate, or peaking) is most definitely determined on the basis of the energy requirements of the system that will be available from those capacity resources over all hours. The economics of energy production and its role in utility planning can be observed when one views the significant increase in the percentage of combined cycle (CC) generation, while the role of coal and several other sources of power have diminished, as shown in Chart 9-A mentioned above. This increase in CC generation is largely due to two key drivers: the low costs of natural gas fuel, and the relatively lower capital costs per kilowatt for combined cycle units. Thus, DEP's portfolio of planned resources to meet its future load requirements takes into consideration both the fuel and capital cost of meeting its summer and winter peak demands, as well as the fuel and capital costs of satisfying its planned energy requirements for the other hours of the year.

Q. DOES DEP'S COSS METHODOLOGY ACCURATELY REFLECT THE COINCIDENT PEAK OF ITS STYSTEM?

A. No. Although the Public Staff believes that DEP is planning its system to meet both winter and summer peak, as well as total load throughout the year, if it were to use one peak in its COSS methodology, the system peak actually occurred in the winter. As mentioned earlier in my testimony, not only did the 2018 (test year) system peak occur in the winter, so did the system peaks in all but two years since 2008. In addition, DEP currently forecasts its annual system peaks to be winter peak dominant through 2029, and currently plans its generation needs based on a winter planning scenario.

Q. IS THE DEP WINTER PEAK AN ANOMOLY THAT SHOULD BE DISREGARDED?

A. No. As mentioned above, both the summer and winter peaks are significant now, and are projected to remain so for the foreseeable future. As such, both peaks should receive weight in determining the peak load portion of production plant cost allocation.

Q. WOULD THE PUBLIC STAFF SUPPORT A CP COSS METHODOLGY USING ONLY THE WINTER PEAK?

A. No. The Public Staff would not support a winter peak CP (WCP) methodology, because it bases all production plant allocation solely on the one-hour winter peak, and ignores the other 8,759 hours of the year, thus having similar flaws as the SCP methodology. All of the shortcomings identified above for SCP exist with the WCP methodology. Nevertheless, if the Commission were to approve a COSS methodology based solely on a one-hour peak, which the Public Staff strongly opposes, the WCP methodology would be the appropriate methodology to use because DEP is now a winter peaking and winter planning system. As I demonstrate below, a WCP methodology would have much harsher impacts on certain classes of customers, particularly the Residential Class, than other methodologies.

Q. WHAT OTHER COSS METHODOLOGIES DID THE PUBLIC STAFF ANALYZE?

A. In addition to SWPA, SCP, and WCP, the Public Staff also analyzed the impacts of Summer/Winter Coincident Peak (SWCP), Four Coincident Peak (4CP), and 12 Coincident Peak (12CP) methodologies.

Q. WHAT IS THE SWCP COS METHODOLOGY?

A. The SWCP COS methodology utilizes both the annual summer and winter peaks for the system, jurisdictions, and classes, then averages them, and then computes allocation factors based on each jurisdiction's and class's contributions to the average summer and winter system peak. For the test year, those two peaks occurred in the months of January and June. SWCP is similar to SWPA in one way: it utilizes the same summer and winter peaks used in the peak allocation portion of SWPA; however, it does not incorporate any type of average demand component to reflect usage of generation plant over the entire year. It has the same shortcomings as the SCP and WCP, other than the fact that it tends to mitigate out extremes that occur at only a single seasonal peak.

Q. WHAT IS THE 4CP COS METHODOLOGY?

A. The 4CP COS methodology is similar to the SWCP methodology, except that it utilizes the four highest monthly peaks of the year. For the test year, those peaks occurred in the months of January, June, July, and August. As is the case of the SWCP methodology, it does not incorporate any type of average demand component to reflect usage of generation plant over the entire year.

Q. WHAT IS THE 12CP COS METHODOLOGY?

A. The 12CP methodology averages the highest monthly coincident peaks for each calendar month of the year. Because each monthly peak is weighted equally in calculating the annual average peak, any weather extremes from one month or one season are moderated. As with the other CP COS methodologies discussed above, however, there is no average demand component incorporated. The 12CP COS methodology has been historically utilized by the Federal Energy Regulatory Commission for its COS purposes.

Analysis of COS Methodologies

Q. HAVE YOU ANALYZED THE DIFFERENCES BETWEEN AND AMONG THE VARIOUS COS METHODOLOGIES DISCUSSED ABOVE FOR THIS CASE?

A. Yes. As can be seen in Exhibit JSM-1, I have compared the total energy requirements of the NC Retail Jurisdiction and the NC Retail

Classes with the allocation of production plant by COSS methodology.

Q. WHY DO YOU BELIEVE THIS TYPE OF COMPARISON IS RELEVANT?

A. While I am not advocating for a perfect match between the allocation of production plant and total energy consumed by a jurisdiction or customer class, it is worthwhile to illustrate who is paying for the production plant as compared to who is getting the benefit of the relatively low cost energy produced by a combined, integrated system of generating facilities.

As Exhibit JSM-1 illustrates, all six methods allocate between 59.59% and 61.61% of production plant to the North Carolina retail jurisdiction. This analysis looks at the energy consumed by end users of Company owned generation, but does not include purchased power, which is allocated proportionally to jurisdictions and customer classes. The North Carolina retail jurisdiction consumes approximately 61.11% of system energy, so there is a relatively close match between energy consumption and the allocation of production plant.

However, on a North Carolina retail customer class basis, the differences between energy consumption and production plant allocation are more pronounced. For the Public Staff preferred

SWPA allocation methodology Residential customers account for 43.22% of the energy consumed by the North Carolina retail jurisdiction, yet this class is allocated 49.38% of the production plant. Using the same percentage of energy consumption by jurisdiction and customer class, the other five methodologies all allocate greater amounts of production plant than the SWPA methodology, ranging from 49.60% for the Company preferred SCP, to 64.30% for WCP.[10]

At the other end of the spectrum are the large time of use general service and industrial customer classes, represented in Exhibit JSM-1 as MGS and LGS. These classes consumed 28.94% and 21.66% of jurisdictional energy respectively, yet are allocated 26.82% and 17.63% of production plant respectively under SWPA. Under SCP, MGS and LGS are allocated 28.18% and 15.99% of production plant, respectively. For WCP, the allocation percentages are 20.21% and 9.46%, respectively.

Q. DO YOU CONTEND THAT THERE SHOULD BE A PERFECT MATCH BETWEEN THE ENERGY CONSUMED AND THE PRODUCTION PLANT ALLOCATED?

A. No. If that were the case, the allocation methodology would be based solely on energy consumption. As I have stated previously in this testimony, system peaks are significant, and represent the total

[10] As noted previously in my testimony, DEP forecasts its system peaks and plans its system generation resources on the basis of it being a winter peaking system.

quantity of generation that must be present on the system to meet the highest demands. Thus, it is reasonable to allocate a portion of production plant based on one or more peaks. The SWPA allocates a significant portion, approximately 45%, of production plant on the basis of the summer and winter peaks. Because some customer classes have different load factors (a function of energy consumed from the system to peak demand placed on the system), there will necessarily and appropriately be a difference in the energy consumption percentages and the production plant allocation percentages. Classes with lower load factors such as the Residential Class will be allocated more production plant because of their relatively higher peak demand on the system. Nevertheless, it is important to recognize that energy consumed should play a role in the allocation of production plant as well. Of the six allocation methodologies represented in Exhibit JSM-1, only the SWPA reflects the spectrum of purposes for which system production plant is planned and built.

Q. HAVE YOU DONE AN ANALYSIS OF THE IMPACTS OF DIFFERENT COSS METHODOLOGIES ON THE JURISDICITONAL AND CLASS REVENUE INCREASES FOR THIS CASE?

A. Yes. Exhibit JSM-2 shows the overall rates of return on rate base for the North Carolina Retail Jurisdiction and various customer classes for the SWPA, SCP, and WCP COS studies. I have selected these three COSS methodologies to show the preferred methodology of the Public Staff (SWPA), the preferred methodology of the Company (SCP), and the methodology the Company should use if it were to continue using a single coincident peak methodology using its current yearly peak (WCP).

I have shown the rates of return under present revenues annualized (before any increase) and then, assuming the jurisdiction and each customer class is brought to the overall 7.41% return requested by the Company in this case, I have shown what the proposed increase or decrease would be under the three COS methodologies listed above.

As illustrated, the SCP produces the greatest North Carolina jurisdictional increase over present revenues at 17.55%, followed by SWPA at 17.15% and WCP at 16.45%.

For the Residential Class, the WCP produces the greatest required increase at 31.29%, followed by the SWPA at 21.72% and the SCP at 21.64%.

For the General Service Classes, the WCP results in a 19.69% increase for SGS, but only a 0.03% increase for MGS and a 4.18% decrease for LGS over present revenues to bring each class to the overall ROR. The SWPA results in increases of 18.95% for SGS, 10.07% for MGS, and 15.83% for LGS. However, under SCP, the SGS Class would require increases of 22.20% for SGS, 12.68% for MGS, and 13.85% for LGS.

The Lighting and Traffic Signal classes have similar results under all three COS methodologies.

Q. TO WHAT DO YOU ATTRIBUTE THE DIFFERENCES IN RATES OF RETURN AND REVENUE INCREASE PERCENTAGES?

A. The rates of return differences are a result of the differences in the allocation of production plant based on either peak only, or a combination of peaks and overall energy use. The revenues under current rates do not change by methodology, and the allocation of other types of plant (e.g., transmission[11], distribution, customer, general) are not impacted by the way production plant is allocated. Some costs, such as depreciation, property taxes, and fixed O&M are dependent on the way production plant is allocated, however, and do impact net operating income by both jurisdiction and customer class.

[11] Transmission plant is impacted by the peak demand inputs utilized in the particular allocation methodology, but is not impacted by whether or not energy, or average demand, is utilized as an input. For example, for the SCP and WCP methodologies, the same peak inputs are utilized for both the production and the transmission plant allocation calculations. For the SWPA methodology, the average of the summer and winter peak demands is used as an input to calculate the allocation of transmission plant, but the average demand is not an input. The inputs for calculating transmission plant allocation are identical under both the SWPA and SWCP methodologies, but the production plant allocation inputs are different, due to the fact that SWPA utilizes average demand to allocate production plant, while SWCP does not.

The revenue increase percentages are a function of the rates of return. They represent the revenue increase required to bring the jurisdictional and class rates of return from present to the Company's requested overall rate of return of 7.41%.

III. Adjustments to Test Year Data

Q. DID DEP ADJUST THE TEST YEAR DATA USED TO CALCULATE THE COS PRODUCTION PLANT ALLOCATION FACTORS?

A. Yes. As discussed on page 10 of DEP witness Hager's direct testimony, DEP adjusted the system peak to remove demands related to Company use and other transactions not considered part of native load, including a peaking NCEMC sale. These adjustments are appropriate and should be made for any COSS to be utilized in this case. I reviewed the Company's test year peak demand and energy sales data related to this adjustment and believe the adjustment is appropriate for this proceeding.

IV. Allocation of Transmission and Distribution Plant

Q. EARLIER, YOU STATED THAT ALLOCATION OF PRODUCTION PLANT DOES NOT IMPACT THE ALLOCATION OF OTHER TYPES OF PLANT. DOES THE COMMISSION NEED TO CONSIDER CHANGES TO THE WAY TRANSMISSION AND DISTRIBUTION PLANT IS ALLOCATED?

A. Yes. As part of our analysis of DEP's Grid Improvement Program (GIP), we discovered that the benefits derived from some of the associated transmission and distribution assets are disproportionally related to the way the GIP transmission and distribution plant is allocated. For example, distribution plant allocation is heavily weighted towards the Residential Class, while the benefits derived from the GIP investments in distribution plant is heavily weighted towards the General Service and Industrial Customer Classes, as noted in the testimony of Public Staff witness Jeff Thomas. As recommended by witness Thomas, I believe that this is an area of cost allocation that deserves further study and analysis, and recommend that the Commission order DEP to study the allocation of GIP investments based on the realized benefits of those investments, and report its findings no later than the filing of its next general rate case.

V. Recommendations

Q. WHAT SPECIFIC RECOMMENDATIONS ARE YOU MAKING TO THE COMMISSION?

A. I have three recommendations to make.

- Adopt the SWPA COS methodology for the allocation of production plant because it most accurately and fairly reflects the planning and operation of DEP's production plant to meet the energy needs of its customers.

- Require DEP to study the allocation of GIP transmission and distribution investment/costs versus the benefits realized, and report its findings to the Commission no later than the filing of its next general rate case.
- Require DEP to solicit formal input from the Public Staff and other interested intervenors to this proceeding in developing its analysis of the allocation of GIP transmission and distribution investment/costs versus the benefits realized.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JAMES S. MCLAWHORN

I graduated with honors from North Carolina State University with the Bachelor of Science Degree in Industrial Engineering in May of 1984. I received the Master of Science Degree in Management with a finance concentration from North Carolina State University in December of 1991. While an undergraduate, I was selected for membership in both Tau Beta Pi and Alpha Pi Mu engineering honor societies.

I began my employment with the Public Staff Communications Division in June of 1984. While with the Communications Division, I testified before the Commission in general rate proceedings regarding matters of telephone quality of service.

In September of 1987, I was employed by GTE-South as an engineer in the Capital Recovery Department. I was responsible for analysis and recommendations to Company management regarding appropriate depreciation rates for recovery of the Company's capital investments.

I began my employment with the Electric Division of the Public Staff in November of 1988. I assumed my present position as Director of the Electric Division in October of 2006. It is my responsibility to supervise and make policy recommendations on all electric utility matters before the Commission.

I have testified previously before the Commission in numerous proceedings including Virginia Electric and Power Company Rate Cases Docket No. E-22, Subs 314, 333, 412, 532, and 562; in Duke Energy Carolinas, LLC's Rate Cases Docket No. E-7, Subs 487, 909, 989, 1146, and 1214; in Duke Energy Progress, LLC's Rate Cases Docket No. E-2, Subs 1023 and 1142; in New River Light and Power Company Rate Cases Docket No. E-34, Subs 28 and 32; in Nantahala Power and Light Company Rate Case Docket No. E-13, Sub 157; in the Application of Dominion North Carolina Power to join PJM in Docket No. E-22, Sub 418; in Duke Power Company's request to merge with in Duke Power Company's request to merge with Cinergy Corporation in Docket No. E-7, Sub 795; in Dominion Energy, Inc.'s request to merge with SCANA Corporation in Docket No. E-22, Sub 551; in Duke Energy Carolinas, LLC's request for approval of its Save-A-Watt cost recovery model in Docket No. E-7, Sub 831; in Duke Energy Carolinas, LLC's solar distributed generation program in Docket No. E-7, Sub 856; and, in the Generic Investigation into Section 111 of the 1992 Energy Policy Act in Docket No. E-100, Sub 69.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))))	TESTIMONY OF JAMES S. MCLAWHORN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION SUPPORTING SECOND PARTIAL STIPULATION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

Testimony of James S. McLawhorn Supporting Second Partial Stipulation

On Behalf of the Public Staff

North Carolina Utilities Commission

July 31, 2020

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

A My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Public Staff – Electric Division.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE ON APRIL 13, 2020?

A. Yes.

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

A. The purpose of my testimony is to support the Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation) filed on July 31, 2020, between Duke Energy Progress, LLC (DEP or the Company), and the Public Staff (Stipulating Parties) regarding certain issues related to the Company's pending application for a general rate increase.

Q. WHAT BENEFITS DOES THE SECOND PARTIAL STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, among the most important benefits provided by the Second Partial Stipulation are:

(a) A significant reduction in the Company's proposed revenue increase in this proceeding; and

(b) The avoidance of protracted litigation by the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

Q. WHAT ARE THE SPECIFIC AREAS OF AGREEMENT BETWEEN THE STIPULATING PARTIES IN THE SECOND PARTIAL STIPULATION?

A. The Stipulating Parties were able to reach agreement on the following issues in the Second Stipulation:

- The parties agree to a return on equity of ROE of 9.6% - This ROE is below the 2020 average for vertically integrated utilities, and is the lowest ROE for an investor-owned utility in North Carolina in at least 30 years (in anyone's memory currently on the Public Staff);
- The parties agree to a capital structure ratio for each company of 52%/48% – This ratio is very close to DEP's current capital structure;
- The parties agree that DEP should return federal unprotected EDIT over five years, NC EDIT over two years, and deferred revenues over two years – this is consistent with the treatment of EDIT for other utilities;
- The parties agree to the Company's request for deferral accounting treatment for the following programs, as described in witness Oliver's Exhibit 10, limited to the estimated three-year capital budget period of 2020-2022: Self-Optimizing Grid (SOG) (all subprograms including Capacity and Connectivity, Segmentation and Automation, ADMS), Conversion to CVR, Integrated Systems Operations Planning (ISOP), Transmission System Intelligence, Distribution Automation, Power Electronics, DER Dispatch Tool, and Cyber Security. For all other GIP investments proposed by the Companies in

these dockets, the Companies agree that they should withdraw their request for deferral accounting;

- DEP should update to its May 2020 cost of debt, which is 4.04%;
- DEP may update plant through May 2020. Its revenues should be updated through May, but only 75% should be allowed to recognize the uncertainty regarding effects of COVID. The update should include benefits and executive compensation;
- Coal ash capital projects such as dry ash storage, STAR water treatment project deferrals should be amortized over eight years;
- For purposes of this case only with no precedential effect, the Public Staff accepts the Summer Coincident Peak (SCP) cost of service allocation methodology;
- This acceptance of the SCP cost of service allocation methodology should have no impact on the rate design study proposed by Public Staff witness Floyd and endorsed by DEP and DEC witness Pirro. DEP also agrees to conduct an analysis of various cost of service study methodologies;
- In addition to $6 million DEP has agreed to contribute in its settlement with the North Carolina Sustainable Energy Association, the North Carolina Justice Center, the North

Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy to the Helping Home Fund, DEP agrees to contribute $5 million to assist low income customers with payment of their bills; and

- DEP should reduce the annual funding of its Nuclear Decommissioning Fund by $8.7 million.

Q. ARE THERE ANY AREAS ABOUT WHICH THE STIPULATING PARTIES DID NOT REACH AGREEMENT?

A. Yes. The Stipulating Parties did not reach agreement regarding the following:

- Coal ash costs - Cost recovery of the Company's coal ash costs, recovery amortization period and return during the amortization period;
- Depreciation Rates – The depreciation rates appropriate for use in this case, including the Company's proposal to shorten the lives of certain coal-fired generating facilities ; and
- any other revenue requirement or non-revenue requirement issue not specifically addressed in the First Stipulation, the Second Stipulation, or agreed upon in the testimony of the Stipulating Parties.

The Public Staff fully supports its filed positions on these particular issues, and intends to demonstrate the appropriateness and reasonableness of its positions through litigation in this case.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Q. Mr. McLawhorn, do you have a summary of your direct and second partial stipulation supporting testimony?

A. Yes.

Q. And those have been provided to the parties and the Commission staff; isn't that correct?

A. Yes, they have.

MS. DOWNEY: Commissioner Clodfelter, I would further move that Mr. McLawhorn's summaries of his direct and second partial stipulation supporting testimony be entered into the record.

COMMISSIONER CLODFELTER: Without objection, so ordered.

(McLawhorn Exhibits 1 and 2 were identified as they were marked when prefiled.)

(Whereupon, the prefiled testimony summaries of James S. McLawhorn was copied into the record as if given orally from the stand.)

Summary of the Testimony of James S. McLawhorn

Docket No. E-2, Subs 1193 and 1219

The purpose of my testimony is to provide the Public Staff's recommendation on the appropriate cost-of-service (COS) methodology for use in this case.

The Public Staff believes the appropriate methodology is the Summer/Winter Peak and Average methodology (SWPA). The Company has proposed the use of the Summer Coincident Peak methodology (SCP).

When the Company is selecting the appropriate type of generation plant to build, it must consider the quantity of energy the plant will be required to supply as well as the peak demand the plant must help to meet. The SWPA methodology recognizes and reflects the fact that the Company plans its system to meet the demands customers place on its generation plant throughout the year.

On the other hand, the SCP methodology assigns responsibility for generation plant and plant-related costs based solely on one single hour out of the entire year. Under SCP, a customer class can avoid all production plant cost responsibility by having no consumption at the time of the one hour summer peak.

In addition, I compare a number of other COS methodologies, including those included in the Commission January 22, 2020 Order in this case.

Finally, I recommend that DEP study the allocation of Grid Improvement Program (GIP) transmission and distribution investments and costs versus the benefits realized, and report its findings to the Commission by the filing of its next general rate case. In his review of the cost-benefit analyses of the various GIP programs, Public Staff witness Jeff Thomas found that the benefits of many of the programs are heavily weighted towards non-residential customers, while the costs, particularly for distribution, are not recovered in the same manner under current cost allocation methods; thus, my recommendation for the Company to study this issue, with input from the Public Staff and other interested parties, and report back to the Commission on the results. This study is even more critical now, given the Company's settlements with other parties to this case regarding the allocation of GIP costs.

This concludes my summary.

Summary of the Second Partial Stipulation Testimony of James S. McLawhorn

Docket No. E-2, Subs 1193 and 1219

The purpose of my partial settlement testimony is to support the Second Agreement and Stipulation of Partial Settlement (Stipulation) between Duke Energy Progress, LLC (DEP or Company) and the Public Staff.

The Stipulation, as filed on July 31, 2020, sets forth agreements between DEP and the Public Staff on a number of areas impacting the overall revenue requirement in this proceeding including: (1) excess deferred income taxes, (2) cost of capital, (3) the Company's Grid Improvement Plan, (4) cost of service, and (5) accounting adjustments. Other areas of agreement include: (1) May 2020 updates, (2) principles surrounding class revenue apportionment, (3) additional cost of service studies, (4) a comprehensive rate design study, and (5) audits and reporting obligations.

Unresolved areas that impact the overall revenue requirement about which DEP and the Public Staff have not reached agreement in this case include: (1) recovery of coal ash costs and (2) depreciation rates.

Despite being only a partial settlement of issues in this case, the Stipulation still provides two important benefits for ratepayers:

(a) A significant reduction in the Company's proposed revenue increase in this proceeding; and

(b) The avoidance of protracted litigation between DEP and the Public Staff before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, I believe that the Stipulation is in the public interest and encourage the Commission to approve it.

This concludes my summary.

MS. DOWNEY: And I believe Ms. Edmondson will take over with Mr. Floyd.

DIRECT EXAMINATION BY MS. EDMONDSON:

Q. Good morning, Mr. Floyd. You've previously testified during the consolidated portion of this hearing as well as in the DEC hearing? You're on mute.

A. (Jack L. Floyd) I did.

Q. And since those hearings, you filed in this docket, second supplemental testimony consisting of nine pages and four exhibits on September 16th, and an errata to your first supplemental testimony, and four corrected exhibits on September 28th?

A. That's correct.

Q. And in regard to the corrected first supplemental testimony, besides the corrections you filed on September 28th, do you have any changes or corrections to that prefiled first supplemental testimony?

A. I do not.

Q. And if I asked you the same questions here today, would your answers be the same as corrected?

A. They would.

Q. Do you have any further changes or corrections to the corrected exhibits filed on

September 28th?

A. No.

Q. And, Mr. Floyd, in regard to the second supplemental testimony, do you have any changes or corrections to that prefiled second supplemental testimony?

A. No.

Q. And if I asked you the same questions here today, would your answers be the same?

A. They would.

Q. Do you have any changes or corrections to the exhibits to your second supplemental testimony?

A. I do not.

Q. And did you prepare a summary of your direct first supplemental and second supplemental testimony?

A. Yes.

MS. EDMONDSON: Commissioner Clodfelter, Mr. Floyd's direct and original first supplemental testimonies were entered and copied into the record in the consolidated hearing, and the exhibits to those testimonies were marked for identification at that time. So today I would move that the prefiled errata to Mr. Floyd's first supplemental testimony, his first supplemental testimony as corrected, his second supplemental testimony and summary be entered into the record in this proceeding and copied into the record as if given orally from the stand; and that his exhibits attached to these testimonies be marked for identification as Floyd Corrected First Supplemental Exhibits 1 through 4, and Floyd Second Supplemental Exhibits 1 through 4.

COMMISSIONER CLODFELTER: Thank you, Ms. Edmondson. Are there any objections to the motion?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, motion is allowed.

(Public Staff Floyd Exhibits 1 through 3 and Public Staff Floyd Supplemental Exhibits 1 through 4 were moved at the consolidated hearing and admitted into evidence.)

(Floyd Corrected First Supplemental Exhibits 1 through 4, and Floyd Second Supplemental Exhibits 1 through 4 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct with

Appendix A and supplemental moved at the consolidated hearing; and second supplemental, errata to first supplemental, and summary testimony of Jack L. Floyd were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		TESTIMONY OF
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	JACK L. FLOYD PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

TESTIMONY OF JACK L. FLOYD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

APRIL 13, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jack L. Floyd. 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. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations concerning:

1. The class rates of return (ROR) on rate base under present rates, the principles the Public Staff considers in evaluating proposed revenues requested by Duke Energy Progress, LLC (DEP or the Company) and the assignment of the Public

Staff's proposed revenues by customer class to be used in setting rates;

2. DEP's proposed modifications to certain rate schedules;
3. The status of the Company's Advanced Metering Infrastructure (AMI) Project; and,
4. The Commission's January 22, 2020 Order regarding low-income rates and the minimum bill concept (Affordability Order).

Q. WHAT DID YOU REVIEW IN DEVELOPING THE PUBLIC STAFF'S RECOMMENDATIONS?

A. The Public Staff's recommendations are based on a review of the Company's Application and Items 39, 40, 42, and 45 of the Company's Form E-1 filed by DEP, the direct testimony and exhibits of Company witnesses Hager, Henning,[1] McGee, Oliver, Pirro, Smith, and Schneider, various accounting adjustments, and DEP's responses to numerous data requests from the Public Staff and other intervenors to this proceeding.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My testimony recommends the following:

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[1] Company witness James Henning's testimony was adopted by Larry Hatcher in a December 20, 2019 filing.

1. That any proposed revenue change be apportioned to the customer classes such that:
   a. Any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
   b. Class RORs are maintained within a band of reasonableness of ± 10% relative to the overall NC retail ROR;
   c. All class RORs move closer to parity with the North Carolina (NC) retail ROR; and
   d. Subsidization among the customer classes is minimized;
2. Except for status of Schedules R-TOUD, CSE, and CSG, that the Commission find that the proposed modifications to the Company's rate schedules are reasonable for purposes of this proceeding;
3. That the Commission order a comprehensive rate design study that will address rate design questions related to, among other things:

- Firm and non-firm utility service, and the degree of customer-owned generation receiving both types of service,
- Various types of end-uses such as electric vehicles (EVs), microgrids, energy storage, demand response, and distributed energy resources (DERs),
- The formats of future rate schedules (basic customer charges, demand charges, energy charges, etc.),
- Marginal cost versus average cost rate designs and pricing,
- Unbundling of average rates into the various functions of utility service (i.e., production, transmission, distribution, customer, general/administrative, etc.),
- Decoupling revenues from sales; and
- Socialization of costs versus categorization of specific costs and corresponding impact on rates/revenues;

4. That the Commission order the convening of a stakeholder process to address affordability issues for low-income residential customers.

CALCULATION OF CLASS RORS AND ASSIGNMENT OF REVENUES

Q. HOW ARE RORS USED IN DETERMINING REVENUE ASSIGNMENT?

A. RORs indicate how the revenues produced by the various customer classes cover the costs to serve those classes. They also inform how any additional revenues will be apportioned to the customer classes. An ROR that is less than the overall system or jurisdictional ROR indicates that the revenues received from a specific jurisdiction or customer class do not fully cover its share of system costs. Conversely, an ROR that is greater than the overall system or jurisdictional ROR indicates that a jurisdiction or class's revenues exceed the necessary cost coverage. While it is appropriate to address revenue cost recovery inequities as revealed through RORs, it is equally important to keep in mind that such an assignment is based on a snapshot in time of the Company's cost and load data. A different timeframe, test year period, or other perspective would likely yield a different representation of cost causation and revenue assignment. Due to the variability in RORs, the Public Staff has historically targeted a ±10% "band of reasonableness" for class revenue assignment as discussed in more detail later in my testimony.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S GOALS IN ASSIGNING CHANGES IN REVENUES.

A. The Public Staff believes that assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR as determined by the cost-of-service study (COSS), and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

1. Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
2. Maintain a $\pm$10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;
3. Move each customer class toward parity with the overall jurisdictional ROR; and
4. Minimize subsidization of customer classes by other customer classes.

Q. DID THE COMPANY ADHERE TO THESE PRINCIPLES IN ITS ASSIGNMENT OF ITS PROPOSED REVENUE INCREASE?

A. Witness Pirro's testimony indicated that the Company's revenue assignment considered maintaining RORs within a band of reasonableness, moving classes toward parity with the overall ROR, and reducing cross-subsidies. His testimony did not mention the principle of limiting increases in base revenues to within two percentage points of the NC retail jurisdictional increase.

With respect to the Public Staff's first principle that no class be assigned an increase more than two percentage points greater than the overall jurisdictional revenue percentage increase, a review of Revised Pirro Exhibit 2, Column "D" (excludes existing and proposed rider revenues[2]) indicates that Company's proposed assignments of revenues for the residential, small general service (SGS), and the SGS-constant load classes do not comply with the first principle. Including existing and proposed rider revenues (Revised Pirro Exhibit 2, Column "H") brings all customer classes in compliance with the first principle.

A review of the RORs calculated by the Company in its filed Form E-1, Item 45C, (SCP) indicates that the assignment of the Company's

[2] Energy Efficiency, Fuel Deficiency, EDIT-1, Job Retention Recovery, EDIT-2 (proposed) and REPS Riders.

proposed revenue increase does not comply with the second principle of maintaining a ±10% "band of reasonableness" for RORs for the SGS-constant load, Seasonal and Intermittent, Area Lighting, Street Lighting, and Sports Field lighting customers classes.

With respect to the third principle, the Company's assignment of the proposed increase does move each customer class closer to parity with the NC retail jurisdiction ROR.

With respect to the fourth principle of reducing subsidization, Witness Pirro did take subsidization into account in his calculations of revenue requirement by reducing the difference between class RORs and the overall jurisdictional ROR when assigning revenue to the customer classes.

Q. IS THE PUBLIC STAFF MAKING A RECOMMENDATION ON THE ASSIGNMENT OF THE REVENUE REQUIREMENT TO NORTH CAROLINA RETAIL CUSTOMER CLASSES?

A. The Public Staff intends to update its recommended jurisdictional revenue requirement and file supplemental testimony to provide a final recommendation on our recommended revenue change. I will provide the Public Staff's assignment of our proposed revenue change at that time.

Q. IF THE COMMISSION ORDERS A BASE REVENUE DECREASE IN THIS PROCEEDING, WHAT RECOMMENDATIONS DOES THE PUBLIC STAFF HAVE REGARDING THE ASSIGNMENT OF THE REVENUE DECREASE TO THE CUSTOMER CLASSES?

A. In the event of a base revenue decrease, I believe it is appropriate to focus on addressing any disparities in the class RORs. In addressing disparities in RORs, any revenue decreases assigned to individual customer classes should be limited so that no other customer class sees an increase in its assigned revenue requirement simply to address a disparity in RORs. In other words, in the event of a revenue requirement decrease, no customer class should see an increase simply to bring the class ROR within 10% of the jurisdictional ROR.

RATE DESIGN

Q. PLEASE DISCUSS THE RELATIONSHIP BETWEEN A COSS AND RATE DESIGN.

A. Rate design should follow the same cost causation approach underlying the COSS, such that each customer class, or customer, is responsible for an appropriate share of the costs that are planned for and incurred in order to serve them. This includes both fixed and variable costs. However, strict adherence to this cost causation principle may not always be possible if doing so would result in "rate shock" for certain customers or customer classes. In addition, and depending on the COSS methodology utilized, cost responsibility results can vary significantly due to unusual events that occur in the test year. The COSS functionalizes costs, thus providing a basis from which to start rate design, but does not necessarily dictate the final rate design. Other considerations and objectives such as undue impacts on low usage customers must also be considered when developing rate design.

Q. DOES THE COMPANY'S RATE SCHEDULE PORTFOLIO ALIGN WITH ITS COSS IN THIS PROCEEDING?

A. No. As discussed by Company witness Hager and Public Staff witness McLawhorn, the Company continues to rely on its historical use of the summer coincident peak (SCP) COSS methodology in this proceeding. This is inconsistent with the winter peaking characteristics of the Company's overall system. DEP's existing rate schedule portfolio, however, remains oriented around summer peaking utility service.

Q. BRIEFLY DESCRIBE YOUR REVIEW OF THE COMPANY'S PROPOSAL FOR ITS RATE SCHEDULES.

A. Witness Pirro discussed the load research data, marginal cost data, and the relationships between seasons, on-peak and off-peak hours, and system planning considerations identified in the Company's integrated resource plan that the Company reviewed and considered. However, the Company made very few modifications to any of its rate schedules other than to increase individual rate elements within each schedule to accomplish the revenue increase assigned to the rate class itself, including retaining the same relationships between the summer and winter rates.

The Company also acknowledged that it is costing and revenue models were not updated to reflect current pricing because the Company wants to use its new AMI meters and data analytics to explore the potential for new rate designs.

Most notably, the Company did not provide any discussion or proposals that would address issues related to rate designs that are being discussed in other dockets and proceedings that reflect the future of utility service. For example, there were no proposals for EVs, microgrids, energy storage, or DERs.

Q. PLEASE DISCUSS ELECTRIC VEHICLES IN MORE DETAIL.

A. The Public Staff's comments in the EV Pilot dockets[3] criticized the Company for its lack of any proposal for specific rate designs that might inform the proposed EV pilots. If the Company is going to be responsive to the trends of EV adoption that are anticipated in the

[3] Docket Nos. E-2, Sub 1197, and E-7, Sub 1195.

next few years, then new EV rate designs will need to be considered now.

I believe it is appropriate for the Company to begin working on new EV rate designs now, and to discuss those designs with stakeholders as they are considered and developed. Therefore, I recommend that the Commission require DEP to develop and propose EV rate designs as part of the larger rate design study recommended in my testimony.

Q. DO YOU HAVE ANY SPECIFIC COMMENTS OR RECOMMENDATIONS CONCERNING ANY OF THE COMPANY'S PROPOSED RATE SCHEDULES OR RIDERS?

A. Yes. Notwithstanding my earlier testimony highlighting the status quo nature of the Company's rate schedules, I am generally supportive of the few proposed changes to its rate schedules and service regulations as discussed by witness Pirro. The Company did not propose substantial changes to the structure of its rate schedules in this proceeding. However, there are several rate schedule issues that merit further discussion. Those issues involve the basic customer charge (BCC); Schedules R-TOUD, CSE, and CSG; lighting rate schedules; the smart meter (AMI) opt-out option in Rider MROP; and certain fees in its service regulations.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO MAINTAIN THE BCCs AT CURRENT LEVELS.

A. The Company has not proposed any change in this proceeding to the BCCs in any of its rate schedules. Company Witness Pirro stated that DEP decided to maintain the current BCCs due to past concerns raised by low-income customer advocates. Instead, the Company proposes a stakeholder process to discuss opportunities to address low-income, fixed-income, and low-usage customer concerns.

Q. DOES THE PUBLIC STAFF AGREE WITH MAINTAINING BCCS AT CURRENT LEVELS?

A. The Public Staff does not object to the Company's proposal to leave BCCs at current levels for purposes of this proceeding. As discussed later in my testimony, the Public Staff supports convening a stakeholder process to address affordability issues, including the appropriate amount of the BCC.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S POSITION CONCERNING SCHEDULE R-TOUD.

A. Schedule R-TOUD is a residential time-of-use (TOU) schedule that was closed to new customers in the Sub 1023 rate case pursuant to the Commission's approval of a Stipulation between the Company and the Public Staff. Schedule R-TOUD remained open to new and existing customers who were served under the TOU compensation provisions of Schedule NM (Net Metering). Schedule R-TOUD bills service using demand and energy rates, rather than an energy-only structure. The Public Staff has received a number of requests from customers over the years, who would like service under a demand and energy structure. Given the deployment of smart meters and the Company's initiatives to provide customers with more choices concerning their energy consumption, Schedule R-TOUD is ready-made to provide that choice now. Therefore, the Commission should reopen Schedule R-TOUD.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S POSITION CONCERNING SCHEDULES CSE AND CSG.

A. Schedules CSE and CSG provide service to churches and schools operated by churches. These schedules were closed to new customers in 1977 (E-2, Sub 297), with customers slowly being migrated to other rate schedules over the last 43 years. Currently there are 44 customers on Schedule CSE (when electric space heating is the only source) and one customer on Schedule CSG (no restrictions on equipment). The Public Staff sought information showing the bill impacts if these 45 customers were migrated to other rate schedules. The Company indicated that the 44 customers on Schedule CSE would see their bills increase by an average of 21% if they were migrated to other schedules. The lone Schedule CSG customer would see an increase of 113%. These data make two points. First, these rates are very likely understated and not covering the costs to serve these customers. If migration to another schedule results in a significant increase, then the current rates paid by those customers were understated, recognizing that bringing the rates in line with other schedules in the MGS customer class would represent a significant increase to these customers. Second, keeping these subsidized rates closed to other customers, and allowing only a few to benefit, particularly after over four decades, is unduly discriminatory rate design.

I recognize the significant impact that would result by forcing these customers onto other rate schedules. However, it is not appropriate to allow these conditions to persist given the apparent discriminatory nature of Schedules CSE and CSG, compared to the rest of the MGS customer class. Therefore, the Public Staff recommends the Commission require the Company to notify these customers of their contemporary rate schedule options, and to work with them to migrate to other schedules by the time DEP files its next general rate case. The Public Staff also recommends that DEP adjust the rates for Schedules CSE and CSG in this case to decrease the revenue gap between these schedules and the MGS class schedules (after any increase approved in this case), to which they would otherwise qualify, by 33%. Another adjustment of 33% (50% of any remaining differential after the adjustment in this case) should be made in the next general rate case, with a goal of migrating these customers to the most advantageous MGS schedule by the Company's following[4] rate case.

Q. PLEASE DISCUSS THE CHANGES TO THE LIGHTING RATE SCHEDULES.

A. As noted by witness Pirro, the Company's initiative to consolidate the rates of public and private lighting is finished except for three areas, which if approved, will complete this initiative. Other than the changes to specific lighting rates, the Company is also requesting approval to: (1) eliminate high pressure sodium, (HPS) lighting options for new installations under each lighting schedule, and offer light emitting diode (LED) lighting for those installations; (2) require replacement of existing mercury vapor (MV) lighting and related fixtures by the end of 2023; (3) modify the term for lighting contracts from one to three years; and (4) make Schedule SLR (Residential Subdivisions and Neighborhoods) subject to the Company's Outdoor Lighting Service Regulations.

Witness Pirro indicates that the Company is emphasizing LED technology by ending the availability of HPS vapor fixtures in all three lighting schedules. He notes the improved energy efficiency, color,

[4] 33% adjustment in this case; 50% of any remaining differential in the next rate case; 100% of any remaining differential by the following rate case.

and light provided by LED technology. The evidence of this transition to LED technology is apparent when comparing the billing units of the various lighting types in the Company's Form E-1, Item 42 in this case to the same information in the last rate case.[5] With these changes to the lighting schedules regarding the availability of MV and HPS fixtures, this transition is expected to continue.

I reviewed the cost data provided by the Company regarding the proposed changes to individual rates under each lighting schedule. I believe the changes in rates and the related lighting services are reasonable and should be approved. Any new rates should be commensurate with the new revenue requirement approved by the Commission in this proceeding. With respect to the contract terms and the application of the lighting service regulations to Schedule SLR, both changes are reasonable attempts to consolidate the terms and conditions applicable to lighting services and each lighting rate schedule.

Q. PLEASE DISCUSS THE MANUAL READ OPTION OF RIDER MROP.

A. Witness Pirro did not propose any change to the fees associated with the manual read option in Rider MROP (AMI Opt-Out). He stated that

[5] The comparison suggests that LED comprised 53% of the lighting fixtures in Schedules ALS and SLS in this case versus 37% in the last rate case (Sub 1142).

these fees have been in effect for less than a year and that it was premature to adjust them at this time. Witness Pirro also testified that the costs of opting out of an AMI meter could justify an increase in the one-time setup fee from $170 to $180.52 and the recurring monthly fee from $14.75 to $20.75.

The Manual Read Option (AMI Opt-Out option) was approved by the Commission in 2019[6] to respond to customer concerns surrounding exposure to radio frequency (RF) emissions and data privacy. The Rider MROP Order also provided a fee waiver process for customers providing certified medical documentation of their susceptibility to RF emissions.

In response to the Public Staff's inquiry as to the current deployment of AMI and subscriptions to the AMI Opt-Out option, the Company indicated that for its North Carolina service territory, through August 2019, it has:

- Deployed 626,804 residential AMI meters and 95,810 non-residential AMI meters;
- Exchanged 208,000 of its 596,233 non-AMI residential meters and 112,611 non-AMI non-residential meters with an AMI meter since August 2019.

[6] Docket No. E-2, Sub 834, dated January 23, 2019 (Rider MROP Order).

- Enrolled 1,105 residential and small general service customers in the AMI Opt-Out option, with 667 successfully qualifying for the medical waiver of fees in Rider MROP.

The Rider MROP Order required the Company to update the rates of the AMI Opt-Out option in its next general rate case. In response, the Company provided confidential calculations of the rider fees, which I reviewed and compared to those originally filed in Sub 834. Those calculations were updated with new cost inputs related to this proceeding and new projections of AMI Opt-Out participants. The updated inputs and the decrease in the number of likely participants result in a 6% increase in the one-time fee and a 41% increase in the monthly fee using the same methodology by which the original fees were calculated. My review suggests that these proposed fees are cost justified. However, the Public Staff does not recommend a change at this time.

The Public Staff believes that any costs associated with the AMI Opt-Out option not recovered by the rider itself should be socialized and recovered from all customers at this time. Otherwise, the increased cost to a customer exercising the AMI Opt-Out option could become overly burdensome, if that customer did not receive the waiver of fees. Furthermore, all customers pay for metering costs in base rates. The incremental additional costs associated with the AMI Opt-Out option are not material when compared to the overall expense of metering. The current charges provide a reasonable hurdle to discourage a customer from opting out of AMI metering without a legitimate reason.

Q. HAS THE COMPANY REFLECTED THE USE OF AMI IN ITS CONNECTION FEES?

A. Customers will receive a benefit from the deployment of AMI meters in this case through lower connection and reconnection fees. Witness Pirro proposes to decrease the connection charges from $17 to $9.14 and the reconnection charges from $19 to $12.94 during normal business hours and from $55 to $19.48 outside of normal business hours. These reductions are due to savings resulting from the Company no longer having to dispatch its personnel to the customer's location to perform connections and reconnections.[7]

I reviewed the Company's calculations of these proposed rates and I find them to be reasonable.

Q. HAS THE COMPANY UTILIZED AMI DATA TO DEVELOP NEW RATE DESIGNS OR INFORM THE EXISTING RATE DESIGNS?

A. No. Witness Pirro states that as of the end of 2019, the Company is approximately 60% completed with its deployment of AMI meters. In

[7] See the November 15, 2019 Order in Docket Nos. E-7, Sub 1210, and E-2, Sub 1214, granting partial waiver from Commission Rule R12-11(m)(2) and imposing limits on the requirements to have Company personnel on the customer's premise immediately before disconnection.

the Sub 1142 proceeding, I testified on the extent of the Company's AMI deployment at that time. My testimony highlighted the Company's commitment to exploring and developing new rate designs once smart meters were fully deployed and data from those meters became available. As soon as practicable, the Company should begin incorporating AMI data into its load research efforts supporting both rate design and integrated resource planning, thus providing a more detailed understanding of how the electric utility system is being used by all its users. Duke Energy Carolinas, LLC (DEC) is slightly ahead of DEP in its AMI deployment. I expect both companies will share their learnings from the AMI data that become available. This will be necessary to inform a new comprehensive rate design study as discussed below.

COMPREHENSIVE RATE DESIGN STUDY

Q. WHAT IS THE COMPANY'S APPROACH TO RATE DESIGN IN THIS PROCEEDING?

A. As explained by Company Witness Pirro, the Company's rate design approach used in this case effectively maintains the current rate designs of its rate schedule portfolio, with only minor modifications to the differential of on- and off-peak rates in the TOU schedules.

Q. HOW DOES THE PUBLIC STAFF PROPOSE TO MOVE TOWARD A NEW RATE DESIGN?

A. The Public Staff believes the Company should undertake a comprehensive rate design study prior to the filing of its next rate case to allow stakeholders the opportunity to participate in the discussion. The study should provide an analysis of each rate schedule to determine whether the schedule remains pertinent to current utility service, and should include recommendations as to whether each schedule should be modified or replaced; and a discussion of the potential for developing new schedules to address changes affecting utility service needs; as well as providing more rate design choices for customers.

Q. PLEASE DESCRIBE YOUR VISION OF A COMPREHENSIVE RATE DESIGN STUDY.

A. A comprehensive study should encompass the issues facing the utility of the future, particularly those issues that I have discussed previously in my testimony. The Company is already conducting a study of its cost-of-service. A study of rate designs should follow soon thereafter. Both are inextricably related. Rate designs should be rooted in a few broad principles that require rates to:

1. Be forward-looking and reflect long-run marginal costs.
2. Be focused on the usage components of service that are the most cost- and price-sensitive.
3. Be simple and understandable.

4. Recover system costs in proportion to how much electricity consumers use, and when they use it.
5. Give consumers appropriate information and the opportunity to respond to that information by adjusting their usage.
6. Where possible, be dynamic.[8]

These guiding principles must allow consumers and users of the electric system to: (1) connect to the utility system for no more than the cost of connecting to the grid; (2) pay for utility service in proportion to how much they use the system; and (3) receive fair and just compensation for the energy they supply to the utility system. Each of these principles should be reflected in smarter rates.

Q. ARE THERE ANY EXAMPLES OF UTILITY SERVICES THAT ARE NEW OR EVOLVING AND ESPECIALLY JUSTIFY THE NEED FOR A COMPREHENSIVE STUDY?

A. Yes. Net metering and other distributed generation resources, microgrids, energy storage, and EVs are prime examples of systems and uses that provide both benefits to the grid and impose costs on the utility. We are seeing increasing amounts of these systems and uses on the grid, and expect even more. I have spoken to a number of net-metered customers who question the rationale behind the

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[8] "Smart Rate Design for a Smart Future", the Regulatory Assistance Project (RAP), at page 6. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

resetting of banked energy credits, which was a component of the rate structures adopted for net-metered customers. Other larger distributed generation resources may not fully realize the value of the ancillary services they provide or the costs in terms of standby service the utility provides when their generation is not available. Microgrids typically act like traditional utility service, but their ability to island themselves when the surrounding grid is out of service imposes costs on the system in the form of added facilities needed to island and sustain the microgrid's customers. Energy storage has the potential to affect traditional cost-of-service principles by diminishing the influence of peak demand in cost-of-service and rate design. Electric vehicles have the potential to influence the load shape of the utility on both a system and a locational basis, providing both load and capacity at times when the utility could use both.

Other examples include TOU rates that currently may not reflect the seasonal and hourly load shapes that represent the utility's cost-of-service. DEP's current TOU rate designs also provide limited choice and opportunity for customers who may desire a demand-energy rate or all-energy oriented TOU rate design. The Company's current TOU rate designs are different from DEC's recently implemented dynamic pricing pilot programs. Those pilots are intended to gauge response to price signals and do not address the on- and off-peak periods or the general structure of DEP's current TOU rate designs.

A final example is customer choice between firm utility service (24 hours, 7 days a week) and non-firm service (standby to any extent) that provides electric service when the customer-owned generation is not available for the customer's use. The full cost-of-service for each type of service is vastly different and not adequately provided for in the Company's portfolio of rate schedules.

Q. WHAT OTHER CONSIDERATIONS WOULD JUSTIFY A RATE STUDY?

A. There are several other considerations worth mentioning. First, the unbundling of average rates into generation, transmission, distribution, and customer component costs may be appropriate in order to address firm and non-firm utility service. Customers with distributed energy resources may not receive full service requirements from the utility, and unbundling could provide insight into the benefits these customers provide to the system as well as the costs to serve them. Second, revenue stability may require some form of decoupling of revenues from sales. Third, grid improvement costs, coal ash clean-up costs, and the transition to a more carbon-free generation portfolio are driving utility rates higher. Fourth, rate designs need to encourage the efficient use of the electric system and promote energy efficiency. Fifth, customers desire more, not less, information and the dynamic ability to receive and respond to that information.[9] Finally, it has been almost eight years since the merger of DEP and DEC, yet their rate design structures remain very different in many ways. Many of these differences are confusing and seem illogical to customers that receive service from both utilities. A rate study could assist in a transition to eventual consolidation of the rate designs of the two utilities.

Q. WHAT TIMEFRAME DO YOU ENVISION FOR A RATE STUDY?

A. This study is no trivial matter. This will be a serious and lengthy undertaking and involve many stakeholders. For example, DEC's Schedule OPT resulted from an 18-month process that brought business and industry together to formulate a TOU rate design with broad support. This proposed rate study will likely require a significant amount of time to develop, as well as to implement. Any significant transition of this type, however, is likely to produce winners and losers. Thus, a gradual implementation would be necessary to minimize any adverse impacts.

AFFORDABILITY

Q. PLEASE DISCUSS THE COMMISSION'S ORDER DIRECTING THE PUBLIC STAFF TO FILE TESTIMONY.

[9] "Rate Design – What do Consumers Want and Need?" Smart Energy Consumer Collaborative, September 2019. https://smartenergycc.org/rate-design-what-do-consumers-want-and-need/

A. The Commission's January 22, 2020 Order directed the Public Staff to "investigate DEP's analysis of affordability of electricity within its service territory as well as programs available to DEP's customers that address affordability with a particular focus on residential energy customers." In the Order, the Commission directed the Public Staff to address the following issues:

1. An overview of Lifeline Rates and whether this approach would be appropriate for North Carolina;
2. The applicability, design, and effectiveness of DEC's Supplemental Security Income (SSI)[10] discount;
3. A comparison of the SSI discount to other tariffs available to customers that address affordability issues;
4. An overview of similar affordability tariffs or plans available by the other affiliates of DEP; and
5. The merits of using a "minimum bill" concept in lieu of a fixed customer charge.

Q. DOES THE COMPANY'S APPLICATION FOR A GENERAL RATE CASE AND DIRECT TESTIMONY ADDRESS ANY OF THESE REQUESTS?

A. No, the Company's Application and direct testimony, which were filed before the January 22, 2020 Order, did not specifically address these

[10] https://www.ssa.gov/ssi/

requests. Company witness DeMay noted in his testimony that the Company is committed to helping customers who struggle with financial hardships. He cited several energy efficiency and philanthropic programs that provide assistance to help customers with their energy bills and offered to do more for those most in need. Witness DeMay also explained the Company's proposal to keep BCCs at current levels despite the Company having a cost-of-service justification for higher BCCs. He outlined the Company's proposal to engage interested stakeholders to discuss ways and opportunities for the Company's rate design to assist low-income customers such as low-income bill credits, bill round-up programs, and modifications to the SSI discount. He concluded by stating that a stakeholder process was necessary to adequately consider those opportunities.

Q. DID WITNESS DEMAY OFFER ANY OTHER SUGGESTIONS FOR ASSISTING LOW-INCOME CUSTOMERS?

A. Witness DeMay stated that the Company's application was developed using a lower Return on Equity (ROE) (10.3%), rather than the 10.5% ROE recommended by Company Witness Hevert. As discussed in the testimony of witness Woolridge, the Public Staff does not agree with Witness Hevert's ROE. The Public Staff also believes the Company's request for a lower ROE does not provide targeted rate relief for low-income customers for two reasons. First, it is virtually impossible to gauge the significance of the offer in terms of a reduced or forgone revenue requirement. Second, a lower ROE does not specifically benefit low-income customers, but accrues to the benefit of all ratepayers.

The ROE is one of the most contentious issues in any rate proceeding, with witnesses using various methods, calculations, interpretations, and findings to support their respective positions. Whether the ROE is litigated or settled, there is never any certainty in what the ROE should be or the amount of the revenue requirement until the Commission issues its order in the rate case. Given this contentiousness, it is impossible to benchmark the significance and amount of revenue the Company forgoes with a reduction of 20 basis points in an ROE. The Public Staff believes it is more appropriate for the Commission to determine the appropriate ROE, and then look for other more targeted ways and opportunities to mitigate rate impacts for low-income customers that fall within its jurisdiction.

To address affordability, the Public Staff suggests that it would be preferable for the shareholders of the Company to forego the anticipated revenues associated with the reduction in ROE proposed by Mr. DeMay and for DEP to use those funds to support other assistance programs or mitigate the possible revenue impacts associated with any proposal arising from the stakeholder process. If any new low-income program results in other customers paying a slightly higher rate to recover costs associated with any low-income programs, it would be equitable for shareholders to participate in a similar manner.

Lifeline Rates

Q. WHAT ARE LIFELINE RATES?

A. I researched the term "lifeline rate" and discovered several definitions pertinent to the discussion on affordability. Below is a sampling of definitions I found:

1. Repealed Section 114 of PURPA[11] effectively allowed states to approve rates for residential customers that were lower than standard rates, without providing a definition of rates that were lower than the "standard rates" as defined by Section 111(d)(1) of PURPA (cost-of-service based rates).[12]
2. House Bill H.R. 6009 was introduced in the 1977-78 Congress, but no action was taken on it after it was referred to committee.[13] It used the term "Lifeline electric rates" for rates with charges for subsistence quantities of electric energy to residential consumers that would not exceed the lowest rate charged to any other

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[11] Floyd Exhibit No. 1, Public Utility Regulatory Policies Act of 1978. Section 114 was repealed in 2016. https://uscode.house.gov/view.xhtml?req=(title:15%20section:2624%20edition:prelim)

[12] "COST OF SERVICE.—Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the cost of providing electric service to such class, as determined under section 115(a)."

[13] https://www.congress.gov/bill/95th-congress/house-bill/6009?s=1&r=66

electric consumer. It required the use of graduated rate structures for consumption of electric energy in amounts above subsistence quantities.

3. A report prepared for the Hydro Quebec Distribution Company[14] defined “Lifeline rate” as a rate structure under which an initial block of consumption is priced lower than subsequent and higher blocks of consumption. Under this definition, a Lifeline rate may or may not be priced “below cost.”

This research suggests that “lifeline” rates are effectively inclining block rates, which provide a lower price for the initial block of usage than the next block of usage. The premise is that if a customer were a low-usage customer, the impact of increasing rates would be mitigated by having the initial block of usage priced lower. The concept of lifeline rates appears to have been conceived in the late 1970s in response to the oil crisis of the early 1970s.

The Public Staff does not generally support inclining block rate structures, because they are not cost-based. The first kilowatt-hour (kWh) of use is typically more costly to produce than the next, a function of the fixed costs of utility service. Inclining block rates shift

[14] “INVERTED BLOCK TARIFFS AND UNIVERSAL LIFELINE RATES: Their Use and Usability for Delivering Low-Income Electric Rate Relief,” Roger Colton. Fisher, Sheehan & Colton. February 2008.

http://www.fsconline.com/downloads/Papers/2008%2002%20Hydro_Quebec_Lifeline-Final.pdf the recovery of revenues from the initial block to higher kWh blocks. By doing so, customers who buy less kWhs are not contributing an appropriate amount toward the recovery of fixed utility costs. This reality exacerbates the need for future rate cases and fails to address the real cost causation of electric utility service. The shift in revenue recovery from low use customers to high use customers could also adversely affect low-income customers that are not low usage customers.

Supplemental Security Income (SSI)

Q. DOES THE COMPANY HAVE A PROGRAM LIKE THE SSI PROGRAM OFFERED BY DUKE ENERGY CAROLINAS, LLC?

A. No. The SSI discount that is available for residential service for DEC is not offered by DEP.

Q. PLEASE PROVIDE SOME BACKGROUND FOR THE SSI DISCOUNT.

A. As part of my review in DEC's rate case, I reviewed several past orders and filings regarding the SSI Rates. Based on my research, the SSI rate was originally approved on August 31, 1978 in Docket No. E-7, Sub 237 (Sub 237 Order). The Sub 237 Order identified SSI customers as customers who were "relatively price-inelastic, blind, disabled, or aged receiving SSI from the Social Security Administration. The SSI discount was established so that the

Commission could collect data in a comprehensive study of "lifeline type rate schedules as mandated by the 1977 North Carolina General Assembly."[15]

The Commission's proceeding in Docket No. E-100 Sub 43 (Sub 43 Proceeding) was an effort to implement Section 114 of PURPA. The Sub 43 Proceeding included an RTI Study[16] that investigated the SSI discount. Around this time in the early 1980s, the Company filed another general rate case (Docket No. E-7, Sub 338). The Commission brought the SSI discount/lifeline rate issue into the Sub 338 case.

The Order Granting Partial Rate Increase issued November 1, 1982 (Sub 338 Order) provides a good summary of the SSI issue and the Commission's consideration and decision.[17] An excerpt of testimony from the Sub 338 Order provides a good summary of the SSI issue.

> "During the course of the hearing in Docket No. E-7, Sub 338, witness Desvousges of RTI testified that: (1) SSI recipients have lower electricity usage, lower appliance saturation, smaller homes, and smaller family size than non-SSI customers; (2) SSI recipients have a lower percentage of use during single peak hours (i.e., higher load factor) but greater percentage of use during total on-peak hours than non-SSI customers; and (3) the

[15] See Finding of Fact 25 in the Sub 237 Order.

[16] Floyd Exhibit No. 2, "An Evaluation of a Lifeline Rate Alternative: The Supplemental Security Income Rate," William H. Desvousges, C. Andrew Clayton, Dale P. Lifson. RTI Economics, September 1981.

[17] See the evidence and conclusions associated with Finding of Fact 29 in the Sub 338 Order.

difference in usage patterns between SSI recipients and non-SSI customers does not create a difference in cost.

Witness Stutz, representing the intervenor Lillia Brooks, et al., testified that: (1) the higher load factor at single peak hours and the lower appliance saturation of SSI recipients strengthens the hypothesis that they may be cheaper to serve than non-SSI customers, but that the hypothesis has not yet been proven either way; (2) the RTI conclusion regarding the percentage of usage by SSI recipients during single peak hours versus total on-peak hours is not valid, because it is based on a marginal cost approach not used anywhere else in Duke cost allocations; and (3) the RTI conclusion regarding cost differences between SSI recipients and non-SSI customers is not valid because no cost allocation study was performed using the same embedded cost methods which are used to determine the costs for non-SSI customers.

Witness Stutz contended that further study was needed of the elasticity of demand between SSI recipients and non-SSI customers and that a fully distributed cost of service study was needed in which SSI recipients and non-SSI customers are identified as separate customer groups. Witness Desvousges contended that such elasticity of demand study and such fully distributed cost of service study were not a part of the RTI contract. Witness Stutz recommended that, even though approximately $100,000 had already been spent studying the cost to serve approximately 8,000 SSI recipients on the Duke system, further studies should be made at further expense in order to complete the analysis properly.

Witness Stutz conceded that data is not now available in the form necessary to perform the embedded cost allocation study he recommended, and that, even if it were, the cost allocation method currently used (i.e., summer coincident peak method) is subject to change. Therefore, he recommended that the SSI rate be retained until further studies are complete and that further studies be made utilizing the same cost allocation method used to determine costs for SSI recipients and for non-SSI customers.

The Commission makes the observation that, while the RTI study shows SSI recipients to have a higher

> percentage of total use during on-peak hours than non-SSI customers, it does not determine if the same thing holds true for those kWh subject to the SSI discount (i.e., the first 350 kWh per month). The Commission also makes the observation that determination of on-Peak costs versus off-peak costs need not be based on marginal cost but can be based on embedded cost as well.
>
> Based on the testimony and evidence presented herein, the Panel is of the opinion that the studies to determine a cost justification for the SSI rate are inconclusive. An additional concern is the expense which must be incurred for further studies in view of the limited number of SSI recipients who are the object of study. There may be many more low income, low usage customers who are not HI recipients but have similar usage characteristics, and further study should perhaps include them.
>
> The Commission concludes that the SSI rate should be retained for purposes of this proceeding and that final determination of the question of and the scope of studies should be resolved by the Commission in Docket No. E-100, Sub 43."

Sub 338 Order Beginning at page 139.

General rate case orders for DEC that followed the Sub 237 Order and Sub 338 Order, including the more contemporary rate case orders for DEC since 2007 (Subs 828, 909, 989, 1026, and 1146), do not provide much insight on the SSI discount. I do note that DEC witness Barbara Yarbrough addressed the history of the SSI discount in her rebuttal testimony in the Sub 909 case. However, the Public Staff and DEC settled many issues in that case and the SSI discount was not specifically addressed in the approved settlement agreement or final order.

Q. HAVE YOU REVIEWED THE RTI ECONOMICS STUDY THAT WAS PART OF THE PROCEEDINGS IN DOCKET NOS. E-100, SUB 43, AND E-7, SUB 338?

A. Yes.

Q. IS THERE ANY PERTINENT INFORMATION FROM THE RTI STUDY THAT IS APPLICABLE TO UTILITY SERVICE IN 2020?

A. The RTI Study is almost 40 years old. Utility service in the late 1970s and early 1980s is vastly different than it is today. The findings of the RTI Study are informative, however. The RTI Study indicated a difference in the energy consumption behavior of SSI customers and non-SSI customers. SSI customers used about half the energy that non-SSI customers used. The differences were greater in winter peak periods. Load factors and usage profiles were different. In addition, electric appliance use was lower for SSI customers than non-SSI customers. SSI customers tended to have smaller, less expensive homes and smaller families. Each of these differences certainly suggests a difference in the cost to serve each group.

I reviewed another study that was published by the US Department of Energy (DOE Lifeline Study)[18] that studied other similar programs around the nation. It was clear to me that the data from the late 1970s

[18] "Lifeline Electric Rates and Alternative Approaches to the Problems of Low-Income Ratepayers – Ten Case Studies of Rejected Programs," July 1980. https://www.osti.gov/servlets/purl/5699224

and early 1980s may not be appropriate for consideration today. One very apparent example is average energy consumption. In the early 1980s, the average was approximately 500 kWh per month. This is consistent with the RTI Study (Table 4-8). The Company's billing analysis in this proceeding calculates an average usage for residential customers of 1,100 kWh per month. I believe this suggests a very different usage and cost pattern from the ones observed in the RTI Study and DOE Lifeline Report.

I also reviewed a 2010 study from the Edison Foundation[19] that concluded low-income customers did have a flatter load profile (higher load factor) and that they were responsive to dynamic pricing signals. This study is contemporaneous and may provide some useful information regarding load shapes of low-income customers, costs, rate designs, participation in TOU rates, demand response, and adoption of energy efficiency measures.

Q. IS THERE ANY DATA FROM THIS PROCEEDING TO SUGGEST ANY DIFFERENCES IN USAGE BETWEEN SSI CUSTOMERS AND NON-SSI CUSTOMERS?

A. No, not from DEP.

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[19] https://www.edisonfoundation.net/IEE/Documents/IEE_LowIncomeDynamicPricing_0910.pdf

Q. DO YOU HAVE ANY RECOMMENDATIONS CONCERNING THE SSI DISCOUNT AND ITS APPLICABILITY TO DEP?

A. Yes. This issue is ripe for discussion in the stakeholder process recommended by DEP witness DeMay and as outlined in my DEC testimony in Docket No. E-7, Sub 1219. The stakeholder process is the best place to evaluate whether an SSI discount such as provided by DEC in the context of providing new rate structures to help all low-income customers would be appropriate for to address issues of affordability for DEP customers. DEC's minimal SSI discount and the narrow eligibility requirements are likely causing the effectiveness of the discount to be insignificant. The evidence is inconclusive from DEC's billing analysis.

Affordability Tariffs by other Duke Energy Affiliates

Q. WHAT OTHER RATE PLANS THAT ADDRESS AFFORDABILITY ARE AVAILABLE IN OTHER JURISDICTIONS WHERE DUKE ENERGY PROVIDES ELECTRIC SERVICE?

A. The only rate plan addressing affordability offered by a Duke Energy Company affiliate in another jurisdiction is the Rate RSLI, or Residential Service - Low Income, offered by Duke Energy Ohio. Limited to 10,000 customers, the program offers customers that are at or below 200% of the Federal poverty level a $4 per month discount on the monthly customer charge. The energy charge itself is not discounted.

Other Affordability Tariffs Around the Country

Q. DID YOU INVESTIGATE OTHER DISCOUNT OR RATE PROGRAMS AROUND THE COUNTRY?

A. Yes. Several investor-owned electric utilities offer various types of low-income assistance programs. Floyd Exhibit No. 3 provides a list of the ones I reviewed and the web links to those programs. The most prevalent model seems to be a bill discount that either applies a percentage reduction to the total bill or a flat dollar discount. The most common qualification factor is one based on household income as a percentage of the federal poverty guidelines, age, enrollment in another governmental assistance program, or some combination of the three.

Minimum Bill Concept

Q. PLEASE DISCUSS THE MINIMUM BILL CONCEPT.

A. The "minimum bill" concept guarantees the utility a minimum annual revenue level from each customer even if the customer consumes no energy.[20] It provides some stability in utility revenues that could mitigate future requests to increase rates. Some minimum bill

[20] Floyd Exhibit No. 4. - "Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches to Recovering Basic Distribution Costs," (RAP Report), November 13, 2014. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-electricutilityresidentialcustomerchargesminimumbills-2014-nov.pdf

concepts also include a fixed amount of energy sales. In other words, customers would be charged for a fixed amount of energy regardless of actual energy consumption.

The Company's TOU residential schedules (minimum bill is the BCC plus REPs charges) and non-residential rate schedules already include a minimum bill provision. For example, Schedules SGS-TOU and LGS include the following language (from Exhibit B of the Application):

> The minimum monthly charge shall be the sum of (1) the Basic Customer Charge, (2) the REPS Adjustment, (3) 5.502¢ per kWh, and (4) $1.85 per kW for the higher of: (a) the Contract Demand or (b) the maximum monthly 15-minute demand during the current and preceding 11 billing months.
>
> ***Schedule SGS-TOU***
>
> The minimum monthly charge shall be the Basic Customer Charge plus the REPS Adjustment plus a charge for 1,000 kW.
>
> ***Schedule LGS***

According to page 49 of the billing analysis in revised Form E-1, Item 42, accompanying the November 22, 2019 revised filing, approximately 800 non-residential customers were impacted by minimum bill provisions.

Q. PLEASE DISCUSS THE MERITS OF USING THE MINIMUM BILL CONCEPT IN LIEU OF A FIXED CUSTOMER CHARGE.

A. Minimum bills are designed to recover a portion of fixed costs to serve the customer. As discussed above, a minimum bill amount would include at least the amount of the BCC, or fixed customer charge, but could include additional costs as well. The Public Staff has generally been supportive of BCCs that are based on cost causation principles. However, other stakeholders have raised affordability concerns over the impact of higher fixed charges.

The RAP Report provides a good comparison of the impacts under three pricing scenarios (high and low customer charges and a minimum bill approach). The RAP Report illustrates how the customer charge and energy charge work together to produce the revenues. A low customer charge requires a higher energy charge to recover the same revenue. The minimum bill approach only affects the low usage customer, but eventually produces similar revenues as the combined customer and energy charges do. The RAP Report goes on to discuss the elasticity of electric rates and usage and concludes that any approach using a high fixed charge approach is not popular with customers.

Q. WOULD A MINIMUM BILL APPROACH REPLACE THE BCC?

A. Not necessarily. An appropriate minimum bill provision applicable to residential customers would need to be designed in a manner that ensures all customers are contributing toward the fixed cost to serve them. It would have some impact on the amount of the other charges used to produce revenue because the minimum bill rather than the combination of customer, demand, and energy charges would produce more of the total revenue. However, such a provision should not be a substitute for appropriately pricing the basic customer charges.

Q. WHAT IS THE IMPACT OF IMPLEMENTING A RATE DESIGN THAT DOES NOT RECOVER THE FIXED COSTS TO SERVE THE CUSTOMER?

A. Cost causation requires that the combined rate elements in a rate schedule (BCC, demand, and energy charge) be appropriately designed to recover the fixed costs to serve the customer. When one element is underpriced, the remaining elements have to support the recovery of fixed costs. Any rate schedule that fails to recover the fixed costs associated with the customers taking service under that schedule will shift the cost to serve those customers to other customers on other rate schedules.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S VIEW OF AFFORDABILITY ISSUES AND THE COMPANY'S PROPOSED STAKEHOLDER PROCESS TO ADDRESS AFFORDABILITY.

A. Affordability is an important issue for all customers, residential and non-residential alike. Residential customers face difficult challenges balancing bills each month. Non-residential customers face similar challenges deciding where and how to conduct business and whether to invest in infrastructure and jobs.

The Public Staff continues to believe that rate design must first be based on cost-causation principles. After cost-based rates are determined, public policy may provide further guidance in designing final rates. The Public Staff believes the stakeholder process is the most appropriate venue to have this conversation. I believe the January 2020 Order provides the outline of issues that should be discussed in this process. However, it is also incumbent upon the Commission to give the parties some guidance on affordability issues. The Public Staff recommends the following parameters for a stakeholder process:

1. Set a timeline for the process, including a deadline for the filing of recommendations to the Commission. I believe a maximum of one year is reasonable.
2. Investigate how "affordability" has changed over time, and seek to define it for purposes of utility service today.

3. Investigate the success of existing rates, low-income assistance, and energy efficiency programs to address affordability.
4. Analyze the data related to load, cost, and revenue profiles of low-income customers and the residential class in general, cost-causation, impact to cost-of-service, potential for subsidization, impact on revenues and rates for all customers, program eligibility, extent of assistance needed to be meaningful, definition of a "successful program," etc.
5. Require periodic reporting to the Commission on the status of the process.

Any rate discount for low-income customers will shift revenue recovery to other customers in the form of slightly higher rates. This shift or subsidization must be thoroughly understood in terms of the dollars to be shifted and the effect on rates paid by other customers. I am also concerned that this shift could adversely impact those customers who would be just outside of the threshold for qualifying for any program.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

JACK L. FLOYD

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Chemical Engineering. I am licensed in North Carolina as a Professional Engineer. I have more than 17 years of experience in the water and wastewater treatment field, nine of which have been with the Public Staff's Water Division. In addition, I have been with the Electric Division for almost 16 years.

Prior to my employment with the Public Staff, I was employed by the North Carolina Department of Environmental Quality, Division of Water Resources as an Environmental Engineer. In that capacity, I performed various tasks associated with environmental regulation of water and wastewater systems, including the drafting of regulations and general statutes.

In my capacity with the Public Staff's Water Division, I investigated the operations of regulated water and sewer utility companies and prepared testimony and reports related to those investigations.

Currently, my duties with the Public Staff include evaluating the operation of regulated electric utilities, including rate design, cost-of-service, and demand side management and energy efficiency resources. My duties also

Include assisting in the preparation of reports to the Commission; preparing testimony regarding my investigation activities; reviewing Integrated Resource Plans; and making recommendations to the Commission concerning the level of service for electric utilities.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		SUPPLEMENTAL
Application of Duke Energy Progress,	)	TESTIMONY OF
LLC, for Adjustment of Rates and	)	JACK L. FLOYD
Charges Applicable to Electric Utility	)	PUBLIC STAFF – NORTH
Service in North Carolina	)	CAROLINA UTILITIES
		COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

SUPPLEMENTAL TESTIMONY OF JACK L. FLOYD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

APRIL 23, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jack L. Floyd. 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. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is to present the Public Staff's recommended distribution of revenues based on the results of the summer coincident peak (SCP), winter coincident peak (WCP), and summer/winter coincident peak and average (SWPA) cost-of-service methodologies. My calculations are based on the request of Duke Energy Progress, LLC (DEP or the Company) for a base revenue increase and an Excess Deferred Income Tax (EDIT) rider, and the Public Staff's adjustments to that request.

The Public Staff's recommended base revenue increase of $129,014,000[1] and an EDIT credit of $105,421,000[2] are provided in the supplemental testimony and exhibits of Public Staff witness Dorgan. I have used this information to assign the revenues and credits to the customer classes.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. My testimony includes four exhibits. Floyd Exhibit 1 illustrates the rates of return (ROR) on rate base, the percentage change in base revenues, and the impact of the EDIT credit rider for each cost-of-service methodology. Floyd Exhibits 2, 3, and 4 provide an illustration of the base revenue and EDIT-2 credit assignments recommended by the Public Staff, as well as scenarios illustrating revenue assignments under an "equal rate of return" scenario and an "equal percentage increase" scenario for each cost-of-service methodology.

Q. BRIEFLY EXPLAIN HOW YOU DISTRIBUTED THE BASE REVENUE CHANGE.

A. I used the "per books" versions of the Company's cost-of-service studies for each methodology to develop a distribution framework that incorporates the overall base revenues, expenses, net income, and rate base for the test year. Using this framework, I then took Public Staff witness Dorgan's

[1] Line 42, Dorgan Supplemental Exhibit 1, Schedule 1.

[2] Line 48, Dorgan Supplemental Exhibit 1, Schedule 1.

adjusted present and proposed revenues, expenses, and rate base to develop the Public Staff's recommended base revenue change. The assignment of the Public Staff's recommended revenue change is developed using the four basic revenue assignment principles I outlined in my direct testimony. Those principles are:

1. Any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
2. Class RORs are maintained within a band of reasonableness of ± 10% relative to the overall NC retail ROR;
3. All class RORs move closer to parity with the NC retail ROR; and
4. Subsidization among the customer classes is minimized.

The results of my work are provided in my supplemental exhibits. The Public Staff's proposed assignment adheres to each of these principles.

Q. HOW DID YOU ASSIGN THE PUBLIC STAFF'S EDIT CREDIT?

A. Taking the recommended EDIT credit revenues for Year 1 as provided by Public Staff witness Dorgan, I used the same approach as used by Company witness Pirro as shown in Pirro Exhibit 8. The recommended revenues and energy sales have been updated through February 29, 2020, and are consistent with the calculations of revenues and sales provided in the supplemental testimonies of Public Staff witnesses Dorgan and Saillor, respectively.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ASSIGNMENT OF BASE REVENUES AND THE EDIT-2 CREDIT?

A. While my testimony provides an illustration of how base revenues and EDIT-2 credit should be assigned using the SCP and WCP cost-of-service methodologies, the Public Staff continues to believe that the SWPA cost-of-service methodology is the most appropriate methodology for this case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1193

In the Matter of Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	))))))	SECOND SUPPLEMENTAL TESTIMONY OF JACK L. FLOYD PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUBS 1193 AND 1219

SECOND SUPPLEMENTAL TESTIMONY OF JACK L. FLOYD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 16, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jack L. Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am Manager of the Electric Revenues, Rates, and Services Section of the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. DID YOU PREVIOUSLY FILE DIRECT AND SUPPLEMENTAL TESTIMONIES IN THESE PROCEEDINGS?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SECOND SUPPLEMENTAL TESTIMONY?

A. The purpose of my second supplemental testimony is to present the Public Staff's recommended distribution of updated revenues through May 2020 based on the results of the summer coincident peak (SCP), winter coincident peak (WCP), and summer/winter coincident peak and average

(SWPA) cost-of-service methodologies.[1] My calculations are based on the request of Duke Energy Progress, LLC (DEP or the Company), for a base revenue increase and an Excess Deferred Income Tax (EDIT) rider, and the Public Staff's adjustments to that request. The adjustments reflect items agreed to in the First Agreement and Stipulation of Partial Settlement between DEP and the Public Staff (First Settlement Agreement) filed on June 2, 2020, and the Second Agreement and Stipulation of Partial Settlement between the Company and the Public Staff (Second Settlement Agreement) filed on July 31, 2020, as well as other adjustments recommended by the Public Staff on which the Public Staff and the Company have not reached agreement. The Public Staff's recommended base revenue increase of $264,977,000 and a Year 1 EDIT credit of $168,214,000 are provided in the second supplemental testimony and exhibits of Public Staff witness Maness.[2] I have used this information to assign the revenues and credits to the customer classes.

My second supplemental testimony and exhibits also responds to the Second Settlement Testimony and Exhibits of Witness Michael J. Pirro filed on August 21, 2020, which reflect the First and Second Settlement

[1] In the Second Partial Settlement, for this case only, the Public Staff accepted, subject to certain conditions, use of the SCP cost of service allocation methodology, which shall not constitute precedent and shall have no effect on the Rate Design Study proposed by the Public Staff and agreed to by the Company.

[2] Due to rounding Floyd Second Supplemental Exhibits, do not exactly reflect the "NC Retail" level base revenue increase and EDIT credit.

Agreements, as well as the Company's Agreement and Stipulation of Settlement with Carolina Industrial Group for Fair Utility Rates II (CIGFUR) filed on June 26, 2020, as amended on August 6, 2020 (CIGFUR Settlement). Additionally, I address terms of settlement related to rate design included in separate settlement agreements filed between the Company and Harris Teeter, LLC (Harris Teeter Settlement) on June 8, 2020, and DEP and the Commercial Group (Commercial Group Settlement) on June 9, 2020.[3]

Q. DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. My testimony includes four exhibits. Floyd Second Supplemental Exhibit 1 illustrates the rates of return (ROR) on rate base, the percentage change in base revenues, and the impact of the EDIT credit rider for each cost-of-service methodology. Floyd Second Supplemental Exhibits 2, 3, and 4 provide an illustration of the base revenue and EDIT credit assignments under an "equal rate of return" scenario and an "equal percentage increase" scenario for each cost-of-service methodology.

Q. HOW DID YOU ASSIGN THE PUBLIC STAFF'S RECOMMENDED REVENUE CHANGE AND EDIT CREDIT?

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[3] Settlements were filed on July 9, 2020, between Vote Solar and DEC, and on July 23, 2020, between DEP and the North Carolina Sustainable Energy Association, the North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy. My second supplemental testimony does not address these two settlements because they do not include any provisions affecting rates or rate design.

A. I assigned the Public Staff's recommended revenue changes consistent with the revenue assignment principles discussed in both my direct and first supplemental testimonies. I also assigned the Public Staff's recommended EDIT credit consistent with the Second Settlement Agreement, which required that the EDIT credit rate use a levelized rider.

Q. WHY DOES YOUR ASSIGNMENT OF THE EDIT CREDIT DIFFER FROM THE METHOD USED BY COMPANY WITNESS PIRRO IN HIS SECOND SETTLEMENT EXHIBIT 8?

A. While the Company and the Public Staff agreed to use a levelized rider, i.e., a rider that would be at the same level each year, the Company agreed in the CIGFUR Settlement to return EDIT to customers on a uniform cents per kilowatt-hour (kWh) basis. This means each customer would receive the same credit amount per kWh, which would benefit non-residential customers. This effectively shifts approximately $30 million from the residential, small general service, and lighting customer classes to the medium and large general service classes. I have distributed the EDIT credit by returning the monies to customer classes based on amounts each class paid, which is the method Mr. Pirro used in his direct testimony and exhibits filed on October 30, 2019, and supplemental direct testimony and exhibits filed on March 13, 2020.

Q. DO YOU AGREE WITH THE TERM OF THE CIGFUR SETTLEMENT THAT REQUIRES ADJUSTMENT OF PEAK DEMAND TO REMOVE INTERRUPTIBLE LOADS IN FUTURE COST OF SERVICE STUDIES, WHETHER ACTIVATED OR NOT?

A. No.

Q. HAVEN'T YOU SUPPORTED THIS TYPE OF ADJUSTMENT IN A PREVIOUS RATE CASE?

A. In my testimony in Docket No. E-22, Sub 479 (Sub 479 Case), filed on September 24, 2012, in the application for a general rate increase of Dominion North Carolina Power (now Dominion Energy North Carolina, or DENC), I supported DENC's adjustment to impute the winter peak component had DENC activated all of its available demand-side management (DSM) programs at the time of the winter.[4]

Q. ISN'T THERE AN INCONSISTENCY IN YOUR CRITICISM OF THIS TERM OF THE CIGFUR SETTLEMENT AND YOUR TESTIMONY IN THE SUB 479 CASE?

A. No, for several reasons. DENC supported a cost allocation methodology that equally weighted the summer and winter peaks. Additionally, DENC had activated all of its DSM resources and interruptible loads at the time of its summer peak in the Sub 479 Case test year, but only activated a portion

[4] Testimony of Jack L. Floyd, Docket No. E-22, Sub 479, filed September 24, 2012, at 6 – 8.

of those resources at the time of its winter peak. Thus, the relationship between the summer and winter peaks was distorted without the adjustment. For comparison, if such an adjustment had been made in this case, the impact of the adjustment would differ because DEP has utilized the single summer peak for cost allocation, while DENC relied upon the Summer Winter Peak and Average (SWPA) cost of service methodology in the Sub 479 Case. Thus, even those customers who could contribute to reducing their peak loads could not avoid all production plant cost responsibility for the interruptible portion of their loads that was present in the other hours of the year, due to the average demand component of SWPA.

Additionally, DEP activated some of its DSM and interruptible resources at the time of its test year summer and winter peaks. The Company's 2018 Integrated Resource Plan indicates that approximately 22 and 225 megawatts of DSM and interruptible resources were activated at the time of the summer and winter peaks, respectively. This means that the summer and winter peaks for the test year already incorporate the effects of the reduced demands associated with these resource activations. These resources that were activated represent only a portion of the available demand response resources. Nevertheless, the affected customer classes received the benefit of a reduced peak demand allocator in this case.

Q. WHAT RECOMMENDATIONS DO YOU HAVE REGARDING THE NEW RATE SCHEDULE AND DEMAND RESPONSE PROPOSALS OFFERED IN THE CIGFUR SETTLEMENT?

A. The Commission would first need to consider whether new interruptible programs should be part of the Company's DSM and energy efficiency (EE) portfolio, or part of the base rate schedule portfolio. This distinction will be necessary to address how the costs and revenues of these proposals would be recovered. Since the enactment of N.C. Gen. Stat. § 62-133.8 and 9 in 2007, the Commission has generally included new "demand response" in the DSM/EE portfolio,[5] participation in which requires opting into the DSM/EE rider.

Should the Commission determine that demand response adopted as new time-of-use rate schedules be recovered through base rates, the comprehensive rate study is the appropriate venue to consider the proposals for opening Schedule LGS-RTP to new customers and new load, and new interruptible programs.

Q. DOES THE PUBLIC STAFF AGREE WITH ALL OF THESE TERMS REGARDING RATE DESIGN IN THE HARRIS TEETER AND COMMERCIAL GROUP SETTLEMENTS?

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[5] *See* February 26, 2009 Order in Docket No. E-7, Sub 831, in which the Commission held that Duke Energy Carolinas, LLC's existing Rider IS and SG demand response programs were effectively closed to new participation and that new demand response would be approved as part of the PowerShare program in the new DSM/EE portfolio.

A. No, the Public Staff does not agree with all of the terms at this time. It is premature and counter-productive to begin redesigning rates and the terms of service under specific rate schedules, without having a full understanding of the rationale for each change and the impact on other rate schedules and revenues. The Company did not propose any significant changes in its rate schedules in this proceeding, nor has the Company conducted the necessary analysis to justify largescale changes to its rates at this time. Making discrete changes to individual rate schedules to satisfy individual customers or consumer groups simply constrains the ability to conduct a comprehensive study of rates and rate design in the future, as I have proposed in my direct testimony. It would be shortsighted to implement specific changes now without having any understanding of the impact those changes on other customers. Given the “status-quo” nature of the Company’s current rate designs and schedules, any change that is made now simply as a matter of settlement hinders the ability to properly address rate of return issues in the next rate case proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1193

In the Matter of

Application of Duke Energy Progress, 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 FIRST SUPPLEMENTAL TESTIMONY OF JACK L. FLOYD PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of

Petition of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))

CORRECTIONS TO THE FIRST SUPPLEMENTAL TESTIMONY OF JACK L. FLOYD

Mr. Floyd's first supplemental testimony should be corrected as follows:

1. The EDIT credit amount on Page 3, Line 2 should be $234,435,000.
2. On Page 3, Footnote 2 should read, “Sum of lines 44 through 47, Dorgan Supplemental and Stipulation Exhibit 1, Schedule 1.”
3. Corrected Floyd Supplemental Exhibits 1-4 are attached.

Summary of Testimony
(Direct, First Supplemental, and Second Supplemental)
Jack L. Floyd

Docket No. E-2, Subs 1193 and 1219

The purpose of my testimony today is to present the Public Staff's analysis and recommendations regarding rate design, rate schedules, and revenue assignment; and to discuss the status of the deployment of advanced metering infrastructure.

With respect to the Company's proposed modifications to its rate schedules, I conclude that they are reasonable for purposes of this proceeding. I also discuss the Public Staff's revenue assignment principles that should be used to apportion any revenue increase approved in this proceeding. Those principles include maintaining the class rates of return on rate base within plus or minus 10% of the overall rate of return resulting from this case, moving all customer classes closer to the NC retail jurisdictional return, limiting any increase to a particular customer class to no more than two percentage points greater than the jurisdictional increase approved in this proceeding, and minimizing any subsidization among the customer classes. However, in the event the Commission orders a decrease in the revenue requirement as recommended by the Public Staff, I believe it is more appropriate to focus on addressing disparities in the class rates of return. I also provide the Public Staff's assignment of the base revenue changes and the excess deferred income tax credits proposed by the Public Staff (Corrected First Supplemental testimony and Second Supplemental testimony and exhibits), which are consistent with these revenue assignment principles. It is important to understand that my recommendations on revenue apportionment are developed using the test-year cost of service study and rate schedule portfolio, updated as appropriate for both supplemental testimonies. These revenue principles should be incorporated in the comprehensive rate study I recommend in my testimony.

I also discuss the many changes occurring with electric utility service, and the need for the Company to undertake a comprehensive study of its rate designs to address these changes. I outline six broad principles for the study, as well as three other key objectives: to allow customers to connect to the grid for no more than the cost of the connection, to ensure that users of the system pay for service based on how they use the system, and to treat all users fairly and equitably. There should be no doubt that this formidable task will involve many stakeholders, and will take time to develop and implement.

I also discuss several issues associated with the Company's AMI deployment. The Company is close to completing its deployment of smart meters, which has allowed the Company to reduce its connection and reconnection charges. The AMI deployment also impacts the rates and costs associated with Rider MROP, which applies to customers who elect to opt-out of having a smart meter. However, very few customers have elected to opt-out of smart meters. While the Company did not propose changes to the charges in Rider MROP, I recommend that the Company maintain the current charges and that any additional costs associated with Rider MROP be socialized and recovered from all customers. Last, I note that the AMI deployment should allow the Company to begin using the usage data available from these meters in its load research.

This concludes my summary.

MS. EDMONDSON: Secondly, pursuant to the stipulation of live testimony and exhibits of certain rate design and cost allocation witnesses filed on September 24, 2020, I move that the testimony of the panel of James McLawhorn and Jack Floyd in Docket Number E-7, Sub 1214, at transcript Volume 18, pages 208 through 211, and 258, 261 through 264, and 346 through 349, as well as transcript Volume 19, pages 11 through 108, be copied into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: Any objection to the motion as made?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, motion is granted.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, transcript Volume 18, pages 208 through 211, and 258, 261 through 264, and 346 through 349; and Volume 19, pages 11 through 108 were copied into the record as if given orally from the stand.)

Examination Exhibit 1 was admitted into
evidence.)

MS. LEE: And, Chair, we also request that the witness be excused.

CHAIR MITCHELL: All right. Ms. Wilson, you may step down, and you are excused. Thank you very much for your testimony today.

THE WITNESS: Thank you very much.

CHAIR MITCHELL: All right. At this point in time, I believe we are now with the Public Staff. Ms. Downey, you may call your witnesses.

MS. DOWNEY: Yes, Chair Mitchell. Public Staff would call Jack Floyd and James McLawhorn.

CHAIR MITCHELL: All right. I see Mr. McLawhorn. I'm looking for Mr. Floyd. Mr. Floyd, sing out so I can see you.

MR. McLAWHORN: Madam Chair, his office is just down from mine. I'll check to see if he's having a problem.

CHAIR MITCHELL: All right. Please do so.

MS. DOWNEY: Apologies for the delay.

(Pause.)

CHAIR MITCHELL: All right. While we have a minute, we will break for lunch at 12:30, and we will end our day today at 4:30 as we have been doing. Tomorrow we will begin at 8:30. Just putting you all on notice.

All right. I see Mr. McLawhorn is back. Do you have a report for us?

MR. McLAWHORN: Yes. He's getting on right now.

CHAIR MITCHELL: Okay.

MR. FLOYD: Sorry about that. I was down the hall.

CHAIR MITCHELL: Mr. Floyd, just in time. All right.

Whereupon,

JACK L. FLOYD AND JAMES S. MCLAWHORN,
having first been duly affirmed, were examined
and testified as follows:

CHAIR MITCHELL: Ms. Downey, you may proceed.

DIRECT EXAMINATION BY MS. DOWNEY:

Q. Mr. McLawhorn, we'll start with you.

Please state your name, business address, and present position?

A. (James S. McLawhorn) My name is James McLawhorn. My business address is 430 North Salisbury Street, Raleigh. I am the director of the Public Staff's energy division.

Q. Mr. McLawhorn, did you prepare and cause to be filed on February 18, 2020, direct testimony in this case consisting of 38 pages, an appendix and two exhibits?

A. Yes, I did.

Q. Do you have any corrections or changes to that testimony at this time?

A. I do not.

Q. If the same questions were asked of you today, would your answers be the same?

A. They would.

MS. DOWNEY: Chair Mitchell, I would move that the direct testimony of Mr. McLawhorn be copied into the record as if given orally from the stand, and that his exhibits be marked as prefiled.

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

(McLawhorn Exhibits 1 and 2 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony and Appendix A of James S. McLawhorn was copied into the record as if given orally from the stand.)

Q. Mr. McLawhorn, do you have a summary of your direct and second stipulation supporting testimony that was served to the other parties and the Commission?

A. Yes.

MS. DOWNEY: Chair Mitchell, I would move that Mr. McLawhorn's summaries of his direct and second stipulation supporting testimony be moved into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, that motion is allowed.

(Whereupon, the prefiled summary of testimony of James S. McLawhorn was copied into the record as if given orally from the stand.)

MS. DOWNEY: And we'll move to Mr. Floyd.

DIRECT EXAMINATION BY MS. EDMONDSON:

Q. Mr. Floyd, you have previously testified during the consolidated portion of the hearing?

A. (Jack L. Floyd) Yes.

Q. And so we already introduced you, but go ahead and give your name and title again, please.

A. I'm Jack Floyd, engineer with the energy division of the Public Staff.

Q. And, Mr. Floyd, since the consolidated hearing, you filed in this docket an errata to your first supplemental testimony that was entered into the record at the consolidated hearing, as well as four corrected exhibits. And you also filed second supplemental testimony consisting of 14 pages and 4 exhibits, both of those on September 8, 2020, correct?

A. Yes.

Q. In regard to the corrected first supplemental testimony, besides the corrections that you filed on September 8th, do you have any further changes or corrections?

A. Not at this time, no.

Q. So if I asked you the same questions today, would your answers be the same as the corrected testimony?

A. They would.

Q. And, Mr. Floyd, in regard to the second supplemental testimony, do you have any changes or corrections to that prefiled second supplemental testimony?

A. I do not.

Q. If I asked you the same questions here today, would your answers be the same?

A. They would.

Q. Do you have any changes or corrections to the exhibits to your second supplemental testimony?

A. No.

Q. And I missed a question. Did you have any further changes or corrections to the corrected exhibits to your first supplemental testimony?

A. No, I do not.

Q. Okay. And did you prepare a summary of your direct first supplemental and second supplemental testimony?

A. Yes, I did.

Q. Okay.

MS. EDMONDSON: Chair, Mr. Floyd's

direct and original first supplemental testimonies were entered and copied into the record in the consolidated hearing, and the exhibits to those testimonies were marked for identification at that time.

So today I would like to move that the prefiled errata to Mr. Floyd's first supplemental testimony, Mr. Floyd's first supplemental testimony as corrected, his second supplemental testimony, and summary be entered into the record in this proceeding, and copied into the record as if given orally from the stand. And that Mr. Floyd's exhibits attached to the corrected first supplemental testimony and the second supplemental testimony be marked for identification as Floyd Corrected First Supplemental Exhibits 1 through 4, and Floyd Second Supplemental Exhibits 1 through 4.

MS. CRESS: Chair Mitchell, this is Christina Cress with CIGFUR. I would object to the admission of Mr. Floyd's second supplemental testimony for the same reasons that I provided in detail on the record yesterday morning. I will spare the Commission those details here, because I believe I sufficiently belabored evidentiary objections concerning his second supplemental testimony yesterday morning, but I would just like to note my renewed objection for the record. Thank you.

CHAIR MITCHELL: All right. Noting the renewed objection of counsel for CIGFUR III, I will allow your motion, Ms. Edmondson.

MS. EDMONDSON: Thank you.

(Floyd Exhibits 1 through 4, Supplemental Floyd Exhibits 1 through 4, Corrected Supplemental Floyd Exhibits 1 through 4, and Second Supplemental Floyd Exhibits 1 through 4 marked for identification.)

(Whereupon, the prefiled direct and Appendix A, supplemental, errata to first supplemental, and second supplemental testimony as well as summary of the testimony of Jack L. Floyd was copied into the record as if given orally from the stand.)

MS. EDMONDSON: And the panel is available for cross examination.

CHAIR MITCHELL: All right. We will begin with the commercial group, Mr. Jenkins.

MR. JENKINS: Thank you, Madam Chair.

CROSS EXAMINATION BY MR. JENKINS:

Q. Gentlemen, it's a privilege to cross examine such an illustrious group.

Mr. McLawhorn, let's begin with you, if I may. I direct you to page 33 of your direct testimony. Are you there, sir? Mr. McLawhorn, can you hear me?

A. (James S. McLawhorn) I can hear you, Mr. Jenkins.

Q. Okay. At page 33 of your direct testimony, you provide there and in your exhibits the results of three class cost of service studies; is that right?

A. That's correct.

Q. Why did you do that?

A. Well, several reasons. One, one of the cost of service studies, the summer/winter peak and average, is at the time of the filing of my direct testimony as the Public Staff's preferred cost of service methodology, the summer CP or SCP is the one that Duke filed and they preferred with their prefiled -- their application in this proceeding. And then the winter coincident peak was one that Duke had also included in their application. So I provided analysis and comments on those three methodologies.

In addition, the Commission had expressed some interest in an order they issued in January. I believe it was January 20th or thereabouts. I'd have to check that date. In that they wanted the Public Staff to comment on an analysis of various cost of service methodologies.

Q. And so do you believe that providing various class cost of service study method results might give the Commission a better view concerning those results?

A. Well, it certainly allows them to look at these three, in particular, and see what type of results were produced in -- during the test year of 2018.

Q. Okay. And one of the methods is the winter coincident peak that you mentioned that uses DEC's current yearly peak; is that correct?

A. It used the peak for 2018, yes.

Q. Under the -- that WC method that you also show in your Exhibit 2, doesn't the OPT class currently provide revenues that greatly exceed DEC's cost to serve that class?

A. (Witness peruses document.)

Under that methodology, it did provide a rate of return that was in excess of the retail rate of return for that given year, yes. Although --

Q. And if you were -- sorry.

A. May I finish my answer? Although I would note that, in the other two methodologies that were presented, the SCP which Duke has advocated in this case, and the SWPA, the OPT rates of return were substantially below the retail rate of return for 2018.

Q. And if you were to blend the results from these three class cost of service methodologies, wouldn't the blended results show that the OPTG class should receive a rate increase that is below the system average?

A. I have not done that analysis to determine what the rate increase would be. If you averaged the rates of return together, you would certainly get a number that is above the rate of return for SCP and SWPA, although I'm not a fan of averaging averages, because you're not always comparing apples to apples in that case. You would be comparing rates of return that were based on different levels of rate base since the different methodologies arrive at different NC retail rate base amounts.

Also, I think what it would be showing you is that the WCP methodology results in a substantially different result than the other two methodologies. So it's -- you know, for lack of a better term, if you're comparing the three, it would appear to be somewhat of an outlier. And we could talk about the reasons why if you want to, but I'll leave that up to you.

Q. Okay.

MR. JENKINS: Thank you, Madam Chair, that's all I have for Mr. McLawhorn. I do have other questions for Mr. Floyd, but this might be a good time to break.

CHAIR MITCHELL: All right, Mr. Jenkins, let's do go ahead and take our lunch break. We will go off the record now, and we will go back on at 1:30. Thank you very much.

MR. JENKINS: Thank you.

(The hearing was adjourned at 12:30 p.m. and set to reconvene at 1:30 p.m. on Thursday, September 10, 2020.)

P R O C E E D I N G S

CHAIR MITCHELL: All right. It's 1:30. Let's go back on the record, please. We will resume with cross examination for the McLawhorn/Floyd panel.

Mr. Jenkins, we are with you.

MR. JENKINS: Thank you, Chair.

Whereupon,

JACK L. FLOYD AND JAMES S. MCLAWHORN,

having previously been duly affirmed, were examined and continued testifying as follows:

CROSS EXAMINATION BY MR. JENKINS:

Q. Mr. Floyd, can you hear me okay?
A. (Jack L. Floyd) I can.
Q. Good. Now, we've both been involved in too many of these Duke rate cases than we might care to admit; isn't that right?
A. Yes. You may have a few more under your belt than me.
Q. Now, do I understand correctly the gist of your stated opposition to the commercial group settlement is that you prefer not making any changes now in rate schedules that might impact a future study of rate design?

A. I think that's a fair statement. I have approached this whole subject with a rather cautionary stance. And I have expressed, at all levels, I think, that the caution that I think needs to be placed on this study. It is a large, formidable task, and to do anything at this time, I think, is taking stale data and trying to fit it into something that really needs to serve the utility of the future. I asked the Company through discovery if they had updated analysis of cost curves, revenue curves, a bunch of other questions related to load research, and the responses that I got were basically, you know, we maintained the existing rate structures.

The last analysis was done in the last case, the Sub 1146, and that was a limited analysis. So with all of that said, I -- you know, I just feel like --

CHAIR MITCHELL: All right. Mr. Floyd, I have to interrupt you, I apologize. We're getting significant feedback here. Everyone double-check that your lines are muted. I don't know where that feedback is coming from. All right. Mr. Floyd, we may be having a problem with your line. All right. Mr. Jenkins, while Mr. Floyd is responding to your questions, please mute the line.

MR. JENKINS: It is muted.

CHAIR MITCHELL: No, you're not muted. All right. Now you're muted, Mr. Jenkins. Mr. Floyd, you may proceed with your response.

THE WITNESS: I'll just close in response that I think one of the things that has gotten us to the place we are today, in terms of rate design, is that -- and Mr. Jenkins kind of highlights some of the history we've had with these rate cases. I think Duke Carolinas is now -- this is the sixth case in what I call the modern era of rate cases since about 2007, and there had been very little change in terms of rate design through that whole period.

The biggest change has, I think, occurred with the OPT class, the consolidation that Mr. Jenkins, I think, will agree, was forced upon the parties to be done. Lighting has been addressed in terms of structure and costing out the components of the lighting rate schedules, and we're facing a new utility paradigm that I believe requires new study, new data, new research. And to do anything piecemeal at this time is limiting that comprehensive study.

And again, I can't -- I can't stress enough that I believe a comprehensive approach with all the stakeholders is really what's necessary at this time.

Q. Thank you. You're not saying that you substantively oppose the OPT changes that the commercial group settlement would implement?

A. I don't -- I'm not opposed to them, per se. And let me say this. I'm not opposed to -- I'll use the off-peak energy rate as an example. I think Mr. Pirro in his testimony conveyed that that rate was developed taking into account a better understanding of the on-peak/off-peak cost relationships, rather than simply applying an across-the-board percentage increase.

That being said, I have not seen any analysis behind that, but I take him at his word. I've had a good working relationship with Mr. Pirro. If that's the case, then that is a positive step in rate design. However, that is an isolated adjustment or change in structure. And again, my cautionary stance is predicated on looking at all of the factors: OPT, residential, lighting, the whole works. And then where can we go with adopting rate schedules that facilitate the electric vehicle adoption and things like that.

You know, these are just things that I'm bantering around, but, you know, I will take Mr. Pirro at his word that the $0.03 -- or 3.02 cents off-peak rate in the OPT small secondary energy rate is -- the way he described it the other day, is a positive step.

(Reporter interruption due to technical difficulties.)

CHAIR MITCHELL: Let's take a five-minute recess.

COURT REPORTER: Thank you.

(At this time, a recess was taken from 1:36 p.m. to 1:41 p.m.)

CHAIR MITCHELL: All right. Let's go back on the record. Mr. Jenkins, Mr. Floyd, you may proceed.

MR. JENKINS: Thank you. And you're doing a great job, Chair Mitchell, with a difficult set of circumstances.

Q. Mr. Floyd, when will rates from Duke's next rate case go into effect?

A. Typically a month or so after the final order they will be required to comply -- or to file a compliance filing. And we'll review that, make comments as necessary, and the Commission will issue an order.

Q. So that could be 2023, 2025, anytime right?

A. I would not expect it to take that long. I mean, in this proceeding, it's typically 60 to 90 days before we get an order, and then another 30 days. So early -- at this point, early '21.

Q. I'm sorry. My question was for the next Duke rate case.

A. Oh, I'm sorry. Well, I mean, I have no idea when the Company will file a proceeding. We have asked that such a study take place, but that it be completed either before or incorporated into the next case.

Q. Now, you don't believe that any comprehensive review of rates will necessarily end all disputes with the respect to rates, do you?

A. I'm not giving a Pollyanna answer to that. No, I don't. There -- I think there will always be disputes in rate design. If anything, it is -- it is mostly art sprinkled with some science and data. But until all the parties can come together on all the issues, which I don't ever expect while I'm here, we'll continually have dispute.

Q. Now, you've been fairly consistent over the years in suggesting more comprehensive rate studies, haven't you?

A. Over the years, I think this is the first case that I -- the Public Staff has actually put pen to paper in direct testimony with this concept, but I have certainly talked about it internally with folks. And, you know, whether or not it's intervening counsel that thinks I go rogue, my own attorneys think I do that a lot. I don't -- I have pushed rate design and cost of service -- I mean, these are inextricably linked. I have pushed both to modernize, because for the last 10 years, whether it started with the smart grid initiative, smart meters, and everything that has happened since, I see electric utility service changing, and rate design has not. And rate design needs to move into the modern era.

Q. Well, for example, in the last rate case, let's look at your testimony there.

MR. JENKINS: And, Chair Mitchell, I'd ask that the Commission take administrative notice of the direct testimony of Jack Floyd prefiled on January 23, 2018, in Docket E-7, Sub 1146.

CHAIR MITCHELL: All right. Hearing no

objection, the Commission will take judicial notice of Mr. Floyd's testimony filed on January 23, 2018, in E-7, Sub 1146.

MR. JENKINS: Thank you.

Q. At page 14 through 15 of that testimony, you noted that DEC, quote, did not propose substantial changes to the structure of its rate schedules, end quote, because smart meters were still being installed and that DEC would develop innovative rate designs in the future. Do you recall that?

MS. EDMONDSON: Can Mr. Floyd get a copy of that?

MR. JENKINS: Unfortunately, because the testimony was filed so late, we did not -- it was after the time for us to provide copies.

Q. But do you recall that, Mr. Floyd?

CHAIR MITCHELL: Mr. Floyd, you're muted.

THE WITNESS: I'm holding my space bar down and it's not working, so. Is it working now? Okay. I'm familiar with the testimony. I may not be literally familiar with all the words.

Q. And do you recall that, despite waiting for future rate designs, you testified the Commission should address three rate design issues in the last DEC rate case: the basic facilities charge, standby charges, and lighting?

A. I do.

Q. Now, before that, in the 2009, 2011, and 2013 DEC rate cases, the Commercial Group pointed out intraclass subsidies within the OPT rate class, and the Commission made steps to eliminate those subsidies.

Do you recall that period?

A. I do. And I think, at this point in time, most of those issues, at least to my knowledge today, have been resolved.

MR. JENKINS: Madam Chair, I'd ask that the Commission take administrative notice of the final order of September 24, 2013, in Docket E-7, Sub 1026.

CHAIR MITCHELL: All right. Hearing no objection, we will -- the Commission will take judicial notice of the final order issued in E-7, Sub 1026.

Q. And, Mr. Floyd, I do so because there's a good summary of this history in that order. But in that case, a Staff/DEC stipulation was reached that, among other things, would delay any OPT changes until some additional study was performed. And the Commission, in its final order, with respect to that OPT subsidy issue at page 98 stated that, quote, it cannot allow the imbalance that is already known to continue while the Company and Public Staff study the situation for another year or two, end quote.

And my question is, wouldn't you agree one reason for the Commission to do so is that, however helpful rate design studies can be, the Commission's statutory duty is to ensure that ratepayers that are actually paying the bills now should have rates that are as fair and reasonable as possible?

A. I would agree with that. But like I said, I believe most of those issues have been resolved. There are certainly technical and structural changes that really need to be addressed, but most -- well, I think all of that, except for maybe the Sub 1146 case, certainly did not have the benefit of advanced metering infrastructure. And that really is the underpinning cornerstone for moving from what I call traditional rate design into a more modern era of rate design.

And for Duke Carolinas, as I understand, they are pretty much done with the smart meter AMI deployment and have already started to collect load research. That load research is where the basis of any new rate design should start. Anything outside of that under the traditional approach would simply be an exercise of moving $1 of cost to another -- from one bucket to another, and that's what I want to try to avoid in this case.

Now, I admit I have -- I have agreed with the Company's status quo design, because I simply don't have any new data or analysis on which to base any new type of rate design. But that's why I'm pushing so hard. Duke -- and really I'm pushing all the other parties. Public Staff is kind of in the middle of the road here on this, but we're pushing for a new paradigm of rates. And I think the history that you explained certainly conveys the frustrations of both the Public Staff and the Commission and the need to move past the traditional way of doing rate design.

Q. You would agree, wouldn't you, Mr. Floyd, that this has been a very rough year for businesses in North Carolina?

A. As it has for everyone, yes.

Q. Yes. In fact, are you aware that one member of the Commercial Group, namely J. C. Penney, was forced to file a bankruptcy petition since this rate case began?

A. I have seen news reports of such, yes.

Q. So isn't it true that individual businesses may not have a number of years to wait for additional rate review?

A. I understand the -- and sympathize with that a little. However, when we are talking a 5-plus billion dollar revenue requirement for a monopoly utility service, I don't see how we do anything quickly.

MR. JENKINS: Thank you, Chair Mitchell. Nothing further.

CHAIR MITCHELL: All right. CIGFUR?

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Good afternoon, gentlemen. I am going to be looking at a different device. I've got multiple screens going here. I'm sure you can relate. So although it's probably not going to look like I'm looking at you, I am, and I'm going to try to make this interaction feel as organic as possible, if that's even feasible under the current circumstances.

So, Mr. McLawhorn, I will start with you, if that's all right, sir?

A. (James S. McLawhorn) That's fine.

Q. Okay. Is it fair to say that the Company acts in reliance upon directives and decisions of this Commission?

A. Among other regulatory authorities, yes.

Q. And is it also fair to say that intervenors, likewise, act in reliance upon this Commission's directives and decisions?

A. I would say the intervenors certainly pay attention to the directives of the Commission. They're free to advocate positions that may not agree with past Commission decisions, as long as they're within their legal bounds.

Q. Okay. Would you agree that pollution control costs benefit all customers?

A. Yes, there's some benefit, I would think. They may benefit some customers more than others. Certainly, as we've heard a lot of testimony in this case and the last rate case about coal ash, we've seen the effects of impacts on groundwater, and the attempts to mitigate that have a greater impact to customers who live closer to the plant sites than they do to others. But I would -- I would generally agree with that statement.

Q. So benefits flow to all customers, but perhaps geographic proximity to the origin of the pollution, the benefits for those customers would be greater; is that sort of the logic?

A. For some environmental costs, yes. I don't think you can make just a blanket statement. I picked out one particular area of environmental remediation in particular.

Q. Understood. Would you agree with me that the Public Staff has included numerous safeguards to protect ratepayer interest in its second stipulation and settlement with the Company?

A. Could you be a little bit more specific? And I have a copy of the stipulation if you want to direct me to that.

Q. Does the stipulation contain parameters in which the Company must act as it relates to the grid improvement program, specifically pertaining to numerous details on program components and time limits on those programs?

A. It certainly does address the grid improvement program, and it has, for example, specific programs that we stipulated with the Company that would be included in any deferral if the Commission agrees with the stipulation. And there was language about reporting requirements and other things that we will -- the Public Staff will work with the Company and other parties on.

Q. Okay. Sir, the Commission has been approving the customer component in the allocation of distribution costs since 1973; is that right?

A. You're talking about the monthly fixed customer charge. It has been approved by this Commission for many decades. I don't know the exact year of when it began, but I'm sure it was in a part of the proceedings in 1973.

Q. Okay. So would you agree with me, subject to check, that its origins date back to Docket Numbers E-7, Sub 145 and E-22, Sub 141?

A. Particularly, I'm more familiar with the E-22 docket, and I believe that's the one in which the Commission approved the minimum system approach. I think. I'm not looking back at my notes, but I assume that's the one you are referring to for Dominion that was VEPCO at the time.

Q. So just by my count, would you agree that that's 47 years now that the Commission has been approving this method of cost allocation for components within the distribution system?

A. It's been 47 years since that was approved. I don't know that there has been explicit approval by the Commission in each and every case since then. I guess by not speaking to it, you could say there was implicit approval by the Commission. But I don't know -- well, I know for a fact there hasn't been explicit approval in their orders in each and every case.

Q. Okay. Although the Public Staff has, in this proceeding, insinuated that much has changed about the provision of electric service since 1992, and therefore, the NARUC cost allocation manual perhaps should not be given as much weight as an authoritative source, the Public Staff did, in fact, rely on the NARUC cost allocation manual and cited to it in support of the conclusions that the Public Staff reached in its 2019 report on the minimum system method; is that correct?

A. We did, and I will state why. And I'll also say that, as I answer these questions, Mr. Floyd was more directly involved with the development of the report, so he may wish to add to my comments. But yes, we certainly did cite to the 1992 NARUC cost allocation report. As it's mentioned in the regulatory assistance project report that came out in January of this year, there really has been no comprehensive analysis of cost of service methodology since that report in 1992 that was issued by NARUC.

So that is certainly a reason why we referenced it when we issued our report back, I believe, in -- it was in 2019 or 2018. I think it was 2019. And then now we have a new study that was produced by the regulatory assistance project this year. So at least we have something else on a national comprehensive level to look to, other than just the NARUC report.

Q. Mr. Floyd, is there anything you want to add?

A. (Jack L. Floyd) Let me see if I can get this button to work. The only thing that I would add really is that, you know, one of the final conclusions of that report asks the Commission to convey its interest and seek a new NARUC study on this very topic. And I don't know where that stands at the moment. But the regulatory assistance project document came out earlier this year, and it provides a new opportunity to look at cost allocation, and to some extent rate design.

I do believe that both are important enough and to move into a different view, different analysis, different perspective, whatever word you want to come up with, to address this future utility service rate design question that I'm trying to get everyone to talk about.

Q. So this 2019 report -- and that's how I'm going to refer to the Public Staff's report that it published in 2019 on the minimum system method at the direction of the Commission.

This 2019 report, you would agree with me, was pretty comprehensive and pretty thorough, right?

A. Well, it was a good report. It -- we relied heavily on what the Company's descriptions of the minimum system approaches that they took, and we formulated our opinions about where to go. And, you know, at the end of the day, it really is an exercise in determining just how distribution costs are to be allocated. And the Public Staff continues to believe that there is a demand-related portion to that and a customer-related portion to that. And that whether or not it is the minimum system that is used or something else, both of those points need to be considered in the allocation of distribution costs going forward.

Q. But the 2019 report specifically stated that the minimum system method is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge?

A. (James S. McLawhorn) If I might, and then I will let Mr. Floyd respond to that. It did address that, Ms. Cress. I think it's a reflection of the fact that there had -- there had not been any other comprehensive literature that had been produced at that point. We had analyzed the different methodologies for allocating costs to fixed customer cost from the different methodologies that were included in the 1992 NARUC report. And it is also a reflection of the fact that -- to tie it back to Mr. Floyd's rate design study plea, for lack of a better word, that many customers -- well, there are only -- for some customers, and residential in particular, there are only two ways to recover costs, through the monthly fixed charge and through an energy charge. And as more and more customers, including residential customers, have the ability to bypass or to reduce their energy consumption while their other fixed costs may not necessarily go down commensurate with their energy reduction, if you bill all of these demand charges into the energy charge, or a substantial portion -- not all of them but a substantial portion -- then there's going to be a shifting of costs among customers. And some customers are not going to be paying their share of the costs that they impose or rely upon the system for.

Q. Is there anything you were going to add, Mr. Floyd?

A. (Jack L. Floyd) No.

Q. Okay. If you could pull that report up for me, and it's already been admitted into the record. I believe it was identified as DEC Hager Redirect Exhibit 1.

A. (James S. McLawhorn) I have that.

Q. I'll wait for Mr. Floyd. You know, and please -- I should have said this at the outset, but both of you please feel free to interject at any time. I do feel like there's a lot of bleed over between the topics that you two cover, and so some of these questions certainly were a toss-up as between who would be the most appropriate candidate for answering them.

Mr. Floyd, do you have it in front of you now?

A. (Jack L. Floyd) I do.

Q. Okay. And so, if you'll just read with me page 16, starting with the last paragraph that begins on page 16 and carries over to page 17. This report states in part that:

"After our review, the Public Staff believes that the use of MSM" -- and correct me if I'm wrong, but that means minimum system method -- "by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge. While not precise, MSM is a logical methodology for classifying costs of a distribution system as demand or customer related."

Is there anything about those two sentences that your testimony here today is changing or contradicting?

A. In terms of rate design, or cost of service, or both?

Q. In terms of anything that this -- these two sentences could possibly apply to.

A. No. I responded a moment ago that, you know, the Public Staff still believes that distribution costs have a demand-related component and a customer-related component. The minimum system method, MSM, is a reasonable approach to distinguishing what portions are demand related and what portions are customer related.

That has not changed.

I think, you know, we also say in the report that the minimum system method establishes a maximum. And I think, from the prefiled testimony of other intervenors, the Justice Center and others that have discussed the impacts on low-usage, low-income customers, the minimum system method gives us a maximum amount. And I've explained this in previous cases, is that this is somewhat of an art to determine. And what we have typically used the minimum system to do is to set up boundaries. Establish a maximum boundary in this case. And then, at a minimum, we've looked at the basic customer method.

And we feel like somewhere in between lies the answer. And that -- I think that approach has -- is consistent with this report, or this report is consistent with that approach. But there is a recognition through all of this that, as James mentioned just a moment ago, about the only place to get revenue out of certain rate schedules is either a basic customer charge or an energy charge. And those two charges must work together to cover the customer-related, the demand-related, and the energy-related costs of service. And between the two elements, produces the necessary revenue.

So there's a -- there's a method to the madness between establishing boundaries for where a basic customer charge lands, and that's really all, at the end of the day, what we've done. And as long as we're somewhere in the middle, we try to look at and apply cost causation as much as possible. But then again, we have the policy objectives of not trying to impose too significant of an increase in a basic customer charge, which does rely heavily on the determination of -- from the minimum system method. But we try not to impose such a significant change in that charge in any particular rate case.

A. (James S. McLawhorn) And if I could just add on to what Mr. Floyd said. Just to make sure there's no misunderstanding in the report from the section that you read, Ms. Cress, which you correctly read it, the Public Staff in its report said that the minimum system methodology is a reasonable method. We did not say it's the ideal method, or the best method, or the greatest method, but it is a reasonable method for this determination. As you have pointed out, it has been used since 1973, so it's been in practice for a very long time.

But this had -- and as Mr. Floyd has said several times, this is not an art. There's no cookbook to flip open and give you the exact temperature or the exact number. If there were, we wouldn't be sitting here having questions from all the different parties and all the interest on this. So that's where the art comes in.

So yes, I totally agree with Mr. Floyd's testimony that minimum system sets a maximum amount. And I believe the minimum intercept method, or one of the others -- I'd have to go back and get the exact terminology -- sets somewhat of a minimum boundary. And I guess the Public Staff and other parties make recommendations, and then the Commission uses its judgment and determination to decide where between those two numbers is the correct amount.

Q. Okay. And, Mr. McLawhorn, you said that it was primarily Mr. Floyd who was involved in the 2019 report from the Public Staff on the minimum system method, but you certainly would have had to read, and approve, and sign off on that report before it went out the door; is that fair to say?

A. Yes. I would say Mr. Floyd was the Public Staff's lead technical investigator on that report, but as his direct supervisor, I was certainly involved and aware, and not just at the very end, but I did read the report, and signed off on it, and made the recommendation to higher Public Staff management.

Q. Okay. And so we've talked about how long of a standing precedent we have here as it pertains to this particular cost allocation methodology.

Would you agree that it would take a pretty compelling reason to depart from many decades of ratemaking practice and precedent?

A. We certainly don't make changes for no good reason, you know, just to change. We do change things from time to time. If we -- if there was a convincing argument that there was a better way to analyze and to go about something, we would certainly be open to that and giving consideration. So we would not want to make wholesale changes that might cause some sort of rate shock. Barring that, we would not be opposed to recommending a change.

Q. Okay. So you conceded that there has to be a good reason. How good of a reason are we talking?

A. Well, it would need to be theoretically sound, first and foremost. I'm not sure I know how to answer your question completely. It's sort of like I would know it when I saw it, but there would have to be evidence that was presented that said this is a better way. And I'm certainly not discounting that. We have -- through the changes in technology that have been referenced numerous times, we have new information available to us or becoming available to us through the use of AMI data collection and other things that we've never had before as cost of service analysts and rate design analysts. It's never been available.

Q. Would you agree that the Commission has tools available to it to achieve its objectives of parity, and equity, and fairness that do not necessarily include changing the fundamental allocation methodology that has historically been used?

A. I'm not sure I 100 percent follow your question. The Commission has tools available to it to ensure equity without making changes? I mean, they have the data that they've always had, but oftentimes that data is very broad. It's not discrete in many cases. It's the best that we've had. So given that, the Commission had the ability to make the decisions that it needed to make. That doesn't mean if there's better information or better ways, that we can't refine what we've done historically and improve upon it.

Q. In other words, the cost allocation methodology is not necessarily the only way that the Commission could perhaps address some of its concerns related to issues of equity or social justice; is that fair to say?

A. Well, I wouldn't presume to speak for the Commission on what they think they can and can't do. Some of those issues -- I know some people have concerns with the legal bounds around that. And, you know, I would not want to suggest what the Commission could and could not do from an equity or social policy standpoint.

A. (Jack L. Floyd) Ms. Cress, I'd like to intersect some response to that, too. My take on General Statute 62-133 gives the Commission a very wide latitude in determining rate design and rates, and looking at how rates are set in terms of the revenue requirement they are trying to achieve. That wide latitude certainly can address some of the things without being more specific, but it relies upon the facts of each case where we end up in terms of how those customers relate to one another in producing the assigned revenues. And we do that in the context of a rate of return on rate-base calculation.

And then looking at these other policy objectives that the Commission or the General Assembly or -- have imposed upon the Commission that need to be implemented as part of that rate design. It's -- the question of how many tools or what tools they have is a very, I believe, a wide open question that -- you know, I believe the statute gives the Commission a wide latitude.

Q. Okay. Would you gentlemen agree that a change in the cost allocation methodology could have profound impacts across all ratepaying classes?

A. (James S. McLawhorn) That is a possibility. That's something that would be looked at in any study. I don't know if you're working your way into the recommendation in my prefiled direct and in the stipulation, that the Company has agreed to look at a variety of different cost allocation methodologies. But assuming that you are, I'll go ahead and cater that. That is certainly one of the things that we will be looking at. I don't think anyone would want to advocate for a change that was going to have, you know, drastic detrimental impacts on certain customers.

A. (Jack L. Floyd) Ms. Cress, the methodology is one part of the question. That certainly imposes constraints and provides perspective for the cost of service. But the other question -- or another part of that question, I believe, has to do with the cost of service structure, itself. And let's talk about Duke Carolinas a little bit.

Duke Carolinas has five broad customer classes: residential, general service, industrial, lighting, and the OPT, which is basically the nonresidential time of use schedule, and there are sub-pieces of the OPT. Those are fairly broad classes that encompass a lot of customers. And one of the reasons that I've been pushing a rate study, and along with that a cost of service study, I reckon, is that load research may actually show that we have different types of customers within these broad classes.

We need to study that. And I think some of that study is already underway with the study the Commission ordered in -- I believe it's the E-100, Sub 101 interconnection docket. Duke is working on that now. It may have something to produce for us sometime in the fall, but sometime soon. But it is not necessarily, or not only a question of methodology. We need to look at how the structure of the cost of service also impacts rate design.

Q. Okay. Just briefly, let me pause for a moment and address Chair Mitchell quickly.

MS. CRESS: Chair Mitchell, I'm not sure if the Company's revised witness list has made its way to you following the changes from yesterday, but I did just want to make you aware that CIGFUR requested more time than it had initially requested following Mr. Floyd's second supplemental testimony on Monday. We have now requested 30 minutes for this panel, and I do have quite a few questions left, but I will try to pick up the pace. I was just making you aware that it wasn't still a five-minute reservation.

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

MS. CRESS: Thank you.

Q. So, Mr. McLawhorn, you acknowledge the possibility that a change in cost allocation methodology could have profound impacts across ratepaying classes.

Would you also concede that some of those impacts might be unforeseen?

A. (James S. McLawhorn) Certainly anything is possible. I mean, I can't make a determination going into something when we haven't even looked at it yet. But again, that's one of the recommendations that -- or one of the agreements in the stipulation, that an analysis would look at the pros and cons of any such methodology that's studied. And even -- even so, even if there were a change in cost allocation methodology -- and let me just say, nobody has recommended that something be changed at this point. It's merely been a recommendation that there be a study looking at it, because we have not done this -- we've been using the same thing for, you cited, 40-plus years for the minimum system methodology. We may have been using the same cost allocation methodology longer than that. Certainly, it's been in use -- the current methodology has been in use since before I was here.

There are arguments that parties would make that that means you shouldn't change. But we know that the electric utility industry is changing the way costs are being incurred, and the reasons they're being incurred are changing. The types of facilities that are being installed now. We're moving more away from central generating plants to more distributed generation, more focus on the transmission and distribution system. It's time to take a look at a lot of things, and cost allocation methodology being one of those.

And, you know, today, the Public Staff has certain parameters and -- that it follows even within a cost allocation methodology for how revenues are allocated or apportioned among classes to avoid any type of sudden shift in revenues that we often refer to as rate shock. And I'm certainly not proposing that that wouldn't still be a consideration if we were to change cost allocation methodologies. I think that would be important to keep that in mind.

Q. So I think, if I'm hearing you correctly, you would agree with me, would you not, that it would be premature, as we sit here today, to depart from the Commission's standing precedent on this issue without first undergoing and undertaking the very thorough comprehensive and transparent studies that you both are discussing; is that fair?

A. Yes. And I think that's exactly what my testimony says and what is included in the stipulation. And if anybody read it any differently, then I didn't do a very good job with my testimony. That is all that was intended by what's in there.

Q. Is it fair to ask other customers to pay a portion of the costs that the Company incurs to connect customers to its system?

A. You mean new customers?

Q. Yes, to connect new customers.

A. Well, that's an interesting question. Certainly, we've got a public -- this is -- a utility is a public service company. It's sort of a "we're all in this together" company, and nobody has discrete rates that they pay just for their service and just the exact cost of their service.

So, you know, I'm not -- I may not be interpreting your question exactly right, but, for instance, a new customer comes on the Company's system, if they're at the distribution level, there are going to be costs to connect that customer to the system. Of course, distribution costs are pretty much directly assigned to the customer classes where they occur, or very close to that. So it's -- they're pretty much recovered from customers within their class. But, you know, if you ask a new customer to pay, you know, the full freight for sort of a marginal cost to be connected to the system, we would be departing from our historical use of average costs.

So the customers that are there today had the benefit of paying average costs when they -- I guess to go back to an old phrase, everybody was a new customer at some point in time on the utility's system. And that historical average embedded cost methodology is how rates have been set historically. And so I don't know if that answers your question or not. I rambled a little bit.

Q. That's quite all right. Hopefully these next couple of questions will be more straightforward.

Primary customers don't use secondary lines; is that right?

A. As a general rule, that's correct. I believe Mr. Floyd may have a different thought on that, but I believe that's generally correct.

Q. And same thing for transmission customers?

A. If you're a transmission customer and you take service directly off the transmission system, then there should not be a direct impact to the distribution network, barring some unforeseen, odd power-flow issues.

Q. So you would agree that customers served from subtransmission or single-customer substations should not be allocated secondary or primary voltage costs?

A. Would you please -- would you repeat the question? I'm sorry, I'm thinking.

Q. Sure. You would agree, wouldn't you, that customers served from subtransmission or single-customer substations shouldn't be allocated the secondary or primary voltage costs?

A. I guess taking your question in a vacuum, that sounds reasonable. I think I would have to -- I would have to think about that a little longer. I hesitate to give an absolute answer on the spot.

Q. I'll go with the one that you just gave, which was that it sounds reasonable.

A. Okay. That's fine.

Q. So moving on to the -- DEC has always used the SCP, correct?

A. As far as I know, that's correct, that's been their testimony.

Q. And they've never used the SWPA?

A. DEC has never used the SWPA. DEP did, and -- of course, until they were acquired by DEC, and, of course, Dominion still uses it.

Q. In your arguments supporting your contention that the Commission should reverse past precedent as to the SWPA, you cite to a number of past Commission cases and precedent; do you not?

A. I do, yes. Including their most recent -- well, that's -- I'm sorry, that's not in the DEC case, sorry.

Q. Did you cite to the last time that the SWPA issue was fully litigated in a Duke rate case, specifically Docket Number E-2, Sub 1023?

A. No. I was the witness in that case. That was a DEP case, and I testified and recommended that the DEP, or Progress at the time, maintained the use of the summer/winter peak and average methodology, which they had had for a number of years prior to that. That was after the merger of Progress Energy and Duke Energy Carolinas. The Company, in their rate case, requested that the Commission approve the SCP methodology, and the Commission agreed with the Company in that case. So that did not support my position, so I did not cite that.

Q. Okay. So that's why you didn't include that one in your testimony here in support of SWPA, because it contradicted your recommendation?

A. I think most witnesses include testimony that supports their position and not testimony that does not agree with their position in any case.

Q. Understood.

MS. CRESS: Chair Mitchell, at this time, I'd request that the Commission take judicial notice of its order granting general rate increase in Docket Number E-2, Sub 1023, issued on May 30, 2013.

CHAIR MITCHELL: All right. The Commission will take judicial notice of its order issued in E-2, Sub 1023 as requested.

MS. CRESS: Thank you.

Q. Mr. McLawhorn, is it fair to say that the arguments that you use in this case to support the SWPA are substantially the same as those that you raised when you were a witness in the E-2, Sub 1023 case; is that fair to say?

A. For the most part. I would also point out that, since that time, and in particular in the most recent Dominion Energy case, E-22, Sub 562, which I think the Commission has already taken notice of the order in that case, that Dominion advocated for the SWPA. The Public Staff supported that. The Commission had significant language in that Dominion order stating that it found the SWPA to be a reasonable methodology to be consistent with how Dominion plans and operates its system, and that a methodology focused only on a single peak would not be appropriate for Dominion.

I understand that Dominion is a separate company, but the logic that the Commission used for justifying approval of the SWPA in the Dominion case is, essentially, the same logic I used in my testimony. And if you go and read Ms. Hager -- Duke witness Hager's rebuttal of me in the DEC case, she states that I described the planning process of DEC, the IRP process of how the Company plans and operates its system correctly. She took no issue with that, and that is the same logic that the Commission used for approving SWPA in the Dominion case.

Q. Okay. Did the Public Staff challenge the Commission's rejection of the SWPA in Docket E-2, Sub 1023, whether by appeal, or moving for a rehearing, or requesting a reconsideration?

A. We did not at that time.

Q. Okay. Has the Public Staff cited any quantifiable studies in support of its arguments for the SWPA in this case?

A. Quantifiable studies? No, I don't believe . So the peak and average methodology was certainly one of the methodologies included in the 1992 NARUC manual among many, including the SCP that Duke uses. There are some new -- there's some new analysis and new discussion of methodologies that include -- that are not based solely on peak allocation in their regulatory assistance project manual from January of this year, and that is one of the reasons we have asked for some of those studies to be included. In fact, that study is very critical of a single coincident peak allocation methodology.

Q. And likewise, Public Staff has not cited any quantifiable studies in support of its arguments that the minimum system method in this case should be reconsidered; is that fair to say?

A. In this case, we have not cited any studies. I think, again, as we stated earlier, we've not stated that the minimum system is a methodology that gives you the absolute number; it is a number that gives you a maximum amount, and then there are other methodologies that set more of a minimum boundary on that, and with the understanding that perhaps the correct answer is somewhere in between.

Q. And the Public Staff also has not provided any model runs or other predictive forecasting in support of the SWP [sic] method in this case, correct?

A. SWPA. No. That is part of the study that we're asking to be done.

Q. Okay. You're not aware of any order allowing deferral accounting treatment that allocates cost on the front end before it's spent and before such time as the Companies are coming back in to seek recovery of those costs, correct?

A. I am not personally aware of that. A later Public Staff, one of the accounting witnesses, Ms. Boswell or Mr. Maness, might be a good candidate to ask that. I don't believe the Public Staff has recommended that in this case. So certainly cost allocation usually takes place at the time of recovery of the cost.

Q. Thank you. So, Mr. Floyd, I think these next ones are for you.

Is it fair to say that some customers on the OPT-V rate are served directly from the substation?

A. (Jack L. Floyd) I don't know that, personally, but either secondary, primary, or transmission.

Q. So assuming that there are, indeed, some customers on the OPT-V rate that are served directly from a substation, would it be fair to say that those customers would not use a large portion of the majority

of the Company's distribution system?
A. If we're talking about the substation between transmission and primary, I think you're correct. They would be allocated transmission costs and substation costs. But at a point further down the line, so to speak, they would not be allocated those costs.
Q. Because DEC's OPT rates have voltage designations, specifically OPT transmission, OPT primary, OPT secondary, the Company does not allocate secondary distribution equipment to primary and transmission customers, correct?
A. I believe -- I believe that's the case, yes.
Q. And that's entirely appropriate, correct?
A. It is appropriate. And again, this kind of illustrates the nature of OPT, itself. I mean, it was a hotly debated rate schedule, and stakeholders came to agreement on the structure, itself. And that's why you see small, medium, and large levels of service under each, the secondary, primary, and transmission levels of service. And it was an effort to recognize the point at which service was delivered to the customer on a voltage basis.
Q. Okay. And you would agree, wouldn't you, that capacity shouldn't be built to serve nonfirm load?

A. That, I think, literally, yes. Nonfirm load, we might have to discuss what that means.

Q. Well, you tell me what you think nonfirm load means.

A. Well, it -- when a customer primarily serves their own load and wants to be backstopped by the incumbent utility, that's one level. And then there's another level on a daily basis of whether or not they want service routinely over many hours. And then when there are load-related issues, that they get curtailed, that's another issue. That kind of describes the gamut of what nonfirm might mean to individual customers.

Q. Is it fair to say that your opposition to curtailable demand has nothing to do with rate design?

A. Explain your question a little bit more.

Q. Well, I think you should just take the question at face value and answer it as you see fit.

A. I'm not sure how to answer the question. Curtailable load is typically outside of cost of service. It is -- you know, customers who have curtailable load receive credit for that load when the utility is calling that that load be curtailed. Those are typically marginal types of costs, and they're not reflected in the embedded average cost of service. I'm not sure how else to respond to your question.

Q. Well, but the removal of curtailable load is the correct thing to do; is it not?

A. It depends. The cost of service is predicated on system demand under a single coincident peak methodology. It's predicated on the actual demands at the time of the coincident peak. So it's -- it could be there at the time of peak, and should be reflected in the cost of service. The ability to curtail is the customer's decision to make, and then credits -- marginal cost-oriented credits are paid to the customer to be able to do that. But the Company is still looking to serve that load on a routine basis.

A. (James S. McLawhorn) Ms. Cress, if I could interject a little bit there. I think where the Public Staff has an issue with the removal of the interruptible load from a cost of service standpoint, we are opposed to that if it is going to allow certain customers to interrupt for just a few hours of the year and then avoid paying for plant that they are using and getting the benefit from over the vast majority of the other hours of the year. We believe that is totally inappropriate, to be able to use the plant for, you know, 85 to 90 percent of the year and avoid paying for it, particularly production plant.

As I will note, last week, Duke witness Immel, when he was being crossed on September 3rd by the Sierra Club, he stated that capacity has value in more hours than just the very peak hours of the year. That there is value in capacity or in production plant in all hours, and if customers are going to be allowed to avoid that while using that plant 85 percent of the rest of the year, that's simply not appropriate.

Q. You would agree, though, that the Company wouldn't -- the Company wouldn't agree to remove that load if it wasn't the right thing to do?

A. I would agree that there can be differences of opinion on that. Historically, we don't adjust loads in a cost of service study unless it is a known permanent change, such as a wholesale customer has left the utility system, or a major industrial plant has left the system, and we know that load will be back, then we might make that type of adjustment in a cost of service study. But we don't make ad hoc adjustments in a cost of service study.

Q. Okay. Mr. Floyd, in your first supplemental testimony and exhibits, you used a base rate increase of $126.7 million and an EDIT decrease of

$272.6 million; is that right?

A. (Jack L. Floyd) I believe that was the incorrect exhibits.

Q. Oh, okay. So the corrected exhibits show what?

A. (Witness peruses document.)

I believe the $126 million base revenue number is correct. The change, the correction that I made was to the EDIT credit. Instead of reading 272 and change, it should read $399,343,000.

Q. Okay. And in your second supplemental testimony and exhibits, you use a base rate increase of $290 million, which is obviously a $146 million approximate increase from the $126.7 million.

Can you explain this -- these different numbers?

A. You might -- you might get a better answer by asking Ms. Boswell. She's the accountant witness. My numbers of base revenue and EDIT credits derive from her exhibits. And that's one reason that we file -- the Public Staff typically wants to file, along with its accounting schedules, the impact the revenue assignment would have on the classes. But my numbers simply come from her exhibit.

Q. Okay. In your original testimony and exhibits, I believe pages 8 to 9 -- and I'll let you get there.
A. You said the original direct?
Q. That's correct.
A. Okay. Page 8?
Q. Page 8 and 9; yes, sir.
A. Okay.
Q. You state that, in a rate reduction case, no class should receive an increase in order to bring other classes to the 10 percent band. Your SCP exhibit seems to show residential and OPT customers getting increases in order to bring other customers within this, quote, band.
A. This is -- a decrease is when we look at overall revenue decrease. So if Ms. Boswell's exhibit were to show a negative base revenue number, not a positive number, then I would say that we don't want any class to see a decrease at the expense of trying to resolve other rate design issues that cause significant increases to other classes. That's the reason for that statement.
Q. Did you include that rate reduction language in your first and second supplemental testimony and

exhibits?

A. I don't believe so. The rate design -- excuse me, the rate design principles were looking at an increase in both situations.

Q. So that's the reason that the rate reduction language was left out of your second and first supplemental?

A. Yes. It was not material.

Q. Okay. In your supplemental testimony, you said you were using per-book studies and adjusting those, but you don't show, do you, the adjustments that you made or how you -- how you reached those adjustments or those numbers?

A. Yes. I have a somewhat convoluted spreadsheet that takes into account all of the Public Staff's adjustments, whether rate base expense or otherwise. And what I've tried to do is to look at the impact from, again, the base revenue change on the NC retail level. And then I look at what impacts that has to each class. The -- I cannot -- I do not have the capability of making individual changes to individual expenses within the cost of service.

What I try to do is look at the overall rate base change, the overall net income change, the expense change, and then determine the changes in the allocation factors across the board that would be impacted by our recommendations on those items. And I pass that along to what the Public Staff ends up proposing, in terms of a proposed revenue requirement, or proposed rate base, a proposed level of expense. And that's how I end up where I end up with the calculations. But in my exhibits, I have a very convoluted spreadsheet.

Q. But we just don't get the benefit of seeing that spreadsheet?

A. You can -- you can see it anytime you want.

Q. Can I come down there to the Dobbs Building?

A. Yes.

Q. Okay. So you say that you use per-book studies, but in your second supplemental testimony, it does not -- it does not say what type of studies you used; is that correct?

A. I used the same per-books level of allocation. And under each method, the single coincident -- summer coincident peak, winter, and the peak and average. The -- what I've learned over the years is that I look at the allocations of the rate base expense, net income across the cost of service, and they don't materially change between the per books; the present annualized, which is the 45-B cost of service; the proposed rates, which is the 45-C. They don't change materially over the three views, so I just stick with the per books. Again, this is a high-level analysis of applying the Public Staff's recommended revenue and requirement of rate base.

Q. Okay. And I think this is my last question. The Commission has, in the past, on a number of occasions considered lifeline rates, and each time has rejected implementing those rates; is that a fair assessment?

A. I'm not aware that the Commission has considered lifeline rates in the context of electric utility service. There is certainly precedent for it in telephone service, but I did not find, during my study, where that occurred in electric utility service.

Q. Mr. McLawhorn, would you add anything to that?

A. (James S. McLawhorn) I am not aware of the Commission's consideration of lifeline rates for electric service either, at least not during my tenure with the Public Staff.

Q. Okay. I think that's everything I have.

Thank you.

CHAIR MITCHELL: All right. At this point, we are going to take an afternoon break. We will go off the record. We will come back on at 10 after 3:00. 3:10.

(At this time, a recess was taken from 2:58 p.m. to 3:10 p.m.)

CHAIR MITCHELL: All right. Let's go back on the record. North Carolina Justice Center. Mr. Neal, do you have questions for the panel?

MR. NEAL: Chair Mitchell, this is David Neal, I have just a few.

CHAIR MITCHELL: All right.

MR. BOEHM: Chair Mitchell, this is Kurt Boehm with Harris Teeter. I think that -- I'm not sure that you've got my cross here. I think I was next on the list. I just want to make sure you have it.

MR. NEAL: That is correct. I'm happy to defer to Mr. Boehm.

CHAIR MITCHELL: All right. I am just seeing the updated information. Mr. Boehm, you may proceed.

MR. BOEHM: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. BOEHM:

Q. Good afternoon, Mr. Floyd.

A. (Jack L. Floyd) Good afternoon.

Q. And I think that all of my questions are directed towards you. And all of my questions will be about your second supplemental testimony that you filed earlier this week.

In your second supplemental testimony, when you prepared that, you obviously reviewed the settlement agreement signed by DEC and Harris Teeter which was filed with the Commission on May 28th; is that correct?

A. I did.

Q. And do you have that settlement agreement, the Harris Teeter settlement agreement, in front of you?

A. Stand by.

(Witness peruses document.)

I have the version of the one with the Commercial Group, and as I believe, they're pretty identical.

Q. I think that's probably the case. We could probably work with that, if you don't have our -- if you don't have the Harris Teeter one.

A. I do. I just made the one copy.

Q. Okay. Hopefully there's not a big inconsistency in the way that they're numbered. But I think you're correct that the content is generally the same.

Now, on page 9 of your second supplemental testimony, you were asked whether you agree with all the terms of the Harris Teeter, Commercial Group, and CIGFUR settlements, and you respond:

"No. The Public Staff does not agree with all the terms at this time. It is premature and counterproductive to begin redesigning rates and the terms of service under specific rate schedules without having the full understanding of the rationale for the change and the impact on other rate schedules and revenues."

Did I read that correctly?

A. Yes, sir.

Q. Now, when the Harris Teeter settlement -- and I understand you have a slightly -- perhaps slightly different settlement in front of you -- it contains really just two paragraphs, paragraphs 2 and 3, that address rate design; is that right?

A. It does say that. And I've got a copy of that, and they are both identical, both the Harris Teeter and the Commercial Group, in terms of the reference, I believe.

Q. Thank you. So there's paragraph 2, which essentially states that the parties agree that any grid improvement plan cost allocated to OPT-V customers shall be recovered via OPT-V of demand charges."

And that addresses rate design, correct?

A. It does.

Q. And then paragraph 3, which I think you discussed a little bit with Mr. Jenkins earlier, which essentially sets the off-peak energy charge at 3.022 cents per kWh, and then it makes corresponding adjustments to some of the other charges in OPT-VSS; is that correct?

A. It does.

Q. And then all the other paragraphs in the settlement are, you know, waiver of each other's witnesses, and things that don't really involve rate design; is that right?

A. Yes.

Q. Now, going back to the statement that you made on page 9 of your second supplemental testimony, you say that:

"The Public Staff does not agree with the Harris Teeter settlement and that it's premature to begin redesigning rates without having a full understanding of the rationale for the change and impact on other rate schedules and revenues."

Is that correct?

A. Yes. And I think I -- I think I've been fairly clear with my cautionary approach to anything rate -- changing rate design.

Q. Now, I just want to kind of focus in on this statement that, "without having a full understanding of the impact on other rate schedules and revenues."

Would you agree that the -- that the rate design changes agreed to by Harris Teeter and DEC, that they do not have impact on any rate -- any customers taking service on any other rate schedule, other than OPT-VSS?

A. I would -- I would agree with you literally that that's true. And let me explain what I mean. Is that you are only changing the small secondary off-peak energy rate consistent with, I think, with what Mr. Pirro said earlier was not an across-the-board type of change. But the issue that I have with anything changing in terms of rate design now is that I really -- I really don't have a good sense of what impacts that could have to the other rate elements within the OPT small secondary. And I also don't understand or have a full understanding of what that would do in terms of shifting revenue responsibility, cost causation from one class of OPT customer to another, or interclass between OPT and the other customer classes. And that's why I'm cautious.

You know, anything rate design, at this moment, is based on insufficient data. Insufficient analysis as indicated by the Company. Now, I know Mr. Pirro said something earlier this week about it being more aligned with cost causation, and I take him at his word. I don't think the Public Staff has any literal fundamental concern with the $0.03 off-peak energy rate. However, because I don't know of the other things that it could do to the revenue picture for OPT and the revenue picture with the other -- OPT versus the other classes, I'm -- I am suggesting and recommending that the Commission take a very cautious approach to this.

Q. Thank you. I appreciate that response. And just sort of just to follow up, going back to your statement on page 9. You say that you don't have a full understanding of the impact on other rate schedules, which you just addressed, and then the other part is revenues. Which I assume that you meant revenues -- how much revenue DEC collects from each customer; is that what you mean by revenues?

A. No. What I'm talking about is in terms of the what I call subclasses of the OPT. And there's, I believe, 10 subclasses. But how does -- how does it impact the return on rate base? That's how we measure cost causation. How does it intraclass OPT, and then interclass with the other non-OPT classes? I don't have a full picture of that, and because I don't have a full picture, I take a cautious approach.

Q. Sticking with the same statement on page 9, you also state that we don't have a full understanding of the rationale for the change; is that correct?

A. I did not until this week. Again, the oral testimony that was provided by Mr. Pirro shed some light on how that rate was established. I don't remember the exact timing of it, but I did not have that at the time that this testimony was filed.

Q. Did you review the direct testimony of Harris Teeter witness Mr. Beaver when you prepared your second supplemental testimony?

A. No.
Q. So your -- you did not review Mr. Beaver's testimony where it contains approximately 10 pages of questions and answers explaining that DEC's proposed rate for the OPT secondary under-recovers the demand-related charges while over-recovering the energy-related charges relative to the underlying cost for DEC's own cost of service study?
A. I reviewed it in the context of the direct testimony. I did not go back and try to review his testimony in terms of how that applied to the settlement terms we're talking about.
Q. Okay. So --
A. If you'll tell me which testimony or which page of his testimony you're speaking of, I'll pull it.
Q. Sure. So as I said, Mr. Beaver's testimony has about 10 pages on this issue and the rationale for his proposal to make a change like this, but I would direct you to page 12 of his testimony.
A. You said page 12?
Q. Yes.
A. Okay. I'm there.
Q. So do you see the table marked JDD-3 on page 12?

A. I do.
Q. And the off-peak energy charge in that table, which is the last column. And here Mr. Beaver, he compares the DEC proposed off-peak energy charge of about 3.2 cents to Kroger's proposed off-peak energy charge of about 2.9 cents; do you see that?
A. I see it, yes.
Q. And would you agree that the settlement that was agreed to by Harris Teeter and DEC falls right in the middle of these two bookends?
A. Yes, I would agree to that. But again, I don't really have a basis for how these rates were determined, and I don't -- I don't recall any analysis. I certainly didn't review any analysis in terms of the second supplemental.
Q. Thank you. You stated in your testimony, and I think we discussed this with -- earlier today, that staff would like to see the Commission order a comprehensive rate design and cost of service study; is that correct?
A. Yes, sir.
Q. Now, is there any reason why the Commission couldn't approve the Harris Teeter and DEC settlement and then also order a comprehensive rate design and

cost of service study? They're not mutually exclusive are they?

A. They're not mutually exclusive, nor are they mutually inclusive. And that's a kind of a funny way to say that. But what I'm -- what I'm trying to avoid with my recommendations with this comprehensive rate study is that I have learned, over the 13, 14 years of looking at these rate cases, that once something gets established, it is extremely difficult to break it apart. And that's -- that's certainly obvious in this case when you see the level of feedback that I've gotten on my recommendation of a study.

What I don't want to happen is, first of all, we're using stale data to decide rates and rate design that could serve future utilities service. And that may or may not be a good idea. I just simply cannot give you an answer to that question now. What I want to be able to do is to take the use of load research that's predicated on the advanced metering infrastructure, learn how different groups of customers, maybe individual customers at some point, learn how they're using energy and how they are imposing costs on the system, and whether it is an off-peak energy rate or whether it's something else.

I don't want to constrain the ability to study any of these going forward. And I believe I'm correct in saying that Mr. Pirro committed to looking at this rate and all the other rates, OPT and everything else in the study, itself. I think the Company agreed with my position for a comprehensive study to do that.

So again, I don't want to belabor the point, but anything we do, small or large, to rate design now is just -- is just putting an obstacle in the way of doing it on a more comprehensive basis.

Q. Thank you, Mr. Floyd. Getting back to paragraph 2 of the Harris Teeter stipulation, this is the paragraph that states that the signatories agree to any grid improvement plan costs allocated to OPT-V customers shall be recovered via OPT-V demand charges.

A. Yes.

Q. I wasn't clear from your second supplemental testimony. Do you -- do you oppose this paragraph?

A. At this point, I would say yes, I do oppose it, and I'll tell you why. It kind of follows along the same lines as what I just spoke of. We do not -- the Public Staff has never advocated that any particular rate element -- and that's what I call basic customer charges, demand charges, and energy charges, in whatever shape, matter or form they take. These are rate elements. I don't believe the Public Staff has ever advocated that a particular rate element recover particular types of costs that go along with that rate element. And I'll say a demand rate to recover demand costs. We've never advocated for that. Because the rate design has to work together in such that all the rate elements work cohesively to produce the revenues that the Company expects from customers on a particular schedule. That's why I have -- I have discussed the issue of fixed cost recovery, I've discussed the issue of demand, or customer, or energy-related costs.

We -- what this does, in my mind, is take a very literal understanding of cost of service, cost causation, and a literal approach to rate design. And I think we all need to be careful what we ask for in terms of literally assigning a specific cost to being recovered literally from a specific rate element. And that's, again, the cautious approach that I'm asking to take.

Q. Would you agree that grid improvement costs are largely or maybe even entirely demand related or customer related?

A. They -- they are distribution and transmission system related. There are elements of demand-related and customer-related classifications of costs for both.

Q. But they're not energy related?

A. That -- there's some debate about that. They could be. You know, with the grid improvement, as I understand what's going on, is that it's not entirely driven by demand. Some of what's going on could be construed to be energy related. We don't typically allocate costs for distribution and transmission on energy, but because of the plans for grid improvement, I think that needs to be discussed.

And the Public Staff witness McLawhorn, his testimony -- I believe it's him. It may have been Mr. Thomas who talked about the benefits-oriented allocation process that needs to be looked at in terms of grid improvement. I don't know what that would have, as far as impact on OPT demand charges or anything else.

Q. Thank you, Mr. Floyd, those are all the questions I have.

CHAIR MITCHELL: All right. Next up, Mr. Neal, Justice Center.

CROSS EXAMINATION BY MR. NEAL:

Q. Good afternoon. Good afternoon, Jack Floyd and Mr. McLawhorn. I think I'm going to start with you, Mr. McLawhorn. First, just a quick question. Earlier on cross this afternoon, I believe I heard you say -- and this is, I think, nearly a quote, nobody has recommended that a change be made to cost allocation methodology in this case.

Did I mishear you, or is that what you said earlier today?

A. (James S. McLawhorn) I did say that. I was speaking in terms of both the recommendation for a study to look at different cost allocation methodologies as well as the grid improvement plan, how those costs are potentially allocated. Now, I probably should clarify, certainly in my direct -- original direct testimony, the Public Staff recommended use of the SWPA cost allocation methodology, whereas Duke had recommended SCP. But in the second stipulation that we signed with Duke, we agreed to stipulate for this case only to use the SCP. And Duke agreed to participate with the Public Staff and other interested parties in looking at various other cost-allocation procedures. So what was what I meant in my answer, that no one is recommending to change cost allocation in this case at this time.

Q. And, Mr. McLawhorn, have you read the testimony of Jonathan Wallach that's sponsored by my clients in this case?

A. I have, but I have not read it recently. I can pull that up if you want to ask me a particular question about it.

Q. I'll just ask generally, I don't think you need to pull it up.

Do you recall that he recommended that the Company -- that the Commission ordered the Company to stop using the minimum system method in its cost allocation study?

A. I will accept that, subject to check.

Q. And do you recall that he also recommended that the Commission reject the Company's use of the non-coincident peak demand allocator to allocate distribution costs in its cost of service study?

A. Yes, I do recall that.

Q. And, let's see, you also had some discussion about the minimum system method report from the Public Staff, which I believe has been previously admitted as DEC Pirro/Hager Redirect Exhibit 1.

A. Yes.
Q. Just to clarify one thing I think I heard you say.
Within the minimum system method report, is it the Public Staff's position that the minimum system method could be used for setting the maximum allowable basic facilities charge, and then the basic customer method would be the methodology for setting the minimum? Is that the Public Staff's position?
A. Yes. I believe both Mr. Floyd and I both agreed with that.
Q. Okay. I think I heard you say earlier today that the zero intercept would be the minimum. I just wanted to clarify that. But you meant the basic customer method?
A. Yes. I should have gone back and checked, but yes, that's correct.
Q. Thank you.
A. You are correct.
Q. And there was also some discussion about the fair way to allocate costs for those customers who accept service from the transmission lines.
Were you able to hear the testimony of Duke witness Ms. Hager last week?

A. Yes.
Q. Do you recall a question I had for her about whether or not the Company utilizes a minimum transmission system analysis in order to create a hypothetical transmission minimum-size grid that would then make a part of the transmission system customer allocated as a customer charge?
A. Yes, I remember that.
Q. And it's your recollection that the Company does not do that; is that right?
A. I do not believe they do, no.
Q. Okay. All right. Mr. Floyd, if I could turn your attention to the -- that same Public Staff minimum system method report, the DEC Hager/Pirro Redirect Exhibit 1. If you turn to page 16 for me.
A. (Jack L. Floyd) Okay.
Q. If you look at that, at the bottom of the page, I believe you were asked a question about this last sentence on the page, the "after our review, the Public Staff believes"; do you see that sentence?
A. I do.
Q. And that is a footnote 25. Could you read footnote 25?
A. "The position of the Public Staff in any

future rate case is dependent on the application filed in that case. The Public Staff reserves the right to develop a new or different position concerning the MSM in any future proceeding before the Commission."

Q. Thank you.

MR. NEAL: I have no further questions, Chair Mitchell.

CHAIR MITCHELL: All right, Mr. Neal. Next up, NCSEA.

MR. LEDFORD: Thank you, Chair Mitchell. Peter Ledford. NCSEA does not have any questions for this panel.

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

All right. Mr. Culley with Vote Solar?

MS. CULLEY: Thank you, Chair Mitchell, no questions.

CHAIR MITCHELL: All right. And last, my notes indicate that Duke has cross for the panel?

MS. JAGANNATHAN: Yes, Chair Mitchell. Molly Jagannathan here on behalf of Duke.

CROSS EXAMINATION BY MS. JAGANNATHAN:

Q. Mr. McLawhorn, if I could just start with you. I believe you cleared this up a bit with Mr. Neal, but I just want to clarify -- well, first of all, just to orient us, when we talk about using the minimum system method, we're talking about a classification of distribution costs; isn't that right?

A. (James S. McLawhorn) Yes.

Q. And the Public Staff is not opposed to the Company's use of minimum system for allocating distribution costs in this case, right?

A. That's correct.

Q. Okay. Thank you. And when we talk about summer coincident peak, and summer/winter peak and average, and winter coincident peak, we're talking allocating production and transmission demand-related costs; isn't that right?

A. Yes. Those methodologies don't impact the allocation of other types of plant, just production and transmission.

Q. Okay. Thank you. And is it your understanding that the Company is required to file cost of service studies using winter coincident peak, summer coincident peak, and summer/winter peak and average?

A. Yes, that's correct.

Q. And you indicated earlier that, in the second partial settlement with the Company, the Public Staff agreed, for purposes of this rate case, to accept the Company's proposal to allocate cost of service based on summer coincident peak; isn't that right?

A. Yes.

Q. Okay. Now, turning to you, Mr. Floyd.

With your second supplemental testimony, you filed schedules using winter coincident peak, summer coincident peak, and summer/winter peak and average; isn't that right?

A. (Jack L. Floyd) I did.

Q. Okay. And that was just because the Company initially filed those three methodologies, but not because you're advocating something other than summer coincident peak in this case?

A. That's part of the answer. It's also somewhat of a standard practice for the Public Staff to represent to the Commission what the impact of revenue assignment would be under the multiple methodologies that are part of the case.

Q. Okay. Thank you. And you would agree with me that, between the settlement with the Public Staff and the settlement with CIGFUR, the Company has agreed to perform and consider no less than seven different cost of service studies prior to the next general rate case; isn't that right?

A. We'll be busy, yes.

Q. And you would agree with me that the Public Staff's and Company's agreement to use summer coincident peak in this rate case has no impact on the ability for the Public Staff, the Company, and other parties to study new and different costs of service technologies; is that right?

A. That is my understanding, and I would object if we did limit it to just one.

Q. I figured you might. And then I just have a question from your second supplemental testimony.

You state that you oppose the provision of the settlement with CIGFUR in which the Company agreed to remove curtailable load from allocation factors in its next rate case; isn't that right?

A. Yes, I did.

Q. And I think in that testimony you indicate that you supported a similar adjustment for Dominion previously, but you explain that your different views in that case are justified because of the different allocation methodologies that Dominion uses versus what the Company currently uses; is that right?

A. That is part of it, but there's a factual difference between this case and the Sub 479 -- E-22, Sub 479 Dominion case. Dominion actually used part of their interruptible demand response resources during the winter peak. And they -- if we didn't make the adjustment in that case, there would have been a slight distortion in the peak component of the summer/winter peak and average calculation. That did not happen in the Duke case. Duke did not -- Duke Carolinas did not use their curtailable load or demand-side management resources at either the winter or the summer peak in the test year for this case.

Q. Okay. But is it fair to say that you don't know whether they will use those resources in the test year in a future rate case, right?

A. Absolutely. I mean, we can have another polar vortex or something in the summer.

A. (James S. McLawhorn) Ms. Jagannathan, if I can interject. I agree with everything that Mr. Floyd said, but even if the Company did interrupt the load in a future test year at one of the peaks, as long as the Company relies on a cost of service methodology that only focuses on a single or two -- if it were to go to a two-coincident peak and not contain an average component, the Public Staff would still oppose the adjustment because it would allow certain customers -- as I said earlier, I believe, in cross from Ms. Cress, that it would allow certain customers to avoid paying for production and possibly transmission plant that they are using the vast majority of the other hours of the year. That's not the case with the Dominion cost-allocation methodology.

Q. Okay. Thank you. And so would it be fair to say that it would depend on what cost-allocation methodology the Company proposes in its next rate case as to what the Public Staff's position would be on this issue?

A. Cost-allocation methodology and whether the Company actually utilized the interruptible and demand-side management resources. It would be a combination of those two factors.

A. (Jack L. Floyd) I agree.

Q. Okay. Thank you both. And, Mr. Floyd, I just have one more question for you. Just circling back to the minimum system method.

I think you indicated that the Public Staff kind of said that it was reasonable to use minimum system method to kind of establish the maximum bounds for a fixed or a basic facilities charge, right?

A. That's correct.

Q. And even though the Company uses the minimum system method, it doesn't use that maximum amount when setting its fixed or basic facilities charge, right?

A. That is true. It has not -- it has been my experience in the half a dozen cases I've looked at that the Company has never used the maximum that was determined through the minimum system approach in their cost of service.

Q. Okay. Thank you. And it's your understanding, right, that the Company has not proposed any increase to the basic facilities charge in this case, right?

A. That's correct, right.

Q. Okay. Thank you. I don't have any more questions.

CHAIR MITCHELL: All right. Redirect for the panel?

MS. EDMONDSON: No redirect.

CHAIR MITCHELL: All right. Questions by Commissioners, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I have no

questions.

CHAIR MITCHELL: All right.

Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes, thank you. I have just a couple.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. McLawhorn, Ms. Hager says that, when the Public Staff advocates for the summer/winter peak and average method, it fails to follow its argument to its logical conclusions. And it's interesting to me that a couple of the witnesses for some of the intervenors used almost identical language. They say almost identically the same thing word for word.

Would you respond to that criticism of the Public Staff's position? Do you agree with it? And if not, why not?

A. (James S. McLawhorn) I do not agree with it. I'm sure you're not surprised to hear that answer, and I will be happy to respond to it. This is not a new argument by certain parties. I believe the argument has fallacies to it. I -- with all due respect to

Ms. Hager -- and I have tremendous respect for her, I have known her for a long time -- I believe this argument is somewhat of a straw man argument.

The way the system is built -- and I've discussed this at length in my testimony; it's been discussed in many other cases -- is based on a consideration of both peak demand and energy requirements of the customers it's going to serve. That is what the IRP process does when it is determining the appropriate mix of production plant resources to build. That's how you get the most efficient and most cost-effective system for all of the Company's customers, not just some of the Company's customers.

Once this system is built, of course, it has to be operated. And if you -- I have referred to -- I have -- if I can refer you to my prefiled testimony, there is a chart on page 25 that is a load duration curve. And it represents both demands and the percent of hours when the demand is there from the zero point in time to 8,760 hours, although it represents it in percentages. This load duration curve perfectly demonstrates what I just described from a planning standpoint.

It clearly shows that some plant is there to serve peak load and some plant is there to serve a base load that's there in all hours, and in between there's plant that serves a combination of peak and energy. Those plants are dispatched on a least-cost basis. That dispatch produces the lowest cost overall fuel cost.

The reason I said that I believe Ms. Hager's argument is somewhat of a straw man argument, she seems to imply, and other intervenors seem to imply, that if you use the summer/winter peak and average methodology, then you must allocate the production plant to individual customers, meaning that high load factor customers receive all of their energy in all hours from the lowest fuel cost plants. That is not an appropriate way to look at it.

The fuel occurs on an hourly basis, not at a horizontal production plant type of strip. If we didn't look at it that way, then we wouldn't have the lowest overall cost for fuel. So I do not agree with that argument. I believe that that is not the correct way to look at it, and I don't know if that answers your question but that's my explanation.

Q. I think the record is pretty clear from your answer. Thank you.

A. All right. Thank you.

Q. Mr. Floyd, a question -- I'll start it with you, Mr. Floyd, but if Mr. McLawhorn wants to jump in, that's fine too. I have listened to Mr. Pirro and Mr. Huber, and to you last week, and now to both you and Mr. McLawhorn today, and I'm still struggling a little bit to understand the scope of what will be looked at in the comprehensive study. And I want to start the question with you, because I think in response to a question from Mr. Jenkins earlier, you said that cost of service and rate design are -- I wrote it down, inextricably linked.

And so what I'm trying to get clear on is how far into cost of service issues are we going to be going in this comprehensive rate design study? I don't have a real good sense right now of the scope to which that study is going to go into cost of service issues. Can the two of you talk to me about that and give me greater clarity?

A. (Jack L. Floyd) You can't do one without the other. That's the two-second answer. You cannot do one without the other. And I would even argue, you could get two people in a room and come up with a dozen different ways of which one comes first. And I think Mr. Jenkins hit on my frustrations over the years of dealing with rate cases and rate issues -- rate design issues pretty well.

You change the rate design. You make customers more aware of what they're doing in terms of how they use the system, you will change the cost of service, because I guarantee you the load curve is going to change. That's one approach.

The other approach is just the reverse. If you do something in the cost of service, look at a particular methodology, and you stick to that methodology from the first part of it, and you don't consider the other ones, and the impacts of how demand, energy, and customer-related costs can impact one another, then you will inform your rate design a certain way. You're going to get a certain response.

There's a reason that I use the word "comprehensive." I call this modern era of rate cases since 2006, '07. We are in a place kind of like we were in the late '60s, early '70s when the utilities were building generation -- big-dollar generation facilities, and they were trying to go out and push an increased load, because they needed it for these investments. But we're talking billions of dollars of costs today, in terms of grid improvement, what I call the greening of energy, and then coal ash. All of these things are weighing on customers. The low-, medium-, and high-income customers.

And I just -- I find it tough to accept utility service based on old data and being told that I've got to do it the way I've been doing it for the last 50 years, because I don't believe the next 50 years when I'm not here is going to look a lot like it has looked in the last 50 years. And we have to be careful to not impact the most vulnerable, vulnerable customers who have to use the system by doing all of this study and coming up with something that looks a lot different than it does today.

And that's why I'm cautious. I'm cautious about using old data. I'm an engineer. I like to learn how things work. Well, I've got to learn -- I've got to start learning by looking at data, and then seeing what is the data telling me. And that's one reason that the staff has supported AMI, because it gives us the glimpse that we've never had. We could have had it in the last 50 years, but it costs a fortune to do. It's not as costly today on a unit basis going forward.

We've got AMI data. The Company has started looking at how that data is impacting load shakes. Load shakes drive cost of service. Cost of service is going to drive rate design. But those load shakes change their character based on the rates people pay.

And here's something else to keep in mind. Mr. Harris reminded me of this the other day. Is that most customers are pretty satisfied with the electric utility service they have. They don't want a whole lot of manipulation. They don't want a whole lot of sophistication. They want to keep things fairly simple, and that's something we, as regulators and at the Company, need to keep in mind.

There are people out there that do want different types of electric utility services, whether it's electric vehicles, or solar panels, or things like that, but there are healthy crop of customers who just want to be left alone, and we need to figure out a way to do both. And that's why a comprehensive study starting from scratch is important.

Q. Well, thank you for your answer. I think you know my view about doing things the way it was being done just because that's the way they've always been

done. I think you know my views on that subject.
A. I agree.
Q. But I want -- I want you to take me to the next step on this. If we get -- because I'm really looking for assistance on how we go forward here and not take another 50 years to get through this comprehensive study.
So if everything is up for grabs from, as you say, from scratch, how are we going to avoid getting into that kind of swamp, where it takes us another 50 years, and we still may not have a new road map? What kind of guardrails, what kind of parameters does the Public Staff recommend that the Commission establish in order to make sure this is not just a free-for-all?
A. It's -- I'm not sure I have a good answer for that question yet. But I will try to answer it this way.
Q. I don't mean to interrupt you, because I'm not looking really today to get your top-of-the-head answer. I'm putting the question out there, because I think if the Commission -- if the Commission majority, at the end of hearing all of the evidence, decides that the suggestion the Company has made and that the Public Staff has made -- and I have already heard a lot of

opposition to the principle -- is a good one of a comprehensive study, I think we're probably going to need some assistance on developing the parameters, I call them guardrails, the sort of directions the study needs to focus on and the prioritization of topics. Otherwise, I'm afraid we're really wasting everyone's time if we don't do that.

So I don't expect you to answer today, but I want the question out there, because I think the Commission may need to come back to the parties and ask for some answers on that.

A. Let me give a couple of quick responses to that. Is that my testimony outlines some very basic principles, and there's a reason you don't see a lot of meat on those bones, is because I think a lot of folks would have a lot of different ways to interpret those half a dozen or so principles. But rate design -- I don't think the Commission should take this as a static endeavor. This is something that future Commissions are going to have to constantly deal with in every rate case. Because if we think about it, just in the last 13 -- or 10 to 13 years we've been looking at rate cases, how service has changed in terms of in use of electricity, the efficiency of use, the proliferation of distributed generation, storage is staring us in the face going forward.

These are -- these are formidable things that are impacting utility service. But I don't think the Commission -- if you're thinking you have to put a -- as we say in church, a stake in the ground behind the barn, and that's it, I don't think that's what we're suggesting. We need to start with a framework of where do we want rates to go in the future? What do we want what rates to accomplish? There may be some existing rate schedules that are perfectly fine. I'm not willing to throw everything out just because I want a new study. There may be some justification for keeping what we have.

But my point with a comprehensive study is that we have adjusted rates on an across-the-board percentage increase basis for so long that I think we've lost the integrity of the actual rate structure, itself. And that's why we need the study. It cannot happen overnight; it needs to involve a bunch of stakeholders; and there's going to be a lot of argument. And there's certainly the high potential for disagreement. I'm sure the parties, if they disagree with something that Duke comes up with, is going to argue about it.

But at the same time, it took us two years, roughly, to get a consolidated OPT class. I use that, it's a great example. And the parties literally had to be forced to the table by the Commission. And we ended up sitting down having conversations about it, and we developed a load-based, time-of-use, nonresidential schedule. And I'm using that. I'm expecting the parties to do the same thing with everything else, rate design. Thank you.

A. (James S. McLawhorn) And, Commissioner Clodfelter, if I could just follow on to that. It very well may be that, after this study, we have a rate design, and we say, "Eureka, this is the greatest thing. Why didn't we think of this 25 years ago? This is absolutely the way we need to charge ahead." But when we look at implementing it, as I said earlier on cross, there may be some issues where, by moving to that rate design, it causes some significant cost shifts or cost -- and in this case I'm talking about bill cost, the bill costs to the customer, that we can't go all the way in one step. It would be unreasonable to the customer to do that.

We may have to use gradualism to implement the design and get there. I'm not predetermining that it will, I'm just saying that is a very distinct possibility. And we all need to keep that in mind and not be afraid to take this step because we're so concerned that we won't like the outcome that we refuse to even look at it.

Q. Thank you, gentlemen. I could spend a lot of time, and we don't have a lot more time this afternoon, asking you a lot of detailed questions about some of the things that the various intervenors asked you about. It wouldn't be very productive. I'm not going to do it. Thank you for your time.

CHAIR MITCHELL: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: Thank you, gentlemen, for your testimony today. I'm going to pass on asking you any questions.

CHAIR MITCHELL: Commissioner Hughes?

EXAMINATION BY COMMISSIONER HUGHES:

Q. This will probably make Commissioner Clodfelter even more concerned, but -- about as far as the timeliness of this study. But when I read some of the descriptions of the affordability stakeholder process, I have a hard time seeing where the relationship to that is in this comprehensive rate study. And it seems like they have so much overlap. Are they parallel? Are they together? And does that just make an even longer, more complicated study?

If someone could just comment briefly on that. I see the testimony, particularly of Mr. De May, has a lot of rate design in what he's calling affordability issues. So if you could just quickly comment on that, quickly.

A. (Jack L. Floyd) Yeah. Mr. Hughes, I mentioned a little bit the other day in the consolidated hearing that I don't think you can separate the two issues. At the end of the day, what we need to try to start with is developing rates based on cost causation. And let's look at a purely cost-based rate design suite of rates, and then the Commission can start to evaluate the different policies of what affordability conjures up, in terms of what types of discounts or what types of programs we want to provide, and then how to pay for it, and let that fit into the rate design study.

I don't see them as separate issues. I see them, that they have to almost be done together. But at the end of the day, I think if we are going to ask the customers of Duke Energy, Duke Progress, Duke Carolinas to help fund things that are not so easily fundable in terms of utility service -- we're shifting costs from one group of customers to another -- we need to be as transparent as possible in what that cost shift might be.

And that's one reason why I want to try to take as close to a cost-causation approach to this rate design, and then let's look at the different policies that the Commission and future Commissions might adopt, and how those policies fit into and affect the rates that customers are going to be asked to pay.

Q. Okay. Thank you. No further questions.

CHAIR MITCHELL: All right.

Commissioner McKissick?

COMMISSIONER McKISSICK: Just one or two quick questions.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. And I'd certainly like to thank the panel for the testimony you've provided today, Mr. Floyd, for the testimony you provided previously. I know I asked a number of questions relating to your thoughts concerning these issues, and I certainly understand the inextricable linkages between rate design and cost of service and trying to come up with the right policies that kind of wed them along with the cost-causation theory and the practicalities of implementing it systematically.

I guess the thing I'm trying to understand, assuming we go down this path, I always like to think that there are other places that have visited this same territory previously. Other jurisdictions that have at least attempted to modernize this all. Because, obviously, it needs modernization, and -- but can you all identify places or jurisdictions that have either attempted it successfully or unsuccessfully, or where they went so far but didn't get to the next two or three levels? Is there anything you can share?

A. (Jack L. Floyd) On a comprehensive basis, I'm not aware of anything, but there are certainly jurisdictions that have addressed issues of low-income customers.

Q. Sure.

A. And I -- one of my exhibits in my direct testimony has a list of those. Mr. Howat, the Justice Center witness, provided some good examples of what that would look like across the country. There are other -- I think what you're going to find is a lot of policy -- individual policy-driven rate design questions that get answered. And I go and think, you know, California is always a good example to look at in terms of things to promote certain policies, they want to use rate design to do that. I mean, they have a -- they have a time-of-use -- a somewhat mandatory time-of-use structure there for customers. I'm not sure, you know, we need to go there in North Carolina, but that's something that's a policy-driven type of rate design.

Short of getting something from the General Assembly that says to the Commission, "Thou shalt do X," it's tough to answer your question. What I envision -- and this may, you know, my limited capacity to think forward. What I envision is a comprehensive study involving all the parties, and put everything on the table. But at the end of the day, it is Duke Energy who has the responsibility to provide utility service. And we agree with the rates that provide them sufficient revenues to earn a return.

And how they do that, we hold them accountable in it lots of ways, and we chastise them when we see that accountability strained. But at the same time, we also ask customers to pay their bills and to pay fair and equitable, just and reasonable rates, and however you want to describe them. And my point all along has been that the structure that we have -- if you hear anything out of my testimony, the structure that we have today is based on traditional cost of service rate design and ultimately utility service.

We are not facing that traditional paradigm going forward. We need to start looking at cost of service, cost of causation in terms of what we expect to happen with the utility system going forward, whether that's electric vehicles, whether that's microgrids, whether that's storage, distributed generation, all of those have cost implications. And at the end of the day, like I said earlier to Mr. Clodfelter, is that the most vulnerable customers are the ones that we need to watch out for the most.

And, you know, the Public Staff is going to be very involved in this effort, should the Commission order it, and we're going to have a lot of debate about it with the other parties and Duke Energy. It is a big issue for the Public Staff going forward. And we hope the Commission gives some guidance, but also gives the parties some latitude to have an open debate. Thank you.

Q. Thank you. And I guess the thing I would simply follow up with is this. I mean, just thinking out loud, would the Commission for even a stakeholder process generate input, at least be well-advised perhaps to articulate goals, aspirational goals as to what types of policy should be thoughtfully reflected upon and considered as things that we want to see embodied in a new rate design structure. You know, and, of course, try to set up some timeline. And when I say that, aspirational dates and targets where certain goals, objectives might be obtained, feedback is provided through stakeholders with some type of timeline for eventually getting to where we need to be in advance of the next rate case.

You know, and I'm just trying to think, I don't want to see something that establishes -- first, is an exercise in futility; secondly, which potentially breaks down without any significant change of past policies in terms of what we're trying to modernize; and then thirdly, where we don't get there quite quick enough and we get caught in the quicksand along the way. So, I mean, what are your thoughts on that?

A. Well, I definitely think you need to establish a time frame for this work. That's for sure.

The parties, I mean, we could -- we could talk ad nauseam about these issues, but it -- but in order, I think -- if you're going -- in my mind, if you're going to expect and impose a time frame, I think the Commission needs to give some goals, some objectives that we expect you to undertake X, Y, and Z and to show us what you accomplish by a certain period of time.

Again, this is -- this is -- this is my perspective on behalf of the Public Staff what we expect this study to look like. But I'm also cognizant of the fact that there may be disagreement at the end of the day. And we need to be prepared for it.

But maybe I can give you an example of something. You know, I've been in this -- in the electric division, or energy division now for little over 15 years. I started out in the water division, and before that I worked for DEQ's predecessor Environmental Management. I have done rate design in water and electric, and there's a lot of similarity.

But we need to -- we just -- I'm trying to be conscious of it. Duke and Dominion come to the Public Staff routinely when they have a new rate proposal. That's happened in the last -- multiple times in the last 13, 14 years in my experience. We discuss those proposals. Some of them are totally new services and rates that go along with them. But we look at those, we analyze it, we issue discovery on it, and we try to reach consensus amongst ourselves and the utilities. And then they file these things. We get them on your agenda and recommend approval.

That type of process is kind of a miniature version of what I'm talking about. And I believe that that may provide a good example going forward for a bigger study. I'm starting to repeat myself, I know, but I want to make clear that this is a wide-open study, and the Commission, in addition to a time frame, I think for purposes -- I think all the parties really are looking to you to give us kind of some marching orders. Thank you.

A. (James S. McLawhorn) Commissioner McKissick, if I could, I would agree pretty much with everything Mr. Floyd said. And I do think it would be beneficial for the Commission to give guidance, both in terms of what specific policies you would like to see incorporated in this rate design study as well as put some timeline parameters around it. You know, I'm sure the Commission is well aware, the parties will come back and ask for additional time if we need it, but I believe it's better to do that than for the Commission to just say just go out and do this study and let us know when you're finished with it. We need parameters to keep everybody focused. So I certainly would encourage the Commission to do that as well. So I agree with -- I agree with what Mr. Floyd said.

Q. Thank you both for your input and perspective. I certainly hope that the Commission, in its deliberations, will give serious thought and reflection to the testimony the two of you and many others have provided during the course of this hearing, and that there will be an opportunity to provide that guidance, that structure, those timelines, those policies. It's inevitable that there will be disagreements along the way. There may be unintended outcomes that might perhaps result. Things may not work out necessarily as one might anticipate theoretically as part of the exercise, but you won't know it until you try to collaborate and come up with something that will work.

And I am optimistic that, you know, this will be in the near term, and that perhaps North Carolina can provide some national guidance in terms of what can be done in other jurisdictions as a model for reevaluating the way this works in a new environment and to modernize it the same way they're modernizing the grid, the same way they're modernizing the way you generate electricity, the same way you're looking at distributing energy resources and how they're all tying together, and the way people can use and consume electricity with the new meters that are available, the knowledge exchange and transfer of information through enhanced technology. There's tremendous potential, and I hope that potential will be realized.

COMMISSIONER McKISSICK: Thank you, Madam Chair. I have no further questions.

CHAIR MITCHELL: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: Yes. Actually, I have a follow-up question.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. With respect to the timeline, what would the Public Staff recommend? When should the stakeholder process end before the next rate case begins?

A. (Jack L. Floyd) My testimony shed a little bit of light on that. It's -- I think Duke needs to try to accomplish this before its next rate case, but certainly not limited to waiting for the next rate case.

A. (James S. McLawhorn) I would agree that has certainly been our goal, Commissioner Duffley. Of course, we don't know when the next rate case will be filed, and this case -- when we have made our original recommendation, we had all thought these cases would have been over long before now. So I certainly still hope and believe we can get this done before the next rate case. But, you know, if the next rate case occurs in six months, then that might not be possible, but we'll just have to see.

Q. Right. But let's assume that there's three years between these rate cases. We can all dream, right? So -- but would you want the stakeholder process to end six months before the actual hearing, or six months before the filing of the next rate case if we had time?

A. Well, certainly, Duke would need time to incorporate any of the recommendations into their filing. So I don't know if six months is the ideal time, but it would need to be some period of time prior to the filing of the case that they were going to incorporate it in. So that's -- I would -- I guess I would like -- would want to hear feedback from Duke on that. They have to put the case together, so.

Q. Okay. Thank you.

A. They definitely would need some time.

A. (Jack L. Floyd) And I would add, Commissioner Duffley, I actually don't see this rate stakeholder process ending. I think it's going to be an ongoing thing. I think it was either Commissioner Clodfelter or one of the intervening attorneys that -- you know, this is an ongoing process, and as -- future Commissions, I think, are going to have to deal with how utility service is changing. And policies may change and those kinds of things. So hopefully if we can get a good stakeholder process going in terms of rate designer and cost of service, we can -- that can endure well beyond the next rate case.

Q. Okay. Thank you both.

CHAIR MITCHELL: Anything further, Commissioner Duffley?

(No response.)

CHAIR MITCHELL: All right. Questions on Commissioners' questions?

(No response.)

CHAIR MITCHELL: Any questions from the Public Staff on Commissioners' questions?

MS. EDMONDSON: No questions.

CHAIR MITCHELL: All right. Mr. McLawhorn, Mr. Floyd, thank you for your testimony this afternoon. I'll entertain motions.

MS. EDMONDSON: Yes. Chair, I move that McLawhorn Direct Exhibits 1 and 2 that have been marked for identification as McLawhorn DEC Direct Exhibits 1 and 2 be entered and copied into the record in the DEC rate case dockets. And I move that Floyd Direct Exhibits 1 through 4, Floyd Corrected First Supplemental Exhibits 1 through 4, and Floyd Second Supplemental Exhibits 1 through 4 that have been marked for identification as Floyd DEC Direct Exhibits 1 through 4, Floyd DEC Corrected First Supplemental Exhibits 1 through 4, and Floyd DEC Second Supplemental Exhibits 1 through 4 be entered and copied into the record in the DEC rate case dockets.

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

MS. EDMONDSON: Thank you.

(McLawhorn DEC Direct Exhibits 1 and 2, Floyd DEC Direct Exhibits 1 through 4, MS. EDMONDSON: The panel is available for cross.

COMMISSIONER CLODFELTER: Thank you. According to my notes, Ms. Cress, you would be up first for cross examination.

MS. CRESS: Thank you, Commissioner Clodfelter. The time that CIGFUR had reserved for this panel was estimated prior to the agreement pursuant to the joint stipulation of live testimony and exhibits of certain rate design and cost allocation witnesses, and now that that testimony has been entered into this record, CIGFUR does not wish to cross this panel at this time.

However, we would reserve the opportunity to ask questions on Commission questions to the extent that there are any.

COMMISSIONER CLODFELTER: Understood. And you, of course, have that right.

So with that, Mr. Jenkins, move to you.

MR. JENKINS: Thank you, Mr. Commissioner.

CROSS EXAMINATION BY MR. JENKINS:

Q. Good morning, gentlemen. Alan Jenkins for the Commercial Group.

A. (James S. McLawhorn) Good morning.
A. (Jack L. Floyd) Good morning.
Q. Mr. Floyd, let's look first at your second supplemental testimony. If you could turn to your Exhibit 1. And let's start at page 1.
A. Okay.
Q. Based on the SCP methodology, the medium general service class provides a 7.21 percent rate of return that's higher than the average NC retail rate of return of 6.93 percent; do you see that?
A. Yes, sir.
Q. And in other words, under the SCP methodology, MGS ratepayers pay more than DEP's cost to serve that class, right?
A. They pay slightly above that, but keep in mind that it is still within that 10 percent band. And anything that falls within that 10 percent band, plus or minus, we consider to be appropriate.
Q. Okay. Let's go to the next page, page 2.
A. Same exhibit?
Q. Yes, sir. And there you're -- you show the SWPA results. And under that methodology, the medium general service class provides a 7.82 percent rate of return that also is higher than the average NC retail

return, right?

A. It is. And it is slightly outside of that plus or minus 10 percent band.

Q. Thank you. Now let's look to the final page of the exhibit, page 3.

Under the WCP methodology, which I believe is the winter coincident peak, correct?

A. That's correct.

Q. Under the WCP methodology, the medium general service class return of 11.96 percent far exceeds the average NC retail return of 6.93 percent, correct?

A. It does, yes.

Q. And in your direct testimony, I believe you stated that DEP is now a winter peaking utility, right?

A. That's my understanding; yes, sir.

Q. And in any event, MGS rates are above cost under each cost of service methodology, correct?

A. They are.

Q. Okay. Thank you. Let's move to another topic and try and close a gap in the record.

Mr. Floyd, your testimony is now in the record from the DEC case that you were procedurally but not substantively opposed to the OPT-VSS rate changes from the Commercial Group DEC settlement.

So coming now to DEP case, do you take a similar position with respect to the SGS-TOU rate design changes proposed in the DEP Commercial Group settlement?

A. I do. As I think I have stated a number of times, I want to approach this exercise of a comprehensive rate study cautiously. And the conditions of settlement that, in my opinion, can drain the ability to develop a comprehensive study, I think we should take a cautious approach to.

Now, I will say this. As these days have progressed and the testimony delivered before the Commission in these hearings, taking the Commercial Group and the Harris Teeter settlements in terms of the SGS-TOU for Progress, the Public Staff is optimistic that, based on the Company's testimony, that none of these conditions are going to constrain a future rate study.

The Public Staff is receptive to that testimony and would be willing to, at some point, concede a little bit on the cautiousness of my earlier stance. I think it was Mr. Pirro that said, you know, that the study, they perceive this as a blank slate. And that's acceptable to the Public Staff. That really is what we were hoping to get out of such a comprehensive study.

In terms of the particulars of the settlements in terms of the on- and off-peak rates, I think it was Mr. Pirro who also testified that the values assigned to those rates would be more cost-based in nature than simply making an across-the-board percentage change as a result of the case. And the Public Staff supports that. So my cautiousness is a little more tempered in this case.

Q. It sounds like the Jenkins family motto, which I understand is proceed but cautiously. So you might have some Jenkins blood in you.

A. Okay.

Q. And it was consistent with that cautious approach, and yet allowing some rate design changes, you would agree -- and we can walk through each of these, but I think -- let's see if we can just knock them out with one or two questions.

Do you agree that you've supported in your testimony certain rate design changes in this case?

A. Unique to Progress, yes, I have.

Q. Okay. And you agree also that, in the DEP staff settlement, the second settlement, that staff and

DEP agreed to certain fuel cost factors?

A. I do recall that. I am not a fuel witness, per se, but I do recall those conditions in the settlement.

Q. And finally, you'll agree that that settlement with staff and DEP agreed to make -- to move class rates of return closer toward parity, correct?

A. Yes, sir.

Q. And all of those changes would be made before a comprehensive rate design, right?

A. They will be part of this -- the ultimate outcome of this case, yes.

Q. Okay. Thank you. Nothing further.

COMMISSIONER CLODFELTER: Thank you, Mr. Jenkins.

Mr. Boehm, you are up next.

MR. BOEHM: Thank you, Your Honor. Due to the stipulation and Mr. Jenkins' cross examination, we no longer have any cross.

COMMISSIONER CLODFELTER: All right. Thank you.

Ms. Goldstein, you're next on my list.

MS. GOLDSTEIN: Thank you, Commissioner Clodfelter.

CROSS EXAMINATION BY MS. GOLDSTEIN:

Q. Good morning, everyone. Mr. Floyd, the majority of my questions, I believe, are going to be directed to you.

Starting with just in general, are you familiar with Duke Energy Progress' real-time pricing, our general service real-time pricing rate?

A. (Jack L. Floyd) I am.

Q. Okay. Thank you. And were you aware that that rate was created in 1997?

A. Yes. I spent some time in the progress rate case, the Sub 1023 case, evaluating the RTP rate schedule.

Q. All right. Thank you. And in your testimony for the current rate case, this would be in the -- you discuss that you -- your proponent of the comprehensive rate design study, there's a few rates that you discuss that do not require further study, I believe; is that correct? Those rates you identified were residential TOU-D, CSE, and CSG; is that correct?

A. I wouldn't characterize it as not requiring or needing further study. I think my testimony articulates that, with respect to the R-TOU-D, that that was a closed schedule a couple of cases ago. And that, with the intent of opening new doors for time-of-use-type rate schedules, here is one that is pretty well established and that could be more readily adopted and opened again.

In terms of the other two, the CSE and CSG, they are fairly unique, they are fairly old. And they are -- they have been closed for a period of time. And there is an issue of what I -- what I believe may be a discriminatory rate schedule by keeping that closed. And so I wouldn't characterize it as not needing further review on that basis.

Q. Okay. Thank you. Understood. And then are you aware, Mr. Floyd, that RTP is currently capped at participants of 85 customers?

A. Yes, I am.

Q. Okay. And capping that rate, do you believe that causes any discrimination against customers that would otherwise be willing to participate on that rate and curtail their usage?

A. Not in the same terms as the other three that I've mentioned. This -- this is a 20-year-old or so rate, and it has had an experimental designation the entire time, I do believe. And it -- as I mentioned earlier, in the Sub 1023 case, I investigated the RTP rate in a lot of detail. And so I went back and looked at my notes from that case to basically get an idea. And it was -- I think, Mr. Pirro testified to this to some degree, that the administrative burden of manually billing and calculating the RTP bill for customers was the basis of why they had not expanded it. And that's exactly what I found when I went back to the Sub 1023 case and looked at my notes.

I also looked in terms of this case, the Item E-1 -- the Form E-1, Item 42 billing determinates. And you'll see, if I'm interpreting this correctly, that there are approximately 65 to 70 customers participating in that schedule. So there is some opportunity, I think, today that customers can still enroll. Now, the administrative burden component of the discussion, I think there's some further study. Because, since this Sub 023 case, Progress -- Duke Carolinas -- Duke Energy as a company has instituted a process to implement a new billing system, their Customer Connect system.

And in -- I believe it was in the Sub 1142 case, I went back and asked about that in terms of the Customer Connect, and one of the things the Company represented to me in discovery was that the hourly pricing or the real-time pricing billing process is hopefully going to be -- the administrative burden of doing these manual bills is going to be reduced with Customer Connect.

So I think there are opportunities for expansion of the RTP. And certainly I think the RTP process, the calculation or the algorithm used for the calculation should be part of this study going forward.

Q. Okay. Thank you. One question, and you are -- as far as you understand, you believe that there are spots available in the RTP rate currently?

A. As I interpret the Item 42 billing data, yes.

Q. Okay. And have you -- I assume you were not aware that Hornwood, Inc., who we represent in this proceeding, have been requesting to be put on this rate for about a year and a half?

A. No. I mean, I've had some conversation over the years with Mr. Coughlan, but I did not know specifically about Hornwood.

Q. Okay. Thank you. Moving to the admin fee, we discussed -- well, you discussed the manual billing part of administering RTP.

Are you aware that customers pay approximately -- well, exactly $1,980 per year in an admin year?

A. Yes. I think it's $165, $175 a month or so.

Q. Yes, sir. $165, I believe.

A. Okay.

Q. And as of this rate case, isn't it correct that DEP has not requested to increase that administrative fee?

A. They've proffered no change at all to the RTP. And part of that is that the RTP is a marginal rate schedule and -- which is typically outside of cost of service.

Q. Okay. Going back to the admin fees, do you -- are you aware of what those fees generally cover?

A. I would -- I would have to say I have not looked at that in this case to look at the detail behind it. There was not -- nobody suggested any changes in the application or the parties. And the Public Staff, its last investigation of it really was done in the Sub 1023 case. I have not looked at that charge and the administrative components what are -- that are behind that charge in this case. I have not investigated it at this time. But I would have to think that most of it is the manual billing process.

Q. Yes, sir. And given that DEP has not requested to increase that portion of the admin fee and has not in quite some years, wouldn't that indicate that DEP is covering their -- they're recovering their costs that are incurred for the manual billing and administering this rate?

A. I think that's a safe presumption, yes.

Q. Okay. Thank you. You discussed the deployment of new technology and metering.

Would you agree that RTP's been in existence, as already established, for 23 years, and it is able to be administered with the current technology and meters that are in place?

A. That's correct. I think Mr. Pirro highlighted the energy profile component of how they do the metering and billing process.

Q. Okay. Thank you. Thank you. And are you, Mr. Floyd, aware of the pilot rates that are being offered in the DEC territory right now that Mr. Pirro testified that they are -- DEP is studying?

A. The nine different pilots; yes, I am.

Q. Okay. And are you aware that those pilot rates are only available to customers up to 75PW?

A. That's true. And that was the target

audience with the pilots, because it seemed to be that the lower-load customers who had the fewer time of use options when those pilots were first contemplated.

Q. Okay. So as far as you know, there is no real-time pricing available or design available to any DEP customers currently that are less than 1,000 kW, correct?

A. That's correct. Now, they do have some other nonfirm riders. They have -- they have several of those. I can't articulate exactly what some of the names of those are, but they have several of them for nonfirm service riders, standby riders, those kinds of things.

Q. Okay. And given that the admin fee is just short of $2,000 per year, wouldn't that incent or disincent customers who might not be able to curtail their load and possibly save money from participating on these rates? I'm really referring to some of the smaller customers.

A. Right. And I -- yes, it would. The RTP was not designed, I think, for small customers. I mean, the 1 megawatt demand limit is a formidable hurdle for many customers. That's why I believe there is an opportunity for more time of use. Now, whether it's real-time pricing or something less volatile, but there are certainly opportunities for more time of use for this -- for this middle ground that I think you're somewhat targeting. And I -- that is one of the objectives of this rate study, that hopefully, between the pilots that you mentioned earlier that Duke Carolinas is doing, up to 75 kilowatts, from 75 to maybe a megawatt, there's a -- I think plenty of fertile ground for new time-of-use RTP opportunities.

Q. Okay. Thank you. And then in just considering the customers that are 1,000 kW and above, the current kW requirements on RTP, if the Commission approved simply to reduce -- or keep the 1,000 kW requirement but eliminate the cap, is that something that you think would -- would you agree with that? Would you support that?

A. Well, it's -- I think we need to look at it. I think we need to see if there are other opportunities for more customers to participate in the existing RTP. I hate to use this word again, but I'm a little cautious about changing things like demand thresholds and so forth, because -- without a comprehensive study.

We need to look at things in concert with one another. And I'll -- and in particular, RTP rates, I think people need to keep in mind, you know, these are marginal service kinds of rates, and we don't -- the more load of a customer that gets enrolled in a nonfirm, or real-time pricing, or marginal cost-based rate, you start to have to ask the question about what are they contributing to fixed cost.

Now, typically, marginal rates -- marginal rate schedules, like the RTP component, are not assigned fixed costs. That's one of the benefits to the customer. But in terms of that, it's when the system needs the capacity, they are encouraged to curtail or pay a penalty. And the reason being is that the Company has a plan for capacity to serve that portion of load. We don't need but so much marginal load on the system, so much incremental load on the system simply because, you know, at some point you're paying credits for incremental load that you may never call.

And there's an economic analysis, I think, that needs to go into all of what I'm saying, and that ought to be done through this comprehensive rate study. So that's why I say a cautious approach. I'm not sure I can articulate everything we need to look at in terms of an RTP-like rate for smaller customers, or even expanding the one we have for larger -- for the current customers that are eligible for that. We need to look at it on a comprehensive basis.

Q. Okay. Foregoing the retention in kW, again with the 1,000 kW and above customers, hasn't this rate been -- I mean, I guess you could say studied for the last 23 years. I do want to make a distinction or correction; it is a nonexperimental rate at this point.

A. Okay. Yeah, it's -- I think we -- there's plenty of experience with real-time pricing rate structures, hourly pricing rate structures. I don't know that the nature of it is unknown. I think we know how it works. The customers understand the algorithm behind the costs that are associated with that, and when those costs are imposed in terms of their ratchets, as we call them, the activations. I'm just not sure how much of it is unknown at this point.

Q. Okay. And if the RTP rate was expanded, would the curtailment of customers allow for possibly postponing the construction of additional peak power plants or accelerate the closing of coal-fired power plants?

A. Not necessary -- excuse me. Not necessarily. And that goes back to what I said a moment ago, is that typically marginal rate schedules, the load associated with those are not planned for in the first place. That's why they're marginal, in terms of not including fixed cost recovery. They -- in other words, the Company serves that load with the excess capacity that they have on a day-to-day basis. And when that capacity becomes constrained, that's when the real-time pricing algorithm activates the additional charges, so to speak, to encourage the customer to curtail or pay a penalty.

So I don't -- I wouldn't -- I would not equate the RTP load with the need to expand system capacity.

Q. Okay. So -- but do you agree that DEP does receive a benefit from the customers who are shifting load during those high price times?

A. The system does receive a benefit, yes. All customers receive a benefit from that.

Q. Okay. Thank you. Mr. Floyd, just a couple more questions. In your summary testimony that was just filed last couple of days, you mentioned that -- it's page 2, the very middle paragraph.

A. Uh-huh.

Q. That some of the key objectives for the rate study are to ensure that users of the system pay for services based on how they use the system.

Would you agree that RTP is designed for that exact purpose?

A. Yes.

Q. Okay.

A. The incremental component of RTP is that; it's a marginal rate which pretty much says the same thing.

Q. Okay. Thank you. And then just to clarify as well, because we've discussed the marginal. The customers on RTP do still get bill -- or are still billed under their standard rate, correct, for their CBL usage?

A. For their customer base line, yes. So it would be on an LGS or some other rate schedule. That's billed under the schedule LGS.

Q. Okay. Thank you, Mr. Floyd. That concludes all of my questions.

A. You're welcome.

COMMISSIONER CLODFELTER: Thank you, Ms. Goldstein.

Mr. Neal, I believe the panel is with you.

MR. NEAL: Thank you, Commissioner Clodfelter. No questions at this time.

COMMISSIONER CLODFELTER: All right. According to my list, Mr. Smith or Mr. Ledford, you have the panel next.

MR. SMITH: We have no questions at this time. Thank you.

COMMISSIONER CLODFELTER: Thank you, Mr. Ledford -- Mr. Smith.

Mr. Culley, next on my list.

MS. CULLEY: No questions at this time. Thank you, Commissioner.

COMMISSIONER CLODFELTER: All right. And that brings us to -- let me ask if any other intervenors have cross examination for this panel.

MS. CRESS: Commissioner Clodfelter, this is Christina Cress with CIGFUR.

COMMISSIONER CLODFELTER: Yes.

MS. CRESS: I truly had not intended to ask any questions of this panel, and this was not a ruse to simply try to go out of order, but because of testimony elicited from Mr. Floyd, I do just have one question if the Commission might allow me to ask it.

COMMISSIONER CLODFELTER: I'll allow you to do that before we go to the Company. You may proceed.

MS. CRESS: Thank you, Commissioner Clodfelter.

CROSS EXAMINATION BY MS. CRESS:

Q. Mr. Floyd, you testified about softening your stance on being cautious with respect to certain rate design provisions contained within the Commercial Group and Harris Teeter settlements with DEP; do you recall?

A. (Jack L. Floyd) Yes.

MS. CRESS: Commissioner Clodfelter, I apologize. This is actually going to be two questions.

COMMISSIONER CLODFELTER: You may have two.

MS. CRESS: Thank you.

Q. Mr. Floyd, your softening of your position on those pieces of the settlement, that also applies to the CIGFUR settlement with DEP; does it not?

A. Well, it depends on what piece of that you're talking about. Would you be more specific?

Q. Your concerns -- I guess this will be three.

Your concerns related to the provisions pertaining to studying certain rate design elements and getting together with CIGFUR to examine the possibility of certain rate designs in future rate cases.

A. I think the Public Staff is open to looking at all possibilities for whatever rate schedules would benefit both customer and Company. I'm not -- without being -- I'm trying to look for the CIGFUR settlement here so I can make sure I'm referencing appropriately, but --

(Witness peruses document.)

I think we can -- I think we can say that, in terms of individual rate schedules, the incremental -- or not incremental -- the interruptible load aspect of the settlement may be a little bit of a different animal to discuss. But in terms of the rate schedules, the options for RTP and some of these other example rate schedules that were given by CIGFUR in the settlement certainly bear investigating.

Q. Thank you, Mr. Floyd.

MS. CRESS: And thank you, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you, Ms. Cress.

Ms. Jagannathan?

MS. JAGANNATHAN: Thank you, Commissioner Clodfelter. I just have a couple of questions for Mr. Floyd.

CROSS EXAMINATION BY MS. JAGANNATHAN:

Q. How are you doing?

A. (Jack L. Floyd) Good morning.

Q. You were discussing with Ms. Goldstein the LGS-RTP rate; isn't that right?

A. Yes.

Q. And by its terms, that's limited to large general service customers, right?

A. That's correct.

Q. Okay. And I believe you testified there are open spots, and I wasn't sure if you heard Mr. Pirro's testimony that LGS-RTP was full, I think fully described; do you disagree with that?

A. Well, that's what prompted me to go back to look at the E-1, Item 42. And I think my testimony earlier stated that my belief, my interpretation of that data seems to suggest that there may be openings.

Q. Okay. Thank you. And in any case, you would not be surprised that the Company would not allow non-large general service customer who wanted to be on

LGS-RTP to participate in that rate, whether there are open spots or not?

A. I don't -- I can't imagine why they would.

Q. Okay. And would it surprise you to know that Hornwood is not a large general service customer?

A. I know nothing about Hornwood's load.

Q. Okay. Thank you. That's all I have.

COMMISSIONER CLODFELTER: Thank you. Last call, any other parties have cross examination on this panel?

(No response.)

COMMISSIONER CLODFELTER: All right. Ms. Downey, Ms. Edmondson, we're back to you on redirect.

MS. EDMONDSON: I have a couple questions for Mr. Floyd.

REDIRECT EXAMINATION BY MS. EDMONDSON:

Q. Mr. Floyd, in regard to the CIGFUR settlement, Ms. Cress was asking you about your position, any opposition to any of the terms or any softening about --

COMMISSIONER BROWN-BLAND: Excuse me, this is Commissioner Brown-Bland. Ms. Edmondson, could you get a little closer to your mic?

MS. EDMONDSON: Sure. Can you hear me better now?

COMMISSIONER BROWN-BLAND: Little bit.

MS. EDMONDSON: Okay. I'll see if I can turn it up. I think -- let's see. Okay. I'll try to talk louder.

Q. Ms. Cress asked you about had the Public Staff changed its position in regarding any of the terms of the CIGFUR settlement. You -- as far as the -- and she asked you about the rate study and the rate schedules.

Was your concern, as far as studying those rate schedules, or was it more involved with whether those rates should be part of base rates or the DSM-ED rider?

A. (Jack L. Floyd) My answer -- earlier answer was not in the context of the efficiency rider versus base rates. It was more a base rate question, I think. As I -- as I look at the settlement section E of this, it's paragraphs 1 primarily list some examples of other RTP-like rate schedules. And that's what I was alluding to, that those -- those designs ought to be evaluated in the context of this comprehensive study, rate study. That's what I was alluding to.

Q. And I think I'm -- Mr. Pirro and Mr. Huber said that you would be looking at both base rates and DSM-type rates in the comprehensive rate study?

A. I heard that testimony. It raised a few flags with me, simply because the construct of the energy efficiency rider is rooted in the Senate Bill 3, 62-133.8 and 9, and there has to be a distinction between the cost associated with demand-side management and energy efficiency programs and base rate components of utility service. We have a DSM-EE rider for that purpose. And my accounting friends across the hall, we all ensure that there is a distinction made between the cost associated with efficiency and demand-side management programs and base rate utility service because of that statutory construct.

This was an issue that started as -- with the initial efficiency portfolios of both companies and Dominion when we started down the road after Senate Bill 3, looking at demand-side management, demand response programs. And the Commission -- the Commission stated in its Docket E-7, Sub 831 order back in 2009 that they would close the Duke Carolinas existing interruptible programs, and any new demand-side management, demand response -- and time of use is a demand response-type program -- would be part -- new programs, new enrollment would be part of the DSMEE rider.

Now, that -- that is -- I think that topic needs to be discussed in terms of the comprehensive rate study, because we have not historically treated time-of-use-type rate schedules, base rate schedules as efficiency or demand response or demand-side management. We are going to need to delicately address that and to preserve the ability to have time of use rate schedules maintained in base rates and demand-side management programs maintained in the DSM-EE rider.

I'm open to having those discussions with stakeholders, but that is a -- that is a -- that is an issue that needs to be addressed.

Q. But since Senate Bill 3, has all new demand response been put in the DSM-EE rider?

A. Yes, it has. In terms of Duke Carolinas' PowerShare program and Duke Progress' EnergyWise and what they call their CIG, commercial, industrial, governmental demand response program, yes, it has. It's been recovered in the DSM-EE rider since 2009, '10.

Q. Okay. Thank you. That's all I have.

COMMISSIONER CLODFELTER: Any further redirect for the panel? If not, we'll move to Commissioners' questions.

MS. GOLDSTEIN: Commissioner Clodfelter, I'm sorry to interrupt. I'm not sure if this is the correct form or -- it's definitely untimely, but an objection. The questioning of Ms. Jagannathan of Mr. Floyd regarding Hornwood's size. They are, in fact, a large general service customer.

COMMISSIONER CLODFELTER: Well, we're now -- I'm not sure that's so much an objection as it is an argument about what the facts in the case are. And so, Ms. Goldstein, I'm going to suggest that we need to be sure that you have in the record in your case all facts sufficient to support the position you wish to argue with the Commission.

MS. GOLDSTEIN: Okay. Thank you.

COMMISSIONER CLODFELTER: I'm not sure if that's really an objection to the question. It's a difference of opinion about what the facts of the case are. And I'm going to -- if you need to offer additional evidence for the record, I'll hear you on a motion to do so if you think you need to offer additional evidence, at the appropriate time.

MS. GOLDSTEIN: Okay. Thank you.

COMMISSIONER CLODFELTER: Okay. All right. We'll go to Commissioners' questions. Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Yes, my question is for Mr. Floyd.

EXAMINATION BY COMMISSIONER BROWN-BLAND.

Q. And I just want to ask you a couple of questions related to EDIT. In your second supplemental testimony, page 5, there at line 6 where the question is posed and the rest of that page contains your answer. And the question was about why -- why your assignment of the EDIT credit differed from the method used by Company witness Pirro in his second settlement exhibit.

A. (Jack L. Floyd) Right.

Q. And you indicated that the Company had agreed in the settlement with CIGFUR to return the EDIT to customers based on a uniform cents-per-kilowatt-hour basis; but that you had distributed the EDIT credit by returning the monies to the customer classes based on the amounts each class had paid.

A. That's right.

Q. And my question is, has the Commission, to your knowledge, used your method, based on the amounts paid, to distribute the EDIT credit in prior cases, either electric, natural gas, or water?

A. I'm not sure about gas or water, wastewater, but in the last Dominion, if not the last two Dominion cases, they were done on a class basis. The reason I bring this up is that EDIT -- EDIT is something that we know customers pay. It can be directly assigned to the class that paid it. And with that knowledge, I mean, we should be giving customers back the money they paid in terms of overpaying in this case. And so it is -- I think we are able to discern pretty well what each class paid to the Company, in terms of the tax burden.

Part of the -- part of this, in terms of the electric utility service -- like I said, I'm not aware of -- I know the Commission has awarded the EDIT credits on a level -- on a uniform rate basis, and therein lies my problem. The settlements in the last case -- cases with Duke Carolinas Progress addressed the EDIT being returned on a levelized rider.

When the compliance filings were made, my job is to look at the rates that come out of those cases and to make sure they produce the revenues that the Commission has granted. My -- my point, or the thing that I did in my review, is I interpreted levelized as uniform; and that, I believe, might have been a mistake. Levelized, in terms of accounting, means -- and my accounting friends have corrected me -- means basically the same amount over multiple years. Does not necessarily mean the same rate, uniform rate.

And so what I have proffered in this case -- and let's go back to the original Duke Carolinas/Duke Progress filings in these cases. They filed a class-specific rate for EDIT. The Public Staff did not object to those original proposals of returning EDIT, because they do return the money to the class that paid it. That's the key. That was consistent with the Dominion cases. Notwithstanding what the Commission has awarded in other -- or two other utilities that it regulates.

Part of the -- part of the problem, too, I think, is that we tend, as regulators, to love to return things on a uniform basis because it's fairly easy mathematically. Again, I go back and restate, here with EDIT, we know what the residential class, what the nonresidential classes paid to the Company.

They should be getting that money back directly. My proposal does that. The original proposal does that.

Q. All right. Thank you for that. With regard to -- you mentioned -- did you say the last Dominion and was it the last Duke?

A. It wasn't the last Duke. Both Duke cases have been on a uniform basis.

Q. Uniform?

A. Yes. The issue was this time, in looking at the case, looking at -- well, what prompted the review was the difference between the original filing of Progress' and Duke Carolinas' cases and the settlements that came out between Duke and CIGFUR. That changed the way the EDIT -- that prompted me to review it. There was no reason to dispute it in the original filing.

Q. Well, so just refresh my memory from just a few minutes ago, you mentioned you were aware of your method being employed in Dominion, and was it one other?

A. I believe it's the last two Dominions.

Q. The last two Dominions?

A. Yes.

Q. All right.

A. I don't know that it was done in gas or water. My understanding in talking with other Public Staff members is that those had been done on a uniform basis also.

Q. All right. You don't happen to know off the top of your head, do you, as some folks do, the docket numbers for those cases? E-22?

A. Unfortunately, it's E-22, Sub 562, which is the last case, and 532, which was the 2015, '16 case.

Q. All right. All the career employees have it down.

A. I'm filing my resignation in a minute.

Q. No, no, no, no. Thank you. Another follow-up to that is, can you and the Public Staff provide, as a late-filed exhibit, how the Commission has authorized EDIT to be distributed to customer classes since the recent 2013 state tax changes, and include in that the state and the federal EDIT?

A. I'll rely on Ms. Edmondson to get the details of that.

Q. All right.

MS. EDMONDSON: We will have that prepared.

COMMISSIONER BROWN-BLAND: Thank you,

Ms. Edmondson.

Q. And one more question. Well, I don't want to fall into Ms. Cress' trap, but I think it's one more question. Yesterday, witness Phillips mentioned Docket E-2, Sub 1188, and I don't know if you recall what that was, but what I wanted to clarify was whether that case, that was allocating EDIT, or if it dealt with changing DEP's base rates to reflect the 21 percent there.

A. I do not know. You would be best to ask one of the Public Staff accounting witnesses. I think Mr. Maness is our witness in this case. The -- my exercise and limitation of EDIT was simply to take the accounting witnesses' recommended EDIT credit and assign it for returning to the customer classes the rates, and that's the extent of my knowledge in terms of how the EDIT was calculated.

Q. Are you familiar with that E-2, Sub 1188 which was also entered in M-100, Sub 148?

A. Vaguely.

Q. All right. And so you don't know if there's that distinction between the adjustment to the base rates versus the EDIT?

A. I do not.

Q. And my refreshing your recollection about the order, that wouldn't change your knowledge, would it?
A. Unfortunately not.
Q. All right. Thank you. That's all that I have.
COMMISSIONER CLODFELTER: Thank you, Commissioner.
Commissioner Gray?
COMMISSIONER GRAY: No questions for this panel.
COMMISSIONER CLODFELTER: Okay. Chair Mitchell?
CHAIR MITCHELL: No questions.
COMMISSIONER CLODFELTER: Thank you. Commissioner Duffley?
COMMISSIONER DUFFLEY: Yes. I have just one follow-up question to Commissioner Brown-Bland's questions.
EXAMINATION BY COMMISSIONER DUFFLEY:
Q. So, Mr. Floyd, I hope you're doing well this morning.
A. (Jack L. Floyd) Yes.
Q. Good. So you probably heard me ask questions about doing kind of an offset of a potential EDIT

account with coal ash costs and removing the amortization periods, those five-year amortization periods.

If the Commission decided to go that route, would you still be able to perform your returning to customer classes the EDIT?

A. I -- I would -- I'm not sure I can give you a thorough answer at this point about that. I may have to think about that some more. One of the things that I -- here's this word again, "caution." I want to caution the Commission about commingling the return of overcollections with expenses that really don't have a lot of connection between the two. It's like, you know, taking -- using something just because it's available there, to address another problem that really the two -- the issue and the problem have no direct relationship.

The taxes were overpaid. The coal costs are incurred as a function of a whole different gamut of issues and circumstances. So I just caution the Commission against using the EDIT credits that would go back to customers to pay those coal-related or coal ash-related costs.

Can it be done? I mean, at the end of the day, the customer doesn't care. They're going to pay a bill to the utility. It's going to be comprised with base rate items and riders. And, you know, the Commission certainly has the prerogative of doing what you are contemplating. But to give you a more detailed answer, analytical-based answer at this time, I'm not sure I can.

Q. Okay. Thank you for that, Mr. Floyd. I have no further questions.

COMMISSIONER CLODFELTER: Thank you. Commissioner Hughes?

COMMISSIONER HUGHES: Yes, I have a couple questions.

EXAMINATION BY COMMISSIONER HUGHES:

Q. Mr. Floyd, you talked a little bit about the history of the RTP as you knew it, and then you started to get in redirect into that connection between DSM and EE programs that I have to ask you a question on some of the things that you described.

Have you -- have you ever studied the impacts of the RTP, or in the last 10 years studied the impacts of the RTP? By impacts, I mean number of customers that participate, amount of the electric -- electricity that flows through those rates.

A. (Jack L. Floyd) It is -- it is a significant amount. I'm looking at my notes here from the Sub -- I do not do that in this case. Let me preface that. There were no changes to propose for RTP. I did not do that. The last time I looked at this to any extent was in the Sub 1023 Progress case. At that time, the -- I'm reading my notes here. It looks like approximately 1,300 megawatts may have been involved with that rate. That's subject to check.

They are very responsive, typically, to calls by the Company. We get through confidential emails the RTP prices every week, and when we see notable escalations of rates in certain hours, we typically understand that the participants on that rate respond very well. I have not done a more formal study, other than what we did in the rate case, and then the ongoing weekly emails that we get about RTP.

Q. Okay. Thank you. And then, if I understood you right -- I didn't understand whether -- whether DSM and EE programs, a rider would roll in in your vision to this comprehensive rate study or they wouldn't. I understood the distinction, and maybe Commissioner Clodfelter can talk it out, but what was your -- going forth now, what is the recommendation on the record? Would they be included? Would that be included?

A. Yeah. The -- it is, I think, going to be problematic if we start talking about demand-side management energy efficiency cost recovery in the term -- in the context of a comprehensive rate study that is contemplated in these rate cases. The study is intended to look at base rate schedules, to look to see if the current ones are still appropriate. And if not, where -- where we can make adjustments. And then to look for new opportunities for new rate schedules to deal with future utility service.

The problem that arises is rooted in the distinction of time of use being demand response, demand-side management. And historically, time of use has been considered demand-side management.

In the context of Senate Bill 3, there were -- there were efforts made to make a distinction between existing base rate oriented time of use and new demand response programs that would be offered to expand a portfolio of demand response.

And I think one of the issues is that, for interruptible service -- that's, I think, the biggest part of it. For interruptible service, the character of interruptible service is analogous to demand response. And so, in the context of the Duke Carolinas Save-a-Watt portfolio that was approved in 2009 for Duke Carolinas, the -- there was a distinction made by the Commission, because this was an issue, that existing interruptible rates, base rate schedules -- and there were two of them. I think it was rider IS and SG -- would be closed to new customers, and that any new interruptible demand response load would be enrolled in the new power share demand-side management program that was part of the Save-a-Watt portfolio under Senate Bill 3.

And so that -- I don't want to conflate -- I hope we don't conflate the comprehensive rate study with some of these issues of demand response and DSM-EE rider. We need to look at base rate revenue schedules. And if the issue of time of use, real-time pricing, oriented schedules, and demand response becomes an issue out of that study, then we may have to address this. I'm hoping stakeholders can get -- can discuss this.

A. (James S. McLawhorn) Commissioner Hughes, can you hear me?

Q. Yes.

A. James McLawhorn. If I could, I would like to just add a little perspective -- additional perspective to Mr. Floyd's answer on the RTP rates; is that okay?

Q. Please, go ahead.

A. Okay. I just -- since there's been some discussion about RTP rates and the demand-side management energy efficiency, I just wanted to add that, when the RTP rates were first implemented in North Carolina, they were not implemented for the purpose of shifting load. And if you examine the way the rates are constructed, the customer continues to pay a customer baseline under the traditional LGS or LGS-TOU schedule, which is representative of historical usage.

At the time the RTP rates were implemented, they were actually put in place to incent customers to increase usage when the utility had available capacity at a lower marginal cost. So some manufacturing customers could actually increase production above their -- their normal level of production.

And, of course, when -- when -- as Mr. Floyd described, when capacity became short or they were having to go to units or purchase power at a higher cost, the real-time price would go up, and that would send a signal to the customer, okay, you need to back off these increased energy purchases or pay this higher rate.

But it wasn't really for the purpose of shifting their historical load to a lower cost period. And I wasn't sure that message was getting through. I just wanted to add that.

Q. I appreciate that perspective. It's an interesting perspective, and it wouldn't be one that I would necessarily think of now thinking about the main advantage of --

A. Well --

Q. -- rates for --

A. So it really was -- it wasn't called an economic development rate, but I guess it was somewhat analogous to that for existing customers. It was -- at that time we were not -- I think Ms. Goldstein pointed out that the rate had been in effect since '97, '98 for DEP. At that time, we weren't building any -- or very little new generation, and most of what we were building, if we were, it was peaking plant, so we had some additional capacity at certain times in some of the intermediate and base load plants. And it was more efficient to keep those plants running than to cycle them up and down during load -- certain load periods.

And so it was -- it helped to reduce overall costs to everyone on the system to keep the plants running, even selling the energy, the excess energy at basically a fuel rate plus a little bit above that, so.

Q. Got it. I appreciate that. And anything more I learn is going to be outside what I need to know for this case.

A. Okay. Thank you.

Q. So we'll cut it off now. I appreciate both your responses. No further questions.

COMMISSIONER CLODFELTER: Thank you. I want to see if perhaps we can get through Commissioners' questions before we take our morning break. So I'll go to Commissioner McKissick.

COMMISSIONER McKISSICK: Appreciate the testimony that was provided by this panel, and I always find it interesting and insightful, but I have no further questions at this time.

COMMISSIONER CLODFELTER: Commissioner Duffley, I'll come back to you. I think you indicated you may have had an additional question.

COMMISSIONER DUFFLEY: Thank you. I

just wanted to ask one more follow-up for
Mr. Floyd.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. I'm going to come at the question in a different way.

So if the Commission decided to do some type of offsetting of the accounts, would it make this issue of how to do the flowback moot?

A. (Jack L. Floyd) I would -- if you want to do them in concert with one another, I would -- I think I would like to look at the individual components, calculate the revenues by class for each, and then net the two together on a class basis.

Q. Okay.

A. Is that responding to your question?

Q. It is responding, yes. Thank you. No further questions.

COMMISSIONER CLODFELTER: Any -- thank you. At this point, we'll take our morning break. Let's come back at 11:05, and we will pick back up with questions on Commissioners' questions. We will be in recess until 11:05.

(At this time, a recess was taken from 10:49 a.m. to 11:07 a.m.)

COMMISSIONER CLODFELTER: We are now on questions on Commissioners' questions. And I'm really just going to go in the order in which we took the cross examinations and then come back to Public Staff.

So, Mr. Jenkins, that would put you up first. Any questions?

MR. JENKINS: No questions.

COMMISSIONER CLODFELTER: All right. Ms. Cress? Couldn't hear you.

MS. CRESS: Sorry. Can you hear me now?

COMMISSIONER CLODFELTER: Yes, I can.

MS. CRESS: Excellent. CIGFUR has no additional questions. Thank you.

COMMISSIONER CLODFELTER: All right. Mr. Boehm, are you there?

MR. BOEHM: Did you call Mr. Boehm?

COMMISSIONER CLODFELTER: Yes.

MR. BOEHM: No questions, thank you.

COMMISSIONER CLODFELTER: Okay. Ms. Goldstein? You're on mute.

MS. GOLDSTEIN: No, sir. No additional questions at this time.

COMMISSIONER CLODFELTER: All right.

Mr. Neal?

MR. NEAL: Briefly,

Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Yes.

EXAMINATION BY MR. NEAL:

Q. Mr. Floyd, good morning.

A. (Jack L. Floyd) Hello.

Q. This is David Neal representing NC Justice Center, et al. And you will recall, in questions from Commissioner Brown-Bland regarding excess deferred income taxes, you talked about the importance of calculating, I guess by class, how much excess income taxes were paid by those -- by class, and then returning it in a proportionate manner; is that correct?

A. Yes. We know what the classes paid to the Company in terms of EDIT. And so my -- I think my testimony simply tries to return it to the customers on the same basis.

Q. And you would agree that, in those years while residential customers were essentially overpaying because of changes in tax law, that was over -- those excess income taxes were recovered based on the total bills that those customers paid, correct?

A. That's my understanding, yes.

Q. And so that would mean, for example, a residential customer paid those excess income tax portions of their bill both from the kilowatt hour portion of their bill, the volumetric charge, as well as the basic customer charge component?

A. That's true. This is a function of revenue to the utility. Revenue derived from the rate schedules and the components of each of those rate schedules.

Q. And you would agree that the EDIT rider flows back to customers only on the volumetric rate, the per-kilowatt-hour rate, correct?

A. I'm not sure I understand your question. Is that the -- is that a proposal or?

Q. Well, I'm just looking, for example, at Pirro Exhibit Number 1 where he has the excess deferred income tax rider EDIT 2 and shows the Company's -- you know, essentially a decrement rider that's based on the kilowatt hour, the volumetric charge.

A. Right. But are you referring to the original Pirro filing or in his -- what is it, supplemental?

Q. I -- for purposes of this question, I was looking at his original filing, but is there --

A. Yes.

Q. It's my understanding that it's a volumetric -- it's being proposed to return to customers on the basis of volumetric rate.

A. It uses kilowatt hour sales to calculate a rate, whether uniform or a class specific, depending on which exhibit you're looking at.

Q. Right. And so -- but the bottom line is, none of that is returned as a decrement to the basic customer charge?

A. No.

Q. That's all I have.

A. It is based -- it's based on revenues.

MR. NEAL: That's all I have, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Okay. Thank you, Mr. Neal.

Mr. Smith?

MR. SMITH: No questions from NCSEA.

COMMISSIONER CLODFELTER: All right. Thank you.

Mr. Culley?

MS. CULLEY: No questions. Thank very much.

COMMISSIONER CLODFELTER: All right. Ms. Jagannathan, I think we're to you.

MS. JAGANNATHAN: Commissioner Clodfelter, I just had one clarification. Over the break we took an opportunity to look at what Ms. Goldstein brought up, and it's my understanding that Hornwood has several accounts, and one of the several accounts does qualify for large general service. So I just didn't want to mislead or anything. I just wanted to clarify that for the record.

COMMISSIONER CLODFELTER: Thank you. Let me propose, Ms. Goldstein and Ms. Jagannathan, that, since this is a factual issue and needs to be established in the record as a matter of fact, if the two of you will talk and satisfy yourselves that the correct answer is somewhere in the record now, or if not, it can be established in some manner mutually agreeable to the two of you. So the Commission knows that is has the fact that it can rely upon. Okay?

MS. JAGANNATHAN: Absolutely. Yeah, it's my understanding it's not in the record yet, but we'll figure that out between the two of us.

Thank you.

COMMISSIONER CLODFELTER: That's fine. Perhaps you can figure it out by stipulation or some other method, and we'll entertain whatever you propose. Okay?

MS. JAGANNATHAN: Absolutely. Thank you.

MS. GOLDSTEIN: Thank you.

COMMISSIONER CLODFELTER: And that means, Ms. Downey and Ms. Edmondson, questions on Commission's questions?

MS. EDMONDSON: No questions.

COMMISSIONER CLODFELTER: All right. Have I made the rounds completely? If so, that means we're at the point where we can entertain motions to the exhibits.

MS. EDMONDSON: Okay. Commissioner Clodfelter, I would like to move that Floyd Direct Exhibits 1 through 4, Floyd Corrected First Supplemental Exhibits 1 through 4, and Floyd second supplemental exhibits that have been marked for identification as Floyd DEP Direct Exhibits 1 through 4, Floyd DEP Corrected First Supplemental Exhibits 1 through 4, and Floyd DEP Second

Supplemental Exhibits 1 through 4 be entered and copied into the record in the DEP rate case.

COMMISSIONER CLODFELTER: All right. You've heard the motion. Are there any objections?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, the motion is allowed.

(Floyd Corrected First Supplemental Exhibits 1 through 4, and Floyd Second Supplemental Exhibits 1 through 4 were admitted into evidence.)

MS. EDMONDSON: Second motion is I move that Mr. McLawhorn Direct Exhibits 1 and 2 that have been marked for identification be entered and copied into the record in the DEP rate case docket.

COMMISSIONER CLODFELTER: All right. That's the motion. Are there any parties objecting?

(No response.)

COMMISSIONER CLODFELTER: If not, motion is allowed.

(McLawhorn Exhibits 1 and 2 were admitted into evidence.)

MS. EDMONDSON: And third, I would also

ask that Mr. McLawhorn and Mr. Floyd be excused.

COMMISSIONER CLODFELTER: Hearing no objection to that motion, it is allowed.

MS. EDMONDSON: Thank you.

COMMISSIONER CLODFELTER: Thank you, gentlemen.

All right. Ms. Downey, who is next?

MS. JOST: This is Megan Jost with the Public Staff.

COMMISSIONER CLODFELTER: Okay. That's right. I'm sorry, I have you down, Ms. Jost.

MS. JOST: That's okay.

COMMISSIONER CLODFELTER: Wrong line entry on a very complicated chart.

MS. JOST: Understood. The Public Staff, at this time, calls L. Bernard Garrett and Vance F. Moore.

COMMISSIONER CLODFELTER: All right. I have Mr. Garrett. Looking for Mr. Moore. Okay.

Whereupon,

L. BERNARD GARRETT AND VANCE F. MOORE,

having first been duly affirmed, were examined

and testified as follows:

COMMISSIONER CLODFELTER: Okay. Thank

you. Ms. Jost?

MS. JOST: Thank you.

DIRECT EXAMINATION BY MS. JOST:

Q. Mr. Moore, I'll begin with you. Would you 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, Suite 259.

Q. By whom are you employed and in what capacity?

A. I'm employed by Garrett & Moore Incorporated, and I am the president.

Q. Did you cause to be filed in this docket on April 13, 2020, direct testimony consisting of 36 pages and 10 exhibits, eight of which were marked confidential?

A. I did.

Q. Do you have any corrections to your testimony?

A. I do not.

Q. If you were asked the same questions today, would your answers be the same?

A. They would be.

Q. And did you prepare a summary of your testimony?

A. I did.

MS. JOST: Commissioner Clodfelter, at this time, I 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 10 exhibits be marked for identification as premarked in the filing.

COMMISSIONER CLODFELTER: Unless there's objection?

(No response.)

COMMISSIONER CLODFELTER: Hearing no objection, motion is allowed.

MS. JOST: Thank you.

(Confidential Public Staff Moore Exhibits 1 through 7 and 10; and Public Staff Moore Exhibits 8 and 9 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony with Appendix A and testimony summary of Vince F. Moore were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of		
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF VANCE F. MOORE ON BEHALF OF THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219
TESTIMONY OF VANCE F. MOORE
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

APRIL 13, 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 approaches to environmental regulatory compliance taken by Duke Energy Progress, LLC (DEP), at its Coal Combustion Residuals (CCR) units located at the Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon Stations in North Carolina were prudent and reasonable methods of achieving compliance with the laws and regulations governing coal ash management.

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 "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 Lucas 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 DEP's costs incurred at its two high-priority sites, Asheville and Sutton, as well as at the Robinson Station in South Carolina. Our testimony together provides a combined perspective on the prudence and reasonableness of the coal ash closure costs for which DEP is seeking cost recovery in this proceeding.

Q. WHAT IS THE SCOPE OF YOUR INVESTIGATION INTO THE PRUDENCE AND REASONABLENESS OF DEP'S COAL ASH MANAGEMENT COSTS?

A. I reviewed the actions and costs incurred by DEP at its Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon plants to comply with the Coal Ash Management Act (CAMA),[1] including DEP's actions and costs incurred in connection with the SEFA STAR coal ash beneficiation plants at its H.F. Lee and Cape Fear Stations.

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 DEP witnesses Bednarcik, Smith, and Turner. Through the Public Staff, I also submitted extensive discovery to DEP regarding its actions taken at its CCR units and DEP's technical and financial basis for such decisions. I also participated in site visits and conference calls with DEP personnel.

[1] 2014 N.C. Sess. Law 122, as amended by 2016 N.C. Sess. Law 95.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony first presents my opinion on the prudency and reasonableness of DEP's selected methods for general CCR management at each CCR unit I investigated and the related costs from September 1, 2017, through December 31, 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[2] and the associated costs incurred. Based on my investigation, I recommend that the Commission disallow $130,384,392 in costs to construct DEP's H.F. Lee and Cape Fear beneficiation projects that I do not believe were reasonable or prudent.

Q. WHAT IS YOUR OPINION REGARDING THE COSTS DEP SEEKS RECOVERY OF IN THIS RATE CASE FOR MAYO AND ROXBORO?

A. The North Carolina Department of Environmental Quality (NCDEQ) issued Closure Determinations on April 1, 2019, which mandated that CCR impoundments at DEP's Mayo and Roxboro plants and at Duke Energy Carolinas, LLC's (DEC), Allen, Belews Creek, Cliffside,

[2] N.C. Gen. Stat. § 130A-309.216 (2016).

and Marshall plants be excavated. After NCDEQ issued these excavation orders, Duke Energy filed a contested case challenging the orders.

DEP witness Bednarcik states on pages 13 and 14 of her direct testimony:

> Except for preliminary closure plan development, none of the site work that has been conducted at these two sites is specific to cap-in-place closure. All site work to date would also have to be conducted in an excavation closure. Later this year, DE Progress anticipates conducting preliminary site evaluations, 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 DEP's Mayo and Roxboro plants and at DEC's Allen, Belews Creek, Cliffside, and Marshall plants. The direct testimony of Public Staff witness Lucas discusses the current regulatory status of closure of DEP's CCR sites in greater detail.

Based on my review of DEP's approach to compliance with NCDEQ requirements, I take no exception to DEP's requested reimbursements for site work performed at Mayo and Roxboro.

Q. WHAT IS YOUR OPINION REGARDING THE COSTS DEP SEEKS RECOVERY OF IN THIS RATE CASE FOR WEATHERSPOON?

A. Weatherspoon was designated as an intermediate site by CAMA and DEQ and must be excavated by April 4, 2028.[3] I take no exception to DEP's requested reimbursements for site work performed at Weatherspoon.

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

[3] Page 3 of 11, Exhibit 18, Direct Testimony of DEP Witness Jessica Bednarcik filed in Docket No. E-2, Sub 1219, on October 30, 2019.

> 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. . . ."

[4] DEC response to Public Staff Data Request No. 202-5 in Docket No. E-7, Sub 1214.

Q. WHAT PLANTS DID DUKE ENERGY CHOOSE FOR THE THREE BENEFICIATION SITES?

A. Duke Energy chose the DEC Buck plant and the DEP H.F. Lee and Cape Fear plants as the three beneficiation sites. The H.F. Lee plant was chosen on December 13, 2016.[5] The Cape Fear plant was chosen on June 30, 2017.[6]

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 DEP and DEC (Duke Energy), advertised the Request for Information (RFI) for the Beneficiation of Ponded Ash into Concrete Specification Ash.[7] **[BEGIN CONFIDENTIAL]** [redacted]

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[5] Page 3 of 12, Exhibit 16, Direct Testimony of DEP Witness Jessica Bednarcik filed in Docket No. E-2, Sub 1219, on October 30, 2019.

Press Release *Available at* https://news.duke-energy.com/releases/duke-energy-to-recycle-coal-ash-at-h-f-lee-plant-in-goldsboro (last visited March 24, 2020).

[6] Page 3 of 13, Exhibit 15, Direct Testimony of DEP Witness Jessica Bednarcik filed in Docket No. E-2, Sub 1219, on October 30, 2019.

Press Release *Available at* https://news.duke-energy.com/releases/duke-energy-is-building-a-smarter-energy-future-by-recycling-even-more-coal-ash (last visited March 24, 2020).

[7] DEC confidential supplemental response to Public Staff Data Request No. 5-4(e) in Docket No. E-7, Sub 1146.

[redacted] **[END CONFIDENTIAL]**

Q. HOW DID DUKE ENERGY EVALUATE THE RFI RESPONSES?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** SEFA calls its beneficiation system Staged Turbulent Air Reactor (STAR).

Q. DID DUKE ENERGY CONTRACT WITH SEFA TO ENGINEER THE BENEFICIATION UNITS AT H.F. LEE AND CAPE FEAR?

A. Yes.

Q. DO YOU BELIEVE DUKE ENERGY'S DECISION TO AWARD THE ENGINEERING CONTRACT TO SEFA WAS REASONABLE AND PRUDENT?

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[8] DEC confidential supplemental response to Public Staff Data Request No. 5-4(e) in Docket No. E-7, Sub 1146.

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. DID SEFA'S RESPONSE TO THE RFI INCLUDE COST ESTIMATES FOR THE STAR FACILITIES?

A. In reference to SEFA's response to the RFI, DEC clarified that the construction estimate for one 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."[9] Duke Energy's intent was to have SEFA supply the STAR system and provide technical expertise. The remainder of the beneficiation projects would be built by a separate contractor.

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.

Q **DID SEFA'S RESPONSE TO THE RFI PROPOSE A CONTRACTOR TO CONSTRUCT THE STAR FACILITY?**

A. Yes. SEFA's response[10] to the RFI specifically named **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[9] DEC response to Public Staff Data Request No. 202-1 in Docket No. E-7, Sub 1214.

[10] 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 UTILIZE SEFA'S COST ESTIMATES TO ESTIMATE THE ENGINEERING AND CONSTRUCTION COSTS FOR THE STAR FACILITIES?

A. Yes. Duke Energy's December 31, 2017, ARO cost spreadsheet,[11] **[BEGIN CONFIDENTIAL]** [redacted]

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[11] DEC confidential supplemental response to Public Staff Data Request No. 5-19 in Docket No. E-7, Sub 1146.

[12] DEC confidential response to Public Staff Data Request No. 150-3 in Docket No. E-7, Sub 1214.

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted]

[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]

[13] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[14] DEC confidential response to Public Staff Data Request No. 183-5 in Docket No. E-7, Sub 1214.

[redacted] **[END CONFIDENTIAL]**

Q. DID DUKE ENERGY CONTRACT WITH H&M TO CONSTRUCT THE BENEFICIATION UNITS AT H.F. LEE AND CAPE FEAR?

A. No. In response to a Public Staff data request, DEC indicated that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

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[15] DEC response to Public Staff Data Request 202-1 in Docket No. E-7, Sub 1214.

[16] 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.

[17] DEC confidential response to Public Staff Data Request No. 231-21 in Docket No. E-7, Sub 1214.

[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]

[18] DEC confidential response to Public Staff Data Request No. 183-4 in Docket No. E-7, Sub 1214.

[redacted] **[END CONFIDENTIAL]**

Q. WHICH CONTRACTOR WAS AWARDED THE CONTRACTS FOR THE CONSTRUCTION OF THE SEFA BENEFICIATION UNITS?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[19] DEP confidential response to Public Staff Data Request No. 96-3 in Docket No. E-2, Sub 1219.

[20] DEP confidential response to Public Staff Data Request 96-6 in Docket No. E-2, Sub 1219.

[21] According to DEP's confidential response to Public Staff Data Request 112-9 in Docket No. E-2, Sub 1219, the overall estimated contract cost for Cape Fear included the costs of changes made at the other two sites that were known at the time the Cape Fear

Q. BASED ON YOUR ANALYSIS, WHAT HAS BEEN THE MOST SIGNIFICANT SOURCE OF COST INCREASES FOR THE H.F. LEE AND CAPE FEAR BENEFICIATION PROJECTS?

A. The most significant source of cost increases has been the increases in construction costs, which apply to all the beneficiation units. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

SEFA's initial contract for the engineering, procurement, start-up, and commissioning of the H.F. Lee beneficiation project was in the amount of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which has increased to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as a result of change orders. SEFA's initial contract for the engineering, procurement, start-up, and commissioning of the Cape Fear beneficiation project was in the amount of **[BEGIN CONFIDENTIAL]** [redacted] **[END**

contract was executed. These changes and the associated costs are found in DEP's confidential response to Public Staff Data Request 112-9 in Docket No. E-2, Sub 1219.

CONFIDENTIAL] which has increased to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as a result of change orders.

As stated above, Duke Energy selected Zachry for construction of beneficiation plants at H.F. Lee and Cape Fear. Zachry's overall estimated contract cost for construction of the H.F. Lee beneficiation plant was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which has increased to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as a result of change orders.[22] Zachry's overall estimated contract cost for construction of the Cape Fear beneficiation plant was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which has increased to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as a result of additional change orders.

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.

[22] DEP confidential response to Public Staff Data Request No. 96-14 in Docket No. E-2, Sub 1219.

Q. DO YOU BELIEVE THE CHANGE ORDERS TO THE CONSTRUCTION CONTRACTS WITH ZACHRY FOR THE H.F. LEE AND CAPE FEAR BENEFICIATION UNITS WERE REASONABLE AND PRUDENT?

A. Yes. I take no exception to the 18 change orders Duke Energy issued to Zachry for the H.F. Lee beneficiation unit totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. I also take no exception to the 16 change orders Duke Energy issued to Zachry for the Cape Fear beneficiation unit totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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 CONTRACTS TO ZACHRY?

A. In response to a Public Staff data request asking for an explanation of any differences between the "design and items (i.e., equipment procurement, labor, materials, etc.)" included in the **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** In response to a Public Staff data request in this docket, DEP stated that the “differences detailed for Buck [in the “refresh” spreadsheet] are the same for Cape Fear and HF Lee.”[24]

[23] DEC confidential response to Public Staff Data Request No. 202-7 in Docket No. E-7, Sub 1214.

[24] DEP supplemental response to Public Staff Data Request No. 112-9 in Docket No. E-2, Sub 1219.

Based on the foregoing, I do not believe Duke Energy has met its burden of demonstrating that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** See **Confidential Moore Exhibit 6**.

Q. DID DEC WITNESS BEDNARCIK ADDRESS THIS COMPARISON IN HER REBUTTAL TESTIMONY IN DOCKET E-7, SUB 1214?

A. Yes. However, Company witness Bednarcik conflated my comparison of Zachry's overall estimated contract cost and H&M's estimated construction costs with the Winyah STAR facility costs. On page 41 of her rebuttal testimony, witness Bednarcik states that CAMA requirements necessitated the installation at the Buck facility of a second external heat exchanger, grinding circuit, dry scrubbers, and second bag house with additional induced draft fans. In response to a Public Staff data request seeking clarification of the design and construction scope of work and cost differences between H&M and Zachry cost estimates, DEC **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** See **Confidential Moore Exhibit 7**[25] This further supports my conclusion above that Duke Energy has not met its burden of demonstrating that the increased costs for construction of the beneficiation facilities are reasonable and prudent.

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. SEFA's response to the RFI recommended H&M because they had constructed similar facilities designed by SEFA. SEFA's response to the RFI included a cost estimate for H&M to construct the beneficiation unit for **[BEGIN CONFIDENTIAL]** [redacted]

[25] DEC confidential response to Public Staff Data Request No. 231-19 in Docket No. E-7, Sub 1214.

[redacted] **[END CONFIDENTIAL]** Readily available articles state that capital costs for SEFA's beneficiation unit at Winyah Station in South Carolina were approximately $40 million**. See Moore Exhibit 8.** While witness Bednarcik asserted in her rebuttal testimony filed in Docket No. E-7, Sub 1214, that there are "significant, fundamental differences between the [Winyah and Duke] facilities," that render comparison of the respective construction costs of "little to no instructive value," information provided by DEC in response to Public Staff Data Requests suggests otherwise.[26]

Among the differences between the Winyah and Duke STAR facilities cited by witness Bednarcik in her testimony are ash production capacity. According to witness Bednarcik's rebuttal testimony, "the Winyah plant is designed to produce 200,000 tons of ash product per year (a 120 MMBtu facility), while the Buck beneficiation unit must produce 300,000 tons of ash product per year (a 140 MMBtu facility) . . . ." This is inconsistent with SEFA's response to Duke Energy's RFI which states **[BEGIN CONFIDENTIAL]** [redacted]

[26] Page 42, Rebuttal Testimony of DEC Witness Jessica Bednarcik filed in Docket No. E-7, Sub 1214, on March 4, 2020.

[redacted] **[END CONFIDENTIAL]** See **Confidential Moore Exhibit 2**.

Witness Bednarcik also asserts that there are differences in the proportion of ponded ash processed at the Winyah facility (70 percent ponded ash and 30 percent production ash) as compared to the Duke facilities, which would process 100 percent ponded ash. However, according to a paper provided by DEC in response to a Public Staff data request, "The [Winyah] plant routinely operates using 100% reclaimed coal ash from ponds . . . ."[27] See **Moore Exhibit 9**.

An additional difference between the Winyah STAR facility and the Duke STAR facilities witness Bednarcik testifies to is whether construction of the facilities could be achieved through refurbishment/addition versus new construction.[28] Specifically, witness Bednarcik states on pages 41 and 42 of her rebuttal testimony filed in Docket No. E-7, Sub 1214, "the Winyah STAR facility was a refurbishment/addition to an existing carbon burn-out facility and SEFA was able to reuse a significant part of the carbon

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[27] Fedorka, W., et al. (2017) Results in Reclaiming and Recycling Coal Combustion Residuals for Encapsulated Beneficial Reuse, provided with DEC confidential response to Public Staff Data Request No. 231-19 in Docket No. E-7, Sub 1214.

[28] Page 41, Rebuttal Testimony of DEC Witness Jessica Bednarcik filed in Docket No. E-7, Sub 1214, on March 4, 2020.

burn-out facility when constructing Winyah's STAR unit." This statement conflicts with Duke Energy's Ash Beneficiation Projects / Technology Recommendation provided by DEC in response to a Public Staff data request in Docket No. E-7, Sub 1146, which states **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** [29] See **Confidential Moore Exhibit 10**.

In conclusion, when compared to the combination of H&M's cost estimate plus Duke Energy's adjustment, Duke Energy's selection of Zachry to construct its beneficiation units more than doubled the construction cost for each unit. The Company has failed to provide a credible justification for this significant increase. For these reasons, I do not believe Duke Energy's selection of Zachry to construct the beneficiation units at the Buck, H.F. Lee, and Cape Fear Stations 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, Duke Energy should have

[29] DEC confidential response to Public Staff Data Request No. 5-4(e) in Docket No. E-7, Sub 1146.

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 broken 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 a similar 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 DEP 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. PLEASE SUMMARIZE THE FOUR COST ESTIMATES DESCRIBED IN YOUR TESTIMONY.

A. The following tables summarizes the cost estimates to construct the beneficiation units at H.F. Lee and Cape Fear described in my testimony: **[BEGIN CONFIDENTIAL]**

Q. WHAT IS YOUR OPINION REGARDING WHETHER DEP'S CUSTOMERS SHOULD BE REQUIRED TO PAY FOR COSTS ASSOCIATED WITH CONSTRUCTION OF THE BENEFICIATION UNITS AT THE H.F. LEE STATION CAPE FEAR STATIONS?

A. I recommend that the Commission disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the H.F. Lee beneficiation unit and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the Cape Fear beneficiation unit for a total of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The recommended disallowance for each beneficiation unit 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 Duke Energy's contingency adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and Zachry's overall estimated contract costs of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for construction of the H.F. Lee beneficiation unit and **[BEGIN CONFIDENTIAL]** [redacted] **[END**

[33] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

CONFIDENTIAL] for construction of the Cape Fear beneficiation unit.

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 No. E-2, Subs 1193 and 1219

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 Progress, LLC, and the associated costs incurred between September 1, 2017, and December 31, 2019, at its coal combustion residuals units at its Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon 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 plants at the Company's Cape Fear and H.F. Lee stations 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 Progress witnesses Bednarcik, Smith, and Turner. 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 Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon stations.

Based on my review of the Company's 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 Mayo, Roxboro, and Weatherspoon.

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 (RFI) and the time Zachry Construction Corporation submitted its initial contract amounts to construct the SEFA STAR facilities at the Company's Cape Fear and H.F. Lee stations. 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 the amounts of $65,027,398 and $65,320,994 for unreasonable and imprudent constructions costs for the ash beneficiation plants at the Company's Cape Fear and H.F. Lee stations, respectively. The disallowance amounts are 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 amounts.

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.

Q. By whom are you employed and in what capacity?

A. I'm employed by Garrett & Moore Incorporated, and I am the secretary treasurer.

Q. Did you cause to be filed in this docket on April 13, 2020, direct testimony consisting of 49 pages and 13 exhibits, seven of which were marked as confidential?

A. Yes, I did.

Q. Do you have any corrections to that testimony?

A. No.

Q. If you were asked the same questions today, would your answers be the same?

A. Yes.

Q. And did you prepare a summary of your testimony?

A. Yes, I did.

MS. JOST: Commissioner Clodfelter, 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 13 exhibits be marked for identification as premarked in the filing.

COMMISSIONER CLODFELTER: All right. You heard the motion. Is there any objection?

(No response.)

COMMISSIONER CLODFELTER: Hearing no objection, the motion is allowed.

(Confidential Public Staff Garrett Exhibits 1, 2, 5, 6, and 10 through 12; and Public Staff Garrett Exhibits 3, 4, 7 through 9, and 13 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony with Appendix A and testimony summary of L. Bernard Garrett were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

TESTIMONY OF L. BERNARD GARRETT
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

April 13, 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 to include, 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 the results of my investigation into the prudence and reasonableness of costs incurred by Duke Energy Progress, LLC (DEP or Company), at its two high-priority sites in North Carolina, Sutton and Asheville, and at the H.B. Robinson site in South Carolina.

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 us 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 PUBLIC STAFF EMPLOYEES IN THIS CASE?

A. I understand that Public Staff witnesses Lucas 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 evaluates DEP's costs with respect to environmental regulatory compliance at its Coal Combustion Residuals (CCR) units located at the Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon Stations, and so our testimony together provides a combined perspective on the prudence and reasonableness of the coal ash closure costs for which DEP is seeking cost recovery in this proceeding.

Q. WHAT IS THE SCOPE OF YOUR INVESTIGATION INTO THE PRUDENCE AND REASONABLENESS OF DEP'S COAL ASH MANAGEMENT COSTS?

A. I reviewed the actions and costs incurred by DEP at the high-priority sites, Sutton and Asheville, in meeting the Coal Ash Management Act (CAMA)[1] deadline for closure by August 1, 2019. To the extent I determined that DEP's actions and costs incurred were not reasonable and prudent, I recommend that the Commission disallow these costs.

Q. PLEASE DESCRIBE THE RESOURCES UTILIZED TO CONDUCT YOUR INVESTIGATION.

A. In order to prepare this testimony, I reviewed the testimony and work papers of DEP witnesses Bednarcik, Smith, and Turner. Through the Public Staff, I also submitted extensive discovery to DEP regarding its actions taken and cost incurred at its high-priority sites. I also participated in site visits and conference calls with DEP personnel.

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[1] 2014 N.C. Sess. Law 122, as amended by 2016 N.C. Sess. Law 95.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony is focused on specific aspects of DEP's CAMA compliance efforts for the two high-priority sites. First, DEP paid a fulfillment fee related to the disposal of ash from Sutton, Cape Fear, H.F. Lee, and Weatherspoon at the Brickhaven structural fill project that was not reasonable and prudent. I recommend a disallowance in the amount of $33,670,054 related to the fulfillment fee. Second, with respect to Asheville, I recommend a disallowance of $50,238,630 related to the hauling costs for disposal of ash at the R&B landfill.

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 Duke Energy Carolinas, LLC's (DEC), Riverbend Station and from DEP's 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 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 AS 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]

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[2] In her direct testimony, DEP witness Bednarcik refers to the Sanford Mine as the Colon Mine.

[3] eMax Master Contract Number 8323, dated November 12, 2014, between Charah, Inc., and Duke Energy Business Services, LLC as Agent for and on behalf of Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc. Provided by DEC as a confidential response 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.

Q. PLEASE BRIEFLY DESCRIBE THE SUBJECT OF CONTRACT 8323.

A. Along with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** A copy of Contract 8323 is provided as **Confidential Garrett Exhibit 1.**

Q. DID THE 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]

[redacted] **[END CONFIDENTIAL]**

Q. WHAT WERE THE TERMS OF THE FINANCIAL COMMITMENT FOR ASH DESTINED FOR BRICKHAVEN?

A. For ash excavated from Sutton 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]

[END CONFIDENTIAL]

Q. WHAT WAS THE STATUS OF THE PURCHASE ORDERS AT THE TIME OF THE DEEMED TERMINATION?

A. As of **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** No purchase orders were issued for ash to be 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]

[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]

[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]

Q. DO YOU RECOMMEND A SPECIFIC DISALLOWANCE IN THIS RATE CASE?

A. Yes. DEC's Riverbend would be allocated the entire Prorated Costs amount above because **[BEGIN CONFIDENTIAL]** [redacted]

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[4] DEC response to Public Staff Data Request No. 127-3 in Docket No. E-7, Sub 1214.

[redacted] **[END CONFIDENTIAL]** Also, as stated above, no purchase orders were issued for ash to be delivered from Cape Fear, H.F. Lee, or Weatherspoon. Therefore, I recommend the fulfillment fee included in the ARO costs be reduced from $33,670,054, the portion of the fulfillment fee settlement allocated to DEP, to $0.00.

Q. PLEASE PROVIDE A SUMMARY OF THE FULFILLMENT FEE IN THE TESTIMONY OF DEP WITNESS JESSICA BEDNARCIK.

A. On pages 22 and 23 of her direct testimony filed on October 30, 2019, DEP 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 the Charah [ ] Brickhaven, and Colon mines" from DEP's Cape Fear, H.F. Lee, Sutton, and Weatherspoon sites and DEC's Riverbend site. 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 $$33,670,054 that "has been allocated to DE Progress to account for costs incurred by Charah associated with the ash sent from the Sutton location and anticipated to have been sent from [the]

Cape Fear, H.F. Lee and Weatherspoon locations." Witness Bednarcik's workpaper to calculate and allocate 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 on page 23 of her testimony, "it is common and reasonable to require minimum investment from the company receiving the service." Witness Bednarcik further states, "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?

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.

[5] DEC confidential responses to Public Staff Data Request Nos. 1-8 and 112-20 in Docket No. E-7, Sub 1214.

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 Sutton for disposal at Brickhaven and for ash excavated from Riverbend 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.

[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] **[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.

It should be noted 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. SHOULD THE COMMISSION DETERMINE THAT THE FULFILLMENT FEE WAS APPROPRIATE, WHAT METHODOLOGIES USED BY DUKE ENERGY ARE AVAILABLE FOR THE ALLOCATION OF THE FEE?

[7] DEC confidential response to Public Staff Data Request No. 112-20 in Docket No. E-7, Sub 1214.

A. Duke Energy has used two different allocation methodologies at different points in time. Both allocation methodologies highlight the unreasonableness and imprudence of the fulfillment fee paid by Duke Energy to Charah.

Confidential Garrett Exhibit 10[8] illustrates the allocation methodology used consistently by Duke Energy in its alternatives evaluations to select closure methods for the intermediate and low-priority sites and in its ARO cost projections in the E-2, Sub 1142 rate case, prior to the settlement of the prorated costs. Based on this methodology, the percentage allocated to Cape Fear, H.F. Lee, and Weatherspoon is as follows: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Using this percentage, the fulfillment fee allocated to Cape Fear, H.F. Lee, and Weatherspoon is as follows: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** See **Confidential Garrett Exhibit 11**. Based on the foregoing, the fulfillment fee included in the ARO costs in this proceeding would be increased from $33,670,054 to $53,033,497.

[8] DEP confidential response to Public Staff Data Request No. 14-6 in Docket No. E-2, Sub 1142.

The allocation method described above would have DEP ratepayers pay **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for ash that was slated to be excavated from the Cape Fear, H.F. Lee, and Weatherspoon sites and disposed of at the Sanford Mine. This is despite the fact that this was just one of the possible closure methods being considered by DEP at the time, and despite the fact that no purchase orders were issued for ash to be excavated from or disposed of at these locations and, therefore, no financial commitment was established. Duke Energy had contract terms to protect it from financial commitment under Contract 8232 during the early stages of CAMA since the closure methods (cap in place, hybrid, excavation, and beneficiation) were variable for the intermediate (possible reclassification) and low priority sites pending DEQ approval. The fulfillment fee is not satisfying payment for unreimbursed costs incurred by Charah to facilitate disposal of ash that Duke Energy was obligated to send, but is instead functioning as a financial penalty that Duke Energy has agreed to in settlement and is seeking to have customers pay for in rates.

The portion of the fulfillment fee DEP is seeking to recover in this rate case is based on a different allocation methodology which is set out in witness Bednarcik's work paper provided to the Public Staff in response to a data request. See **Confidential Garrett Exhibit 5**.[9] This methodology appears to have been formulated to result in a more even allocation of the fulfillment fee settlement amount between DEC and DEP customers. Like Duke Energy's original allocation methodology, the methodology used in witness Bednarcik's DEP testimony contains a number of flaws including, but not limited to, the following: 1) the allocation begins with a fulfillment fee of $80,000,000, which should be $53,093,377 and no greater than $57,857,800 as calculated by Duke Energy; 2) no purchase orders were issued designating ash from Cape Fear to be disposed of at Brickhaven and therefore allocating $9,315,601 to Cape Fear for Brickhaven Site Development/Acquisition is unreasonable; 3) no closure cost will be incurred at Sanford/Colon because the site was not developed and therefore allocating $2,536,233 to Weatherspoon and $6,391,307 to H.F. Lee is unreasonable; and 4) no post closure cost will be incurred at Sanford/Colon because the site was not developed and therefore allocating $344,460 to Weatherspoon and $868,040 to H.F. Lee is unreasonable.

[9] DEC confidential response to Public Staff Data Request No. 1-8 in Docket No. E-7, Sub 1214.

Q. NOTWITHSTANDING THE FLAWS IN THE ALLOCATION METHODOLOGIES DESCRIBED ABOVE, DO YOU HAVE A RECOMMENDATION FOR HOW TO ALLOCATE THE FULFILLMENT FEE IF THE COMMISSION DEEMS THIS PAYMENT WAS APPROPRIATE?

A. As stated above, I recommend the fulfillment fee included in the ARO costs be reduced from $33,670,054, the portion of the fulfillment fee settlement allocated to DEP, to $0.00. However, should the Commission give substantial weight to the settlement and prorated costs calculation of Duke Energy, consistent with my recommendation in the companion DEC rate case (Docket No. E-7, Sub 1214), I recommend that the fulfillment fee I calculated on pages 29 and 30 above be allocated using Duke's original methodology described above. Using Duke Energy's original allocation method, the fulfillment fee included in the ARO costs in this proceeding would be increased from $33,670,054 to $53,033,497.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THE FULFILLMENT FEE?

A. Yes. Section 7.4 of Contract 8232 states: **[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

[END CONFIDENTIAL]

In addition to the Recovery Amount terms, DEP and DEC have 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.

<u>ASHEVILLE HAULING COSTS</u>

Q. PLEASE SUMMARIZE WITNESS BEDNARCIK'S TESTIMONY REGARDING WORK COMPLETED AT THE ASHEVILLE SITE.

A. As stated in witness Bednarcik's testimony, DEP is seeking recovery of $99,274,167 in costs incurred between September 1, 2017, and June 30, 2019, for excavation activities at its Asheville site.

Regarding the work completed at DEP's Asheville site, witness Bednarcik states as follows on pages 17 and 18 of her direct testimony:

> DE Progress is required to excavate and close its ash basins at Asheville by August 1, 2022. There are two ash basins at Asheville that are subject to the closure requirements of the CCR Rule and CAMA: the 1964 Ash Basin and the 1982 Ash Basin.
>
> Excavation of the 1982 Ash Basin was completed on September 30, 2016. During the period from September 1, 2017, through September 2019, DE Progress excavated ash from the 1964 Ash Basin which was transported to Waste Management, Inc.'s R&B Landfill in Homer, Georgia for final disposal. The Company has begun designing an onsite landfill capable of storing approximately 1.2 million tons of ash from the 1964 Ash Basin.

Exhibit 7 to witness Bednarcik's testimony provides the following information regarding closure activities from September 1, 2107, through February 29, 2020, at the Asheville site:

> As of September 1, 2017, DE Progress had already entered into extensive contracts with engineering and construction contractors to perform the necessary site assessments, develop excavation and compliance plans, and to excavate and transport the CCR for permanent disposal. Costs related to those contracts and activities performed pursuant to those contracts through August 31, 2017 have already been approved by the Commission. DE Progress has continued its efforts to execute the excavation and closure plans for Asheville and comply with state and federal regulatory requirements.
>
> From September 1, 2017 through February 29, 2020, DE Progress has completed or is scheduled to complete the following tasks:
>
> • Excavate ash from the 1964 Ash Basin;
>
> • Transport ash from the 1964 Ash Basin to the R&B Landfill;
>
> • Operate and maintain[ ] the 1964 Ash Basin;
>
> • Obtain environmental permits;
>
> • Install groundwater monitoring wells;
>
> • Monitor and analyze groundwater samples;
>
> • Plan, design, and install permanent water supplies for neighbors;
>
> • Complete construction of the lined retention basin for water equalization after coal station and rim ditch retirement;
>
> • Decommission and grade ash basin dams to meet post-closure dam safety requirements;

> • Initiate and complete water treatment implementation and commissioning;
>
> • Complete design for onsite landfill and submit permit applications for new onsite landfill.
>
> The tasks that DE Progress has performed and will perform from September 1, 2017 through February 29, 2020 are a continuation of the activities for which costs were approved in the prior DE Progress rate case. These activities and associated costs continue to be necessary, appropriate, and consistent with applicable regulatory requirements.

Exhibit 9 to witness Bednarcik's direct testimony, the Company's Asheville Steam Electric Generating Plant Coal Ash Excavation Plan 2018 Update, provides on page 8:

> Ash from the 1964 Ash Basin is currently being transported to a permitted ash monofill at the R&B Landfill in Homer, GA. The on-site landfill at Duke Energy's Rogers Energy Complex remains an option for the Company if events warrant transition to another site. The Company continues to develop and evaluate contingency storage locations.
>
> Plans for ash disposal during Phase III are currently being evaluated and will be finalized in 2019. The on-site landfill at Duke Energy's Rogers Energy Complex remains an option, and the construction of an on-site landfill at the Asheville Plant is being evaluated as well.
>
> The project team will utilize lessons learned from Phase II to develop an off-site disposal strategy and/or alternative beneficial use site(s) that will provide the improvements below:
>
> •Provide a reliable, long-term, cost-effective solution for ash designated for removal
>
> •Support development of a diverse supplier program to drive innovation and competition

•Establish performance baselines and a system to optimize excavation, transportation, and disposal of ash

Q. HAVE YOU ESTIMATED THE COSTS INCURRED BY DEP TO ACCOMPLISH THE EXCAVATION, TRANSPORTATION, AND DISPOSAL WORK DESCRIBED ABOVE?

A. Yes. The Company's response to Public Staff data request indicates that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was spent between September 1, 2017, and December 31, 2019.[10]

Q. WHAT WAS THE QUANTITY OF ASH EXCAVATED, TRANSPORTED, AND DISPOSED OF DURING THAT TIME FRAME?

A. According to the Company's response to a Public Staff data request, a total of 1,651,500 tons of ash were excavated, transported, and disposed of at the R&B Landfill between September 1, 2017, and December 31, 2019.[11]

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[10] DEP confidential response to Public Staff Data Request No. 83-4 in Docket No. E-2, Sub 1219.

[11] DEP response to Public Staff Data Request No. 164-3 in Docket No. E-2, Sub 1219.

Q. HAVE YOU CALCULATED A PER TON COST FOR THE ASH EXCAVATED, TRANSPORTED, AND DISPOSED OF BETWEEN SEPTEMBER 1, 2017, AND DECEMBER 31, 2019?

A. Yes, based on the information provided by the Company, the per ton cost is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. DO YOU CONSIDER THAT AMOUNT TO BE REASONABLE?

A. No. I consider the per ton cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to be excessive.

Q. DID YOU IDENTIFY ANY SPECIFIC ISSUES THAT RESULTED IN THE COSTS OF THE EXCAVATION, TRANSPORTATION, AND DISPOSAL WORK BEING EXCESSIVE?

A. Yes, the costs became excessive primarily as a result of transportation cost associated with the off-site disposal of ash at the R&B Landfill. The transportation cost alone was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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[12] Purchase Order 2380129 provided in DEC confidential response to Public Staff Data Request No. 44-1 in Docket No. E-7, Sub 1146.

Q. DID THE COMPANY HAVE OTHER OPTIONS THAT COULD HAVE BEEN MORE COST EFFECTIVE?

A. Yes. Both disposal of the ash at the Rogers Energy Complex, also known as Cliffside, or in an onsite landfill at the Asheville site could have been lower cost options. Both of these options were identified by the Company Asheville Steam Electric Generating Plant Coal Ash Excavation Plan 2018 Update, which is excerpted above.

Q. DID DEP UTILIZE THE LANDFILL AT THE ROGERS ENERGY COMPLEX FOR ASH DISPOSAL BETWEEN SEPTEMBER 1, 2017, AND DECEMBER 31, 2019?

A. No. In response to a Public Staff data request asking whether the Company considered disposal at the Rogers Energy Complex, DEP referenced the proposal evaluation titled "CONFIDENTIAL PA 58726 RFP Evaluation Master 102716.xlsx".[13] **Confidential Garrett Exhibit 12** presents a summary page, tab "Final Short List Comparison", of the lowest cost options. Based on my review of the information contained in **Confidential Garrett Exhibit 12**, I reached the following conclusions: **[BEGIN CONFIDENTIAL]**

[13] DEP response to Public Staff Data Request No. 164-3 in Docket No. E-2, Sub 1219, and confidential response to Public Staff Data Request No. 6-4(a).

[redacted]

[END CONFIDENTIAL]

Q. DID DEP UTILIZE AN ONSITE LANDFILL AT ASHEVILLE FOR ASH DISPOSAL BETWEEN SEPTEMBER 1, 2017, AND DECEMBER 31, 2019?

A. No. An onsite landfill has not been constructed yet at the Asheville site.

Q. WHAT IS THE STATUS OF THE ONSITE LANDFILL AT THE ASHEVILLE SITE?

A. In response to a Public Staff data request, DEP indicated it began the permitting process for the onsite landfill on April 3, 2019, by submitting the Site Suitability Report to DEQ.[14] In addition, on February 7, 2020, DEP was issued the Final Permit to Construct, Solid Waste Permit, and Zoning Permit to construct and operate the CCR landfill.

Q. DO YOU RECOMMEND THAT COSTS INCURRED AT THE ASHEVILLE SITE BE DISALLOWED?

A. Yes, I recommend the Commission disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This disallowance is calculated by multiplying the total 1,651,500 tons disposed of between September 1, 2017, and December 31, 2019, by the per ton transportation cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which

[14] DEP response to Public Staff Data Request No. 124-2 in Docket No. E-2, Sub 1219.

is the rate DEP paid to transport ash from the Asheville site to the R&B Landfill.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED COSTS INCURRED TO TRANSPORT ASH FROM THE ASHEVILLE SITE TO THE R&B LANDFILL?

A. Yes. The Commission approved rate recovery for costs incurred to transport ash from the Asheville site to the R&B Landfill as part of DEP's previous rate case in Docket No. E-2, Sub 1142.

Q. WHY SHOULD THE COMMISSION CONSIDER THIS ISSUE AGAIN IN THE CURRENT DOCKET?

A. The Commission's approval of rate recovery for the costs incurred to transport ash to the R&B landfill in the Docket No. E-2, Sub 1142, rate case was based on the fact that the ash excavated and transported from the 1982 Basin had to be removed to allow for the construction of the combined cycle plant to meet the deadlines required by the Mountain Energy Act.[15] However, there has been a material change in facts regarding the onsite landfill at Asheville as

[15] 2015 N.C. Sess. Law 110.

compared to the facts set out in DEP's testimony filed in the E-2, Sub 1142, rate case.

Q. WHAT MATERIAL FACTS DO YOU CONTEND HAVE CHANGED?

A. On page 28 of my joint testimony filed with Public Staff witness Vance F. Moore in the E-2, Sub 1142, rate case I stated:

> Upon passage of the MEA in 2015 which extended the closure deadline for the CCR units at the Asheville facility to December 31, 2022, DEP should have pursued an on-site industrial landfill. It does not appear DEP evaluated or identified fatal flaws eliminating the possibility of an on-site industrial landfill. Had an on-site industrial landfill capable of storing three million tons of CCR been pursued, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in hauling costs could potentially be avoided. While the design and construction of an on-site industrial landfill at the Asheville facility would have been technically challenging, it is our opinion that it could be done at a lower cost than hauling the remaining CCR off-site."

On pages 14 through 16 of his rebuttal testimony filed in the E-2, Sub 1142, rate case, DEP witness Kerin stated:

> Potential siting and construction of a CCR landfill within portions of the Asheville 1982 basin and limited portions of the 1964 basin was evaluated as early as 2007 prior to the passage of CAMA. However, earthquake and seismic issues, and its physical proximity to the French Broad River prevented this option.
>
> . . . .

> In summary, while on-site CCR landfills had been researched in the past for Asheville, the Mountain Energy Act of 2015 effectively made construction of a new on-site CCR landfill [ ] technically unfeasible given the short time period to replace the coal-fired generation by 2020, and close both ash basins by 2022.

The reasons for not pursuing an onsite landfill at the Asheville site stated in DEP witness Kerin's rebuttal testimony excerpted above, including seismic issues and proximity to the French Broad River, implied that the construction of an onsite landfill at the Asheville site was impossible in 2015. Witness Bednarcik's testimony that an onsite landfill is possible not only renders the transportation costs associated with disposal at R&B Landfill unreasonable, but provides the Commission with justification to review those costs in this rate case.

Q. DID DEP PROVIDE ANY NEW INFORMATION THAT WOULD EXPLAIN WHY AN ONSITE LANDFILL WAS CONSIDERED UNFEASIBLE IN 2015, BUT IS NOW CONSIDERED FEASIBLE?

A. DEP provided a narrative explanation in the response to a Public Staff data request.[16] See **Garrett Exhibit 13**. The response states, in part, the following:

[16] DEP response to Public Staff Data Request No. 164-2 in Docket No. E-2, Sub 1219.

> The landfill which was conceptually sited over portions of the 1982 and 1964 basins was sized to provide 20 years of capacity and was significantly larger than the landfill currently being built on site (5.2 million tons of capacity vs 1.3 million tons). The site of the current landfill was evaluated and considered to be too small to meet the projected capacity needs in the 2007-2011 time period and was thus not further evaluated at that time.
>
> Note that seismic issues were a significant factor in the design of a landfill sited over ash. Such a design required placement of stone columns and a stone mat to support the landfill during a design earthquake. Siting a landfill over natural soils, such as the landfill currently being built, does not face the same seismic risk and is stable under a design seismic event.

In addition, the response states, "Alternate landfill options were evaluated by Golder Associates and their findings were documented in multiple reports submitted to Progress Energy. DEP is currently trying to locate copies of these documents and will provide them as they are located." It is unclear whether the reports prepared by Golder Associates identified in the response relate to studies completed in the 2007 to 2011 timeframe (not applicable to CAMA and MEA) or to studies completed in the 2014 to 2015 timeframe (applicable to CAMA and MEA). It appears that DEP witness Kerin's testimony in the E-2, Sub 1142, rate case was based on a 2007 evaluation under significantly different design assumptions than in the CAMA, MEA, and CCR Rule era. While the narrative also identifies siting, design, and schedule issues, it does not provide compelling evidence to support DEP's decision to haul ash to the

R&B landfill at a higher cost. As such, I do not believe DEP has met its burden of proving that the transportation costs it seeks to recover were reasonable and prudent.

Q. PLEASE DESCRIBE THE EVIDENCE DEP WOULD NEED TO PROVIDE TO SUPPORT THE DECISION TO INCUR THE TRANSPORTATION COSTS FOR HAULING ASH TO R&B LANDFILL.

A. DEP would need to provide a comprehensive report, prepared by an independent consulting engineering firm and dated in the 2014 to 2015 timeframe. This comprehensive report would need to include a complete and thorough analysis of landfill development options on the site.

SUTTON PLANT

Q. DO YOU RECOMMEND DISALLOWANCE OF ANY OF THE COSTS ASSOCIATED WITH ACTIVITIES AT THE SUTTON PLANT?

A. No. I reviewed the work plans, contracts, and purchase orders for the work completed at the Sutton plant and do not take any exception to the work completed between September 1, 2017, and December 31, 2019, or the associated costs.

H.B. ROBINSON PLANT

Q. DO YOU RECOMMEND DISALLOWANCE OF ANY OF THE COSTS ASSOCIATED WITH ACTIVITIES AT THE H.B. ROBINSON PLANT?

A. No. I reviewed the work plans, contracts, and purchase orders for the work completed at the H.B. Robinson plant and do not take any exception to the work completed to date or the associated costs.

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
- Engineering Design
- USEPA HELP Modeling
- Cost Engineering
- Geotechnical Engineering
- Leachate Management Design & O&M
- Alternative Liner and Final Cover Design
- NPDES Wastewater Design & O&M
- Stormwater Management & Design
- Landfill & Wastewater Operations Planning
- Equivalency Determinations
- Life of Site Analysis
- Recyclables Program Management
- Waste Processing and Recovery
- Landfill Closure & Post-Closure
- Transfer Stations
- Convenience Center Planning / Design
- Compost Systems
- Waste Treatment & Processing
- Special Waste Permitting
- Landfill Gas Remediation Plans
- 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 No. E-2, Subs 1193 and 1219

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 Progress, LLC, or "DE Progress," at its two high priority sites, Asheville and Sutton, to comply with the Coal Ash Management Act, or "CAMA," and at its H.B. Robinson site in South Carolina. The primary focuses of my testimony are whether the fulfillment fee DE Progress paid its contractor Charah, Inc., pursuant to a settlement related to the disposal of ash from the Company's Sutton, Cape Fear, H.F. Lee, and Weatherspoon stations, and transportation costs associated with the disposal of ash from the Company's Asheville site at the R&B landfill 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 Progress witnesses Bednarcik, Smith, and Turner. I also participated in site visits to the Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon stations and conducted extensive discovery through the Public Staff.

Based on my investigation, I concluded that DE Progress acted unreasonably and imprudently in entering into a contract with Charah for the disposal of ash from Sutton station at the Brickhaven Mine. Specifically, I concluded that the termination provisions of the contract contained fundamental flaws that resulted in DE Progress paying an unreasonable and imprudent fulfillment fee to Charah which DE Progress seeks to recover in this rate case. Based on my analysis and conclusions, I recommend the portion of the fulfillment fee included in the ARO cost in the amount of $33,670,054 be disallowed.

With regard to the Asheville site, I recommend a disallowance in the amount of $50,238,630 for costs DE Progress paid to have ash transported from the Asheville site to the R&B Landfill located in Homer, Georgia between September 1, 2017, and December 31, 2019. The Company's failure to pursue an on-site landfill at Asheville until April 3, 2019, represents the failure to pursue a lower cost option. While DE Progress witness Jon Kerin testified in the E-2, Sub 1142, rate case that the Mountain Energy Act of 2015 (MEA) effectively made construction of a new on-site CCR landfill technically infeasible, the Public Staff has learned through discovery responses provided by the Company in this rate case that the Company did not adequately evaluate an onsite landfill to address changes in its ash disposal needs in the CAMA, MEA, and CCR Rule era until recently. Furthermore, DE Progress has failed to provide any reports, studies, or evaluations by a qualified Professional Engineer that justify incurring the transportation costs recommended for disallowance.

This completes my summary.

MS. JOST: Thank you. Additionally, pursuant to the September 28, 2020, amended joint stipulation regarding admission of certain live testimony and exhibits between DEP, the Attorney General's Office, Sierra Club, and the Public Staff, I move that the live testimony of Mr. Garrett and Mr. Moore in the E-7, Sub 1214 hearing be entered into the record in this proceeding as if given orally from the stand; and that live testimony is located in the E-7, Sub 1214 transcript Volume 20, beginning on page 254, line 1, and continuing through page 373, line 11.

COMMISSIONER CLODFELTER: All right. You've heard the motion. Are there any objections?

(No response.)

COMMISSIONER CLODFELTER: Hearing no objections, motion is allowed.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, transcript Volume 20, page 254, line 1 through page 373, line 11 was copied into the record as if given orally from the stand.)

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: And finally, I would also move that the following exhibits that were entered into evidence in the E-7, Sub 1214 hearing be given the same identifications and be moved into the record in this proceeding. And those are DEC Garrett/Moore Cross Examination Exhibits 1 through 5, and Public Staff Garrett/Moore Redirect Exhibits 1 and 2.

COMMISSIONER CLODFELTER: Those exhibits will be so marked for identification purposes.

(DEC Garrett/Moore Cross Examination Exhibits 1 through 5, and Public Staff Garrett/Moore Redirect Exhibits 1 and 2 from Docket Number E-7, Sub 1214 were admitted into evidence.)

MS. JOST: Thank you. The witnesses are available for cross examination and questions from the Commission.

COMMISSIONER CLODFELTER: Thank you, Ms. Jost. The only party I have on my list requesting cross examination is the Company.

Mr. Marzo?

MR. MARZO: Thank you, Commissioner Clodfelter.

CROSS EXAMINATION BY MR. MARZO:

Q. Good still morning, gentlemen, how are you?

A. (Bernard L. Garrett) Good morning.

A. (Vance F. Moore) Good morning.

Q. Okay. The good news, gentlemen, is we covered a lot of ground that as Ms. Jost just mentioned is carried over into this proceeding per the stipulation, but I do have some additional questions that I want to ask you about this morning.

Mr. Garrett -- and by the way, Mr. Garrett and Mr. Moore, I don't believe that we will touch upon confidential information. My questions are framed in that manner. But if for some reason you believe an answer would be better or elicits confidential, please help me in that regard and let me know.

A. (Bernard L. Garrett) Fair enough.

Q. Okay. Mr. Garrett, if I understand your testimony correctly, you're recommending that the Commission disallow the costs the Company incurred to transport 1,651,500 tons of ash from Asheville to Waste Management's permitted R&B landfill; is that correct?

A. Yes, sir, that's correct.

Q. Okay. And in your prefiled testimony, you acknowledge that the Commission approved rate recovery of Duke Energy Progress' costs to transport CCR from Asheville to the R&B landfill in the Company's last rate case, which was Docket E-2, Sub 1142, correct?

A. Yes. I believe the ash that was considered in that rate case was from the 1984 basin, which was moved in order to build the combined cycle plant, yes.

Q. Okay. And do you also, then, agree or understand that the costs the Company seeks to recover in this case were incurred under the very same purchase orders, and orders as a cost that were approved by the Commission in the Company's last rate case?

A. I believe they were under the same purchase orders or at least under the same contract.

Q. Okay. Thank you, Mr. Garrett.

Now, you assert that the Commission should reverse its decision from the 2018 case because there's been -- I think in your words -- a material change in facts regarding the landfill at Asheville as compared to the facts set out in Duke Energy Progress' testimony in that case; is that a fair recitation of your position?

A. Based on the discovery responses that we received during this rate case, I think additional information has come forward that shows that Duke

Energy Progress did not meet its burden of proof regarding incurring these exorbitant transportation costs to haul ash to the Homer, Georgia, site.

Q. And I appreciate that, Mr. Garrett, and we will get into a discussion about the specific change that you're referring to. But I first want to kind of understand your material change standard.

Is that a standard that you are referring to in statute and case law upon which you are referring to?

A. I am referring to -- primarily to the fact that, based on what we've learned in this rate case, it appears that Mr. Kerin's testimony regarding the feasibility of developing an on-site landfill at Asheville was I'd say maybe incomplete or somewhat misleading.

Q. And, Mr. Garrett, I think you may have answered my question, but just for clarity for the record, what I'm asking you essentially is you're not using material change in the form of particular standard? I understood that you were -- from your answer a moment ago, you were using that word just generally to mean that there's something new that you believe should be considered by the Commission in this case; is that -- is that a fair recitation?

A. Yes. Material change meaning the specific evaluations that were done regarding the feasibility of an on-site landfill at Asheville.

Q. Okay. And there's not a case law or standard in place that you're using as a reference point for material change, that's sort of self-created in your testimony, correct?

A. That was the terminology that I used to describe the fact that new information became available in this case was clarified the feasibility of building an on-site landfill.

Q. Okay. And let's discuss that a little bit now. And you just discussed a moment ago, the material change that you believe occurred in this case, you lay out particular, specifically in your testimony, and if you want to turn to it, you can, but it's on page 46 of your testimony. And I'll let you get there if you want to do that. And I'm essentially looking, Mr. Garrett, at lines 11 through 15.

A. Let's see.

(Witness peruses document.)

Okay. I've read that.

Q. And you essentially argue that Mr. Kerin's testimony in the prior DEP case, and to your words, implied that the construction of an on-site landfill at Asheville site was impossible in 2015, but in the present case, Ms. Bednarcik's testimony that on-site landfill is possible provides the Commission with justification to review those costs in this case; is that a fair recitation of what you're saying there?

A. And I think, more specifically, I believe Mr. Kerin's testimony from the prior case indicated that there were fatal flaws on the site with regards to proximity to the French Broad River and seismic issues. And we definitely received clarification that the seismic issues he was referring to related to a 2007 study where the Company was evaluating constructing roughly a 5 million ton landfill on top of the existing ash in the 1964 basin.

Q. And I appreciate that, Mr. Garrett, but let's look at, in the prior case, what you said and what Mr. Kerin was referring to and responded to in that case. If you would, would you refer to DEP Cross Exhibit 38?

A. Let's see here.

MR. MARZO: And for the record, Commission Clodfelter, this is Volume 18 of the transcript of the testimony from Docket E-2, Sub 1142. And I would like to have it marked at the appropriate time.

COMMISSIONER CLODFELTER: This would be the appropriate time to mark it if you intend to question about it.

MR. MARZO: I'd like to have it marked, Commissioner Clodfelter, as Garrett/Moore DEP Cross Exhibit Number 6.

COMMISSIONER CLODFELTER: It will be so marked.

MR. MARZO: Thank you.

(Garrett/Moore DEP Cross Exhibit Number 6 was marked for identification.)

Q. Do you have that document, Mr. Garrett?

A. Did you say Exhibit -- DEP Exhibit 38?

Q. 38, yes, sir.

A. Yes, I have it open.

Q. Okay. Yeah, it should be a transcript, so hopefully that's what you have.

A. Yes, that's what I have.

Q. Okay. If you would, for me, Mr. Garrett, would you refer to page 159 of the transcript. And this transcript is your testimony, yours and

Mr. Moore's combined testimony in that -- in the DEP in the DEP rate case in Docket E-2, 1142.

A. Did you say page 159?

Q. Yes, sir. 159 should be the label on the page. So if you're looking at a PDF, it may be numbered differently, but I'm looking at the actual top right-hand corner page labeling.

A. Yes, it's the same. Yes, sir, I think I'm in the right --

Q. And I'm looking at lines 12 through 16. And the version that you should have should be a noncon -- it should be a nonconfidential public version. And we won't have to talk about the confidential information, but I do want to refer to some language in that section.

In that section from line 12 through 15, your testimony is:

"Had an on-site industrial landfill capable of storing 3 million tons of CCR been pursued, then hauling costs could potentially be avoided."

And the part that I omitted, of course, was the amount of the cost, the dollars related, which is confidential.

Did I state that correctly?

A. Yes, sir.

Q. Okay. Now, if you would for me, could you now turn to DEP Exhibit 44. And if it's helpful to you, Mr. Garrett, we will refer back to Exhibit 38, so to the extent you are organizing it such you can refer back --

A. Sure.

Q. -- please keep that in mind.

A. Okay.

MR. MARZO: Commissioner Clodfelter, this is Volume 20 from the transcripts from Docket Number E-2, Sub 1142. Similarly, I would like to mark DEP Exhibit 44 as DEP -- as, I'm sorry, Garrett/Moore DEP Cross Exhibit Number 7.

COMMISSIONER CLODFELTER: It will be so marked.

MR. MARZO: Thank you, sir.

(Garrett/Moore DEP Cross Exhibit Number 7 was marked for identification.)

Q. And when you're able to get that document open, Mr. Garrett, if you would, for me, refer to page 116.

A. Okay.

Q. And it's actually -- sorry, Mr. Garrett, it's actually page 114. And I'm looking at lines 9 through 24 on that page. And this is a Q and A -- for the record, this is a Q and A between Ms. Townsend from the AGO's office and Mr. Kerin who is testifying at this point in time in the hearing related to his testimony.

Do you see on page 114, at line 9 where Ms. Townsend asks -- essentially asks Mr. Kerin -- and I'll just say what she says. I think it's probably faster for me just to read her words.

"As previously discussed, that while the CCR landfill construction had been researched in the past, CAMA and the Mountain Energy Act forever changed the technical feasibility of an on-site CCR landfill."

She asked him, "What do you mean by the technical feasibility in that statement"; do you see that?

A. Yes.

Q. Okay. And then you see his answer begins on line 16. And Mr. Kerin in response says:

"Technically it's building a landfill of appropriate size that can handle 3 million tons of ash at Asheville site."

If you're familiar with the Asheville site, and I know we provided drawings of the Asheville site with the combined cycle layout, the laydown layouts, it showed where the existing power plant is Lake Julian, the '64 basin, there's not any other location that I can see on the map with terrain there that you are going to build a 3 million -- 3 million ton -- 3 million ton landfill, is his last part.

And I won't read the rest of his answer, but generally that's his response to that question.

Now, let me ask you, Mr. Garrett. Mr. Kerin, throughout his testimony, and I don't know if you recall in that docket, went into great detail about the immense challenges preventing the development of an on-site landfill at the Asheville site during construction of the combined cycle plant; is that your recitation of -- recollection of that testimony?

A. Would you repeat that?

Q. Sure. As he did here in response to Ms. Townsend in the prior case, Mr. Kerin discussed in detail the challenges with building an on-site landfill while also constructing the combined cycle plant that was required by the Mountain Energy Act; isn't that correct?

A. He did discuss those issues, but he made those statements without having the benefit of any evaluation ever being done by a qualified professional engineer with experience in coal ash pond closure in landfill development.

Q. Are you refuting, Mr. Garrett, that there were evaluations done that Mr. Kerin actually referred to that were done as early as 2007 --

A. He -- the evaluation he's referring to in 2007 was specifically looking at, as far as the Asheville site goes, construction of a 5 million ton landfill on top of the existing ash. Those studies that he's referring to in 2007 were not applicable to the CAMA Mountain Energy Act era.

Q. And similarly in that case, Mr. Garrett, my recollection is that you also challenged that there should be some additional -- additional analysis; is that correct?

A. CAMA 2016, if you look at the House Bill 630, session law 2016-95, under closure of coal combustion residual surface impoundments, under high-risk impoundments, the law specifically says the owner of an impoundment shall either convert the coal combustion residuals impoundment to an industrial landfill. That aspect of the law was never evaluated by Duke Energy Progress in their decision-making.

Subsequently to Mr. Kerin's testimony in the previous rate case, DEP did pursue and on-site landfill outside of the 1964 basin, which is allowing them to store -- I think it's like 1.1 million cubic yards of ash on site. But no comprehensive analysis was done in the 24 or 2016 time frame that would have sought to eliminate the transportation cost of hauling to Homer, Georgia.

Q. And, Mr. Garrett, I appreciate your answer, but I don't think you answered my question.

My question was, did you make a similar argument in the prior rate case for an additional analysis?

A. I don't --

Q. You don't recall? Okay. If you don't recall, that's fair.

A. Yes.

Q. Okay.

A. I don't remember that specifically, but --

Q. And would you --

A. -- it should have been evaluated at that time.

Q. And can we agree that the Commission considered thoroughly in the prior rate case the challenges that Mr. Kerin talked about in regards to building an on-site landfill at Asheville while also operating the coal plant, constructing the combined cycle plant, excavating the basins; they considered all those challenges in the prior case, correct?

A. What I recalled was he did list what I would consider to be design issues. Those are the challenges. He did not provide any report that substantiated those design issues would not be overcome. His testimony did indicate that there was a fatal flaw with regards to building a landfill on site at Asheville with regards to seismic issues. And I believe that's the part that was particularly misleading to the Commission.

Q. And you keep using the word "misleading," and I want to get into what you're suggesting Ms. Bednarcik has said in this case. But before we get there, can I ask you just probably a fundamental question?

Would you agree with me that, upon completion of the combined cycle plant, wouldn't you expect that various areas of the facility's site would open up and would be available for some use for an on-site landfill?

A. I do know that they had a laydown area that was being used for the -- for the construction of the plant. And that area is where theirs had sited the on-site landfill.

Q. So let's refer -- let's drill into that a little bit. And I think just to refresh everyone's memory of what occurred back in the last rate case, would you refer to DEP Cross Exhibit 37.

A. 37.

(Witness peruses document.)

Q. Yeah.

MR. MARZO: And this -- Commissioner Clodfelter, this is a diagram of the Asheville site similar to what Mr. Kerin provided to the Commission during the last rate case. I would like to have that marked as DEP -- sorry, Garrett/Moore DEP Cross Exhibit 8.

COMMISSIONER CLODFELTER: All right. It will be so marked. Thank you.

(Garrett/Moore DEP Cross Exhibit 8 was marked for identification.)

Q. And for ease of the Commission as well as for you, Mr. Garrett, Ms. Bednarcik, in her rebuttal testimony -- and I don't know if you have that available -- she has a very similar chart on page 31 of her testimony.

A. I recall that, yes.

Q. Yeah. And I'm going to talk to you about both of them together, so you may want to have both of them available. Her chart is more of a pictorial chart, which I think will be helpful for the discussion. The diagram I sent you is more of the technical sort of diagram that has various aspects of the site and not as well divided out as in her testimony.

So can we talk about both of them; are you okay with that?

A. Yes. I have the Exhibit 37 up. I do not have her figure up, but I believe my answers would be the same.

Q. Okay. And I will describe what I'm talking to, and I know you know enough about the site where we can -- we can basically have that discussion.

A. Sure.

Q. Now, as -- first off, before we get into some of the specific questions, just in looking at the site, if you look at either Exhibit 37 or Ms. Bednarcik's testimony on page 31. If you think about the site as broken up in her testimony into quadrants, am I right that what has been referred to in her testimony as number 2, which is the right-hand -- the right upper-hand quadrant, that's where the coal-fired plant resides?

A. I recall that, yes.

Q. Okay. And if I refer to what's been referred to in her testimony as quadrant number 4, which is the lower right-hand side, that's where essentially the '82 ash basin resides and now the combined cycle.

A. I recall that, yes.

Q. And if I look to the west side of the plant, which is why quadrant number 1 sits, there's a laydown area at the upper left-hand side corner; is that your understanding?

A. Yes, sir.

Q. Okay. And if I look at the lower left-hand corner, there's a 1964 ash basin in that general area; is that your general recollection too?

A. Yes. And I can see that large open area on Exhibit 37 where there's no activity ongoing related to the coal -- the combined cycle plant construction, yes.

Q. Now, as Mr. Kerin fully explained to the Commission in the last rate case, all the potential areas where a landfill could be constructed were fully being utilized for operation of the existing coal facility and for development of a new combined cycle plant; do you recall that testimony?

A. Not that specifically, but.

Q. Okay. And from cross exhibit -- well, we'll now call Garrett/Moore DEP Cross Exhibit 8, it identifies -- in addition to what's in Ms. Bednarcik's testimony in her chart, it identifies the specific laydown areas that were being used during the construction.

A. I'm familiar with that.

Q. Do you recall that?

A. Yes.

Q. Okay. And one of the issue -- one of the areas that was talked a lot about in the prior case, and I'm sure you recall this, would be located essentially in we can call quadrant 1, which was the large laydown area which was the area that was considered to be not used except for the purposes of a laydown area for the combined cycle plant.

Do you recall that?

A. Yes. The area that I'm referring to --

(Reporter interruption due to Mr. Garrett's audio failure.)

Q. Mr. Garrett, I may have lost you. Are you trying to speak?

COMMISSIONER CLODFELTER: Mr. Garrett, we've lost your --

MR. MARZO: Mr. Garrett -- yeah -- I'm sorry, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: We've lost your audio, Mr. Garrett.

THE WITNESS: Can you hear me now?

COMMISSIONER CLODFELTER: I can now.

MR. MARZO: I can now.

THE WITNESS: Okay. It must have just been an internet glitch, then.

COMMISSIONER CLODFELTER: You may need to start your answer over again. I believe we lost it.

THE WITNESS: Okay. When I'm discussing the DEP's failure to evaluate an area, I'm referring to the 1964 ash basin. I'm referring to the conversion of the impoundment to an industrial landfill.

Q. Mr. -- are you done, Mr. Garrett? I think we may have lost Mr. Garrett again. Mr. Garrett, can you hear me?

A. I can hear you, yes.

Q. Okay. So, Mr. Garrett, I understand that your position in this case as well as in the last case was that a landfill was possible. And a 3 million ton capacity landfill was possible, to be precise.

But you didn't provide any analysis in this case of the Asheville site that substantiates where a landfill, even large enough for the 1.651 million tons of ash that you're proposing be the basis of a disallowance, would go, correct?

A. Well, based on guidance from the Public Staff, I believe that it's Duke Energy Progress' burden to demonstrate they exhausted all options available to them to offset the transportation cost for hauling to Homer, Georgia. And they have not provided those evaluations that support that decision.

Q. Now, you understand, and I think we agreed previously, Mr. Garrett, that this issue was already decided in the last rate case, correct? And now you're the party, or you're -- the Public Staff, I'm sorry, is a party who is bringing this issue up to be relitigated.

So what you're telling me is you've done no additional analysis to support your position that this issue should somehow be reconsidered, correct?

A. I don't believe that Duke Energy Progress has met its burden of proof with the information from the 2017 rate case and this rate case that the tons we're talking about that were hauled off site, which were from the 1964 basin, that they did not have an on-site option for those tons.

Q. And you didn't believe that in the last rate case either, correct?

A. The last rate case was specific to the ash that was removed from the 1988 basin for the construction of the combined cycle plant.

Q. And just for the record, Mr. Garrett, you also didn't do an analysis of where a 3 million ton facility would be sited on the site either, which was your argument from the last case as well, correct?

A. I have not prepared any evaluations such that would be needed to make that determination.

Q. Okay. Could we now turn, Mr. Garrett, to what I'll refer to as DEP cross Exhibit 2. It should be your number 2. And this is the order accepting the stipulation deciding contested issues and granting partial rate increase in Docket E-2, Sub 1142, the Company's last rate order.

A. Did you say Exhibit 2?

Q. Yeah. It should be your -- it should be our Duke Energy Progress Cross Exhibit Number 2.

A. Okay. I have that open.

Q. Okay.

MR. MARZO: And, Commissioner Clodfelter, I just ask you take notice of it. No need to mark it.

COMMISSIONER CLODFELTER: The Commission takes judicial notice of all of its prior orders. You've adequately described it for purposes of the record in the case, so I think we can proceed without marking it as an exhibit.

MR. MARZO: Thank you, sir.

Q. If you would, Mr. Garrett, would you turn to page 186 of the order? And on page -- I'm sorry, Mr. Garrett --

A. Yeah, I'm on 186.

Q. Now, Mr. Garrett, on page 186, if you look at the last full paragraph begins "the Commission determines," would you mind reading that paragraph for me, and then I'm going to ask you some questions about it? And you can read it out loud, because this is part of the controversy that we're having, this particular issue, so.

A. I'm not clear on which paragraph you're asking me to read.

Q. Sure. If it makes it easier, I can do it. It starts with -- and I'll read it:

"The Commission determines that similar considerations come into play when assessing the prudence of the Company's decision to transport the Asheville plant CCRs off site once CAMA became law. The MEA, while extending the closure deadline to August 1, 2022, required construction of a new combined cycle plant. The new plant must be built on site of one of the Asheville plant's basins. This meant that the basin had to be emptied of coal ash. That along with the need for an extensive construction laydown area necessary to allow efficient construction of the new plant, left no space at the Asheville plant site at which to build an on-site landfill. As witness Kerin put it, the MEA effectively made construction of a new on-site CCR landfill technically infeasible given the short time period to replace the coal-fired generation by 2020 and to close the coal ash basin by 2022."

A. Okay.

Q. Do you see that?

A. You just read quite a bit, and --
Q. Yeah.
A. -- I'm on page 186 of that document, and it is not covering the topic that you just read.
Q. Are you on PDF 186 or page 186?
A. They match.
Q. Okay. Well, it's my 186. Will you take that subject to check?
MS. JOST: I believe it's on page 189 of the order and the PDF as opposed to 186. Sorry for the interruption.
MR. MARZO: No, I appreciate that, Ms. Jost.
Q. We may be looking at -- there may be some confusion of my numbering of documents, Mr. Garrett, so I will defer to your counsel who has that document that you're looking at. So do you see that language now?
A. I'm still looking for it.
Q. I believe it's 189. Should be a paragraph at the bottom, the first full paragraph.
A. (Witness peruses document.)
Q. Starts "the Commission."
A. Okay. I see it now, yes.
Q. Okay. And take a second to read that if you

didn't follow when I was reading it.

A. It's quite a bit to absorb.

(Witness peruses document.)

Okay. I've read that, and I believe he is -- this is in reference to the ash that had to be moved to construct the combined cycle plant within the limits of the 1988 ash basin. And it's absent of any analysis with regards to the ash that's in the 1964 basin, and it does not address the repurposing of that basin as an ash landfill.

Q. And you understand, Mr. Garrett, that, as the Commission language suggests, that they found that there was -- and I just reassert, there was no space at the Asheville plant site. It doesn't say no space at the '64 basin. It says no space at the Asheville plant site was their finding in the last case, considering Mr. Kerin's testimony and your testimony as well, correct?

A. Apparently, Mr. Kerin gave his testimony without the benefit of an evaluation being done to support that testimony. It was based on, I guess, his own personal assessment of what was feasible and not feasible at the Asheville plant.

Q. And, Mr. Garrett -- well, Mr. Garrett, let me ask you this question.

Can we agree, at least, that that issue, whether you agree with the basis of Mr. Kerin's testimony or not, was fully litigated in the prior rate case?

A. With regards to the ash from the ash basin that was needed to construct the combined cycle plant, yes.

Q. Okay. And the Commission's findings are what the Commission's findings are ultimately in that case, correct?

A. Yes, sir.

Q. Okay. Now, if you would for me, would you refer to -- do you have Ms. Bednarcik's direct testimony with you?

A. (Witness peruses document.)

Her direct testimony?

Q. Yes, sir.

A. Okay. I have it open.

Q. Now, if you would, Mr. Garrett, would you refer to page 18 of her direct testimony? And I'm looking at lines 3 and 4 on that page, and that's where she discusses the landfill that you believe is the basis for having to materially -- or basis for your material change recommendation in this case.

A. Okay. I am on page 18, and --

Q. Can you see lines 3 and 4?

A. (Witness peruses document.)

"The Company has begun designing an on-site landfill capable of storing approximately 1.2 million tons of ash from the 1964 ash basin."

Q. Thank you. Now, that is not -- well, first let's confirm. The capacity, as updated, is 1.3 million tons, correct?

A. I'm sorry, would you repeat that.

Q. The ultimate capacity of that landfill, as updated, is 1.3 million tons, correct? In her rebuttal testimony, they confirm that, in 2019, there was additional capacity added to that.

A. Okay.

Q. Yeah. So can we agree that the basin that -- or the landfill that Ms. Bednarcik is referring to in this case is not a 3-million-ton capacity landfill, correct?

A. This landfill is 1.3 million tons.

Q. Okay.

A. And it does not utilize any portion of the 1964 ash basin. It utilizes the former laydown area of

the combined cycle plant project.
Q. Okay. And have you -- have you reviewed her rebuttal testimony?
A. I have.
Q. Okay. And would you -- would you for a moment refer to page 33 of her rebuttal testimony.
A. (Witness peruses document.)
Okay. I'm on page 33.
Q. Okay. Do you see the question that's asked:
"Was construction and utilization of an on-site landfill of any size feasible between September 1, 2017, and December 31, 2019?"
Do you see her answer is "no"?
A. Yes, I do.
Q. Now, can we agree that nowhere in the record in this case is there testimony that states that a landfill of any size was feasible in 2015 as you're suggesting is a material change?
A. Well, Ms. Bednarcik has recently become involved in the coal ash management. I don't think she was involved in the 2014, 2016 time frame. So she's relying on, you know, documents that were provided to her and conversations she had with people. But her statement that no, it was not feasible, was made

without having -- without Duke Energy Progress having evaluated that as an option.

Q. And, Mr. Garrett, in this case, after that decision and the evidence that was considered in the last case, you're asking for reconsidering an issue, and you're providing no additional analysis, no additional work papers, nothing that suggests that a landfill could have been built prior to the time the Company's considering building it now, correct?

A. I can only speak as far as the feasibility of repurposing the 1964 ash basin based on my own experience doing that exact type of project for another utility Company. I was involved in a project where we developed a very specific sequence of ash excavation in order to open up very small areas within the ash basin, certified them closed, constructed a landfill, and then placed the ash into that landfill in a very specific sequence so that the ash basin could be repurposed.

I think it was -- it was upon Duke Energy Progress to do that type of evaluation to confirm that they had no other option other than to haul ash to Homer, Georgia.

Q. And, Mr. Garrett, from the testimony we just read as well as the order of the Commission, that analysis evaluation was done in the prior case. Now, are you --

A. No, sir, not the evaluation that I'm speaking of.

Q. But that's the evaluation that you argued for and the Commission still made its findings in the last case, correct?

A. I -- I don't know that I argued for repurposing of the 1964 ash basin specifically in that case. It was more broader scope as far as a landfill on site somewhere, because at the time they said they could not do a landfill based on fatal flaws, specifically seismic issues.

Q. So let me understand that, Mr. Garrett. Is the material change your argument in this case is different than your argument was in the last case, so therefore the Commission should reconsider the issue because now you believe you have a different argument that the Commission should consider?

A. My argument is specific to the ash that was hauled between September 1, 2017, and December 31, 2019. And it's specific to the ash that was in the 1964 ash basin and not the 1988 ash basin.

Q. Now, Mr. Garrett, are you aware the coal plant has been retired, correct, at Asheville?

A. Yes, sir.

Q. And are you aware that the 1982 basin has been fully excavated?

A. Yes.

Q. And are you aware that the combined cycle is now constructed?

A. Yes.

Q. Okay. Are you aware that the land that is now available for the on-site landfill that will be completed in 2021 is available because those activities have taken place?

A. It is available because those activities -- those activities have taken place, but it -- during the 2017 rate case, Mr. Kerin's testimony was that no landfill was possible there due to seismic issues in proximity to the French Broad River.

Q. That's not Mr. Kerin's testimony, Mr. Garrett, and I would like for you to show me where that is. Your own testimony, Mr. Garrett, says that you believe that it was implied.

Are you referring to something explicitly Mr. Kerin said regarding the feasibility of an ash basin once the combined cycle was completed, the coal ash basin was excavated -- the '82 basin excavated and the coal plant retired?

A. I interpreted his testimony to be that an on-site landfill, regardless of the timing, was not possible at the site.

Q. Okay. And that's your interpretation, correct?

A. Yes.

Q. Okay. Are you aware that the 1.3 million tons of capacity for the proposed industrial landfill at Asheville is about 300,000 tons less than the total ash excavated from Asheville between September 1, 2017, and December 31, 2019?

A. I'm aware of the tonnage amounts that you're referencing, yes.

Q. Okay. So even under your proposed disallowance, it does not account for the 300-ton different -- 300,000 tons difference in capacity between what the Company is actually constructing at that site and what has actually been hauled off site, right?

A. The -- the 1964 ash basin is 46 acres. The landfill that's been permitted in the old laydown area is 12.5 acres. So a 12.5-acre footprint provides

1.3 million tons of capacity. So rough numbers, two 12.5 million -- or two 12.5-acre landfills would provide 2.6 million tons of capacity and so on.

Q. Okay. So now it's your testimony in this case that there is a 2.6 million ton capacity landfill that can be constructed at the Asheville plant; is that correct?

A. My testimony is that, based on my personal experience on a coal ash pond closure where a landfill was repurposed, it was a feasible option for Duke Energy Progress to at least evaluate.

Q. And in the prior case, you believe that a 3-million-ton capacity landfill was possible and could be constructed. And as we just discussed, what we know in that case is that the Commission did not agree with you and agreed with Mr. Kerin that there was no space for an ash pond -- for an additional landfill while the Company was undergoing construction of the combined cycle plant, right?

A. That was the Commission's determination; yes, sir.

Q. Can we refer back to our first exhibit, which I believe will be Garrett and Moore 6, and that was the transcript, the initial transcript. It was DEP 38, if that helps you, Mr. Garrett, to find it.

A. 38? Okay.

Q. Yeah.

A. (Witness peruses document.)

I have it open.

Q. Okay. If you would for me, Mr. Garrett, if you wouldn't mind turning to what's marked on the actual page as page 157. And once again, just for the record, Mr. Garrett and to the Commission, this is your testimony from the prior rate case docket that I'm referring to. And I'm referring specifically to lines 11 through 13. And in those lines, you state -- and it may be easier just for me to read it and you tell me if I'm being fair to you in terms of my reading of it. You state:

"In addition, on an ongoing basis, we believe DEP should further evaluate other lower cost remediation options for the remaining ash on the site."

Did I read that correctly?

A. Yes.

Q. Now, do you understand that the identification of a potential on-site landfill at this phase of the Asheville excavation is an example of the Company continuing to evaluate, and when feasible, implement cost-effective closure options?

A. Yes, I agree with that.

Q. Okay. Thank you, Mr. Garrett.

MR. MARZO: That's all the testimony that I have, Commissioner Clodfelter, for this panel. I thank you both for your time.

COMMISSIONER CLODFELTER: Thank you for that. I don't have any other party has indicated reservation of cross examination, but I will ask at this point. Are there any other parties who wish to cross examine this panel?

(No response.)

COMMISSIONER CLODFELTER: Hearing no one, Ms. Jost, they're back with you for redirect.

MS. JOST: Thank you. Just one question, Mr. Garrett.

REDIRECT EXAMINATION BY MS. JOST:

Q. Mr. Marzo referred you to page 189 of the Commission's final order in the Sub 1142 case, specifically the sentence that states that:

"Along with the need for an extensive construction laydown area necessary to allow efficient construction of the new plant, left no space at the Asheville plant site in which to build an on-site landfill."

Does Duke's construction now of an on-site landfill, which Ms. Bednarcik has testified to, is that inconsistent with that finding from the Commission's order in the last rate case?

A. (Bernard L. Garrett) I don't think it's inconsistent, no.

Q. So the Commission's finding that there was no space left at the plant and Duke's current construction of an on-site landfill, that's not inconsistent?

A. I may not be following the question. Do I need to read the statement? Would that help if I --

Q. If you would like.

A. Yes.

Q. So this is on page 189 --

A. Okay.

Q. -- of the Sub 1142 rate case.

A. And which paragraph is it?

Q. Hold on, let me get there. It's the second paragraph to the end, the paragraph that begins "the Commission determines." It's the paragraph that Mr. Marzo read and you reviewed. So I'm looking at the sentence that begins about midway through, "That, along with the need for an extensive construction laydown area," and ends "left no space at the Asheville plant site in which to build an on-site landfill."

A. Okay. I follow your question. Okay.

Q. And so is Duke's current construction of a landfill, an on-site landfill, inconsistent with the finding that the Commission made there?

A. Well, the laydown area is the area that they are planning on developing the 1.3-million-ton landfill.

Q. And specifically the -- I guess the second part of that sentence, where it says "left no space."

A. Well, with regards to "left no space at the Asheville plant in which to build an on-site landfill," did not consider the use of the 1964 ash basin.

Q. And Duke is currently building an on-site landfill at Asheville; is that correct?

A. Yes. Yes.

Q. No further questions. Thank you.

COMMISSIONER CLODFELTER: Thank you, Ms. Jost. Let's see if we have questions from Commissioners.

Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: I don't have any questions.

COMMISSIONER CLODFELTER: All right. Thank you. Commissioner Gray?

COMMISSIONER GRAY: No questions for this panel.

COMMISSIONER CLODFELTER: Thank you. Chair Mitchell?

CHAIR MITCHELL: I have no questions.

COMMISSIONER CLODFELTER: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Okay. And Commissioner McKissick, any questions?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: Okay. Thank you. I think we're at the point, then, where we can entertain motions.

MS. JOST: Thank you. I move that Mr. Moore's Exhibits 1 through 10, and Mr. Garrett's Exhibits 1 through 13 attached to their prefiled testimony be admitted into evidence in this docket.

COMMISSIONER CLODFELTER: Without objection, it will be so ordered.

MS. JOST: Thank you.

(Confidential Public Staff Moore Exhibits 1 through 7 and 10; Public Staff Moore Exhibits 8 and 9; Confidential Public Staff Garrett Exhibits 1, 2, 5, 6, and 10 through 12; and Public Staff Garrett Exhibits 3, 4, 7 through 9, and 13 were admitted into evidence.)

MS. JOST: And finally, I would request that the witnesses be excused.

COMMISSIONER CLODFELTER: Just a second. I think -- Mr. Marzo, do you have any exhibits you need to move?

MS. JOST: That's right.

MR. MARZO: Yes, sir, Commissioner Clodfelter. I would ask that my exhibits, which I believe 6 through 8 -- and you can correct me if I'm wrong, but I believe it's 6 through 8.

COMMISSIONER CLODFELTER: 6 through 8 is what I have.

MR. MARZO: 6 through 8 be moved into the record, sir.

COMMISSIONER CLODFELTER: Without objection, they will be admitted into the record.

(Garrett/Moore DEP Cross Exhibit Numbers 6 through 8 were admitted into evidence.)

COMMISSIONER CLODFELTER: All right. Ms. Jost, back to you.

MS. JOST: Thank you. At this point, I would request that the witnesses be excused.

COMMISSIONER CLODFELTER: All right. Unless there is objection?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, thank you, Mr. Garrett, Mr. Moore, you are excused.

THE WITNESS: Okay. Thank you.

COMMISSIONER CLODFELTER: Okay. Where do we go next?

MS. LUHR: This is Nadia Luhr with the Public Staff, and I would now like to call Jay D. Lucas and Michael C. Maness to the stand.

COMMISSIONER CLODFELTER: All right. Mr. Lucas and Mr. Maness. I have Mr. Maness. And, Mr. Lucas, I'm looking for you on my screen.

(Pause.)

COMMISSIONER CLODFELTER: I don't seem to see him. There he is. Okay.

Whereupon,

JAY D. LUCAS AND MICHAEL C. MANESS,

having first been duly affirmed, were examined

and testified as follows:

COMMISSIONER CLODFELTER: Thank you. Ms. Luhr, you may proceed.

MS. LUHR: Thank you.

DIRECT EXAMINATION BY MS. LUHR:

Q. Mr. Lucas, would you please state your name, business address, and current position for the record.

A. (Jay Lucas) Yes. I'm Jay Lucas. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the manager of operations and planning in the Public Staff's energy division.

Q. And, Mr. Lucas, on April 13, 2020, did you prepare and cause to be prefiled, direct testimony consisting of 90 pages, an appendix, and 24 exhibits?

A. Yes.

Q. And on April 23, 2020, did you prepare and cause to be prefiled, supplemental testimony consisting of five pages, a corrected Lucas Exhibit 18, and an updated Lucas Exhibit 19?

A. Yes.

Q. And on May 27, 2020, did you prepare and cause to be filed, corrections to your direct testimony?

A. Yes.

Q. And do you have any other changes or corrections to your prefiled direct testimony?

A. Not at this time.

Q. Did you have a correction that was provided in an errata sheet?

A. Are you talking about this morning?

Q. It was served yesterday.

A. Okay. I do have -- I do have some corrections. That was a data request, Public Staff Data Request 101-1, and that ended up being my Lucas Exhibit Number 18.

Q. And, Mr. Lucas, I believe you're referring to a correction we will be making.

MS. LUHR: Chair Clodfelter, we will be filing a motion with regard to that correction. We just had one small correction to Mr. Lucas' prefiled direct testimony that was indicate in an errata sheet we served yesterday.

Q. And, Mr. Lucas, other than those corrections, if you were asked the same questions today, would your answers be the same?

A. Yes.

Q. And did you prepare a summary of your testimony?

A. Yes.

MS. LUHR: Commissioner Clodfelter, at this time I move that Mr. Lucas' prefiled direct testimony as corrected, supplemental testimony, and summary of testimony and errata sheet be entered into the record as if given orally from the stand, and that his exhibits be marked for identification as prefiled.

COMMISSIONER CLODFELTER: Unless there is some objection, it will be so ordered.

(Public Staff Lucas Exhibits 1 through 18, 20, and 22 through 23; Confidential Public Staff Lucas Exhibits 19, 21, and 24; Public Staff Lucas Corrected Exhibit 2; Corrected Public Staff Lucas Exhibit 18; and Confidential Public

Staff-Revised Lucas Exhibit 19 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct with Appendix A, supplemental testimony, errata, and testimony summary of Jay D. Lucas were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	TESTIMONY OF JAY B. LUCAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

Testimony of Jay B. Lucas

On Behalf of the Public Staff

North Carolina Utilities Commission

April 13, 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.

INTRODUCTION

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 Progress, LLC (DEP or the Company), in Docket No. E-2, Sub 1219, on October 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 DEP, 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;
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; and
5. The portion of the Commission's Order Directing the Public Staff to File Testimony, dated January 22, 2020 (Order), requiring estimated costs for CCR remediation as initially proposed and after the December 31, 2019, Settlement Agreement (2019 Settlement Agreement) between DEP and the North Carolina Department of Environmental Quality (DEQ).

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.

SUMMARY OF RECOMMENDATIONS

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

[1] 2014 N.C. Sess. Law 122, as amended by 2016 N.C. Sess. Law 95.

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 remediation and closure costs not otherwise disallowed. The Public Staff recommends that the Company's shareholders pay 50 percent of the costs for CCR remediation and closure and the Company's customers pay the remaining 50 percent.

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 previous DEP rate case in 2017 (Docket No. E-2, Sub 1142) and the pending appeal of that case before the North Carolina Supreme Court. At the Asheville, H.F. Lee, Mayo, and Sutton plants, DEP purchased property and installed wells and appurtenances for the extraction and treatment of groundwater at a cost of $1,240,328. These plants have substantial violations of the state groundwater standards that have been further confirmed, and the nature and extent characterized and monitored, since DEP's last rate case. CAMA and existing regulations would not require groundwater extraction and treatment, nor would these

processes be necessary, if DEP 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 the Company has appropriately excluded.

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. DEP 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 DEP has admitted to environmental regulators, in violation of its National Pollutant Discharge Elimination System (NPDES) permits, and 7,411 groundwater exceedances confirmed by DEP's own groundwater monitoring data, in violation of the state's 2L rules.[2]
2. DEP has culpability for its environmental violations, even without a showing of traditional imprudence. The Company had a duty to

[2] Groundwater Classification and Standards, 15A N.C. Admin. Code 2L.

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 include corrective actions to remedy the Company's environmental violations.

3. DEP has estimated that the ultimate cost to remediate 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. DEP 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 DEP's environmental violations. The corrective action requirements for the remediation of groundwater

[3] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities, 80 Fed. Reg. 21301 (April 17, 2015).

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 DEQ – goes beyond the CCR Rule in that it requires closure of all ash basins and requires excavation of most of the ash from DEP's unlined basins. Given the difficulty in identifying the costs of corrective action for environmental violations that DEP 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 DEP's coal ash costs.

4. Equitable sharing is appropriate because the costs of remediation and closure of DEP'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 remediation and closure costs.

Q. PLEASE PROVIDE A SUMMARY OF THE RESULTS OF YOUR INVESTIGATION PURSUANT TO THE PORTION OF THE COMMISSION'S JANUARY 22, 2020, ORDER REGARDING COSTS OF CCR REMEDIATION.

A. Confidential Lucas Table 1 below provides a summary of DEP'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]

[1] Costs are DEP only, but system-wide.

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 DEP and Duke Energy Carolinas, LLC (DEC), collectively "Duke Energy." Coal-fired power plants produce CCRs in the combustion process, and CCRs 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.

[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. Electric generating plants have used coal as a fuel since the late nineteenth century, and coal 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 fireboxes 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.

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 DEP has culpability for non-compliance with environmental regulations that are meant to protect groundwater and surface water from

[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.

contamination by CCR constituents. Additionally, DEP's past management of coal ash has resulted in a risk of future contamination that EPA and the 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 DEP'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 DEP has been culpable.

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR CCR.

A. CCR surface impoundments contain certain contaminants, such as acidity, arsenic, boron, cobalt, iron, manganese, 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,

[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).

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 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.

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[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).

[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).

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 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

[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).

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.

CCR units (ash pond impoundments and landfills) at six of the Company's coal-fired power plants in North Carolina are subject to the CCR Rule: Asheville, H.F. Lee, Mayo, Roxboro, Sutton, and Weatherspoon. According to DEP, EPA's CCR Rule is not applicable to the Cape Fear plant. The Company's one coal-fired power plant in South Carolina, Robinson, is also subject to the CCR Rule.

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,

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[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.

[16] Util. Solid Waste Activities Grp. v. EPA, 2016 U.S. App. LEXIS 24320 (D.C. Cir. June 14, 2016).

2016, issued a direct final rule extending the deadline by which inactive 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 DEP'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

[25] 40 C.F.R. Part 423.

[26] Legacy wastewater refers to wastewater from five waste 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 secondary maximum contaminant levels (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

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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.*

ash basins, and if discovered at certain levels, they trigger additional testing requirements for more constituents.

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.

[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

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 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

[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).

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]

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

[35] 15A NCAC 02L .0107 (b).

[36] 15A NCAC 02L .0202(c).

[37] 15A NCAC 02L .0202(b)(3).

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.”

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 Roxboro and Mayo plants from intermediate-risk to low-risk due to DEP's establishment of permanent water supplies and correction of dam safety deficiencies.

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[38] N.C. Gen. Stat. § 130A-309.213(a).

[39] N.C. Gen. Stat. § 130A-309.214.

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 Roxboro 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 CCR surface impoundments at Roxboro in accord with N.C. Gen. Stat. § 130A-309-214(a)(3). In addition, 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 unlined impoundments at Roxboro 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 Asheville, Cape Fear, H.F. Lee, Robinson, Sutton, and Weatherspoon plants. DEP is excavating coal ash at the Asheville plant under North Carolina's Mountain Energy Act (Session Law 2015-110), which amended CAMA and set August 1, 2022, as the closure date for the Asheville impoundments. DEP had selected the Cape Fear and H.F. Lee plants as cementitious beneficiation sites, which also

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[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)

necessitates excavation. The Robinson plant is in South Carolina and not under the jurisdiction of DEQ or CAMA. DEQ had classified the impoundments at Sutton as high-risk in 2016, and DEP was already excavating the impoundments at that plant. In addition, DEQ had classified the impoundment at the Weatherspoon plant as intermediate-risk in 2016, and DEP was already excavating the impoundment at that plant. Lucas Table 1 below summarizes the status of DEP's coal-fired power plants with DEQ:

Lucas Table 1

Plant	**Initial CAMA Classification**	**Current CAMA Classification**	**Did Excavation Orders Apply?**
Asheville	High	High	No
Cape Fear	Intermediate	Intermediate	No
H.F. Lee	Intermediate	Intermediate	No
Mayo	Intermediate	Low	Yes
Robinson	N/A	N/A	N/A
Roxboro	Intermediate	Low	Yes
Sutton	High	High	No
Weatherspoon	Intermediate	Intermediate	No

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 the 2019 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 2019 Settlement Agreement is shown in **Lucas Exhibit 1**.

Q. PLEASE SUMMARIZE THE 2019 SETTLEMENT AGREEMENT.

A. The 2019 Settlement Agreement addresses CCR impoundments at DEP's Mayo and Roxboro plants and DEC's Allen, Belews Creek, Cliffside, and Marshall 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 the Belews Creek plant.[42] In addition, ash (~13,079,000 tons) would remain in four unlined areas at the Marshall plant: 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 the Roxboro plant.

According to the 2019 Settlement Agreement, all closure must be completed in compliance with the deadlines in CAMA. CAMA, however, allows Duke Energy to request deadline variances, resulting in "no later than" closure deadlines in the 2019 Settlement Agreement. **Lucas Exhibit 2** explains the key features of the 2019 Settlement Agreement.

[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.

Q. ARE OTHER DUKE ENERGY POWER PLANTS AFFECTED BY THE 2019 SETTLEMENT AGREEMENT?

A. Yes. The 2019 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.

A. The Asheville, Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon plants discharge wastewater under NPDES permits issued by DEQ. A revised permit for the Roxboro plant is currently under review by DEQ. The Asheville, Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon plants

[43] Page 22, paragraph 45.

also have Special Orders by Consent (SOCs) with DEQ that allow temporary variations from the NPDES requirements. The temporary variations give DEP time to eliminate unauthorized constructed seeps from ash basin dams by decanting the water and decommissioning the coal ash impoundments. Decanting removes most bulk water from the impoundments and can require some wastewater treatment before being discharged. Water that has been in close contact with coal ash is called interstitial water and cannot be decanted because of the higher risk of contamination. Interstitial water requires a higher degree of treatment before being discharged. 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.

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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 March 12, 2020).

Q. WHAT IS THE STATUS OF COAL ASH AT THE ROBINSON PLANT IN SOUTH CAROLINA?

A. DEP has applied for a permit to build an on-site landfill for disposal of coal ash at the Robinson 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 DEP rate case (Docket No. E-2, Sub 1142) describing the legal actions filed against DEP for unlawful management of coal ash and pollution from coal ash.[45]

Q. WHAT IS THE NATURE OF THE LEGAL ACTIONS FILED AGAINST DEP WITH REGARD TO ITS COAL ASH MANAGEMENT?

A. Governmental agencies and environmental groups have sued DEP 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

[45] Page 45, line 1, through page 57, line 2, and Exhibits 8 and 9, Direct Testimony of Public Staff Engineer Jay Lucas filed in Docket No. E-2, Sub 1142, on October 20, 2017.

Center. In addition to the legal actions against DEP in state courts, environmental groups have brought several federal citizen suits against DEP, and the federal government brought a criminal case against DEP for violations at the Asheville, Cape Fear, and H.F. Lee 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 DEP'S LAST RATE CASE?

A. Yes. In summary, the 2019 Settlement Agreement between Duke Energy, DEQ, and community and environmental groups resolved the following legal actions:

- Wake County Superior Court, No. 11032 – Suits for violations at the Cape Fear, H.F. Lee, Mayo, Roxboro, Sutton, and Weatherspoon plants alleging unlawful discharges to surface waters, NPDES permit violations, and violations of the 2L rules.[46]
- US District Court for the Middle District of North Carolina, No. 16-CV-607 – Federal citizen suit filed on behalf of Roanoke River Basin Association for violations at DEP's Mayo plant,

[46] Claims with respect to the Cape Fear, H.F. Lee, Sutton, and Weatherspoon plants were resolved prior to the Settlement Agreement.

alleging unpermitted discharges to surface waters and groundwater violations.

- <u>US District Court for the Middle District of North Carolina, No. 17-CV-452</u> – Federal citizen suit filed on behalf of Roanoke River Basin Association for violations at DEP's Roxboro plant, alleging unlawful discharges to surface waters.

In addition, the following case was dismissed by the court without prejudice:

- <u>US District Court for the Middle District of North Carolina, No. 17-CV-561</u> – Federal citizen suit filed on behalf of the Roanoke River Basin Association, alleging that the closure plans submitted by DEP for the Mayo plant violate the CCR Rule.

Q. SINCE YOUR TESTIMONY IN THE LAST RATE CASE, HAVE YOU BECOME AWARE OF ANY ADDITIONAL CCR-RELATED LEGAL ACTIONS FILED AGAINST DEP?

A. Yes. Four additional legal actions were filed against the Company, as summarized below.

- <u>Wake County Superior Court, No. 17-CVS-10341</u> – Class action litigation filed in August 2017 on behalf of property owners living near DEP's Asheville, H.F. Lee, Mayo, and Roxboro plants, in addition to five DEC plants, alleging groundwater contamination. The parties entered into a settlement, and the class action litigation was dismissed, in January 2018.

- Person County Superior Court, No. 18-CVS-346 – Tort claim filed against DEP alleging private nuisance, negligence, and trespass relating to the unlined coal ash impoundment at the Mayo plant. The parties settled in June 2019 and filed a stipulation of dismissal in August 2019.
- US District Court for the Middle District of North Carolina, No. 17-CV-707 – Federal citizen suit filed on behalf of the Roanoke River Basin Association, alleging that the closure plans submitted by DEP for the Roxboro plant violate the CCR Rule. This case was dismissed by the court without prejudice in May 2018.
- New Hanover County Superior Court, No. 17-CVS-3305 – Tort claim filed against DEP in September 2017 alleging that DEP failed to notify officials or neighbors and failed to take remedial action when it discovered groundwater contamination at the Sutton plant. This case was voluntarily dismissed in June 2018.

POWER PLANT DESCRIPTIONS

Q. HAS THE PUBLIC STAFF HAD THE OPPORTUNITY TO VISIT AND TOUR THE DEP CCR BASIN SITES?

A. Yes. On December 13, 2019, the Public Staff visited the Cape Fear plant. On December 16, 2019, the Public Staff visited the Weatherspoon and H.F. Lee plants. On December 18, 2019, the Public Staff visited the Roxboro and Mayo plants. **Lucas Exhibit 3** shows photographs taken at each of these plants. In addition, **Lucas 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 Bernard 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 DEP's present closure activities and the future cost of compliance.

Q. WHAT IS THE STATUS OF CCR SITE REMEDIATION AT ALL EIGHT COAL-FIRED POWER PLANT SITES?

A. **Asheville** – DEP retired the coal-fired units in January 2020 and has placed most of the combined-cycle natural gas fired units in operation. DEP completed excavation of the 1982 Ash Basin in September 2016 and is still excavating ash and removing interstitial water from the 1964 Ash Basin. DEP was sending coal ash to the Asheville Airport Structural Fill but stopped doing so in July 2015. DEP has removed approximately 6,954,649 tons of coal ash from the Asheville plant site and must complete the removal by August 1, 2022, per Session Law 2015-110 as discussed above. However, DEP currently plans to have excavation complete by February 28, 2022. DEP has constructed a lined retention basin and wastewater treatment plant to treat stormwater and wastewater from the site.

Cape Fear – DEP retired the coal-fired units in 2012. DEP has finished decanting the 1978 and 1985 Ash Basins. The 1956, 1963, and 1970 Ash Basins contain little or no water and have become largely forested. The Cape Fear site has one of the three ash beneficiation projects discussed more fully by Public Staff witness Vance Moore. Currently, DEP plans to excavate all coal ash at the plant site and use the beneficiation project to convert the ash into cementitious products to be sold.

H.F. Lee – DEP retired the coal-fired units in 2012 and placed the combined-cycle natural gas fired units in operation. DEP has finished decanting the 1982 (Active) Ash Basin and is in the process of dewatering the interstitial water. Inactive Ash Basins 1, 2, and 3 contain little or no water and have become largely forested. The H.F. Lee site has one of the three ash beneficiation projects discussed more fully by Pubic Staff witness

Vance Moore. Currently, DEP plans to excavate all coal ash at the plant site and use the beneficiation project to convert the ash into cementitious products to be sold.

Mayo – DEP operates the Mayo plant on an intermediate dispatch basis and has converted it to dry ash handling. The dry ash is placed into a lined landfill, and FGD solid waste is taken to the Roxboro plant. DEP is currently decanting the Ash Basin and remediating the FGD wastewater treatment ponds. DEP has constructed lined retention basins and a zero liquid discharge treatment plant to treat stormwater and wastewater from the site. As per DEP's 2019 Settlement Agreement with DEQ discussed earlier in my testimony, DEP must excavate all coal ash from the Ash Basin.

Robinson – DEP retired this South Carolina coal-fired unit in 2012. DEP is currently excavating all coal ash at the site to prepare for placement of the ash in a lined landfill that is currently under construction. The Ash Basin does not contain any bulk water and will not require decanting. Currently, DEP has not found any interstitial water in the Ash Basin.

Roxboro – DEP operates the Roxboro plant on an intermediate dispatch basis and has converted it to dry ash handling. The dry ash is placed into the Roxboro Monofill, and FGD solid waste from the Roxboro and Mayo plants is stockpiled onsite for purchase by a drywall manufacturer. DEP has constructed lined retention basins and a wastewater treatment plant to treat stormwater from the site. FGD wastewater will be treated by a separate wastewater treatment plant. As per DEP's 2019 Settlement Agreement with DEQ discussed earlier in my testimony, DEP must excavate all coal ash from the West Ash Basin and most coal ash from the East Ash Basin. Coal ash under and in the Roxboro Monofill, which was built partially on the East Ash Basin, may remain in place and must be stabilized with a permanent structure.

Sutton – DEP retired the coal-fired units in 2013 and placed the combined-cycle natural gas fired units in operation. Pursuant to CAMA, DEQ determined that the impoundments at the Sutton plant are high-risk, which requires impoundment closure by August 1, 2019. DEP has excavated all coal ash from the impoundments and placed it in either an on-site landfill or the Brickhaven landfill in Chatham County.

Weatherspoon – DEP retired the coal-fired units in 2011 and still operates four oil-fired combustion turbines at the site. Pursuant to CAMA, DEQ determined that the impoundment at the Weatherspoon plant is intermediate-risk, which requires impoundment closure by August 1, 2028. DEP is currently excavating coal ash and transporting it to South Carolina for beneficiation.

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 previous DEC rate case describing historic academic, industry, regulatory, and utility documents.[47] The principal topic 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[48] 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

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[47] 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.

[48] 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.

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 . . . ."[49]

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."[50] It also notes that wet disposal systems could make the use of land after site closure "perhaps difficult and costly."[51]

Importantly, Section 7 states that "it is difficult to prove non-contamination without monitoring, and the burden of proof is placed on the industry."[52]

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

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[49] *Id.* at S-1.

[50] *Id.* at 3-1.

[51] *Id.* at 3-3.

[52] *Id.* at 7-3.

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 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."[53] 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

[53] 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.

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."[54] "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)[55] was an extensive review of the quantities, physical and chemical characteristics, 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

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[54] 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.

[55] *Available at* https://www.epa.gov/sites/production/files/2015-08/documents/coal-rtc.pdf (last visited February 4, 2020).

> 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.

DEP, 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. DEP 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, DEP should have installed comprehensive groundwater monitoring well networks in the 1980s to determine if the risk was materializing at their ash ponds.

DEP continued to operate ash impoundments (i.e., basins or ponds) at every coal-powered plant until at least 2011. 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. **Lucas Exhibit 5** is a table of when the Company implemented specific environmental controls.

Q. WHAT EVALUATIONS OR ANALYSES DID DEP CONDUCT WITH RESPECT TO THE HISTORICAL DOCUMENTS ON THE RISKS OF CCR STORAGE IN UNLINED IMPOUNDMENTS?

A. The Public Staff asked DEP for a copy of any CCR analysis that DEP had performed in response to the 1979 Arthur D. Little Report, 1981 EPRI Coal Ash Disposal Manual, the 1982 EPRI Manual, the 1988 EPA Report, or the 2004 EPRI Decommissioning Handbook. In response to each item, the Company stated that it "has not been able to locate a specific response to the document in question."

The Company, however, also referenced its response to a data request from the Sierra Club in the Sub 1142 rate case that requested the following:

> Please produce all pre-2014 documents relating to risks posed by storing coal combustion residuals in unlined impoundments, including but not limited to any studies regarding the leaching of arsenic or other constituents of coal combustion residuals from unlined impoundments.

The Company provided a selection of documents, some of which were not specific to DEP and its predecessors. One document provided by the Company that is responsive to the discussion here was a 1979 evaluation conducted by DEP and a contractor. I will briefly address that evaluation below.

Edwin Floyd, Professional Engineer and Groundwater Hydrologist of Moore, Gardner & Associates, Inc. Consulting Engineers prepared the "Evaluation of the Potential for Contamination of the Ground-Water Aquifer by Leachate from the Coal-Ash Storage Pond at the Mayo Electric Generating Plant Site" dated January 31, 1979. The Introduction states:

> This report discusses the results of an on-site investigation of the geology and ground-water conditions and the potential for ground-water contamination by certain trace elements in ash sludge to be deposited in a proposed ash-disposal pond at the Carolina Power and Light Company generating plant site on Mayo Creek in Person County, North Carolina.

In the Geology and Hydrologic Conditions Section, the site subsurface conditions are described in detail. The alluvial soil cover present near the Crutchfield Branch "consists of sandy clayey silts near the surface, grading downward into silty sands overlying a sandy gravel base which rests on clay or saprolite." (Id. at pp 5-6) Unless excavated, the soils that would be directly in contact with coal ash are described as sandy and would have porous characteristics. The underlying clay layer has low permeability, however, its ability to protect groundwater depends on the depth of the groundwater table, area and thickness of the clay layer, and the probability of cracking. Generally, the "water table configuration is determined mostly by topography, with depths to water usually being greatest in the upland areas and shallowest in the valleys." (Id. at p 6) In the Evaluation of Data Section starting on page 7, the subsurface conditions were further investigated by drilling 13 test holes to sample the soils and 12 test holes were completed as monitoring wells to observe the groundwater depth and for sampling. The groundwater depths during the seasonal low period are shown in Figure 1 of the report.[56] The last page of the Summary Section states that leachate from the pond would be filtered by the soils and diluted with natural groundwater and that "[p]eriodic sampling of the ground water from the observation wells around the pond will detect any evidence to the contrary." Despite the thin soil layer and shallow groundwater table, the report concludes that:

> In consideration of the natural action of the soils on heavy minerals in the leachate, the dilution effects of mixing with the natural ground water, and the fact that there are no water supply sources or major water courses for miles downstream from the ash pond dam, it is difficult to imagine that any significant adverse impact on the ground water aquifer could be caused by ponding of the ash wastes at the proposed site.

[56] "Figure 1 is a generalized map of the water-table at the ash pond site as it appeared on October 2, 1978. The water levels reflect the late summer dry season and are at, or very near, the yearly lowest levels. Seasonal fluctuations are probably within the range of 5 to 15 feet in upland areas and 2 to 5 feet in the valleys." (Id. at p 6)

In response to Public Staff data requests for the installation dates of all groundwater monitoring wells and monitoring data, DEP provided no data prior to 2008 for the Mayo plant. This is an indication that the Company did not continue to monitor the groundwater for impacts after this evaluation of the existing subsurface conditions and the construction of the ash basin at Mayo.

The conclusion that adverse impact is “difficult to imagine” is contrary to the earlier suggestion, in the same report, for periodic sampling. It was also imprudent, at least by the end of 1979, to the extent the Company relied on an assumption that there would be no contamination, rather than actually testing for contamination. A few months later in the same year, the Arthur D. Little report noted the risk of groundwater contamination from ash impoundments. In addition, the initial 2L rules prohibiting groundwater exceedances were promulgated in 1979. Without periodic sampling as recommended in the report, DEP was merely trusting that its unlined impoundments would comply with groundwater standards – DEP chose to trust without verifying. This analysis and report were completed as part of the planning for the Ash Basin at Mayo that was constructed in 1983, the same year that the plant’s wastewater characteristics changed and the volume increased when DEP added precipitators. Groundwater monitoring wells were not installed at Mayo until 25 years later in October of 2008.

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 DEP 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.[57] 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. DEP has identified its seeps in response to a Public Staff data request as provided in **Lucas 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 impound fresh water whereas DEP'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, DEP submitted an application for an SOC related to coal ash basin seepage at Asheville, Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon, and a number of DEC plants. On August 15,

[57] Page 34, line 11, through page 44, line 19, and Exhibits 3-7 (Revised Exhibits 5 and 6), Direct and Supplemental Testimonies of Public Staff Engineer Jay B. Lucas filed in Docket No. E-2, Sub 1142, on October 20, 2017, and November 15, 2017, respectively.

2018, the EMC approved the SOC for Mayo and Roxboro. See **Lucas Exhibit 7**. Under the SOC, the Company agreed to pay an upfront penalty of $150,000 as settlement of all alleged violations due to seepage from 10 deliberately constructed seeps and 5 non-constructed seeps, identified prior to January 1, 2015. 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 January 10, 2019, the EMC approved an SOC for H.F. Lee. See **Lucas Exhibit 8**. Under the SOC, the Company agreed to pay an upfront penalty of $72,000 as settlement of all alleged violations due to seepage from 12 non-constructed seeps, identified prior to January 1, 2015. In addition, the Company was required to begin dewatering no later than July 31, 2019, and provide various reports to DEQ.

On January 27, 2019, the EMC approved SOCs for Cape Fear and Weatherspoon. See **Lucas Exhibit 9**. Under the SOC for Cape Fear, the Company agreed to pay an upfront penalty of $48,000 as settlement of all alleged violations due to seepage from 8 non-constructed seeps, identified prior to January 1, 2015. In addition, the Company was required to begin dewatering no later than January 31, 2020, and provide various reports to DEQ. Under the SOC for Weatherspoon, the Company agreed to pay an upfront penalty of $72,000 as settlement of all alleged violations due to seepage from 4 deliberately constructed seeps and 4 non-constructed seeps, identified prior to January 1, 2015. Similar to the other SOCs, the Company was required to provide various reports to DEQ and conduct water quality monitoring associated with the seeps.

Deliberately constructed seeps such as toe drains have been included in the renewed or modified NPDES permits for Asheville, Mayo, and Weatherspoon. 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 DEP'S NORTH CAROLINA PLANTS?

A. DEQ requires DEP 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.[58] See **Lucas Exhibit 10**, pp 4-15. Based on DEP's groundwater monitoring, the cumulative total of groundwater violations has reached 7,411.[59] See **Lucas Exhibit 11**.

Q. WHAT IS THE STATUS OF COMPLIANCE WITH STATE GROUNDWATER STANDARDS FOR DEP'S ROBINSON PLANT IN SOUTH CAROLINA?

A. The Company is required by SCDHEC to monitor groundwater quality around coal ash storage units. Based on DEP's groundwater monitoring, the total number of groundwater exceedances at the Robinson Plant has reached 632. See **Lucas Exhibit 12**.

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 oversee the Company's compliance with the conditions of probation. One

[58] 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.

[59] In the E-2, Sub 1142, rate case, the Public Staff presented 2,857 groundwater violations as identified by DEP. The updated total of 7,411 is representative of the cumulative number of violations, including the 2,857 identified in the previous rate case and the 4,554 identified since then.

of those conditions is the completion of environmental audits by an independent auditor for each of DEC's and DEP's plants 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 DEP'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 DEP's eight coal-fired power plants are posted online[60] 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 **Lucas Exhibit 13** and **Lucas Exhibit 14**, respectively.

[60] *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 DEP'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, DEP 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 3,164 testing results determined to be statistically significant increases over background levels for Appendix III parameters. See **Lucas 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[61], DEP 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, DEP is required to file notices and reports[62], including annual

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[61] The exception being Cape Fear because the CCR Rule does not apply to this site.

[62] *Available at* https://www.duke-energy.com/our-company/environment/compliance-and-reporting/ccr-rule-compliance-data (last visited March 1, 2020).

groundwater monitoring reports summarizing the detection and, if applicable, assessment monitoring activities and data. The Company has compiled a table quantifying 277 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 **Lucas Exhibit 16**.

Q. WHEN DID DEP BEGIN CONDUCTING GROUNDWATER MONITORING AND HAS THE COMPANY CONTINUED TO INSTALL ADDITIONAL GROUNDWATER MONITORING WELLS?

A. DEP installed groundwater wells and began monitoring on a site-specific basis. Voluntary groundwater monitoring wells were installed at Cape Fear, H.F. Lee, and Mayo in 2007 and 2008. DEP states the initial requirement by DEQ to monitor groundwater at each ash impoundment was in 2009. The exceptions were Roxboro, Sutton, and Weatherspoon; groundwater monitoring began near impoundments at these plants in 1986, 1990, and 1990, respectively. In addition, groundwater monitoring was required near the landfill at Roxboro in 1987. In South Carolina, groundwater monitoring was first required by DHEC at the Robinson plant in 1995. See **Lucas 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] DEP did not start monitoring groundwater quality at some of its sites until three decades later. Furthermore, DEP did not engage in comprehensive groundwater monitoring until even later, as quantitatively illustrated by the table in **Lucas 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 DEP TAKE IN RESPONSE TO ITS GROUNDWATER MONITORING DATA?

A. In response to a Public Staff data request seeking an explanation of the action taken by the Company in response to each exceedance prior to 2009 at voluntary groundwater monitoring wells, the Company stated the following:

> From 2004-2006, an investigation was conducted on the Sutton Former Ash Disposal Area (FADA) and the "Old Ash

[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.

> Pond" (also known as the 1971 Ash Basin). The conclusion of the two phases of investigations and the Remedial Action Plan were that groundwater contamination was localized and minor. Any risk to the public or plant personnel could be adequately controlled by administrative controls and land use restrictions.

However, in paragraph 191 of the Joint Factual Statement in the federal criminal case, DEP agreed to the following statement: "In June and July 2013, Flemington's public utility concluded that boron from Sutton's ash ponds was entering its water supply. Tests of water from various wells at and near Sutton from that period showed elevated levels of boron, iron, manganese, thallium, selenium, cadmium, and total dissolved solids."[65] The Company's response to the Public Staff's Data Request did not indicate any actions taken for any other exceedances at any other sites.

When DEP 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. Only with this information could DEP evaluate appropriate corrective action measures.

[65] Exhibit 9 of the Testimony of Public Staff Engineer Jay B. Lucas filed in Docket No. E-2, Sub 1142, on October 20, 2017.

COSTS OF CCR-RELATED ENVIRONMENTAL IMPACTS

Q. FOR CCR MANAGEMENT, HAS DEP INCURRED COSTS RELATED TO NONCOMPLIANCE WITH ENVIRONMENTAL REGULATIONS?

A. Yes. DEP has incurred costs to remediate unpermitted discharges, violations of groundwater quality standards, and other violations of environmental regulations at all DEP 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, 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 DEP's non-compliance with longstanding environmental regulations. In my opinion, the evidence of violations shows DEP 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 DEP's culpability and supports the recommendation of equitable sharing.

DEP DIRECT TESTIMONY ON COAL ASH PROJECTS

Q. PLEASE PROVIDE A SUMMARY OF THE COAL ASH COST RECOVERY DISCUSSION IN THE TESTIMONY OF DEP WITNESS JESSICA BEDNARCIK.

A. In her direct testimony and 19 exhibits filed on October 30, 2019, DEP witness Jessica Bednarcik discussed state and federal regulatory requirements, actions by DEQ, and coal ash related costs requested by

DEP from September 1, 2017, through February 29, 2020. Witness Bednarcik provided actual costs from September 1, 2017, through June 30, 2019, and DEP has periodically provided updates for later months.

The costs in witness Bednarcik's testimony are only those that DEP has booked for financial accounting purposes as Asset Retirement Obligations (AROs).[66] 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 DEP witness Julie Turner. In response to a Public Staff data request, DEP 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, i.e. 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 December 31, 2019, the total actual ARO coal ash costs expended in the period beginning September 1, 2017, and submitted for recovery in this case on a system basis were $624,043,613.

[66] As noted in the testimony of Public Staff witness Maness, for North Carolina retail regulatory accounting and ratemaking purposes, as determined by this Commission, DEP is accounting for and recovering its impoundment closure costs through a deferral and amortization process, rather than a financial accounting ARO process.

Q. PLEASE SUMMARIZE THE DISCUSSION IN THE TESTIMONY OF DEP WITNESS JULIE TURNER REGARDING CAPITAL INVESTMENTS IN THE COMPANY'S COAL FLEET TO MEET ENVIRONMENTAL REGULATIONS.

A. In her direct testimony filed on October 30, 2019, DEP witness Julie Turner stated the following:

> The Company has also made significant investments within its coal fleet to meet environmental regulations to allow for the continued operation of active plants, including the Coal Combustion Residual ("CCR") Rule, the Coal Ash Management Act ("CAMA") and Effluent Limitations Guidelines ("ELG"), totaling approximately $402 million. These investments included the capital additions at Roxboro Station to convert to a dry bottom ash system to comply with the CCR, totaling approximately $96 million, and the Flue Gas Desulfurization ("FGD") Wastewater Treatment replacement, to comply with National Pollutant Discharge Elimination System program and ELG, totaling approximately $130 million. . . . The DE Progress capital additions at Roxboro Station to convert to a dry bottom ash system and the FGD Wastewater Treatment replacement are completed.

The Company did not provide any exhibits or additional direct testimony supporting the $402 million cost recovery request for capital investments in the Company's coal fleet.

Q. ARE THE COSTS IN WITNESS JULIE TURNER'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 DEP PROVIDE ANY ADDITIONAL INFORMATION ON ITS COAL ASH RELATED COSTS?

A. In its E-1, Item 10, NC-1100, DEP 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 Turner's testimony and further breaks down the costs by plant and account number. Over 99% of the capital costs in NC-1105 are in account numbers 311 (Structures and Improvements) and 312 (Boiler Plant Equipment) in Steam Production Plant. Less than 1% of the capital costs are booked as 353 (Transmission Station Equipment) in Steam Production Plant and 315 (Steam Accessory Electric Equipment) in Other Production Plant.

Q. PLEASE PROVIDE A LIST OF COAL ASH RELATED PROJECTS THAT DEP BOOKED AS ARO.

A. **Confidential Lucas Exhibit 19** is a list of projects that DEP booked as ARO.

Q. PLEASE PROVIDE A LIST OF COAL ASH RELATED PROJECTS THAT DEP BOOKED AS CAPITAL.

A. **Lucas Exhibit 20** is a list of projects that DEP 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 October 20, 2017, in Docket No. E-2, Sub 1142, describing groundwater quality at the Asheville, H.F. Lee, and Sutton plants, groundwater extraction and treatment performed by DEP, and associated costs.[67]

Q. PLEASE BRIEFLY DESCRIBE DEP'S EXTRACTION AND TREATMENT OF GROUNDWATER AND RELATED LAND PURCHASES.

A. In summary, DEP contaminated the groundwater at the Asheville, H.F. Lee, Mayo, and Sutton plants in violation of the 2L rules. In the 2015 Groundwater Settlement for remediation,[68] DEP agreed to extract and treat the contaminated groundwater at the Asheville, H.F. Lee, and Sutton

[67] Page 52, lines 6 through 12, and page 66, line 5, through page 67, line 17, and Exhibits 6, 7, and 9, Direct Testimony of Public Staff Engineer Jay Lucas filed in Docket No. E-2, Sub 1142, on October 20, 2018.

[68] 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.

plants.[69] On August 26, 2019, DEP purchased land near the Mayo plant for $82,000 to mitigate groundwater contamination.

The 2015 Groundwater Settlement is signed by the Company and states on page 5 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." DEP's own groundwater monitoring as reported to DEQ shows 2L violations at the Sutton plant. The 2015 Groundwater Settlement also requires accelerated remediation of contaminated groundwater at the Asheville and H.F. Lee plants. DEP has purchased land near the Asheville and H.F. Lee plants to mitigate the risk of groundwater contamination from reaching off-site property owners.

Q. WHAT WAS THE PREMISE OF YOUR TESTIMONY IN DOCKET NO. E-2, SUB 1142, REGARDING GROUNDWATER EXTRACTION AND TREATMENT?

A. As stated on pages 67 and 68 of my testimony in Docket No. E-2, Sub 1142, 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."

[69] DEP also agreed to pay $7 million to DEQ "in full settlement of all current, prior, and future claims related to exceedances of groundwater standards associated with coal ash facilities at Duke Energy's North Carolina facilities."

Simply put, DEP is extracting and treating groundwater at the Asheville and Sutton plants because it is responsible for contaminating the groundwater with coal ash constituents such as arsenic, boron, chromium, manganese, selenium, and others. Similarly, DEP initially pursued extraction and treatment at the H.F. Lee plant but later purchased additional land near the plant to reduce its liability for groundwater contamination. The Public Staff's position in Docket No. E-2, Sub 1142, was that DEP should not place these costs on ratepayers. There is certainly no basis for DEP to extract and treat *clean* groundwater, or to extract groundwater because of natural background constituents. Indeed, DEP witness James Wells admitted during the 2017 DEP rate case that the Company would not have had to install extraction wells if there had been no groundwater exceedances.[70]

Q. WHY DO YOU DISCUSS EXTRACTION WELLS, TREATMENT, AND PURCHASE OF ADDITIONAL LAND SEPARATELY FROM DISCUSSION OF ENVIRONMENTAL VIOLATIONS IN GENERAL?

A. We can identify specific costs associated with extraction, treatment, and purchase of additional land. Such costs are attributable solely to DEP's violation of groundwater standards. DEP would not have incurred those costs if it had not violated the 2L rules.

[70] Docket No. E-2, Sub 1142, testimony heard on December 7, 2017 (Transcript Volume 21, page 176, lines 4 through 8.

Q. DID THE COMMISSION ALLOW DEP TO RECOVER COSTS FOR GROUNDWATER EXTRACTION AND TREATMENT IN DOCKET NO. E-2, SUB 1142?

A. Yes. The Order stated that "[t]he Commission determines that there is insufficient evidence that the Company would have had to have engaged in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule."[71]

The Public Staff asks that the Commission take a fresh look at the treatment of DEP's groundwater extraction and treatment costs and DEP's related purchases of land. As of the last rate case, the Asheville, H.F. Lee, Mayo, and Sutton plants had 725, 250, 0, and 723 groundwater violations, respectively.[72] No party, including DEP, contested the number of groundwater violations. As of this rate case investigation, these four plants have 1,685, 1,402, 328, and 1,778 groundwater violations, respectively. From a factual standpoint, there was no reason for DEP to extract and treat groundwater and purchase land unless DEP was responsible for the contamination, and the exceedance reports show that DEP's coal ash impoundments contaminated the groundwater. 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 and

[71] Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 23, 2018, Docket No. E-2, Sub 1142, p 183.

[72] Revised Lucas Exhibit No. 6, Supplemental Testimony of Public Staff Engineer Jay Lucas filed in Docket No. E-2, Sub 1142, on November 15, 2017.

land purchases at the Asheville, H.F. Lee, Mayo, and Sutton plants if DEP had not violated 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 Asheville, H.F. Lee, and Sutton plants, as well as the purchase of land at the Asheville, H.F. Lee, and Mayo plants to mitigate the risk of spreading groundwater contamination; (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 Asheville, H.F. Lee, and Sutton plants not be included in DEP's pro forma adjustment set forth in the E-1, Item 10, NC-1103. I also recommend that land purchases at the Asheville, H.F. Lee, and Mayo plants to mitigate the risk of spreading groundwater contamination not be included. This position is consistent with the Public Staff's position in the Sub 1142 rate case and the pending appeal before the North Carolina Supreme Court. The reasoning for my position is discussed in my testimony above.

For the period of September 2017 through December 2019, the costs amounted to $1,240,328 on a system basis. I recommend that the Commission disallow these costs 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 DEP plants have been excluded by DEP in its pro forma adjustment set forth in the E-1, Item 10, NC-1103. For the period of September 2017 through December 2019, the costs amounted to $395,005 on a system basis. This adjustment conforms to the precedent of the Commission's determination in the Sub 1142 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 DEP's pro forma adjustment set forth in the E-1, Item 10, NC-

[73] Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 23, 2018, Docket No. E-2, Sub 1142, p 184.

1103. For the period of September 2017 through December 2019, the costs amounted to $1,087,612 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 DEP'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 E-7, Sub 1146 Order, there is no logical distinction between the permanent water supply costs and the bottled water costs that the Commission required DEP to exclude 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, as described above. There is no logical distinction between them and the Company's bottled water costs that the Commission required DEP to exclude in the last rate case. DEP 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 September 2017 through December 2019, the costs amounted to $2,774,583 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 DEP'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 DEP's federal plea agreement. DEP 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 Bernard 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 DEP decision-making at the time DEP constructed the ash basins, 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, the quantification of costs directly resulting from the acts or omissions would be speculative. Also, even where DEP'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 DEP'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 signed by Duke Energy as part of the federal plea agreement discussed earlier in my testimony.

Additionally, there is substantial evidence[74] 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 DEP, shown in **Lucas Exhibits 7 through 9**. In addition, immediately following the Dan River Spill in 2014, and again two years later, DEQ found numerous dam safety issues at DEP's CCR impoundments.[75] There is also evidence of numerous DEP groundwater violations. In

[74] The Public Staff presented prior evidence of environmental impacts in Exhibits 3, 5, 6, and 7, Direct and Supplemental Testimony of Public Staff Engineer Jay Lucas filed in Docket No. E-2, Sub 1142, on October 20, 2017 and November 15, 2017.

[75] Exhibit 3, Direct Testimony of Public Staff Engineer Jay Lucas filed in Docket No. E-2, Sub 1142, on October 20, 2017.

general, DEP did not engage in comprehensive groundwater monitoring[76] until required to do so by its NPDES permits beginning in 2011.

The groundwater violations[77] currently reported to DEQ from DEP monitoring wells are a further indication of the breadth of environmental contamination caused by the Company. The 7,411 North Carolina groundwater violations listed in **Lucas Exhibit 11**, exceeding the 2L standards or IMACs and PBTVs at or beyond the compliance boundary, are attributable to migration of contaminants from DEP's ash basins. The 632 South Carolina exceedances of the Federal MCLs and Secondary MCLs are listed in **Lucas Exhibit 12**. The CCR Rule Appendix III Parameters 3,164 testing results determined to be statistically significant increases are listed in **Lucas Exhibit 15**. The CCR Rule Appendix IV Parameters 277 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 **Lucas Exhibit 16**. It is notable that the number of 2L violations has increased by 4,554, or 159%, since my testimony in the last DEP 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

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[76] See the number of groundwater monitoring wells installed by decade in **Lucas Exhibit 18**.

[77] DEQ affirmed this fact 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.

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[78] as part of the justification for the CCR Rule.

Moreover, DEP'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

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[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.

"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 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*.

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, DEP has a great deal of culpability for the compliance costs related to remediation and ash basin and storage unit closures, and would likely have 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 DEP'S CLAIMS FOR INSURANCE COVERAGE IN DOCKET NO. E-2, SUB 1142?

A. Yes. In DEP's last rate case in 2017, the Commission determined that if any insurance proceeds are ultimately received or recovered for mitigation and remediation costs associated with CCR sites, DEP shall place all such insurance proceeds in a regulatory liability account and hold such proceeds "until the Commission enters an order directing DEP regarding the appropriate disbursement of the proceeds."[79]

Q. HAS DEP 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.

Q. DOES THE PUBLIC STAFF HAVE A RECOMMENDATION REGARDING INSURANCE PROCEEDS ULTIMATELY RECEIVED OR RECOVERED BY THE COMPANY?

A. The Public Staff recommends that insurance proceeds received or recovered by the Company and placed in a regulatory liability account, as ordered by the Commission in the previous rate case, be disbursed back to ratepayers or used to offset the costs to ratepayers of the Company's coal ash costs.

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[79] E-2, Sub 1142, Jan. 23, 2018 Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, page 20.

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 2016 rate case filed by Dominion Energy North Carolina (Dominion), 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

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 Commission also disallowed $9.5 million in the previous DEP rate case for coal ash disposal costs at the Asheville plant based upon the testimony of Public Staff witnesses Garrett and Moore. The Public Staff asks that the

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Company's overall CCR plan, or regarding any specific expenditures other than the ones to be 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.").

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 by DEP'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 the 2017 DEC rate case, Public Staff witness Charles Junis provided testimony[82] that discussed the Public Staff's investigation of Dominion's environmental compliance record in its 2016 rate case. Dominion's environmental compliance record at that time appeared better than DEP's, and the Public Staff, therefore, recommended that DEP's cost recovery in its 2017 rate case should be treated differently.

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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.

Q. PLEASE DESCRIBE DEP'S AND DEC'S TESTIMONY IN THEIR 2017 RATE CASES COMPARING THEIR CCR MANAGEMENT RECORD TO THAT OF DOMINION.

A. On pages 10 through 12 of his rebuttal testimony filed on November 6, 2017, in Docket No. E-2, Sub 1142, DEP witness Julius Wright discussed Dominion's environmental compliance record and indicated that DEP and Dominion were "similarly situated." He further stated, "I believe the Commission's CCR cost recovery methodology in the Dominion case was correct and should be applied in the same way in this proceeding."

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 the testimony of Public Staff witness Charles Junis regarding Dominion's environmental compliance record by providing examples of CCR-related groundwater contamination[83] at Dominion's coal-fired power plants.

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 2016. In addition, Dominion's groundwater contamination remained far less extensive than that of DEP, and the finding of criminal negligence on the part of DEP was another differentiating factor.

[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 groundwater protection standard exceedances of arsenic attributed to wet ash from the unlined former ash settling basins."

Despite critical differences between the cases, witness Wright concluded that the Commission should apply the same standard to DEP and DEC in their 2017 rate cases as it did in the Dominion 2016 rate case, in which the Commission 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 last year's 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 my testimony in that case[84] and includes substantial groundwater exceedances and environmental contamination.

Q. WHAT DOES THE PUBLIC STAFF CONCLUDE REGARDING ITS COMPARISON OF THE ENVIRONMENTAL COMPLIANCE RECORDS OF DEP AND DOMINION?

A. At the time of the Dominion 2016 rate case and the DEP and DEC 2017 rate cases, the extent of Dominion's CCR-related noncompliance—as it was known to the Public Staff—paled in comparison to DEP's environmental noncompliance record. However, in 2019, the Public Staff

[84] Page 68, line 1, through page 74, line 4, and Exhibits 1 and 12-14, Direct Testimony of Public Staff Engineer Jay B. Lucas filed in Docket No. E-22, Sub 562, on August 23, 2019.

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 DEP. One distinction is that Dominion did not plead guilty in a federal criminal case as DEP did. Another distinction is that the Public Staff has evidence of thousands of groundwater violations for DEP, 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 February 24, 2020, Order Granting Partial Rate Increase, 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 DEP shareholders than was allocated to Dominion shareholders in the Notice of Decision because the environmental violations of DEP are far more extensive and far better documented.

Q. HOW DID THE COMMISSION TREAT CCR REMEDIATION COSTS IN THE DOMINION 2019 RATE CASE?

A. The Commission issued its Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase in the Dominion Rate Case, Docket No. E-22, Sub 562, on February 24, 2020.

The Commission determined that it would not apply equitable sharing as recommended by the Public Staff, but instead effectuated a "fair and reasonable balance" between shareholders and ratepayers. According to the Commission:

> . . . there is a well-established history of allocating prudently incurred costs, specifically in the context of extraordinary, large costs such as environmental clean-up and plant cancellation, between ratepayers and shareholders in order to strike a fair and reasonable balance. The Commission concludes that in the present case, fairness dictates this same treatment.
>
> Feb. 24, 2020 Order at 131.

In making its decision, the Commission stated that "[a] number of material facts in evidence call into question the prudence of DENC's actions and inaction and the risks accepted by DENC management at several of its CCR sites." <u>Id.</u> at 132. The Commission also pointed to the magnitude of the costs – approximately $377 million on a system level or $22 million on a North Carolina retail level ($181 per customer). <u>Id.</u> Lastly, the Commission raised concerns regarding the matching principle and intergenerational equity, stating that "DENC's CCR Costs address many decades' worth of coal-ash waste and the closure of coal ash basins related to electric service provided to customers in the past." Id. The Commission goes on to state that "DENC's present and future ratepayers are being burdened with costs arising from past service." Id.

Importantly, the Commission cites its obligation under N.C.G.S. 62-133(d) to consider these material facts of record when setting just and reasonable rates. Id. In sum, the Commission found the following:

> A fair and reasonable balance is found which requires DENC's shareholders to bear some of the risk of clean-up costs associated with CCR liabilities and protects the ratepayers from unreasonably high rates. The Commission concludes that the Company shall not be entitled to earn a return on the unamortized balance of CCR Costs during the amortization period, in light of: (1) the Commission's obligation to set just and reasonable rates that are fair to both the utility and the ratepayer in accordance with N.C.G.S. § 62-133(a); (2) the Commission's historical treatment of extraordinary, large costs, such as MGP environmental remediation costs and plant cancellation costs; and (3) the Commission's obligation to consider all other material facts of record that will enable it to determine what are just and reasonable rates in accordance with N.C.G.S. § 62-133(d). Id.

In addition to not allowing a return on the unamortized balance of the CCR costs, the Commission amortized the costs over a ten-year period consistent with its historical treatment of major plant cancellations, thus allocating to shareholders approximately 26% of the costs, and to ratepayers approximately 74% of the costs. Id. at 134-135.

Q. HOW DOES THE COMMISSION'S TREATMENT OF CCR REMEDIATION COSTS IN THE DOMINION 2019 RATE CASE DIFFER FROM THE PUBLIC STAFF'S EQUITABLE SHARING RECOMMENDATION IN THIS CASE?

A. Both the Commission's "fair and reasonable balancing" approach and the Public Staff's "equitable sharing" approach in the Dominion rate case were intended to allocate CCR-related costs between shareholders and ratepayers in order to achieve just and reasonable rates. The Public Staff recommends—via its equitable sharing approach—that the CCR costs in the present DEP rate case also be allocated between shareholders and ratepayers.

Further, in the present case, the Public Staff recommends a 50/50% allocation between ratepayers and shareholders for the prudently incurred coal ash remediation costs that have been deferred. The Commission used a 10-year amortization period in the Dominion Order to carry out its "fair and reasonable balancing," resulting in 26% of costs borne by shareholders. Here, in order to allocate 50% of costs to shareholders, Public Staff witness Maness recommends a longer amortization period of 26 years.

As discussed earlier in my testimony, the Public Staff's recommendation for a longer amortization period for DEP is due to the fact that evidence of environmental violations and environmental contamination is much more extensive for DEP than it was for Dominion. It is also due to the fact that the amount of CCR costs DEP is seeking to recover is higher, $624 million on a system basis, or $381 million on a North Carolina retail level ($276 per customer or about two-thirds of Dominion's remediation expenses per customer).

Commission's Order dated January 22, 2020
(Portion regarding CCR Remediation Costs)

Q. WHAT DID THE COMMISSION REQUIRE THE PUBLIC STAFF TO INVESTIGATE AND REPORT ON REGARDING DEP'S CCR REMEDIATION COSTS?

A. The Order required the Public Staff to provide total estimated costs and an estimated breakdown of the costs for DEP's CCR remediation for each site and for each impoundment as follows: (1) as initially proposed by DEP, and (2) pursuant to the 2019 Settlement Agreement entered into by and between DEP and DEQ.

Q. DID YOU HAVE ANY DIFFICULTIES COMPLYING WITH THE COMMISSION'S ORDER?

A. Yes. I was able to determine DEP's projected CCR remediation costs by site (or plant), but not by impoundment. DEP 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]

[redacted]. **[END CONFIDENTIAL]**

Q. PLEASE EXPLAIN THE RECENT HISTORY OF DEP'S CCR REMEDIATION COSTS AND ACTIONS TAKEN BY DEQ.

A. For ratemaking purposes, DEP's CCR remediation costs first became a large issue in its 2017 rate case. During that proceeding, DEP was in the process of excavating CCR from the Asheville and Sutton plants because DEQ had designated them as high-risk under CAMA.[85]

DEQ designated the other five coal-fired plants in North Carolina as intermediate risk, which gave DEP more time to close those CCR impoundments and allowed DEP to use cap-in-place for remediation. Those five plants are: Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon. The one remaining plant, Robinson, is in South Carolina and not under the jurisdiction of DEQ or CAMA; however, DEP is excavating the Robinson

[85] 2014 N.C. Sess. Law 122, Section 3.(b), as amended by 2015 N.C. Sess. Law 110.

impoundments under a Consent Order from the SCDHEC as discussed earlier in my testimony.

Q. IN 2017, WHAT WERE DEP'S ESTIMATED TOTAL CCR REMEDIATION COSTS?

A. In September 2017, DEP 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 Exhibit 21** provides a breakdown of this estimate by plant. DEP 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 DEP TO REVISE ITS ESTIMATE?

A. On April 1, 2019, DEQ issued orders (Excavation Orders) to DEP and DEC 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 DEQ ISSUED THE EXCAVATION ORDERS, WHAT WERE DEP'S ESTIMATED TOTAL CCR REMEDIATION COSTS?

A. In September 2019, DEP 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 Exhibit 22 provides a breakdown of this estimate by plant.

Q. WHAT HAPPENED AFTER DEQ ISSUED THE EXCAVATION ORDERS?

A. DEC and DEP filed a contested case challenging the Excavation Orders. However, on December 31, 2019, DEP, DEC, DEQ, and community and environmental groups entered into the 2019 Settlement Agreement that resolved the appeal of the Excavation Orders, as well as other ongoing litigation between DEP and DEC and the community and environmental organizations. The 2019 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 24 million tons of CCR in unlined impoundments to remain in place. The 2019 Settlement Agreement also acknowledges that DEQ, in the future, could grant variances that would allow the CCR beneficiation projects at the Cape Fear and H.F. Lee plants to extend operation from 2029, the CAMA-established closure deadline, to 2035. Extensions would allow for longer use of the beneficiation projects and could possibly avoid construction of coal ash landfills at the plant sites.

Q. WHAT EFFECT DID THE 2019 SETTLEMENT AGREEMENT HAVE ON DEP'S ESTIMATED TOTAL CCR REMEDIATION COSTS?

A. The 2019 Settlement Agreement decreased DEP'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 Exhibit 23** provides the effect of the 2019 Settlement Agreement savings on the amounts in **Confidential Lucas Exhibit 22**.

Q. DOES LUCAS EXHIBIT 23 PROVIDE DEP'S CURRENT ESTIMATED TOTAL CCR REMEDIATION COSTS?

A. No. DEP periodically evaluates and updates CCR remediation costs at all eight coal-fired plants. Changes other than the 2019 Settlement Agreement have affected current costs. DEP's current estimated total CCR remediation costs are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** This projection is for the years 2015 through 2079. **Confidential Lucas Exhibit 24** 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.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))))	SUPPLEMENTAL TESTIMONY OF JAY B. LUCAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

Supplemental Testimony of Jay B. Lucas

On Behalf of the Public Staff

North Carolina Utilities Commission

April 23, 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. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THESE PROCEEDINGS?

A. Yes.

INTRODUCTION

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is three-fold. First, I am presenting to the Commission the Public Staff's position on additional costs for municipal water supplies and water filtration systems that the Company incurred in January and February 2020. Second, I am updating Lucas Exhibit 19 in my direct testimony to include DEP's coal ash Asset Retirement Obligation (ARO) expenses through February 29, 2020. Third, I am correcting an error in Lucas Exhibit 18 in my direct testimony.

ADDITIONAL COSTS FOR MUNICIPAL WATER SUPPLIES AND WATER FILTRATION SYSTEMS

Q. PLEASE PROVIDE THE PUBLIC STAFF'S RECOMMENDATION ON ADDITIONAL COSTS FOR MUNICIPAL WATER SUPPLIES AND WATER FILTRATION SYSTEMS IN JANUARY AND FEBRUARY 2020.

A. I recommend that the Commission disallow the costs shown in Lucas Supplemental Table 1 below:

Lucas Supplemental Table 1 – Costs for Municipal Water Supplies and Water Filtration Systems			
	January 2020	February 2020	TOTAL
Municipal Water Supplies	$ 10,991	$ 7,024	$ 18,016
Water Filtration Systems	$ 63,207	$ 9,183	$ 72,390
TOTAL	$ 74,199	$ 16,207	$ 90,406

Q. PLEASE EXPLAIN WHY YOU RECOMMEND DISALLOWANCE OF THE COSTS LISTED IN THE TABLE ABOVE.

A. I recommend that the Commission disallow these costs for the same reasons that I discuss on page 68, line 17, through page 70, line 10, of my direct testimony filed on April 13, 2020. In summary, in DEP's previous rate case in Docket No. E-2, Sub 1142, the Commission determined that the Company should not recover costs for bottled water that the Company supplied to households near DEP's coal ash impoundments. There is no logical distinction between costs for bottled water and costs for permanent water supplies, as noted in Commissioner Clodfelter's dissent in the Commission's Order in the previous Duke Energy Carolinas, LLC, rate case in Docket No. E-7, Sub 1146. Furthermore, the municipal water supply costs and water filtration system costs are the direct result of the legislature deciding that coal ash constituents from DEP's impoundments created an unacceptable risk to people's groundwater wells.

UPDATED COAL ASH ARO EXPENSES

Q. PLEASE EXPLAIN YOUR UPDATE TO DEP'S COAL ASH ARO EXPENSES.

A. In my direct testimony, I provided Confidential Lucas Exhibit 19, which contains DEP's coal ash ARO expenses for September 1, 2017, through December 31, 2019. In response to a Public Staff data request, DEP provided updated expenses through February 29,

2020. I have updated Confidential Lucas Exhibit 19 to include those expenses as shown in **Confidential Revised Lucas Exhibit 19**.

CORRECTED LUCAS EXHIBIT 18

Q. PLEASE EXPLAIN YOUR CORRECTED LUCAS EXHIBIT 18.

A. Lucas Exhibit 18 in my direct testimony contained a mathematical error. However, correcting the error has no effect on the Public Staff's conclusions or recommendations. I am submitting the corrected version with my supplemental testimony as **Corrected Lucas Exhibit 18**.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, Sub 1193

In the Matter of Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	))))))	PUBLIC STAFF CORRECTION TO THE DIRECT TESTIMONY OF JAY B. LUCAS
DOCKET NO. E-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC, for an Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))))))	PUBLIC STAFF CORRECTION TO THE SUPPLEMENTAL TESTIMONY OF JAY B. LUCAS

<u>CORRECTION TO THE DIRECT TESTIMONY OF JAY B. LUCAS</u>

The direct testimony of witness Lucas, filed on April 13, 2020, should be corrected as follows:

Page 3, lines 4-5 – “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.”

<u>CORRECTION TO THE SUPPLEMENTAL TESTIMONY OF JAY B. LUCAS</u>

The supplemental testimony of witness Lucas, filed on April 23, 2020, 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."

Summary of Testimony of Jay B. Lucas
Docket No. E-2, Sub 1219

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 Progress, LLC (the Company) now has 7,411 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 (DEQ). Groundwater violations are 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 632 groundwater exceedances at the Robinson plant in South Carolina. The 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, the Company 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 the Company 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 7,411 groundwater violations, and in addition to the federal criminal charges to which the Company 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 Asheville and Sutton plants and land purchase at the Mayo plant. These costs, in the amount of $1,240,328, 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 $395,005, should be excluded from

rate recovery as ordered by the Commission in the Company's 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 $1,087,612, are the direct result of the legislature deciding that the Company's 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 the Company's coal ash impoundments and the extraordinary magnitude of costs that produce no new electricity. Public Staff witness Maness discusses additional reasons for equitable sharing.

With regard to projected coal ash remediation costs as initially proposed and after the December 31, 2019 Settlement Agreement between the Company and 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 the Company to excavate all coal ash at its two active coal-fired plants. Third, the Public Staff reviewed the estimated costs as of January 2020, after the Company and DEQ entered into the Settlement Agreement. Lastly, the Public Staff reviewed the Company's estimated costs as of February 2020. The Company 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 my summary.

Q. And my colleague, Mr. Grantmyre, will be presenting Mr. Maness.

DIRECT EXAMINATION BY MR. GRANTMYRE:

Q. Good morning. This is Bill Grantmyre, Public Staff attorney. Mr. Maness, are you there?

A. (Michael C. Maness) Yes, I'm here.

Q. Could you please state your name, business address, and current position?

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the director of accounting for the Public Staff.

Q. And did you cause to be prefiled on September 16, 2020, your second supplemental testimony consisting of 13 pages and two exhibits?

A. Yes, I did.

Q. And on September 29, 2020, did you prepare and cause to be filed a summary of your second supplemental testimony and an errata corrections to your direct testimonies?

A. Yes, I did.

Q. Other than those corrections, if you were asked the same questions again today, would your answers be the same?

A. Yes.

MR. GRANTMYRE: Commissioner Clodfelter, at this time, I move that Mr. Maness' second supplemental testimony, summary of his testimonies, and errata correction sheet be entered into the record as if given orally from the stand, and that his exhibits be marked for identification as prefiled.

COMMISSIONER CLODFELTER: Unless there is objection from any party, it will be so ordered.

(Public Staff Maness Exhibits I through III; Public Staff Supplemental Exhibits I through III; Public Staff Maness Second Supplemental Exhibits I and II; and Public Staff Second Revised Exhibits I and II were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct with Appendix A, and supplemental testimony of Michael C. Maness were moved at the consolidated hearing and copied into the record as if given orally from the stand.)

(Whereupon, the prefiled second

supplementary testimony, testimony summary, and errata 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-2, SUB 1219

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

April 13, 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, first, to present certain accounting and ratemaking adjustments related to the September 2017 – December 2019 Asset Retirement Obligation (ARO)-related and non-ARO-related coal ash clean-up, disposal, and remediation costs 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 Progress, LLC (DEP or the Company), in this proceeding. As part of this adjustment, I am incorporating coal-ash related adjustments recommended by other members of the Public Staff, as well as consultants retained by the Public Staff, as further described later herein, and flowing them through my schedules so that they can be incorporated into the Public Staff's recommended revenue requirement.

Second, I am commenting on the ratemaking treatment of the January 2015 – August 2017 costs of DEP's ARO–related coal ash compliance and cleanup activities, first considered by the Commission in Docket No. E-2, Sub 1142 (incorporating Docket No. E-2, Sub 1103 (Sub 1103) and hereafter referred to as Sub 1142), with regard to those aspects that are still on appeal to the North Carolina Supreme Court.

Third, I am responding to the portion of the Commission's Order Directing the Public Staff to File Testimony, dated January 22, 2020 (January 22 Order), requiring the Public Staff to investigate and report on each of DEP's depreciation studies going back to 2000 with respect to whether any costs for coal ash impoundment closures were included in net salvage for decommissioning of DEP's coal plants, and to explore whether or not DEP and/or its consultants ever otherwise discussed, memorialized, or corresponded about impoundment closure costs being included in net salvage.

Finally, I am presenting the Public Staff's recommendation regarding deferral of 2020 through 2022 costs related to the Company's proposed Grid Improvement Plan (GIP), based in part on recommendations of other members of the Public Staff, as further described herein.

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 Shawn L. Dorgan for inclusion in his Exhibit 1, in which he calculates the overall change in the Company's proposed revenue requirement recommended by the Public Staff, which is then used to determine the recommended rate change.

SUMMARY OF ADJUSTMENTS RECOMMENDED TO DEP'S ARO-RELATED AND NON-ARO-RELATED CCR COSTS

Q. PLEASE BRIEFLY DESCRIBE THE ADJUSTMENTS YOU ARE RECOMMENDING TO DEP'S CCR COSTS.

A. I am recommending adjustments to the Company's coal ash management costs in the following areas:

1. Adjustments to depreciation and amortization expense, as well as rate base amounts, associated with the Company's deferred ARO-related CCR costs, in order to achieve equitable sharing of the costs between ratepayers and DEP's shareholders.

2. Adjustments to depreciation and amortization expense, as well as rate base amounts, associated with the Company's non-ARO-related CCR costs to reflect a longer amortization period than that proposed by the Company.

Additionally, as explained later within my testimony, I am also recommending that the Company's proposed balances of deferred ARO-related CCR costs be reclassified within the Company's rate base, even though said reclassification has no impact on the Public Staff's overall revenue requirement.

ADJUSTMENTS TO DEP'S ARO-RELATED SEPTEMBER 2017 – FEBRUARY 2020 COAL ASH MANAGEMENT ACTIVITIES

Q. PLEASE BRIEFLY DESCRIBE THE BACKGROUND OF DEP'S ARO- AND NON-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 Lucas. Briefly, however, DEP's coal ash, or coal combustion residual (CCR) management activities in large part occur because DEP 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 DEP's coal ash remediation and non-ARO (capital projects) costs are incurred pursuant to several federal and state statutes and regulations, including, but not necessarily 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. As approved by the Commission in its decision in the Sub 1142 case, as discussed further later, the Company has made adjustments intended to result in the recording of a regulatory asset to reflect ARO-related expenditures it has incurred to remediate coal ash storage areas and to comply with the above-described federal and

[1] Groundwater Classification and Standards, 15A N.C. Admin. Code 2L.

state governmental requirements imposed to provide for the safe disposal of coal ash. These adjustments include (1) the implicit elimination of the ARO-related CCR accounting entries made to the Company's books and records prior to March 2020 for financial accounting purposes, and (2) a pro forma adjustment to increase rate base for the regulatory asset resulting from the actual ARO-related CCR expenditures incurred between September 1, 2017, and February 29, 2020 (the Deferral Period). DEP is proposing in this case to increase depreciation and amortization expenses to reflect a five-year amortization of those deferred costs.

With regard to non-ARO CCR capital expenditures, the Company has recorded those capital costs as additions to rate base as per normal utility accounting. However, pursuant to the Commission's decision in Sub 1103 and Sub 1142 (as discussed later), the Company has deferred the annual costs incurred (depreciation, return, incremental expenses) between the dates these facilities went into service and the date the rates in this proceeding are expected to go into effect, and is proposing to amortize those costs over a five-year period with a return.

Q. IN YOUR TESTIMONY, ARE YOU CONSIDERING ALL OF DEP'S COAL ASH COSTS INCURRED THROUGH FEBRUARY 2020?

A. No. Due to time constraints, the Public Staff was not able to consider actual costs incurred beyond December 31, 2019, in this round of testimony. Costs incurred in January and February 2020 will be incorporated into the Public Staff's supplemental testimony filed later in this proceeding.

FINANCIAL AND REGULATORY ACCOUNTING FOR DEP'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 estimated 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) 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 effectively reversed all of the entries made on its financial accounting books in association with the establishment of the FASB-mandated CCR ARO liability, and is instead proposing the deferral and amortization of <u>actual</u> expenditures as they are incurred during the Deferral Period. (A similar procedure was followed in the Sub 1142 case for the expenditures made between January 1, 2015, and August 31, 2017.)

The Company bases its proposal not to adopt financial accounting ARO treatment for North Carolina retail ratemaking purposes on the deferral approval it received in the Sub 1103 and Sub 1142 subdockets, which in turn relies on a 2003 Commission Order in

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[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.

Docket No. E-2, Sub 826; that Order focused on the relationship between the Commission's long-standing treatment of nuclear decommissioning costs and the FASB's required treatment of AROs pursuant to Statement of Financial Accounting Standards No. 143 (SFAS 143), now codified within ASC 410. These Orders essentially allowed DEP 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 1142 rate case, the Company is effectively asking the Commission to replace ASC 410 treatment with its own proposed ratemaking treatment.[3]

Q. HOW IS THE COMPANY PROPOSING TO TREAT ARO-RELATED CCR EXPENDITURES AND OBLIGATIONS FOR RATEMAKING PURPOSES?

A. As noted previously, and consistent with the Sub 1142 Order, the Company has established a regulatory asset for actual CCR expenditures made during the Deferral Period, and proposes to amortize that regulatory asset over a five-year period beginning with the effective date of the rates approved in this proceeding. This is

[3] The Company still follows GAAP/FERC accounting for financial presentation purposes. However, in the present proceeding it seeks to replace the ASC 410 treatment for purposes of North Carolina retail ratemaking. As Company witness Sean Riley notes in his rebuttal testimony in the Duke Energy Carolinas rate case, Docket No. E-7, Sub 1214, the accounting treatment follows the ratemaking treatment. Accounting for GAAP purposes does not determine the ratemaking treatment.

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 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 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 DEFERRAL APPROACH?

A. The effective result of the deferral approach is to replace, for ratemaking purposes, the ARO approach required by the FASB for financial accounting purposes with the 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 826 Order. Under the Sub 826 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 HOW THE DEFERRAL APPROACH CAME TO BE APPROVED BY THE COMMISSION, RESULTING IN A DEFERRED BALANCE OF COAL ASH MANAGEMENT

EXPENDITURES THAT DEP 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 DEP 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 Sub 1103 and E-7, Sub 1110, DEP and Duke Energy Carolinas, LLC (DEC), 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 DEP's and DEC'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 July 10, 2017, the Commission issued an order consolidating Sub 1103 with the Sub 1142 general rate case proceeding. On February 23, 2018, the Commission issued its Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase in Sub 1103 and Sub 1142 (Sub 1142 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 COAL ASH 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, DEP 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 1103 AND THE COMMISSION'S SUB 1142 ORDER?

A. Yes. Consistent with its comments and the Commission's Sub 1142 Order, the Public Staff does not object for purposes of this proceeding to the deferral of a return for the period September 2017 through the effective date of new rates on deferred ARO-related coal ash expenditures. Additionally, due to the magnitude and 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.[4]

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 December 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 Jay B. Lucas;

2. Amortization of the balance of ARO-related deferred coal ash expenditures at the beginning of September 2020[5] over a 27-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;

[4] 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.

[5] If the rates approved in this case become effective on a different date, the beginning of the amortization period should begin on the effective date.

this reversal, in conjunction with the 27-year amortization 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 Lucas. 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 the Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants at the Brickhaven structural fill project, and (b) ash transportation costs related to the Asheville Station – approximately $33.7 million and $50.2 million, respectively, on a system basis;

2. Adjustments recommended by witness Moore with regard to coal ash costs associated with beneficiation activities at the H.F. Lee and Cape Fear Stations - approximately $65.3 million and $65.0 million, on a system basis; and

3. Adjustments recommended by witness Lucas (a) to remove the costs of extraction and treatment of groundwater and other costs of groundwater remediation at various plants and (b) to provide for permanent alternative water supplies or water treatment – approximately $1.2 million and $3.9 million, respectively, on a system basis.

I have accumulated these costs and spread them in a reasonable manner throughout the Deferral 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 DEFERRAL PERIOD COAL ASH COSTS OVER 27 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 Deferral Period 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 Lucas, 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 DEP shareholders to pay. Furthermore, he testifies that DEP'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. Lucas 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. Lucas 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 DEP's coal ash costs.

Q. IS THE TYPE OF EQUITABLE SHARING YOU AND MR. LUCAS 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 ($404,684,000, 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 recommended by the Public Staff for amortization ($267,472,000, including carrying costs) amounts to an average of approximately $162 per N.C. retail customer, using a proforma balance of 1,653,474 customers at December 31, 2019. Requiring the N.C. retail customers to bear the cost of a five-year amortization period for these costs would burden each customer with an additional amount of approximately $32 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 DEP will be incurring significant additional coal ash 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 DEP, the abandonment losses related to Harris Units 2, 3, and 4 and Mayo Unit 2.[6] Furthermore, in DEP's 1983 general rate case, Docket No. E-2, Sub 461, the Commission outlined its policy – applicable to all regulated electric utilities in North Carolina - regarding the treatment of plant abandonment losses:

> The proper rate-making treatment of abandonment losses 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

[6] See in particular the Evidence and Conclusions for Finding of Fact No. 11 in the *Commission's Order Granting Partial Increase in Rates and Charges*, issued on August 5, 1988, in Docket No. E-2, Subs 537 and 333.

Commission's ultimate responsibility with respect to rate-making is to fix rates for the service provided which are fair and reasonable both to the utility and to the consumer. General Statutes 62-133(a); North Carolina ex rel. Utilities Commission v. Morgan (1970), 277 N.C. 255, 86 PUR3d 371, 177 S.E. 2d 405; North Carolina ex rel. Utilities Commission v. North Carolina ex rel. Utilities Commission v Carolinas Committee for Industrial Power Rates (1962), 257 N.C. 560, 45 PUR3d 223, 126 S.E. 2d 325.

Although parties may disagree as to the amortization period, they 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. In the last CP&L rate case, the Commission determined that a ten-year amortization period for abandonment losses resulting from cancellation of Harris Unit Nos. 3 and 4 'will more reasonably and equitably serve to share the burden of the cancellation of Harris Unit Nos. 3 and 4 between present and future ratepayers. Furthermore, use of a ten-year amortization period is also consistent with previous decisions of the Commission regarding amortization of similar property losses set forth in Orders. Amortization of these abandonment losses should be continued as previously ordered. Similarly, the Commission believes that the amortization of losses resulting from cancellation of the South River Project and the Brunswick Cooling Towers should continue as previously ordered by the Commission.

Pursuant to the Commission's reexamination of the proper rate-making treatment of abandonment losses, the Commission has determined that it is neither fair nor reasonable to include any portion of the unamortized balance of such investments in rate base and, furthermore, that no adjustment should be allowed which would 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.

1983 N.C. PUC Lexis 4

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 Docket No. E-7, Sub 1146, for DEC's 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 DEP 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 <u>expense</u> 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)[7]; the second carries no such return requirement.

Q. IN WHICH CATEGORY DO THE ARO-RELATED DEFERRED COSTS PROPOSED IN THIS CASE BY DEP FOR AMORTIZATION FALL?

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.[8] Although the Company could have chosen to propose following the method prescribed by generally accepted accounting principles (GAAP) for non-

[7] 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.

[8] Contrary to statements by DEP and DEC, I am not saying the Company had a choice to ignore GAAP/FERC accounting standards. The choice to which I refer is the Company's request to defer its coal ash costs to a regulatory asset for North Carolina retail ratemaking purposes.

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 as expenses (under the approved deferral approach) 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 DEP 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 … (Petition, page 14)

All of the ARO-related 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 being proposed for ratemaking purposes as 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., The Regulation of Public Utilities, Third Edition (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 nor 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, DEP'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 DEP's coal ash management in North Carolina as articulated by Public Staff witness Lucas, 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 27 years beginning on the date the rates approved in this proceeding become effective.

Q. WHAT SHARING PERCENTAGE DOES A 27-YEAR AMORTIZATION PERIOD PRODUCE?

A. At the net-of-tax overall rate of return recommended by the Public Staff, a 27-year amortization period results in the ratepayers bearing approximately 50.02% of the present value of the Deferral Period deferred costs at September 1, 2020 (with a return accrued to that point).[9] 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

[9] 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.

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 DEP'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 Lucas, is much greater than in the Sub 1142 rate case.

Q. ARE THERE OTHER FACTORS THAT SUPPORT A SHARING OF ARO-RELATED COAL ASH MANAGEMENT COSTS BETWEEN DEP'S RATEPAYERS AND SHAREHOLDERS?

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, though with different percentages. On February 24, 2020, the Commission issued its *Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase* (Sub 562 Order) 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 (although not characterized as an "equitable sharing" by the Commission). 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 DEP than the evidence shown 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 $(112) million, is set forth in Maness Exhibit I, and has been incorporated by Public Staff witness Dorgan.

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 COAL ASH COMPLIANCE AND CLEANUP

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 Dorgan that he 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 DEFERRED COAL ASH CAPITAL COSTS

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-2, Sub 1103, 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 DEP's coal ash ARO, the Company nonetheless maintains that they are eligible for deferral pursuant to the terms of the Sub 1103 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 $10.3 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 $10.3 million revenue requirement by approximately $_3.8 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 Dorgan.

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 1103 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 1103 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 right granted by the Commission in Sub 1103 to defer capital costs associated with CAMA or the CCR Rule should not continue. Therefore, the Public Staff recommends that any further Sub 1103 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-2, SUB 1142

Q. PLEASE EXPLAIN HOW THE ARO-RELATED DEFERRED COSTS AND AMORTIZATION EXPENSE APPROVED BY THE COMMISSION IN DOCKET NO. E-2, SUB 1142, IMPACT THIS PROCEEDING.

A. In the Company's last general rate case, it proposed to defer and amortize ARO-related coal ash remediation costs incurred between January 2015 and August 2017 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 26-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 $6 million annual penalty on the Company for each of the five years. As a result, in the present proceeding the Company has proposed to include in its North Carolina retail cost of service an annualized amount of approximately $41 million in amortization expense related to the Sub 1142 deferred costs, and in its North Carolina retail rate base an annualized end-of period level of unamortized Sub 1142 deferred costs of approximately $142 million, before reduction for accumulated deferred income taxes (ADIT).

Q. WHAT IS THE CURRENT LEGAL STATUS OF THE ISSUES RELATED TO THE SUB 1142 ARO-RELATED DEFERRED COSTS?

A. Several parties have appealed the Commission's Sub 1142 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 appeal 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 1142 COSTS INCLUDED IN THIS CASE, DOCKET NO. E-2, SUB 1219?

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 1142 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 1142 adjustments to be flowed through to the Sub 1142 costs as included in the Sub 1219 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 1142 costs included in the Sub 1219 case.

Q. WHAT WOULD BE THE EFFECT OF THE PUBLIC STAFF'S APPEALED POSITIONS ON THE SUB 1142 COSTS AS INCLUDED IN THIS CASE?

A. The effect in this case would be to reduce annual Sub 1142 coal ash amortization expense from approximately $41 million to approximately $9 million, and reduce the associated net-of-ADIT Sub 1142 rate base amount from approximately $142 million to $0. The revenue requirement impact in the current case of these changes would be an annual reduction of approximately $41 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.

COMMISSION QUESTIONS INCLUDED IN THE JANUARY 22 ORDER

Q. PLEASE PROVIDE A SUMMARY OF THE RESULTS OF YOUR INVESTIGATION PURSUANT TO THE PORTION OF THE COMMISSION'S JANUARY 22, 2020, ORDER REGARDING WHETHER ANY COSTS FOR COAL ASH IMPOUNDMENT CLOSURES HAVE BEEN INCLUDED IN OR CONTEMPLATED FOR NET SALVAGE FOR DECOMMISSIONING OF DEP'S COAL PLANTS.

A. In response to Public Staff data requests regarding this question, DEP indicated that prior to the ARO requirements becoming effective, it had only included the costs of CCR removal and remediation in one previous depreciation study, the one performed in 2010 and filed with the Commission in Docket No. E-2, Sub 1023.

This study remained in effect until the time of DEP's Sub 111142 rate case, and the amounts charged to N.C. retail customers as a result of that study have been offset against the deferred costs for which the Company has proposed recovery in Sub 1142 and the current case. As noted, the study has been filed with the Commission.

With regard to whether the Company had previously explored the possibility of including CCR basin closure or remediation cost in depreciation rates, the Company indicated to the Public Staff that it had not been able to locate any records of such discussions. The Company also stated the following in a data response to the Public Staff:

> Prior to approximately the mid-2010s, and particularly in connection with the promulgation of the US Environmental Protection Agency's final rule on coal combustion residuals ("CCR Rule"), it was not standard industry practice to include anticipated costs of coal ash impoundment closure in net salvage portion of depreciation expense for several reasons. In the early part of the period specified in DR 1 above, 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 fashion 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. Without a definite plan to decommission these plants, or the specific manner at which the facility will be decommissioned, it was not common to include decommissioning costs related to coal ash basin closures in the calculation of depreciation rates. Further, as a general matter, pre-

> CCR Rule coal ash basin closures ordinarily were planned and carried out in conjunction with the relevant environmental authorities."

Company Response to Public Staff Data Request 147, Question 3

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING CCR COSTS?

A. Yes. I would like to note that 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 March 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. To be specific, the Commission should consider whether the allowance of a return during the deferral period should result in a greater portion of the costs being borne by the shareholders during the amortization period.

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 Kim H. Smith, DEP 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. Smith 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. Smith also testifies that deferral can be applied in a flexible way, ensuring 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 Smith, 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.[10]

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

[10] 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.

should be considered extraordinary in type and outside the scope of DEP'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.

As a result of their evaluation, witnesses Tommy and David Williamson identified the following programs as ones 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. Transmission System Intelligence;
4. Underground System Automation; and
5. 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. Yes, I have.

Q. BASED ON THE DATA YOU HAVE RECEIVED, WHAT IS THE TOTAL AMOUNT OF CAPITAL INVESTMENT ESTIMATED FOR THE FIVE PROGRAMS OVER THE YEARS 2020 THROUGH 2022?

A. The total amount of capital expenditure estimated by the Company for the five programs is approximately $186 million.

Q. DID YOU INCLUDE THE ENTIRETY OF THIS $186 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 period (excluding January and February 2020, assuming the 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	(3)
2021	(14)
2022	(25)

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 14.00 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 DEC's 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 five DEP programs identified as being of extraordinary type by the Public Staff in this proceeding (which are very similar to programs for which the Public Staff does not object to deferral in DEC's currently ongoing general rate case, Docket No. E-7, Sub 1214), along with associated incremental expenses (net of quantifiable operational benefits in operating revenues or expenses), incurred over the March 2020 through December 2022 time period (assuming the Company's proposed updates, with appropriate and reasonable Public Staff adjustments, are approved), 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 March 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 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-2, SUB 1219

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))))	SUPPLEMENTAL TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

Supplemental Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

April 23, 2020

Q. MR. MANESS, WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my 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 Progress, LLC (DEP or the Company). These revisions affect my adjustments to the Company-proposed amortization expenses and unamortized balances associated with both (a) DEP'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 Shawn L. Dorgan for inclusion in his Supplemental Exhibit 1, in which he calculates the revised overall change recommended by the Public Staff to the Company's updated proposed base rate revenue increase.

I am also presenting a revised calculation of the basis point impacts estimated to result from the deferral of certain components of the Company's proposed Grid Improvement Plan (GIP). These revisions do not change the recommendation set forth in my initial testimony regarding deferral of GIP costs.

Q. WHAT REVISIONS ARE YOU MAKING TO YOUR RECOMMENDED COAL ASH ADJUSTMENTS?

A. With regard to my recommended adjustment to the amortization expense and unamortized balance of deferred ARO costs (set forth on Maness Supplemental Exhibit I), 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 January and February 2020.

2. I have incorporated the additional adjustments recommended by Public Staff witness Lucas for January and February 2020 to remove costs of providing permanent water supplies and water filtration systems.

3. I have proportionately reallocated the H.F. Lee and Cape Fear Beneficiation adjustments, and the Asheville Transportation adjustment, recommended by Public Staff witnesses Moore and Garrett, respectively, to reflect the addition to the

allocation base of the January and February 2020 ARO-related coal ash expenditures.

With regard to the amortization expense and unamortized balance of deferred non-ARO coal ash costs (set forth on Maness Supplemental Exhibit II), I have added to the balance of deferred costs to be amortized the monthly capital cost impacts through August 2020 of the actual non-ARO-related additions to coal ash project plant in service for January and February 2020.

With regard to the reclassification of ARO-related unamortized coal ash costs I recommended in my initial testimony, I have updated those amounts to reflect the Company-proposed balances as of the end of February 2020. This adjustment has no revenue requirement impact.

I would also like to note that since Public Staff witness Dorgan has reallocated the Company's per books rate base and net operating income amounts, as well as its proposed pro forma adjustments, to reflect the Summer/Winter Peak and Average (SWPA) allocation methodology, I have reflected all Company-proposed amounts in my Exhibits at those amounts. Additionally, I have calculated all of my proposed cost amounts using the SWPA methodology.

Q. DID THE UPDATE TO FEBRUARY 2020 LEAD YOU TO RECOMMEND A CHANGE IN THE AMORTIZATION PERIOD OF 27 YEARS YOU HAVE PREVIOUSLY RECOMMENDED FOR ARO-RELATED COAL ASH DEFERRED COSTS?

A. No. As noted in the initial testimony of witness Lucas, 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 27-year amortization produced a ratepayer sharing ratio of approximately 50.02% of the costs (based on a present value analysis), which the Public Staff considered sufficiently close to 50%. The update of costs through February 2020 did not produce a change in this ratio. Therefore, I continue to recommend a 27-year amortization period for ARO-related coal ash costs.[1]

Q. HAS THE ADDITION OF JANUARY AND FEBRUARY 2020 COAL ASH COSTS TO THE BALANCE AVAILABLE FOR DEFERRAL CHANGED THE IMPACT OF THESE COSTS ON NORTH CAROLINA RETAIL RATEPAYERS?

[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 $162 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 approximately $32 per year, on average, even before considering the rate base impact of the deferred costs.

With the addition of January and February 2020 costs, and the update of customer growth, the measurements of these impacts have increased. Now, the N.C. retail amount presented for amortization after the Public Staff's recommended prudence and reasonableness adjustments (($293,101,000), including carrying costs), amounts to an average of approximately $177 per N.C. retail customer, using a pro forma balance of 1,658,358 customers at February 29, 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 $35 per year, on average, even before considering the impact of including the unamortized amount in rate base.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING COAL ASH COSTS?

A. Yes. I would like to note that I just recently received a response to a data request that I had submitted regarding the Company's supplemental filing. I am currently reviewing that response, and may revise my testimony based on that review, if necessary.

Q. PLEASE EXPLAIN THE REVISED CALCULATION OF THE BASIS POINT IMPACTS ESTIMATED TO RESULT FROM THE DEFERRAL OF CERTAIN COMPONENTS OF THE COMPANY'S PROPOSED GIP, AS YOU NOTED EARLIER.

A. In my initial testimony, I presented an estimated calculation of the basis point impact on earned return on equity (ROE) of those components of the Company's GIP that Public Staff witnesses David Williamson and Tommy Williamson identified as extraordinary in type and, therefore, candidates for deferral. Because of the change in the rate base and required net operating income amounts recommended by the Public Staff in Mr. Dorgan's Supplemental Testimony and Exhibits, the estimated basis point impacts over the 2020-2022 time period have changed slightly, as follows:

Year	Original ROE Basis Point Impact	Revised ROE Basis Point Impact
2020	(3)	(3)
2021	(14)	(13)
2022	(25)	(24)

This is a minor change (one basis point in years 2021 and 2022) that does not affect the recommendation presented in my initial testimony. The calculation of the revised amounts is set forth on Maness Supplemental Exhibit III.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1193

In the Matter of
Application of Duke Energy Progress, 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-2, SUB 1219

In the Matter of
Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

SECOND SUPPLEMENTAL COAL ASH TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUBS 1193 AND 1219

Second Supplemental Coal Ash Testimony of Michael C. Maness

On Behalf of the Public Staff

North Carolina Utilities Commission

September 16, 2020

Q. MR. MANESS WHAT TESTIMONY DOES THIS TESTIMONY SUPPLEMENT?

A. This Second Supplemental Coal Ash Testimony supplements my Supplemental Testimony, filed on April 23, 2020.

Q. MR. MANESS, WHAT IS THE PURPOSE OF YOUR SECOND SUPPLEMENTAL COAL ASH TESTIMONY?

A. The primary purpose of my Second Supplemental Coal Ash 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 Progress, LLC (DEP). These revisions affect my adjustments to the Company-proposed amortization expenses and unamortized balances associated with both (a) DEP's Asset Retirement Obligation (ARO) – related coal ash activities, and (b) its non-ARO-related coal ash projects. I have forwarded my revised adjustments to my Maness Second Stipulation Exhibit 1, separately filed this same date with my Supplemental Testimony Supporting Second Partial Settlement, in which I calculate 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 Kim H. Smith in Compliance with Commission Order Requesting GIP Information, filed by DEP in this proceeding on August 5, 2020 (Additional GIP Testimony), and (b) the Supplemental Testimony and Exhibit of David L. Doss, Jr., filed by DEP 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 SECOND SUPPLEMENTAL COAL ASH 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 4.04%, 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 15, 2020, to audit DEP'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, DEP filed the Second Settlement Testimony and Exhibits (Second Settlement Testimony) of witness Kim H. Smith, which presented the Company's revised proposed revenue requirement pursuant to the terms of the First[1] and Second Partial Stipulations.

Also on July 31, 2020, Public Staff witnesses J. Randall Woolridge, James S. McLawhorn, and I each filed Testimony Supporting Second Partial Stipulation, stating that the Second Partial Stipulation is in the public interest and should be approved. I 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 in accordance with the Second Partial Stipulation.

Q. WHY DOES THE SECOND PARTIAL STIPULATION AND THE COMPANY'S SECOND SETTLEMENT TESTIMONY NECESSITATE THE FILING OF YOUR SECOND SUPPLEMENTAL COAL ASH 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

[1] The Stipulating Parties filed a First Agreement and Stipulation of Partial Settlement on June 2, 2020.

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 a 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 ten-year amortization period for the deferred costs, while the Company proposed a five-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 expense has been decreased.

The Public Staff's revised recommended amortization expense and rate base impact are set forth on Maness Second Revised Exhibit II, filed with this testimony. No difference now exists between the amounts recommended by the Public Staff and those 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 Public Staff witness Lucas, 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 April 23, 2020, I recommended an amortization period of 27 years, which I testified produced a ratepayer sharing ratio of approximately 50.02% 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 6.079% to 6.484%. This increase, via its influence on the present value analysis, decreases the ratepayer sharing ratio resulting from a 27-year amortization period from approximately 50.02% to approximately 48.16%. If, on the other hand, the amortization period is decreased to 25 years, the resulting ratepayer sharing ratio is approximately 50.45%. 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.[2]

My revised recommended ARO-related coal ash cost amortization expense and rate base impacts are set forth on Maness Second Revised 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

[2] 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.

costs that the Commission does decide to include in rate base be presented separately as a regulatory asset outside of working capital.

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 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.[3] In fact,

[3] 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

the Company's own workpapers submitted in the general rate case to calculate its proposed deferral and amortization amounts pay no 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.

The Public Staff's approach is thoroughly consistent with the Commission's August 12, 2003 Order in Docket No. E-2, Sub 826, which the Company used to justify its 2016 petition for deferral of coal ash costs in Docket No. E-2, Sub 1103. In the Sub 826 Order, the Commission directly stated, in ordering subparagraph 2.b:

> That the adoption of SFAS 143 shall have no impact on PEC's [Progress Energy Carolinas'] 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 PEC'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.

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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.

ADDITIONAL GIP TESTIMONY

Q. MR. MANESS, HAVE YOU REVIEWED THE ADDITIONAL GIP TESTIMONY AND EXHIBIT FILED BY DEP WITNESSES OLIVER AND SMITH 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, 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 is appropriate to wait to decide on the reasonable period until the facts and circumstances are clearer.

Q. DOES THIS COMPLETE YOUR SECOND SUPPLEMENTAL COAL ASH 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-2, Subs 1193 and 1219

This summary addresses the coal combustion residual (CCR) portions of my initial Testimony, Supplemental Testimony, and Second Supplemental Coal Ash Testimony, filed (with accompanying Exhibits) in Docket No. E-2, Subs 1193 and 1219 (collectively, Sub 1219), on April 13, 2020, April 23, 2020, and September 16, 2020, respectively. My testimony, along with that of Public Staff witnesses Garrett, Moore, and Lucas, presents (a) the Public Staff's recommendations regarding the deferral and amortization of Duke Energy Progress, LLC's (DEP or the Company) asset retirement obligation related (ARO-related) and non-ARO-related CCR costs incurred between September 1, 2017 and February 29, 2020 (Deferral Period), as well as (b) comments regarding questions asked by the Commission in its January 22, 2020 Order Directing the Public Staff to File Testimony (January 22 Order).

I am recommending or incorporating adjustments in the following areas:

1. The ratemaking treatment of the costs of DEP's ARO–related coal ash compliance and cleanup activities;
2. The appropriate classification within the Company-proposed 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 reasonable level of coal ash expenditures, as recommended by Public Staff witnesses Vance F. Moore, L. Bernard Garrett, and Jay B. Lucas;
2. Amortization of the 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 25-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 DEP's shareholders being required to bear approximately 50% of the present value of the September 2017 - February 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 Lucas, 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. Lucas 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 DEP'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 makes 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-2, Sub 1142, 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 1142 costs as they are included 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.

With regard to the January 22 Order, DEP indicated that prior to the ARO requirements becoming effective for CCR costs with the enactment of the Coal Ash Management Act (CAMA) in 2014, it had only included the costs of CCR removal and remediation in one previous depreciation study, the one performed in 2010 and filed with the Commission in Docket No. E-2, Sub 1023. This study remained in effect until the time of DEP's Sub 1142 rate case, and the amounts charged to N.C. retail customers as a result of that study have been offset against the deferred costs for which the Company has proposed recovery in Sub 1142 and the current case.

With regard to whether the Company had explored the possibility of including CCR basin closure or remediation cost in depreciation rates prior to the 2010 study, the Company indicated to the Public Staff that it had not been able to locate any records of such discussions. The Company also stated that prior to that study (going back to 2000), DEP behaved in accordance with the prevailing presumption by electric companies that coal-burning facilities would continue to operate well into the future; moreover, it was presumed that existing coal ash basins would continue performing their storage function as well.

This concludes my summary.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1193 In the Matter of Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	)	CORRECTION TO THE TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC, for an Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	CORRECTION TO THE SECOND SUPPLEMENTAL COAL ASH TESTIMONY OF MICHAEL C. MANESS RELATED TO COAL COMBUSTION RESIDUAL COSTS

CORRECTION TO THE TESTIMONY OF MICHAEL C. MANESS, FILED APRIL 13, 2020

Mr. Maness's Testimony should be corrected as follows:

1. On Page 49, Line 1, the numerical term "111142" should be changed to "1142."

CORRECTION TO THE SECOND SUPPLEMENTAL COAL ASH TESTIMONY OF MICHAEL C. MANESS RELATED TO COAL COMBUSTION RESIDUAL COSTS, FILED SEPTEMBER 16, 2020

Mr. Maness's Second Supplemental Coal Ash Testimony should be corrected as follows:

1. On Page 7, Line 20, the word "second" should be deleted.

MR. GRANTMYRE: Commissioner Clodfelter, he is available for cross expectation.

MS. LUHR: And, Mr. Clodfelter, before we move on to questions, I wondered if this is appropriate time, to address the stipulation for these witnesses.

COMMISSIONER CLODFELTER: It is the appropriate time.

MS. LUHR: So, Commissioner Clodfelter, at this time, pursuant to the amended stipulation between DEP, the Attorney General's Office, the Sierra Club, and the Public Staff, I would move that the live testimony of witnesses Charles Junis and Michael Maness, in Docket Number E-7, Sub 1214, be copied into the record as if given orally from the stand. The live testimony is located at transcript Volume 20, page 565, line 1 through page 587, line 9; transcript Volume 21, page 11, line 17 through page 132, line 19; and transcript Volume 22, page 13, line 10 through page 48, line 15.

And I would note that the amended stipulation recognized that Charles Junis appeared as the Public Staff witness in the Duke Energy Carolinas rate case while Jay Lucas is providing testimony on the same topic in the current proceeding. So the stipulation provides that Charles Junis is the same witness as Jay Lucas for the purposes of this stipulation.

COMMISSIONER CLODFELTER: I think I understand that, but let me ask a question, Ms. Luhr. Is Mr. Lucas adopting in this case, as his own testimony, the stipulated testimony of Mr. Junis?

MS. LUHR: Yes. And if you want Mr. Lucas to --

COMMISSIONER CLODFELTER: I'll leave that to you, but I just want to be sure I understand the intend of your motion. We can clean it up as we need to clean it up, however.

The all parties have heard the motion. Are there any objections?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, the motion is allowed.

MS. LUHR: Thank you.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, transcript Volume 20, page 565, line 1 through page 587, line 9; Volume 21, page 11, line 17 through page 132, line 19; and Volume 22, page 13, line 10 through page 48, line 15 were copied into the record as if given orally from the stand.)

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?

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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.

CONTINUED CROSS EXAMINATION BY MR. MEHTA:

Q. And good morning, Mr. Maness. Good morning, Mr. Junis.

A. (Michael C. Maness) Good morning.

A. (Charles Junis) Good morning.

Q. Mr. Junis, if you would turn to page 7 of your testimony.

A. I'm there.

Q. And you indicate on line 11 that there are 10,940 groundwater exceedances confirmed by DEC's groundwater monitoring data, correct?
A. Yes, sir.
Q. And that data, all of that data, was submitted by DEC to the environmental regulator, the DEQ, correct?
A. Yes, sir.
Q. And if you flip over to page 46 of your testimony.
A. (Witness peruses document.)
I'm there.
Q. And again, on page 10 and 11, you indicate that the cumulative total of groundwater, quote, violations has reached 10,940, correct?
A. Yes, sir. And those are specific to the North Carolina sites. And I think that is one of the key differences, as we talked about on Friday, between the records of Dominion and Duke, and that there is this plethora of data that is confirmed groundwater violations in violation of the 2L standards that -- degrading the natural quality of the groundwater.
Q. All right. And I'm looking at footnote 57, and you indicate that, of that 10,940, it looks like

3,091 were located, or discovered, or reported, or whatever word you want to use in the prior case, correct?

A. That's correct.

Q. And then -- and 10,940 is the cumulative total, so it would include that 3,091, correct?

A. Yes, sir.

Q. And what that represents, Mr. Junis, the 10,940 number, it represents the number of sampling events across the entirety of DEC's ash basins, the whole groundwater system across the ash basins in which the monitoring results exceed the 2L standards; did I get that correct?

A. Yes. The -- around the North Carolina basins, those are violations of the standard in exceedance of also the background at or beyond the compliance boundary.

Q. Mr. Junis, I want you to imagine a groundwater plume that covers an area near one of these basins, and we'll say it's a -- it's one of the retired basins. So it's been dewatered. There's no longer any hydraulic head that you were talking about earlier and Mr. Hart talked about the other day, and I think Mr. Quarles too. And let's also assume that, just like

Mr. Hart was talking about, this is a heavy clay soil and the contaminants in the plume are metals, so they're not really moving much.

Are you with me so far?

A. I don't think you can assume that they're not moving much because they're clay soils, because a lot of these basins have been in service for decades. And so those attenuative [sic] properties or the capacity of those soils to retain those metals can be exhausted, so they're not going to retain them as much. I will agree that the hydraulic head would be lower because you don't have a standing level of surface water, but there still is some push. I would say that the groundwater would be a little bit slower at that point, though.

Q. Okay. If it's moving, it's moving very slowly, as Mr. Hart indicated, when you have metal contamination and heavy clay soils, whether it's a lessened attenuation, but it's still attenuated, right?

A. And I would add that it is site specific regarding the amount of clay soil and then the layers of the soil levels, you know, the mix of sand or silty soils. And it can even be specific to each basin.

Q. Well, that's a very good point, Mr. Junis.

So in our imaginary plume, we're in one in which the contaminants are really not moving very much based on all of the factors that Mr. Hart and Mr. Quarles have already testified about; are you with me?

A. In general, groundwater moves slowly. Obviously, if there is that hydraulic pressure from a standing surface water, then it would move quicker, but I think we can keep moving with the scenario.

Q. Thanks. So let's say, Mr. Hart [sic], in this area, in our imaginary area, there's a single groundwater monitoring well, and it is sampled under protocols established by the DEQ once a year. With me?

A. Yes, sir.

Q. So you have, at the end of the year in which this well is sampled, one exceedance, or in your terms, a, quote, a violation of the 2L standards, correct?

A. Yes, sir.

Q. Well, let's say, as a result of that exceedance, the DEQ says, well, we need more wells. And so they spend another year putting in 49 more wells and they say we're going to sample these once a week, except just to make the math easier, we'll let you off on Christmas week, and we'll let you off on the week of

the 4th of July, correct? With me so far?
A. I am. I would say that that is not a typical procedure, in recognition that there's usually a site analysis of those subsurface conditions. And usually there's recognition that that frequency would be quarterly, or twice a year, or annually. Weekly would be a very high frequency.
Q. All right. But still, we're operating in this site-specific example in which, for whatever reason, the DEQ wants it weekly.
And you're right, it's an iterative process, correct, Mr. Junis?
A. Yes, sir.
Q. So you put in some wells, you do some analysis of the results, you might put in some more wells, and it goes on like that, correct?
A. Yes, because you're trying to assess the extent and severity of the pollution.
Q. Okay. And so by the end of the year -- now we're sort of in year two, but as per the requirements of the DEQ, we've got 50, not just one wells, and they're being sampled weekly, except we're not doing it during Christmas week and during the week of the 4th of July. Are you with me?

A. I'm following.
Q. So you've gone -- and then they, you know, continue to sample through the third year, and so now we've not just one exceedance or violation, in your terms, we have 2,500; do we not?
A. So you're saying, in each of those 50 wells, you have an exceedance or violation happening 50 weeks of the year, so in one year, yes, you would rack up 2,500 violations.
Q. Okay. And so basically you have a 2,500-fold increase in the number of, quote, violations, but the plume is basically exactly the same as it was two years ago; is that right?
A. I would not characterize it like that. That -- you have now much more defined the extent of that plume, because you're not going to put all 50 wells on top of each other, you are going to spread them out to determine are there other pathways for these pollutants to travel. And because that groundwater is constantly moving, sometimes slower than others, you are sampling new contaminants. This is not the same column of water.
So that is recognition also that, if you've put them farther out, has this plume increased in size?

But it is more defined in terms of a shape and also the severity in terms of the concentration of those contaminants.

Q. I understand, Mr. Junis, but, you know, I didn't tell you how big the area was. Maybe the area is a very large area and can easily accommodate well-spaced-out 50 wells.

So regardless, you still have, under your math, 2,500 violations at the end of year three, whereas at the end of year one, you had one violation, correct?

A. Well, I would just like to clarify that it's not my math. This is the application of the standard. That if you exceed the standard and background at or beyond the compliance boundary, that is a violation which is supported by the amicus brief filed by the DEQ.

Q. I understand your position on this, Mr. Junis, and maybe I shouldn't use "your math."

According to the math, you now have 2,500, quote, violations whereas a couple years before, you had one, quote, violation, correct?

A. Yes, sir.

Q. So, Mr. Junis, the number of, quote,

violations just by itself is not a meaningful data point all by itself, is it?

A. There is always important context, and I think that's recognized in the description of what the procedures are within the state, and that you're not just sinking wells right on top of each other. Again, you are trying -- the intent is to define the extent and severity of the pollution, and that's what's happening in the past two-plus years.

Q. And I agree with you, Mr. Junis, that you should be looking at the context, but the context with regard to this example is, you know, 49 more wells and a lot more frequent sampling, isn't it?

A. In that example, yes, but I don't think that parallels very well to the reality that we're facing.

Q. So you don't think that the reality that we're facing includes many more wells at each site and more frequent sampling at each site?

A. There are more wells and there are more iterations of sampling, but the example of weekly at one site I don't think is an appropriate parallel or comparison.

Q. Well, if you just made it quarterly, would it be?

A. I think that would be more realistic. But I think you'll see -- and this is discussed in some of the historic documents -- that they may start at a higher frequency, and then based on what they're seeing, and their greater determination of what those groundwater flows are, you may see a decrease in that frequency; but then, as you're adding more wells, obviously, there's more sampling events.

Q. And as you're adding more wells and adding more sampling events, and assuming they're hitting the same plume, Mr. Junis, your number of, quote, violations is increasing whether or not the plume is getting any worse, correct?

A. Well, and that's where you're dealing with the iterative process, that typically, if you're seeing a violation in one well, then you are going to add wells further out or in points where you think that pollution could be kind of sneaking through, another pathway. So you're really confirming the existence of that plume and, again, the extent and severity.

Q. Mr. Maness, let's turn back to you for a moment. And as I understand your position, the coal ash costs that DEC has incurred and it seeks to recover in this proceeding are what you call, I think, deferred expenses, correct?

A. (Michael C. Maness) (No audible response.)

Q. Mr. Maness, you are on mute.

A. I apologize. Deferred expenses, yes, I believe that's the term I use. And given the controversy that we had in the last case regarding the use of that term, and I made a point to submit a data request to the Company in this case, Data Request 159, to untangle many of the statements that were made in the last case. And that -- the response to that data request clearly illustrates that when the Company makes the deferral entries on its books, it isn't, in fact, deferring the GAAP ARO depreciation expense that it records for financial statement purposes. It makes a deferral entry for regulatory accounting purposes of that expense. And so yes, I think the term "deferred expenses" is correct.

Q. Well, we did, as you indicated, go through all that in the last case, the last DEC case, certainly at -- in great detail in the last DEC case, probably in less detail in the last DEP case. And the Commission disagreed with your characterization of these costs as deferred expenses; did it not?

A. Yes. But I did not feel that that

determination really reflected the true facts of the matter, and that's why I elicited additional facts from the Company in this case that I believe do clearly illustrate that what the Company is deferring on its books are, in fact, its ARO depreciation expenses that it records for financial accounting purposes before consideration of regulatory accounting entries.

Q. And if you -- if you look at page 289 of the prior DEC order, the order issued in Docket E-7, Sub 1146. Do you have that with you by any chance, Mr. Maness? Or you could pull it up.

A. I'm pulling it up, if you can give me the page reference again.

Q. 289.

A. Yes, sir.

Q. And in the last full paragraph there, would you agree with me that the Commission determined that your characterization of the costs as deferred expenses was, quote -- very last sentence, quote, not persuasive, not supported by authority, and not determinative, correct?

A. Yes. And I guess I would apologize to the Commission for not being persuasive in the last case, but when it said that it was not supported by authority, as I said, that was the reason that I elicited additional information from the Company in this case that, to me, clearly demonstrates that that regulatory asset that's recorded on the Company's books for North Carolina retail accounting and ratemaking purposes is, in fact, a deferral of depreciation -- ARO depreciation expense charges that the Company makes to account for a three depreciation expense.

Q. Okay. And in the very next sentence, Mr. Maness, the Commission said -- this is the last paragraph on 289 that carries over to the next page -- quote:

"It is also incorrect as a matter of accounting."

Is that what the Commission said?

A. It is what it says, and, unfortunately I disagree with that conclusion.

Q. Well, Mr. Maness --

A. If you read along -- if you read along -- excuse me, I'm sorry.

Q. No. Go ahead and finish your answer.

A. So if you read along in that paragraph, it says:

"As witness Doss testified, the Company has accounted for these costs, is required under GAAP and FERC uniform system of accounts."

Now, I agree with that, but that only tells part of the story. The -- of course, if you ignore and pretend it doesn't exist, the regulatory accounting entries that the Company has made on its books, you would say that use an ARO depreciation expense is in compliance with GAAP and the FERC uniform system of accounts. But the part of the story that that sentence did not tell is that GAAP and the FERC uniform system of accounts also allow for the recognition of regulatory assets and liabilities when rate-setting authorities, such as this Commission, make entries that indicate that they are not going to have revenue recovery at the same time that that expense is reported; that they are going to, in effect, provide for recovery in the future.

And when that happens, the Company is allowed, under GAAP and under FERC uniform system of accounts purposes, to reflect those deferrals in the Company's financial statements. And that is, in effect, what the Company is doing. The Commission, beginning back with the order in Docket Number E-7, 723 about AROs and nuclear decommissioning expense, told the Company -- instructed the Company in that case to, in effect -- North Carolina retail regulatory accounting purposes, to essentially reverse the income statement effects of AROs. And furthermore, instructed the Company not to reflect those in its financial statements for North Carolina retail regulatory accounting purposes.

That's one of the reasons that, in addition to this deferral accounting, the ARO asset and the ARO liability that the Company records for financial statement purposes are not reflected in rate base.

And therefore, I still stand by the -- my assertion that what I am saying is correct as a matter of accounting, that they make these deferrals of expenses as a result of the Commission's order, if not in Sub 723 and E-7, Sub 1110, and that those are in accordance with GAAP and FERC systems of accounts and required principles. And furthermore, that those entries, themselves, have the effect of removing GAAP and FERC ARO accounting from consideration as to how rates are set by this Commission.

Q. All right. Thank you, Mr. Maness. And I would like, if you would, to turn to DEC Cross Exhibit 25, if you could pull that up for me.

A. Is that the --
Q. I think that's --
A. -- response to 156?
Q. Yes. In response to a Data Request Number 156.
MR. MEHTA: Chair Mitchell, the document, itself, is marked as confidential. It is, in fact, no longer viewed as confidential. It was originally marked as confidential because the information contained within the document was, sort of, between earnings releases, but those -- the earnings releases have now been made, and so the financial information is no longer confidential. And so there needs to be -- there does not need to be any special handling with respect to this document or the testimony regarding the document.
CHAIR MITCHELL: All right. Thank you, Mr. Mehta. I would also note, just the note at the top of the document that appears on each page indicates that the response and the embedded information are no longer considered confidential. So let's go ahead and mark this document, if you so choose, Mr. Mehta.
MR. MEHTA: Yes, Chair Mitchell. We'll

mark it as DEC Junis/Maness Cross Examination Exhibit 3.

CHAIR MITCHELL: All right. The document will be marked DEC Junis/Maness Cross Examination Exhibit Number 3.

(DEC Junis/Maness Cross Examination Exhibit 3 marked for identification.)

Q. And as you noted, Mr. Maness, this document is DEC's response to a data request from the Public Staff, Data Request 156-2, that if you look on the second page, I guess, of the document, the request is listed there:

"Please provide a total estimated cost, including an estimated breakdown of the costs for CCR remediation for each site and for each impoundment pursuant to the settlement agreement entered into by and between DEC and the Department of Environmental Quality."

Did I read that correctly?

A. Yes. I'm a little bit confused because there's more than one page that's listed as being the response to 156-2. So I want to make sure I'm looking at the right one. There's page 2 of the exhibit, and then it says it again on page 5. So I just want to make sure I'm in the right place.

Q. You could actually look at either one of them, because I think there was a supplemental response. And the spreadsheets that begin at page 6 of the exhibit are really the spreadsheets that were submitted in connection with the supplemental response.

A. All right. Thank you.

Q. Now, Mr. Maness, I don't know if you're a fan of alternative history, you know, like what would have happened if the South won the Civil War or if the Nazis had one World War II and things of that nature, but we're going to engage in some alternative history, and we're going to assume that the Commission did not reject your characterization of coal ash costs as expense. And, in fact, we're going to call them expense.

And if you would, Mr. Maness, take a look at -- I guess it's the seventh page of the -- of the exhibit.

A. Yes, sir.

Q. And, of course, this exhibit was submitted back in, looks like January or February, so the column for 2020 is a forecast number; do you see that?

A. Yes, sir.

Q. And it -- just rounding, it essentially says 174 million forecast for 2020, correct?

A. Yes, sir.

Q. And I want you to assume, Mr. Maness, that your friends, Mr. Garrett and Mr. Moore, have been through these expenses with a fine-tooth comb and not even they can find anything wrong with them. Are you with me?

A. I could assume that as a hypothetical. I will point out that this particular request was, I believe, submitted by Mr. Junis and maybe Mr. Lucas as well on the technical side, and I presume was used in conjunction with Garrett and Moore's investigation. But, beyond that, I really can't make any firm conclusions about anyone's opinions regarding the accuracy of the numbers.

Q. Okay. And I'm not concerned right now about the accuracy of the numbers. I'm just going to say let's assume that the Company actually expended, essentially, $174 million in calendar year 2020, and Mr. Garrett and Mr. Moore have been through those costs and not even they have found anything wrong with a single dollar of those costs.

A. All right. As you say, those are forecasts.

But I will -- on that basis, I will accept your hypothetical.

Q. Sure. So, Mr. Maness, the Company files a rate case on, let's say, April 1st of 2021, and its test year coal ash basin remediation expenses are approximately $174 million. And --

A. So --

Q. -- Mr. --

A. I'm sorry.

Q. -- Mr. Moore and Mr. Garrett have said to the Public Staff, those dollars are perfectly fine, there's nothing wrong with any one of them.

Would the Public Staff accept that those expenses should be brought into rates as part of the -- as part of the rate case that is filed in April of 2021?

A. So, Mr. Mehta, this is where things get a little bit complex. For GAAP and FERC financial reporting purposes, before you consider the impact of the Commission's -- or this Commission's orders for regulatory accounting and ratemaking, for GAAP and FERC purposes, that $174 million for 2020 is not an expense. It is simply the cash flow for settling a portion of the ARO liability on the books. So characterize -- in fact, I think the title says cash flow summary. It doesn't say expense summary.

So when you start out with ARO accounting without reflecting yet the impact of this Commission's orders, this would not be the expense for the year. The expense for the year would be a straight line depreciation amount of the ARO asset, which consists of an estimate of the present value of all of the expenditures that the Company is forecasting to have regarding the retirement of these coal ash basins. What happens then is that depreciation expense gets recorded as ARO depreciation expense. When they actually spend the cash, that is simply recorded -- and I am simplifying here, but generally, it's recorded as a credit to cash, as we would call it, and a charge or reduction to the ARO liability.

Now, when you consider the Commission's deferral orders, that switches the whole thing around. What the Company does, as I understand it from the response to Data Request 159, is that that depreciation expense that we talked about just a minute ago is reversed on its regulatory accounting books for purposes of accounting and ratemaking for this jurisdiction, and is, in fact, recorded as a regulatory asset.

But that entire regulatory asset is not proposed by the Company to be included in rate base at this time. What the Company does is they look at how much cash is actually spent during the year, and they move that amount from that initial regulatory asset account to a regulatory asset account that they want to put in rate base in this case and amortize over a certain number of years.

So the genesis of that regulatory asset account is cash that has been spent. And then they want to take that cash that has been spent and amortize it over a certain number of years for recovery.

Q. I understand --

A. I don't know if I need to start over because I know that was a long explanation, but --

Q. I think I understand, and, Mr. Maness, you may be perfectly right in terms of the coal ash costs that are being sought for recovery in this case. I'm talking about --

A. If I could -- if I could just add -- I'm sorry, but add to the end of that answer is that, for regulatory accounting purposes, therefore, when the Company amortizes this pursuant to the Commission's orders, that is the regulatory expense. So it starts out as a deferred expense from the utility's, I'll say default ARO accounting books, and then as cash is spent, they convert part of that regulatory expense, or that regulatory asset, to a deferred expense that they then want to amortize over a certain number of years and include in rate base.

Q. Okay. And again, Mr. Maness, I understand that what you just described is how the Company is seeking recovery of coal ash costs that it has incurred in the period from, I think, January 1, 2018, through January 31st of 2020 in this case. I'm talking about next year's case.

A. Okay.

Q. In next year's case, they have actually spent $174 million, and you say that those $174 million are expenses. And why wouldn't, then, the Company be entitled to include in rates that $174 million as a test year expense once Garrett and Moore have told us that there's nothing wrong with any of those expenditures?

A. Well, since we're talking about next year's expense, the Company could propose that. Historically, the Commission -- the Company and -- has proposed, and the Commission has approved to place those cash expenditures into a regulatory asset account and amortize them over a certain period of time. So I think it's clear that the Company could propose to do that.

CHAIR MITCHELL: All right. Mr. Maness, I'm going to interrupt you. I apologize. Someone is typing sort of furiously here, and they're not on mute, and so it's creating a lot of --

COMMISSIONER GRAY: I think it was Mr. Marzo.

CHAIR MITCHELL: All right. Well, whomever it is, please check your line and mute it. Thank you. All right. Mr. Maness, Mr. Mehta, I apologize. Please proceed.

THE WITNESS: Did you want me to proceed with my answer, or does Mr. Mehta need to --

CHAIR MITCHELL: Let's start over just for purposes of the record and so everyone can follow along. Mr. Mehta, if you would, could you ask your question again.

Q. I'll try to remember what it was. But essentially, Mr. Maness, the question -- the question was premised on -- we're really talking in this hypothetical about not this year's rate case, or the case that we're currently in, but next year's rate case, in which the Company has, in fact, expended $174 million of test year expense, in your words, with respect to coal ash costs.

And my question, I think fairly simply, was why isn't the Company entitled under that circumstance, particularly when Mr. Garrett and Mr. Moore have said there is not a dollar's worth wrong in that $174 million? Why isn't the Company entitled to bring those $174 million of test year expense into rates at the conclusion of the -- of the rate case that we've hypothetically said would be filed April 1 of 2021?

A. So there are several levels of response to that. I think, as I started my answer out, the Company could certainly propose to do that. And at least theoretically Commission could approve it. However, that would be at odds with what the Company has proposed to date to do with these expenditures, and so it would be a change in what the Commission has decided.

Now, the next thing you have to consider is what would treating the expenditures in that way do to what the Public Staff has proposed, because it could present and potentially, at least, in contemplation of 62-133(b) that deals with rate -- that deals with what can be in rate base, it could complicate the Public Staff's assertion regarding equitable sharing. And so that might create some actions on the Public Staff's part that would be a little bit different.

Now, the other thing that would have to be considered -- and I have no idea of the answer to this question; it's certainly a legal matter -- is what does it say about the action that the Commission has taken in Dominion's recent rate case with regard to -- they don't use the term equitable sharing, but with regard to making a decision to exclude the unamortized expenses for rate base for the purposes of setting just and reasonable rates. So that would, I think, have to be considered as well.

And then the last thing, if what I am inferring would be you saying that the Company would propose this, is, if you were just going to include that as a test year expense, is it, in fact, the reasonable ongoing level of expenses. Because, as you can see looking at this work paper, those expenses change over time. So would the $174 million be the appropriate amount to include on a normalized basis?

If you look at this worksheet, it looks like that might be a little low.

Would the Commission, if they're simply going to set this as test year expenses, would it be within the -- what's permitted by 62-133, would it be permitted to base its expenses on a forecast. And so if it wanted to normalize expenses, you'd be looking at, well, for the next five or six years, we've got forecasted expenses over $200 million. I think the Public Staff would certainly look at that with great uncertainty as whether that forecast could be used to simply set test year expenses without some accounting methodology to make sure that we're not simply setting rates based on a forecast; which at least we've -- I would say 99 percent of the time said was not appropriate for ratemaking purposes.

Q. All right.

A. Might also be in a separate situation where the expense might appear high in comparison to what you might be forecasting for future years, and you'd have to consider, well, what do I do in that eventuality? Do I simply say, well, that's too high and some of this expense is not going to be allowed to be put into rates? Do I set up another type of regulatory asset?

So there are just so many questions about that. But I think fundamentally, to answer your fundamental question, the Company could propose it, and then the intervenors and the Commission would have to figure out what to do with that proposal.

Q. All right. So, Mr. Maness, I understand that it's a very complicated -- complicated situation. If I understood your answer correctly -- and it was a long answer, and I was trying to write some notes.

A. I'm sorry.

Q. That's fine. You indicated it might complicate the Public Staff's equitable sharing argument that, and I understand that.

A. It might.

Q. And you indicate that it might implicate the Commission's recent Dominion order, and I understand that.

But you're not saying, Mr. Maness, are you, that the Commission's Dominion order would necessarily govern the result in this case; this case would be decided, I assume, Mr. Maness, on the facts as the Commission finds them in this case and the application of law to those facts, correct?

A. I agree. I guess the first thing is we were talking about future cases, so we would have to assume something about how this case is going to turn out. We'd have to assume something about how the appeal of the last case is going to turn out. How any appeal that might come about in this case is going to turn out. So it is entirely hypothetical.

I think the one thing that you didn't mention with regard to the Commission that I did is, of course, the Commission would, and they certainly are -- have the discretion to do this. They would be departing from the approach that they've taken in, at this point, at least four general rate cases, if I'm counting correctly, going all the way back to the DENC rate case prior to the most recent one.

Q. All right. And that's what your point was with respect to the historical treatment actually that the Company proposed and the Commission approved in prior cases; did I capture that correctly?

A. Yes, sir.

Q. And the -- and what the Company proposed is -- is in what we've been calling, I think for the last few years, the Savoy letter, correct?

A. Well, I think it was first -- the Company first stated they were going to follow that practice in the Savoy letter, but then they came back later and actually asked the Commission to approve that treatment.

Q. Okay. And the Savoy letter -- I think if you look at DEC Cross Exhibit 26, that is the Savoy letter, correct?

A. Hold on one second, let me -- I got off my exhibit page here. Let me get back to it.

(Witness peruses document.)

From looking at the first page, that does appear to be what we term the Savoy letter.

MR. MEHTA: And, Madam Chair, I'd like to go ahead and mark what was DEC Exhibit 26 as DEC Junis/Maness Cross Examination Exhibit 4.

CHAIR MITCHELL: All right. Mr. Mehta, the document will be marked DEC Junis/Maness Cross Examination Exhibit Number 4.

MR. MEHTA: Thank you, Chair Mitchell.

(DEC Junis/Maness Cross Examination Exhibit 4 was marked for identification.)

THE WITNESS: Mr. Mehta, could I ask you a quick question?

Q. Sure.

A. I neglected to write down the previous DEC Exhibit 25 that was the 150 response, can you tell me, just for taking my own notes, what number cross exhibit that is for this panel?

Q. Number 3.

A. All right. Thank you.

Q. So -- and, Mr. Maness, we don't have to spend a lot of time with the Savoy letter. The Commission spent a lot of time with the Savoy letter in the prior order.

But did you hear Mr. Young's testimony? It seems like a very long time ago, but it probably was only a few weeks.

A. I heard -- I heard parts of his testimony, so yes, in general, I did hear a lot of his testimony.

Q. And he, essentially, characterized the program that DEC has been on, really since the Savoy letter, as one of spend, defer, and recover; do you recall him saying something like that?

A. I don't directly recall that, but I certainly will accept it, because I agree that that is the program that they have been on.

Q. And that is the program that is actually laid out in the Savoy letter, correct?

A. Sometimes I get a little bit mixed up between what's in the Savoy letter, what's in the Commission's order approving deferral, which, essentially, I guess, for the most part affirmed what's in the Savoy letter, and then what the Commission approved in the 1142 and 1146 general rate cases. I think that the approval of the ratemaking treatment really didn't occur until those rate cases, but I could be wrong about that. But that's what we assumed would be what the Company would be doing based on the Savoy letter and the Commission's later approval in E-7, Sub 1110.

Q. Okay. Understood. And the -- and, obviously, whatever the Commission did in E-7, Sub 1110, which was consolidated with E-7, Sub 1146, is a matter of record in the Commission's order approving the deferral and approving the recovery, correct?

A. Yes, sir.

Q. And the other thing you mentioned in that very long answer -- very long and very complete answer, I must say; thank you, Mr. Maness -- is that it's not necessarily true that $174 million is representative of, sort of, normal coal ash spend, and so it's not clear whether that's the correct number to be used as the historical test year number; did I get that more or less correct?

A. Generally once -- if you get past all the other, sort of, obstacles and different hairpin-curve turns that you might have to take in reaching that point is determining what would be representative on an ongoing basis, you would get to the point that you would say, well, while it's historical, it might not be representative.

Q. Okay. And the Commission actually in the prior order dealt with the notion that the test year expense might be historically accurate but not necessarily representative; did it not? And I'm looking particularly, Mr. Maness, at the bottom of page 322 of the Commission's order in the prior case, E-7, 1146, where the Commission is dealing with the proposal made by the Company of a run rate.

A. That last paragraph, I can see the term run rate there; is that where you're directing me?

Q. Yes. And let me just read it to you, and you can tell me if I read it correctly.

"With respect to CCR remediation costs to be incurred during the period rates approved in this case will be in effect, the Commission determines that the, quote, run rate or the, quote, ongoing compliance costs mechanism advocated by DEC will not be approved. By requesting the creation of an ARO in addition to the run rate, DEC concedes that treating CCR expenditures as a recurring test year expense is inadequate."

So the Commission actually agreed with your -- the position you just stated with respect to the adequacy of treating CCR expenses in a given year as representative of what those expenses would be, correct?

A. I agree. Now, and the Public Staff's opposition to the run rate in the last case was also connected to complications it might present to our equitable sharing proposal.

Q. Yeah, understood. I'm certainly very cognizant that the Public Staff is very fond of its equitable proposal.

MR. GRANTMYRE: This is Bill Grantmyre.

I don't believe Mike Maness finished his answer.

Q. Well, I apologize, Mr. Maness. Go right ahead and finish it.

A. As you know, Mr. Mehta, I'll never turn down an opportunity to elaborate. The -- as I said, that it was our assertion, our position was partly at least due to a concern that it might complicate our equitable sharings proposal. But I'm not saying that that's my conclusion that it does. I think that would be a legal matter to see if there was a complication.

Now, I would also say that a run rate would also present challenging but not insurmountable accounting and ratemaking questions from a technical sense with doing equitable sharing or some sort of other reduction in revenue requirements similar to what the Commission has done in the Dominion case.

Q. All right. And, Mr. Maness, just to go back to the prior order.

After the Commission said that, in effect, DEC concedes that treating them as a recurring test year expense is inadequate, it goes on to say, quote, future annual costs, the evidence shows, are predicted to vary substantially from year to year, correct?

A. Yes.

Q. And so the Commission says that, instead of a run rate, quote, CCR remediation costs incurred by DEC during the period rates approved in this case will be in effect, shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case net of sum deductions, correct?

A. Yes.
Q. And those costs that DEC has incurred during the, quote, period rates approved in the prior case will be in effect, are the costs that are now being sought for recovery, correct?
A. Can you -- I lost you there a little bit.
Q. All right. At the very top of page 323.
A. Yes, sir.
Q. So the costs that DEC incurred during the period rates approved in this case, quote, unquote, meaning the prior case. With me?
A. Yes, sir. Thank you.
Q. So those costs shall, according to the Commission, be booked to an ARO and shall accrue carrying costs at the weighted average cost of capital, correct?
A. Yes, sir.
Q. And then the order goes on to say the Commission will address the appropriate amortization period in DEC's next general rate case, correct?
A. Yes.
Q. And the next general rate case is this case, correct?
A. Yes, sir.

Q. And the Commission goes on to say, quote, and unless future imprudence is established, will permit earning a full return on the unamortized balance.

That's what the Commission said in the prior case, correct?

A. That is what they said. Now, I'm not an attorney, but it sounds a little bit like they were trying to bind the Commissions to a certain decision in this case. So I guess just from a layperson's understanding of how things work here before the Commission, I don't know that that actually is a fact.

Q. Well, it's a fact that they said what they said?

A. They said what they said; yes, sir.

Q. The legal implication of what they said is, of course, something that is a matter of law, correct?

A. Yes, sir. Could I point out -- could I make a little tangential point with regard to --

Q. Mr. Maness, even if I said no, you can't, you would, so why don't you go ahead.

A. There's something in some of the terminology that I think all of us have used from time to time up here that disturbs me a little bit, and that is to use the term ARO or asset retirement obligation for what the Commission is doing.

Now, the Commission is certainly free to call what it is doing what it thinks is appropriate. What all always bothers me a little bit is I think it can be a little bit confusing because ARO is a very GAAP-specific, I guess a term of art, as you would say. It typically is taken to refer to how the FASB says these sort of costs, these legal -- legally required costs of removal should be accounted for. And so it always, I think, can be a little bit confusing to use that terminology for regulatory treatment.

And so I guess I would just -- I would like it if we sort of stayed away from that in the future, but I totally understand, you know, that the Commission is certainly free to call its defer -- as you said, spend, defer, and amortize, or recover, they can call it what they wish to call it.

Q. All right. Just like Mr. Junis can call an exceedance a violation or a violation an exceedance or whatever the term is; is that right?

A. No.

Q. All right. I'll turn back to you, Mr. Junis.

Now, on page 37 of your testimony, you indicate that you are incorporating by reference your

testimony and exhibits from the last rate case, correct?
A. (Charles Junis) That's correct.
Q. And you indicate that the testimony and the exhibits are voluminous, which they sure are.
A. That's correct.
Q. And you indicate that, basically, the principal topic is the history of known environmental impacts associated with coal ash, correct?
A. That's correct.
Q. And you wouldn't actually hold yourself out as an expert on that topic, would you?
A. I mean, I'm providing expert testimony. I dove very far into this. I've worked on now the past two Duke cases, the Dominion case, and then these two Duke cases, and I would say, you know, in my DEC testimony was the first real deep dive into what was known at the time and trying to put on that hat of that 1980s or 1970s Duke engineer decision-maker of what should they have known and what should -- and what they should have done based on that knowledge.
Q. All right. I understand. I mean, you've done a whole lot of reading, and I appreciate that you have done a whole lot of reading, correct?

A. A whole lot of reading that also has the context of my engineering experience and education. And so I think, just as good as anyone else, I could provide substantial insights regarding this subject matter.

Q. Tell me, Mr. Junis, what were you doing in the 1980s?

A. That's a good question. For a very brief portion of the 1980s, I was alive, so.

Q. Well, I guess I was not expecting that answer, but thank you. That's a very candid answer.

When were you born?

A. I was born in 1989.

Q. And in the reading that you did, Mr. -- all kidding aside, the reading that you did included, as you've testified in your prefiled testimony, you cite to the 1981 EPRI manual, which is Joint Exhibit 7?

A. Yes, sir.

Q. And the 1982 EPRI manual, which is Joint Exhibit 8?

A. Yes, sir.

Q. And we went over those with Mr. Quarles at some length the other day. It may have been Thursday or Friday, I don't remember exactly which, but last

week some time, correct?
A. Yes. And I was listening to that testimony and wouldn't mind the opportunity to provide some additional context to those documents also.
Q. Okay. And you also mentioned the 1988 EPA report to Congress, and we looked at that one with both Mr. Hart and Mr. Quarles last week, correct?
A. Yes, sir.
Q. And you conclude first -- and this is on page 39 of your testimony, around line 17, that these studies indicate that the electric generating industry knew or should have known that unlined ash ponds, quote, posed a serious risk to the quality of surrounding groundwater and surface water, correct?
A. That's correct.
Q. And what do you mean by a serious risk?
A. Well, conveniently, DEC sent us a data request, and we sent them back a definition. And I'd just like to read that to make sure there's no confusion.
"The Public Staff understands serious to mean having important or dangerous possible consequences and risk as the possibility of loss or injury."
So in the context of my testimony, serious

risk means that unlined surface impoundments presented a strong possibility of degrading the quality of surrounding groundwater and surface water.

Q. Well, when you said "having important or dangerous," what do you mean by dangerous?

A. So dangerous would be the potential health effects of exceeding these standards. Many of the 2L standards are based on drinking water standards, because that is the assumed best use of these groundwaters, according to the 2L standard.

Q. Okay. All right. So you conclude further -- and this is on page 42 of your testimony, and I will paraphrase. You just tell me if I'm being fair. That DEC, being a large player in the industry, either knew or should have known about these EPA and EPRI documents and should have improved and modernized its practices in the 1980s in accordance with that available knowledge.

Did I essentially capture what you're trying to say there?

A. Yes, sir. And I would just add that, you know, given its prominence, DEC and DEP and their historic companies basically helped set industry standard. So it's kind of a cyclical defense of, well, we were using the industry standard while setting the industry standard. And in a number of these documents, it talks about, in these late '70s, early '80s time frame, a recognition of the potential risks tied to unlined impoundments and that there was a national trend moving away from wet to dry handling.

Q. Okay. And -- but DEC and DEP are not the only players in the industry, correct, Mr. Junis?

A. Certainly not.

Q. And there were certainly other utilities in the industry that were doing essentially exactly the same thing that DEC and DEP were doing back in the 1980s; were they not?

A. Yes. However, if you look at, like, the '88 report to Congress, it breaks down by EPA region. And region 4, which covers a significant chunk of Duke Energy's portfolio, was significantly skewed towards wet handling as opposed to other EPA regions.

Q. And that was because of the availability of water resources to support wet handling; is it not, Mr. Junis?

A. That's certainly a component, but I would not say that's the lone determination.

Q. Mr. Junis, I guess maybe to use Mr. Hart's word, you also believe that DEC should have been more proactive with the knowledge that it possessed back in the 1980s, correct?

A. I would say -- I'm sorry, I got a little feedback here. But yes, my only kind of recommendation of what they should have done differently is that they should have performed groundwater monitoring and comprehensive groundwater monitoring through an iterative process. Because you cannot make any other decisions without that information. That's kind of the starting point that is referred to in the '81 manual, the '82 EPRI manual, it's discussed about the deficiency of groundwater data available to the 1988 report to Congress.

This is a repeated issue. And that's -- I know you went into this with Mr. Hart, but the studies at Allen, my main issue with the outcome from that is Duke stopped. They got done with those studies, and they stopped monitoring the groundwater there, as opposed to seeing the red flags of certain exceedances and then making -- drawing those conclusions and extrapolating them to all their other sites.

Instead of recognizing, okay, for a relatively low cost, we can monitor and know for a fact is there or isn't there degradation of the groundwater. And they chose not to. So that's my biggest problem with the historic handling of coal ash.

Q. So, Mr. Junis, let me make sure I understand.

Is it your opinion that DEC should have closed ash basins and shifted to dry handling of coal ash, bottom coal ash as well as fly coal ash, sometime in the decade of the 1980s?

A. Again, you cannot make that decision without the underlying information. You needed groundwater monitoring and comprehensive groundwater monitoring to make that determination of whether there was or wasn't impacts that necessitated that change, or the possibility of other corrective actions to limit that spread.

Q. So -- but, Mr. Junis, if you were actually looking at it in 20/20 hindsight, you would agree that, had they done what you called comprehensive groundwater monitoring, they would have decided that it would be prudent to switch to dry ash handling as opposed to wet ash handling, correct?

A. Well, you never want to get into a position of applying hindsight. I mean, that's a key critique of this analysis, is you're supposed to provide an alternative based on what was known and available at the time. And so trying to go back, you needed to do that assessment, that site-specific assessment, to then determine the right -- the course of action. And that's where you could have utilized the 1982 EPRI manual on upgrading these facilities, potentially. And that it was offering, you know, maybe a slurry wall was the appropriate action, or extraction wells were the appropriate action to help contain this potential seepage and groundwater contamination.

Or, you know, a further choice, if those didn't work, or you decided it was significant enough, maybe you do shift to dry ash handling, but there's certainly a trend towards that.

Q. And so, Mr. Junis, if the decision is made to switch to dry ash handling, that would involve the closure of an ash basin, correct?

A. That's correct.

Q. And how would -- Mr. Junis, how would that occur back in the 1980s?

A. It depends on how the Company proposed to do it.

Q. Well, if you look, Mr. Junis, at -- we'll look at Joint Exhibit 7.

A. All right.
Q. Page 3-3, which if you're looking at it on a PDF, is page 102.
A. I'm there.
Q. The first full paragraph on the page indicates, next-to-last sentence:
"Site closure normally involves the placement of a soil cover over the pond surface and the diversion of surface water from the site," correct?
A. That is what it says.
Q. And if you look at the 1988 report to Congress, Mr. Junis, and the page reference is 4-12.
A. All right. Give me one second while I get that open. Do you know what page of the PDF that is?
Q. Yeah. I'm looking for it. I'll get it to you in just a second. Page 151 of the PDF. It's also -- if you're looking at the joint exhibit, itself, it's DOCX 6516. Sorry, I'm on the wrong page. You need to go to page 148 of the PDF, DOCX 6513.
A. Okay. One second. All right.
Q. And you see here the EPA drew us a picture of what closed disposal pond with waste remaining looks like. It's the lower of the three pictures, correct?
A. Yes, sir. So that is one method of closure.

If this closure happened back in the late '70s, or early '80s, or anywhere historically, there would have been less ash in those impoundments than there is today.

Q. But they would still have -- if they closed them in accordance with how the EPRI manual said is normal and the EPA has said is normal, they would have closed or could have closed them with the ash there covered by soil, covered by a vegetative covering on top of the soil, correct?

A. Correct. And that would eliminate that hydraulic head. You're still going to -- if it's just a soil cover, obviously, any precipitation is going to soak in and create seepage that could mobilize those contaminants. But I would say that this, while typical, is still one of the options. So, for example, at Allen, prior to the study, there was ash that was dredged from one area and moved to another. So you could have closed that impoundment, dewatered it, and then moved the contents of that unlined impoundment into the new lined landfill for dry ash handling.

Q. And, Mr. Junis, the -- what's depicted at the lower, the lowest picture, the third picture on the EPA report to Congress, page 4-12, is, in fact, what happened with respect to the inactive basin at the W.S. Lee site, correct?

A. You said W.S. Lee? I mean, we were talking about Allen, but subject to check, that's what happened at W.S. Lee.

Q. And for that matter, it's what happened at the H.F. Lee site for Duke Energy Progress, correct? Again, subject to check.

A. Yes.

Q. And today, as a result of the DEQ's orders, both inactive basins are being excavated, correct?

A. Yes, sir. But that's where I do want to emphasize what I said before, that that quantity in those retired ponds is less if you had -- you had retired them earlier instead of meeting the capacity. If you had recognized, okay, there is a risk and there is groundwater degradation. If we stop using this, that quantity could have been significantly less.

Q. Mr. Junis, you're speaking of all this from the standpoint of a utility engineer, correct? Not a hydrogeologist, which you're not, correct?

A. That's correct.

Q. Okay. I just want to make sure I understand where you're coming from in your testimony. And you mentioned the landfill at Allen. Today, Mr. Junis, the landfill at Allen is being excavated in accordance with the settlement agreement between the Company and the DEQ, correct?

A. Can you refer to that, because I was not referring to the Allen landfill, I was referring to -- that impoundment area was broken down into areas A, B, and C, and ash was moved or dredged from area B into A prior to the use of area C.

Q. Well, all of areas A, B, and C are being excavated today, or will be excavated in accordance with the originally dictates of the DEQ and now the settlement between the DEQ and DEC and DEP and the environmental groups, correct?

A. Yes, sir.

Q. And back then in the 1980s, Mr. Junis, the DEQ did not actually have any rules or regulations regarding how to close an ash basin, did it?

A. That is correct. I will say, though, that many of these documents talk about the authority to make sure that there was safe practices. And so with the existence of 2L, with the existence of the Clean Water Act, with the existence -- at least beginning of RCRA, even though they weren't included for a portion -- a period of time, there were laws in place to allow the regulator to make sure that this was a safe practice, and a prohibition on the degradation of groundwater which the Company had a duty to adhere to.

Q. And, in fact, Mr. Junis, isn't it true that even as late at 2013, the DEQ, the agency entrusted with the enforcement of the groundwater standards, had not, as late as that date, come to a conclusion on how to close an ash basin, had they?

A. That's correct that they did not provide strict guidelines or instructions of how you were supposed to do it, but they still had those laws to have the authority to make sure that the current practice was appropriate.

Q. And, Mr. Junis, if you'd just look at DEC Exhibit 8, Cross Exhibit 8. Have you got that in front of you?

A. Yes, I do.

MR. MEHTA: And, Chair Mitchell, what Cross Exhibit 8 is, is an email chain from March and April of 2013 with attachments. And if we could mark that as DEC Junis/Maness Cross Examination Exhibit Number 5, that would be great.

CHAIR MITCHELL: All right. Mr. Mehta,

the document will be marked DEC Junis/Maness Cross Examination Exhibit Number 5.

(DEC Junis/Maness Cross Examination Exhibit Number 5 was marked for identification.)

Q. And, Mr. Junis, looking at Cross Examination Exhibit Number 5, again, it's an email chain, so you start at the bottom and work up, correct?

A. Typically, yes.

Q. And going from the bottom to top, we first have an email from Debra Watts, who is at DEQ, correct?

A. Yes.

Q. And she's sending it to Allen Stowe, who is with Duke Energy, correct?

A. Yes, sir.

Q. And she states in the first sentence of her email that she's enclosing ash pond closure guidelines that DEQ staff, particularly the aquifer protection section, has developed over the preceding year, correct?

A. Yes, sir.

Q. And she goes on to state that much of their draft guidelines were based on what was previously discussed with DEQ regarding Weatherspoon closure,

correct?
A. Yes, sir.
Q. And Weatherspoon is one of, at the time, DEP Progress' retired coal-fired plants, correct?
A. Yes, sir.
Q. So sometime back in 2012, Duke Energy had engaged in discussions -- at least in 2012, engaged in discussions with DEQ with regard to closure of Weatherspoon, correct?
A. Yes, sir.
Q. And Ms. Watts states further that she would like Duke Energy's feedback on their draft guidelines, correct?
A. Yes.
Q. And, in fact, the email at the top is Mr. Stowe's response saying, "I have attached our feedback," correct?
A. That's correct.
Q. And Ms. Watts also says that, after she's received the feedback from DEC and DEP, she's going to solicit feedback from the environmental groups, correct?
A. What page are you on at this point? I'm sorry.

Q. Still -- I guess it's still her email, so it's the bottom of the first page, and it's the second full paragraph.

A. (Witness peruses document.)

Okay. I see that, yes.

Q. And, now, when you look at the feedback, and, unfortunately, when you copy these as a PDF, the -- you know, all of the interlineations that you get in a redline sort of disappear, but if you just go to page 3 of 4 of the draft guidelines, which I guess is the fifth page of the PDF.

A. I'm there.

Q. Let's actually go up, page 2 of 4, so the fourth page of the PDF.

A. Okay.

Q. And the -- at least the draft that was presented back to the DEQ presents three closure options, correct? Close in place, clean, and hybrid?

A. Yes, sir.

Q. In two of those options, the closure in place and the hybrid, involve leaving ash in the pond, correct?

A. (Witness peruses document.)

Yeah. So there's actually four options

listed. There's closure in place, clean closure, hybrid closure, and then any other closure methods as approved by the aquifer protection section chief that must be demonstrated to be effective at protecting water quality.

Q. But the three that are on page 3 of 4, two of them involve leaving ash in the basins, correct?

A. Correct.

Q. It doesn't take a rocket scientist to surmise, Mr. Junis, that the environmental groups would not agree to that, would they?

A. I'm not going to speculate for the environmental groups, but I think everyone's concern, including the regulator and hopefully the Company, would be that that would be safe closure. That there is direct evidence, both scientific and engineering, that shows that that can be protective of the environment.

Q. Well, the position of the Sierra Club in Duke Energy Progress and Duke Energy Carolinas' last rate cases was leaving ash in the basins would not be protective of the environment, correct?

A. That is my understanding, yes.

Q. And it certainly was their position in the

Office of Administrative Hearing challenge by both DEC and DEP to the DEQ's order requiring full excavation of all of the ash basins, correct?

A. Yes. Based on my understanding, I would agree.

Q. So let's see, Mr. Junis, I guess we're in the spring of 2013, so not quite a year before the Dan River, and a little over a year before the passage of CAMA, correct?

A. Will you repeat that? I'm sorry, I lost you there.

Q. This email chain is the spring of 2013, right?

A. Yes.

Q. So not quite a year before the Dan River incident, and a little over a year before passage of the CAMA legislation, correct?

A. That's correct.

Q. And at that point, DEQ not only had no finalized set of rules regarding basin closure, but also no new real prospect of achieving consensus regarding finalized rules; would you agree with that?

A. I mean, I don't necessarily want to draw a conclusion from this lone set of documents. Obviously, that's docked for protection, section, but there are multiple divisions within the Department of Environmental Quality that would be of interest or concerned about pond closure and the construction of new storage units.

Q. But certainly the aquifer protection section was in that position, correct, Mr. Junis?

A. Yes.

Q. Mr. Junis, is it any wonder that, in enacting CAMA, the General Assembly undertook to tell DEQ precisely how DEQ should supervise and implement the closure and specify the time frame for closure of what the General Assembly deemed to be high-priority sites?

A. Can you repeat that again? I'm not sure I caught what the question is.

Q. My question, Mr. Junis, is, is it any wonder that, in enacting CAMA, the General Assembly undertook to tell DEQ precisely how DEQ should supervise and implement basin closure, and specified the time frame for closure of what the General Assembly deemed to be high-priority sites?

A. Yes. The high-priority sites were determined to be excavation within a relatively short period of time.

Q. That wasn't my question, Mr. Junis.

My question was, is it any wonder that the legislature told the DEQ how to do it in CAMA?

A. To make sure I understand what you're asking of me, you're saying, because of this document, and that they had not determined exactly how closure should happen, that then that is why the legislature predetermined it for their high-priority sites?

Q. Well, I guess my question is, this is a conversation that had been going on for a long time, correct? That is, how to close the basin had been going on for a long time?

A. Yes.

Q. And there was no clarity about it back in the 1980s, correct, from the DEQ?

A. That's correct.

Q. And there was no clarity about it 30-plus years later in 2013 either, was there?

A. While there was no strict guidance of how to do it, there were regulations in place that had to be adhered to. So it kind of -- the benchmark of success or the goals to be accomplished were prescribed by law. That you were not to degrade the groundwater or surface water. And so that would probably be the guiding principles when trying to determine proper closure. And, obviously, the Company did close some impoundments during that period of time.

Q. Well, which period of time are you talking about, Mr. Junis?

A. Well, you said the '80s and '90s, and obviously some of these impoundments were at least made inactive or a surface cover put on.

Q. Okay. You're talking the W.S. Lee- and H.F. Lee-type closures, correct?

A. Yes, sir.

Q. Okay. I think it was a rhetorical question, and we could move on, Mr. Junis.

A. All right. I apologize for not understanding there.

Q. That's perfectly fine. Mr. Junis, let's go back to the 1980s. And I realize that you were not born for most of it. But let's say your proactive utility decided to go ahead and close the basins, or decided to retrofit the ash ponds, something of -- some impact like that, okay? You with me?

A. I understand.

Q. And actually, on the subject of retrofitting and -- the ash ponds to line them, Mr. Junis, you know,

do you not, that the Sutton -- in 1984, the Sutton plant built a new ash pond, correct?
A. Yes, that sounds correct.
Q. And the new ash pond was lined with a clay liner, correct?
A. That sounds familiar. Maybe like a 1-foot clay liner.
Q. And whatever the thickness of the liner was, it was proposed and done in conjunction with the DEQ at the time, correct?
A. Yes. And I'm trying to recall. Obviously, that's a DEP site, but I recall there was even some interaction with the Corps of Engineers on that site.
Q. So there were lots of regulators involved in the selection of the clay liner for that site, correct?
A. I wouldn't say every party necessarily signed off on that selection, but that is what resulted.
Q. Well, who didn't sign off? Who from the regulatory community didn't sign off?
A. Again, this is a DEP site not subject to this case, but my recollection is that the Corps of Engineers expressed some concerns, but, obviously, it was the duty of the North Carolina DEQ to have final say in that.

Q. And it had final say, and it signed off, right?

A. That's correct.

Q. And 30 years later, Mr. Junis, DEP is required to excavate the Sutton ponds, all of them, including the one that had the clay liner, correct?

A. That is correct.

Q. And, Mr. Junis, again, putting yourself back in the 1980s, you know, closing ponds, converting to dry ash, building landfills, installing groundwater monitoring systems, all of that thing, those things cost money, correct?

A. Those certainly do cost money.

Q. And if your proactive utility back in the 1980s had incurred those costs and then went into a rate case to try to recover those costs, it's the Public Staff that would be the guardian of the wallets of the using and consuming public, correct?

A. That's correct. And the Commission is also trying to balance and protect customers and the Company.

Q. And the first thing that the Public Staff would have asked that proactive utility is, "Have you investigated your own ponds," correct?

A. I mean, I certainly think that that would be a question asked if I was in that position at that time. We would certainly want to know, is this a reasonable and prudent business decision necessitated by science and engineering evidence. You know, what is the basis for that decision?

Q. And the answer, Mr. Junis, would have been, why, yes, we, DEC, have investigated our own ponds. And not only us, but a contractor contracted for by the EPA, and a contractor contracted for by EPRI have investigated at least the Allen ponds, correct?

A. All right. So are we still talking a hypothetical situation or now are we talking specifically about Allen?

Q. Well, what I'm asking you is, if the Public Staff had asked the question, "Have you investigated your ponds," the answer would be, "Yes, we have, Duke Energy Carolinas, plus the EPA through Arthur D. Little, plus EPRI," correct?

A. They investigated the ponds at Allen, not every single Duke site.

Q. And the ponds at Allen were assumed, at the time, to be representative of other Duke sites; were they not?

A. That was a key assumption in the conclusions made by those reports, and I think that was a faulty assumption, especially given how so many documents referred to as site specific analysis. Even the Duke witnesses in this case, Mr. Wells, Ms. Williams, and Ms. Bednarcik have all referred to, to my knowledge, the site specific, the necessity of site-specific analysis to determine the right course of action.

I will also add that the Allen study, if you look at the analytical methods used for that groundwater analysis, those were prefiltered samples. That's actually a practice that is prohibited by the CCR rule and was prohibited in the state prior to that, because you are then quantifying -- and the Commission is very familiar with this from discussions in the Aqua rate cases. You get into soluble and insoluble, or what is dissolved and suspended. And so they were prefiltering out those insoluble or suspended constituents, which would underquantify the total concentration level of those constituents.

So while there were exceedances that were identified in the Allen studies, those could have been higher and for more constituents had the sampling been done differently. And in addition, if I may.

Q. No, go ahead. I thought you were finished.

A. That's all right. The leachate testing, that is a methodology to estimate. And it is very clear in the Allen study that they say there has not been a steady state reached for the actual leachate. And so the study states that, while the current conditions are approximately 80 percent groundwater and 20 percent leachate, they expected that to conservatively flip to 80 percent leachate, 20 percent groundwater. And so that means that they expected -- and they state in the report, that they expected the concentrations to go up. And from that, Duke stopped looking. They stopped monitoring groundwater despite that conclusion within the data.

So -- and I just want to make sure that that's clear, this breakdown between 80/20 and then flip-flopping. I want you to think about you have a cup, and you put 20 -- or 80 percent water, it's almost close to full, and then you power 20 percent coffee. So it's going to tint a little bit, but it would be closer to water than coffee. Now, in the reverse, if it's 80 percent coffee and then you add 20 percent of water, that's still going to look a lot like coffee. It might have lightened it up a little bit, but that would be characteristic of coffee. And that's the switch here between the amount of leachate, 20 percent, to then the expected being 80 percent leachate that is seeping into the groundwater at the Allen site. And what did Duke do in 1985 after that study? They did not monitor at that site for multiple decades.

Q. All right. So, Mr. Junis, as -- what you've just told me, essentially, is the -- looking at that study from the vantage point of 2020, in which you are, you have all kinds of criticisms regarding that study, and I assume the EPA Arthur D. Little study, and I assume the EPRI study that was done by a different environmental contractor; is that correct?

A. So that was the culmination. The 1985 report addressed that. And while the sampling, the analytical methods, is some hindsight, but it was recognized in the past, because the Federal Register in 1976 clearly delineates between total and dissolved. And that's this difference of what is mobilized or soluble and insoluble. So that is not completely guilty of hindsight analysis.

And then you could have certainly, from a 1985 eye, reading that report, made that conclusion about the leachate. That is clear as day. There is no

20/20 hindsight in that analysis.

Q. And so, Mr. Junis, again, going back to the Public Staff being the guardian of the wallets, the Public Staff would have also asked DEC at that time, what does the EPA think about all this, correct?

A. Yes. And I would say that the EPA was still looking at it. The difficulty for the EPA -- and Ms. Williams has some great experience and insights into that -- is that they were trying to create a regulatory construct that fit the entire nation. And the '88 report makes it very clear that there is varying practices of how to store or dispose of coal ash. And that's a clear distinction.

I would say a landfill is more indicative of disposal, while a wet impoundment is more storage, because that -- there was a lot of actions necessary to consider kind of the final closure of those impoundments.

Q. And, Mr. Junis, when we look at what the EPA concluded in its years-long study of coal ash in the 1988 report, it concluded, did it not, that the current waste management practices were adequate, correct?

A. Can you point me to where it says that?

Q. If you look at page 7-11, I'll try to get you the PDF page in just a moment.

A. Appreciate that.

CHAIR MITCHELL: Mr. Mehta, just for purposes of the record, which document are you looking at right now?

MR. MEHTA: Joint Exhibit 13, Chair Mitchell.

CHAIR MITCHELL: All right. Thank you.

(Pause.)

THE WITNESS: So I believe that is DOCX 6720.

Q. I believe that is correct. You're right.

A. Okay.

Q. And doesn't it say there:

"The EPA reaches a conclusion that current waste management practices are adequate to protect the environment?

A. Yes, sir. And I included all three of these conclusions in my Sub 1146 testimony that I do reference or incorporate by reference. I would add, though, that that is based on the information they had. And one of the key pieces in this document is how little groundwater monitoring was occurring at the sites they were surveyed. I believe it was about a quarter of the impoundments and landfills -- this is not just specific to impoundments -- had groundwater monitoring. That is deficient. And the EPA recognized that, and that's why, you know, they continue to study this issue.

And it's interesting, this document says we'll issue a determination in six months; that determination didn't come out until 1993.

Q. And they did continue to study this issue, didn't they, Mr. Junis?

A. Yes, sir.

Q. And they continued to study it up until 2015 when they came out with a rule on how utilities are supposed to operate, correct?

A. Yes, sir. And even so, it's even continuing to be modified, because I think the EPA was striving for better. And that's one of the most concerning parts of Ms. Bednarcik's testimony, I believe -- was that last week? It's been so long. She stated very authoritatively that, based on reviewing all of this historic documentation, that if she was in a position to decide, she would have done nothing different in the management of coal ash over that period. I have great concerns about a scientist or engineer looking back over decades of time and not finding one thing that could have been done better or differently.

I can say in my testimony I could go back, that was filed this year, there is always room for improvement. And that's pretty scary to conclude that nothing would have been done differently.

Q. Well, Mr. Junis, I'm very gratified to hear that the Public Staff has this attitude towards a proactive utility.

Would you accept, Mr. Junis, that climate change presents a serious risk to our environment?

A. I think we're getting --

MS. LUHR: Objection. Chair Mitchell, that goes beyond the scope of Mr. Junis' testimony.

MR. MEHTA: Chair Mitchell, I have listened time, and time, and time again to cross examination that is, quote, wide open in North Carolina, and I believe that any question is not beyond the scope of cross examination in North Carolina.

CHAIR MITCHELL: Well, I don't know if I necessarily agree with you, Mr. Mehta, about that, but I will overrule the objection and I will allow it to proceed. But first, we're going to take a break. We will go off the record. We will come back on the record at 11:00. Thank you.

(At this time, a recess was taken from 10:46 a.m. to 11:00 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please. Mr. Mehta, you may proceed.

MR. MEHTA: Thank you, Chair Mitchell.

MS. DOWNEY: Chair Mitchell, I'm sorry. This is Dianna Downey, if I might?

CHAIR MITCHELL: All right. Ms. Downey, you may proceed.

MS. DOWNEY: We had two pending motions to excuse Mr. Metz and Mr. Thomas, and wanted to know if there was an update on those.

CHAIR MITCHELL: Yes. Ms. Downey, we have been working to get an order out, and to the extent that it has not yet been issued, Public Staff witnesses Thomas and Metz have been excused. Ms. Downey, you are on mute.

MS. DOWNEY: In the light of that, Chair Mitchell, would now be the appropriate time to move their testimony into evidence, or do you want me to wait?

CHAIR MITCHELL: You may proceed and move their testimony at this time.

MS. DOWNEY: Than you, Chair Mitchell. I would move that the second supplemental testimony of Dustin R. Metz filed September 8 --

CHAIR MITCHELL: Actually, I'm going to interrupt you, Ms. Downey. Just thinking this through, let's hold your motion until the conclusion of the current panel, and then after we've moved in any evidence with respect to the panel, then we can get to your motions for the Public Staff witnesses Metz and Thomas. So please help me remember that when we get to that point in time.

MS. DOWNEY: Will do. Thank you.

CHAIR MITCHELL: All right. Mr. Mehta, with you, please.

MR. MEHTA: Thank you, Chair Mitchell.

Q. So, Mr. Junis, when we were -- just before we broke for the morning break, I asked you if Public Staff accepts that climate change presents a, quote, serious risk to our environment?

A. And I would respond to that that the Public Staff hasn't taken a position on climate change, and we would defer to the expertise of the environmental regulator. And our role is that we seek the least-cost method of compliance with environmental regulations typically.

Q. And you would have sought the least-cost method of dealing with coal ash back in the 1980s, wouldn't you have?

A. Least-cost compliance with the environmental regulations is how that was termed.

Q. Okay. And the compliance with environmental regulations is in the purview of the DEQ, correct?

A. That's correct. But, obviously, that speaks to the material evidence. When a utility comes in for recovery of their expenditures, that the environmental aspect would be part of the considerations of the Commission.

Q. So, Mr. Junis, do you, personally, believe that climate change presents a serious risk to our environment?

MS. LUHR: Objection again, Chair Mitchell. This goes beyond the scope of Mr. Junis' testimony.

MR. MEHTA: Chair Mitchell, again, I mean, without going to the extreme, cross examination in North Carolina is not confined necessarily to the scope of direct -- of the direct testimony.

CHAIR MITCHELL: All right. I'm going to overrule the objection, and I'm going to allow Mr. Junis to answer the question.

THE WITNESS: All right. Mr. Mehta, do you mind repeating the question?

Q. Do you personally believe that climate change presents a serious risk to our environment?

A. And, Mr. Mehta, how do you define "serious risk."

Q. The same way you do, Mr. Junis.

A. All right. And when you refer to climate change, you're -- that's a pretty broad term, in terms of the potential impacts of it; is that correct?

Q. Well, how do you define climate change?

A. I would say that's -- I would determine -- or my definition would be fairly broad of climate change, and, personally, I do believe that it poses a serious risk.

Q. And one way to address that serious risk is to decarbonize, correct, the generation of energy?

A. That is one method; yes, sir.

Q. So why, Mr. Junis, does the Public Staff oppose the increased depreciation expense associated with early retirement of DEC's remaining coal plants in this case?

A. I would just say that that is not in my testimony. You would have to refer to another Public Staff witness regarding that issue.

A. (Michael C. Maness) May I respond, in part, to Mr. Mehta's question?

Q. Well, Mr. Maness, you would do it whether I said yes or no, so go ahead.

A. No, I'm asking permission of the Commission and you, Mr. Mehta.

Q. Go ahead. We're not into restricting the record in these proceeds, Mr. Maness. Please go ahead.

A. In the DEC case, that is an accounting issue being testified to by Public Staff witness Boswell. In the DEP case, it's a little bit different, it's primarily an issue that's being addressed by our energy division employees. So I just wanted to make that clear on the record.

Q. Sure. But, Mr. Maness and Mr. Junis, it is an issue -- it is a proposition that the Company has made, early retirement of the remaining coal-fired plants, that the Public Staff opposes, correct?

A. The public -- in the DEC case, the Public Staff is opposed to imposing on ratepayers in the very next few years the entire undepreciated cost of the plants. It's not an argument about whether or not the plants should be retired.

Q. But it's an argument about who should pay for them and when, correct?

A. It's an argument that, obviously, we cannot go back and charge past ratepayers for those costs. It's an argument about what would -- what pattern of cost recovery would result in fair and reasonable rates for the customers now and going into the future.

Q. Okay. And, Mr. Junis, another way to decarbonize is to build really large battery systems, utility-scale battery systems, correct?

A. (Charles Junis) There are a multitude of methods to help address climate change. There are some questions -- and I'm speaking about this personally now at this point, because that's how you framed the beginning of this line of questioning -- and there are -- you have to weigh the impacts of any path. So a battery has its own impacts, so that's how I would answer that.

Q. Well, you are aware, Mr. Junis, are you not, that utility-scale battery systems, while they're under development, have not really been tested out and shown to work at that scale, correct?

A. I am not familiar with utility-scale battery storage.

Q. Well, if you -- would you accept, subject to check, that utility-scale batteries are a technology that is available -- well, let me put it this way.

Batteries are a technology that is available today, correct?

A. Can you refer to me -- to my testimony of how this is related? I'm drawing a little bit of difficulty in answering this line of questioning.

Q. Mr. Junis, I'm just asking you a question based on your experience with the Public Staff, okay?

The Public Staff understands, does it not, batteries today are an available technology that could assist in the decarbonization of the generation of electricity, correct?

A. I would say that that is a question better suited for one of my colleagues in the energy division.

Q. Do you know or not, you personally, Mr. Junis?

MS. LUHR: Chair Mitchell, this has been asked and answered.

CHAIR MITCHELL: Mr. Mehta?

MR. MEHTA: Well, I'm not quite sure that it, in fact, has been answered, which is why I've asked it.

CHAIR MITCHELL: All right. Mr. Junis, answer the question, please, sir.

THE WITNESS: All right. Mr. Mehta, would you mind repeating the question?

Q. Do you, Charles Junis, or Chuck Junis, know whether or not battery technology is available today to assist with the decarbonization of the generation of electricity?

A. To my knowledge -- and this is again my personal knowledge, and it depends on also how you define battery, because there is storage of energy in different forms, be it in compressed air, compressed water, in the movement of water, or in a more typical battery, that that is one tool available to utilities.

Q. Okay. And do you know, Mr. Junis, you personally, whether the battery -- and I'm really talking about the latter battery that you mentioned, the more, quote, typical battery.

Do you know whether that technology, while available, has been proven out at utility scale?

A. I do not know that.

Q. Okay. Would you accept, subject to check, that it has not?

A. Is that generally on a, you know, worldwide and -- you know, at what -- when you say "utility scale," are you -- there is just so many factors there that I'm not sure I can agree with that.

Q. Okay. Well, let me try to narrow it down.

Would you accept, Mr. Junis, subject to check, that in the United States, utility-scale battery storage has not been proven out as a technology?

A. Subject to check, I would accept that.

Q. Okay. Would the Public Staff, Mr. Junis, be in favor of a utility within its -- its, the Public Staff's, regulatory ambit of being an early adopter of utility-scale battery technology, even though that technology is not proven, might not work, and would probably cost more money?

A. Again, I believe that that question would be better suited for one of my colleagues in the energy division.

Q. You can't answer that question?

A. You asked me to answer that question on -- regarding the Public Staff's opinion, and I am not comfortable making that determination. That that is more suited to one of my colleagues in the energy division.

Q. Okay.

MR. MEHTA: Chair Mitchell, I have no further questions of this panel at this time.

CHAIR MITCHELL: All right. Any additional cross examination for the panel?

(No response.)

CHAIR MITCHELL: All right. Redirect for the panel?

MS. LUHR: Thank you, Chair Mitchell. I have several questions for Mr. Junis.

REDIRECT EXAMINATION BY MS. LUHR:

Q. Mr. Junis, counsel for DEC asked you about your comparison of the environmental compliance record of Duke Energy Carolinas with that of Dominion; do you recall that?

A. (Charles Junis) I do.

Q. And have you had the opportunity to refresh your recollection with regard to the Public Staff's investigation during the Dominion rate case?

A. Yes, I have.
Q. So let's start with the discussion you had with Mr. Mehta about the Dominion complaint and consent order, which he introduced as DEC Junis/Maness Cross Exhibits 1 and 2.
A. Yes. And let me make sure I have those pulled up. So those were DEC Potential Exhibits 22 and 23, correct?
Q. Yes, that's right.
A. All right. And --
Q. So --
A. Go ahead. I'm sorry.
Q. So, Mr. Junis, with regard to the seeps referenced in those documents that Mr. Mehta asked you about, if I can get you to turn to the consent decree, which was DEC Potential Cross Exhibit 23, and if you can please turn to page 3.
A. Yes.
Q. Which is page 6 of the PDF. And can I have you read paragraph H?
A. Yes.
"On July 21, 2017, the Virginia Department of Game and Inland Fisheries identified an area of groundwater seepage along the James River shoreline

adjacent to defendant's Chesterfield power station, and subsequently notified both DEQ and defendant of the same. Defendant investigated and later determined that the groundwater seepage identified by DGIS, which is the Virginia Department of Game and Inland Fisheries, which contained elevated concentrations of constituents and was daylighting to the James River originated from an existing coal pile. In addition, on May 11, 2018, Dominion self-reported to DEQ its observation at low tide of a small area of groundwater seepage south of the coal ash impoundment at the Chesterfield power station, which contained elevated concentrations of constituents and was daylighting along the James River shoreline, close quote.

I would just like to clarify that Mr. Mehta asked if we were aware of said seeps in the DENC investigation, and I helped Mr. Lucas with his testimony. And Mr. Lucas' testimony in Docket E-22, Sub 562, Exhibits 10 and 11 detail our knowledge of these seeps related to the Chesterfield power plant.

In comparison or contrast, DEC and DEP, in the joint factual statement, had identified nearly 200 seeps. And then, if you look at my page 44 of my testimony in this case, you will see a description of the SOCs, or special orders by consent, that were entered into by DEC. And they paid up-front penalties for -- at Cliffside -- I'm sorry. Allen, Cliffside, and Marshall, they paid an up-front penalty of $156,000 due to the alleged violations of seepage from five deliberately constructed seeps and 16 nonconstructed seeps. And then at Belews Creek and Buck, they paid an up-front penalty of $84,000 for two deliberately constructed seeps and 10 nonconstructed seeps.

And then, in addition, the federal plea agreement addresses seepage at River Bend. So the records for DEC and DENC are quite different regarding seeps.

Q. Thank you. And the seeps you just read about in the consent decree, did you take those seeps into account when you made your recommendation in this rate case?

A. I did, as part of our comparison of the environmental records and the determination of our equitable share.

MS. LUHR: And, Chair Mitchell, I would request at this time that judicial notice be taken of the direct testimony and exhibits of Jay B. Lucas filed on August 23, 2019, in Docket

Number E-22, Sub 562.

CHAIR MITCHELL: All right. Hearing no objection, the Commission will take judicial notice of the Lucas testimony filed in E-22, Sub 562 on August 23, 2019.

MS. LUHR: Thank you.

Q. And, Mr. Junis, taking a step back, you and Mr. Mehta had discussed the Public Staff's overall investigation into the environmental compliance record of Dominion during the Dominion rate case.

Can you -- can you briefly describe the Public Staff's investigation?

A. Yes. So I want to be very clear, and when we talked about this trying to be better. So you had significant coal ash closure costs in the 2017 DEC and DEP rate cases, and DEP was filed first in that iteration. And so we progressively improved our discovery. And I'm sure Ms. Morris and Mr. Robinson are very aware of all of these data requests, but we tried to refine that process.

And so we went from the Duke cases into the Dominion rate case, and we used a lot of the same questions. Perhaps changing, obviously, the state involved and certain circumstances and the Company name, but we're asking for a lot of the same information. For example, regarding seeps, we sent a data request asking Dominion if they had seeps of unauthorized discharges or unpermitted discharges of wastewater from the coal ash impoundments. They said no.

We sent a follow-up data request that actually widened the scope of the request, and again, they said no. And then we followed up as an additional step, which should not be necessary. We followed up with the Virginia DEQ, and they informed us of the seeps at Chesterfield, which were, in fact, addressed to Mr. Williams, who was the environmental witness for Dominion.

So that is the level of investigation that we're doing, not only for Duke, but for Dominion also regarding coal ash costs.

Q. Thank you. And would you describe your comparison between Duke Energy Carolinas and Dominion, the comparison between their two environmental compliance records as being qualitative or quantitative?

A. So it would be qualitative because of the complexities and challenges of a quantitative comparison. If you just looked at, well, who has more exceedances or who has more seeps, and didn't look at the context or weight those factors such as, you know, the federal plea agreement that Duke entered into regarding Dan River, regarding River Bend, that was criminal negligence, so that would be weighted pretty significantly. But you had to do that in a qualitative manner because it is so complex. And the differences of the regulatory regime in two states, and the history of the sites, and the number of sites.

Q. Thank you. And along those lines, do you recall counsel asking you whether Duke Energy Carolinas had entered a guilty plea with respect to groundwater violations?

A. Yes, I do recall that. And it -- while it is not a guilty plea in the plea agreement, groundwater exceedances are addressed in the joint factual statement.

Q. And if we can just take a look at that quickly, I believe the joint factual statement is in the record as Hart Exhibit 3.

Do you have that with you, Mr. Junis?

A. Yes. Give me one second to pull that up. And that was also incorporated by reference into my testimony from the Sub 1146 case as Junis Exhibit 31 was the joint factual statement.

(Pause.)

Q. Just let me know when you have that.

A. Yes, I have it. I'm sorry.

Q. Okay. If you can turn to page 43, and I'm at the bottom of the page looking at paragraph 138.

A. Yes, I have it.

Q. If you could, for me, begin reading about halfway through the paragraph beginning with "monitoring of groundwater."

A. Yes.

"Monitoring of groundwater at coal ash basins owned by Duke Energy Carolinas and Duke Energy Progress has shown exceedances of groundwater quality standards for pollutants under and near the basins including arsenic, boron, cadmium, chromium, iron, manganese, nickel, nitrate, selenium, sulfate, thallium, and total dissolved solids, close quote.

And I would just add, you know, based on my understanding, not as an attorney, the joint factual statement is the basis of the criminal conduct that then resulted in the plea agreement. So this is all the information that was agreed to by Duke -- both Duke entities and the prosecutor, that this is the information that is relied on for that plea.

Q. Thank you. And moving on, Mr. Mehta presented you with a scenario regarding groundwater testing at a hypothetical facility; do you recall that?

A. Yes, I do.

Q. And under this scenario, a facility would be testing wells on a weekly basis except for two holidays every year; is that right?

A. Yes. That was the hypothetical scenario.

Q. Okay. Do you know if DEQ typically requires testing on a weekly basis?

A. That would not be typical.

Q. And do you recall counsel stating in a question that exceedances are, in your terms, violations?

A. He did say that.

Q. Do you know whether DEQ considers them to be violations?

A. It is my understanding, based on the amicus brief, that DEQ agrees.

Q. Okay. And let's just quickly refer to that amicus brief, which is Public Staff Potential Redirect Exhibit 31.

MS. LUHR: And, Chair Mitchell, let's see, I'd like for Public Staff Redirect Exhibit 31 to be identified as Public Staff Junis/Maness Redirect Exhibit Number 1.

CHAIR MITCHELL: All right. The document will be so marked.

(Public Staff Junis/Maness Redirect Exhibit Number 1 was marked for identification.)

Q. Okay. And, Mr. Junis, are you -- well, let's start with the document. This is an amicus brief filed by DEQ on September 25, 2019, in the current appeal before the North Carolina Supreme Court from the 2017 DEC and DEP rate cases; and are you familiar with this document?

A. Yes. This is also Junis Exhibit 10 to my testimony in this rate case.

Q. And can you please turn to page 7, which is -- well, page 7. Let me know if you need the PDF page number.

A. Page 7 according to the numbering at the top of the page?

Q. Yes, the top middle of the page.

A. Yes, I'm there.

Q. Okay. And can you read for me the sentence beginning with "accordingly," and it's the third paragraph on the page.

A. Yes. Quote:

Accordingly, a violation occurs at a permitted facility if the permitted activity causes contaminate levels at or beyond the compliance boundary that exceed the 2L standards. For an unpermitted activity, a violation occurs if the activity results in an exceedance of the 2L standard anywhere, close quote.

Q. Thank you. So based on DEQ's amicus brief, does it appear that DEC also believes that an exceedance is a violation of the 2L rules?

A. Yes.

Q. Thank you. Mr. Mehta also asked you if other industry members throughout the 1980s were doing the same thing as Duke Energy Carolinas with respect to coal ash management; do you recall that question?

A. He did.

Q. Okay. Was Duke Energy Carolinas responsible for complying with the 2L rules during that time regardless of whether other industry members were doing the same?

A. Yes. Duke was -- did have to adhere to the

2L standards since 1979. The degradation of groundwater was prohibited.

Q. And I believe Mr. Mehta also asked you whether you believe Duke Energy Carolinas should have been more proactive in the 1980s/1990s time period.

A. Yes. A few times he used the term "proactive" regarding a utility -- hypothetical utility.

Q. And is that your position, that Duke Energy Carolinas should have been more proactive?

A. It's my opinion that Duke Energy should have been a responsible utility, and that it would have been reasonable, based on the information available, to start groundwater monitoring earlier.

Q. Thank you. Those are all my questions.

CHAIR MITCHELL: All right. Questions from the Commissioners beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Yes.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Junis, I have a few questions, and some of them are just clarifying about what's meant or intended. But we'll just kind of walk through it. So, Mr. Junis, you -- once again, this is the third time, or maybe the fourth, that we've heard about the culpability versus the not imprudence position of the Public Staff.

Can you succinctly state what the culpability is and how it's different from imprudence?

A. Yes. So culpability is Duke's responsibility or duty to comply with environmental regulations, and they have failed to do so. That is evidenced by the groundwater violations; that is evidenced by the violations of G.S. 143-215.1, which is the unpermitted discharge of wastewater; and that is evidenced by the federal plea agreement, amongst other things.

With that duty, you get into the complexity of determining what the costs would have been incurred if CAMA and the CCR rule didn't happen, or are these costs exceeding what would have been the minimum requirement of the CAMA or the CCR rule had there not been environmental violations. And this distinction and the complexity of how you recreate a record, and that's the issue.

Typically a prudence analysis involves not only a recognition that it was imprudent or unreasonable to make that decision, but then you have to come up with a feasible alternative. And that is nearly impossible to do with the amount of time that we're covering, and the lack of information that would have been necessary to determine that alternative path.

And I think -- I think there was one more point. Oh, so in the DEP rate case, we sent a data request to the Company highlighting a number of periods in time and asking the Company of what it would have cost to do each of those actions. That information included groundwater monitoring, a certain number of wells; that included different forms of corrective action; and that also included dry ash handling. And the Company said that they were unable to do that, and also referred to it as impossible.

So that's where our inability to do a typical prudence analysis leads us to the ability of the Commission, within its discretion under G.S. 133-D in setting just and reasonable rates, that an equitable sharing is appropriate to balance the costs between the Company and ratepayers.

Q. So am I understanding you correctly that you equate and the Public Staff equates culpability with a duty?

A. Yes.

Q. And notwithstanding Duke's answer to your data request and other discovery attempts, if there was unlimited time and resources, do you agree that other feasible alternatives could not be determined based on supporting evidence?

A. That's correct. That you cannot materialize or create this information that would have been necessary to properly develop and plan an alternative course of action. And then you don't know how that would have been effective. So the 1982 EPRI manual talks about typically corrective action is not going to be one method, one shoe fits all and then the problem is solved. It may take a group or system of corrective actions to solve the problem. And one of those solutions is always close the impoundment and create a new storage unit.

Q. So you agree with Duke's characterization of possible or impossibility regardless of time resource that you might have?

A. Correct. Which basically eliminates a long-term prudence analysis, and to quantify the cost difference or cost impact of their failure to meet that duty to adhere to environmental regulations.

Q. Now, is the use of culpability, as the Public Staff uses it, a term you've seen in regulatory rules, or a statute, or other jurisdiction? Where did the Public Staff come to settle on the word culpability?

A. So I would compare culpability to responsibility, duty, basically the -- or the requirement to adhere, and that they have some accountability for that.

Q. All right. On page 8 of your direct testimony -- let's see if I can point you to a line. So right around, say, lines 13 forward.

A. Uh-huh.

Q. Are you distinguishing there between remediation and corrective costs versus the actual cleaning closure removal activities relative to basins and landfills?

A. So what we're saying there is that CAMA and CCR rule kind of superseded the existing regulations. And so what we're saying is there was going to be corrective action required without those new regulations, but now you can't delineate the costs and impacts of those two different regulations because CAMA and the CCR are kind of superseded. And that excavation and closure kind of already addresses some of those issues.

Q. But is it the case that, or is there a case to be made that remediation goes beyond just removing and -- removing coal ash and closing an impoundment or landfill?

A. Yes --

Q. Is there something more?

A. I'm sorry.

Q. Go ahead.

A. Yes. All right. Is it all right if I answer?

Q. Yes.

A. I didn't mean to cut you off. For example, we were able to delineate to cost of extraction and treatment at Belews Creek. That is an example of remediation that would not have been required without the existence of groundwater violations, because otherwise, you would be extracting and treating clean water. But because there are violations, it was necessitated, and then it was an accelerated corrective action at Belews Creek.

Q. Did -- do remediation and corrective action-type activities, do they somehow equate with, say, fines and penalties that you mentioned like on page 64 of your testimony? Fines, penalties or the equivalent you say there.

A. I'm sorry. Let me flip to that page to make sure.

(Witness peruses document.)

So that would be a direct cost. So like the SOC up-front penalties, that would be something that should absolutely not be allowed for cost recovery. But remediation and corrective action can also be, like I talked about, extraction and treatment, slurry walls, and functionally, again tying back to CAMA and CCR kind of superseding, the excavation and closure of these sites that otherwise, had you continued to use these and you had these violations, other costs would have been incurred.

And who knows, DEQ may have already required the closure and excavation of these sites had they been allowed to progress without the creation of CAMA and the CCR rule. So it kind of took away that option in delineating what that costs would have been without.

Q. So if there were no closure and -- closure and removal at issue here, if it was more some -- you know, more run-of-the-mill remediation efforts that you see, oversight that DEQ does, do -- is there some notion that doing the remediation, itself, is part of the -- I don't mean to say the punishment, because I don't think the cleanup is intended to be punishment, but is it part of the (sound failure) --

A. I missed that last word.

CHAIR MITCHELL: Yeah.

Commissioner Brown-Bland, would you ask the question again, please, ma'am?

Q. Is it part of the -- is the remediation and the cleanup part of the enforcement, without regard to whether we're talking about actually physically shutting down an impoundment? If it was remediation to clean up water, some effort, some running of some air, whether it's extraction, whatever might be the corrective action; is that part of enforcement?

A. I think that's part of the accountability of the Company; that you created or caused this degradation of the natural environment, and now you are required to remediate or correct that. And that's why we would likely, if it was a more traditional imprudence analysis, recommend disallowance of those costs, like the extraction and treatment at Belews.

Q. So -- and another piece of it is after closure -- cap in place, or total removal, or whatever it may be -- after that basin or landfill is completely closed, no longer in use, but there's still contamination of groundwater or surface water, there would still be separate remediation efforts?

A. That's part of the hard part of delineating. But, for example, if you look at their corrective action plans the Company's filed with DEQ, like at Allen, they are proposing 87 vertical extraction wells and 76 clean water vertical infiltration wells. So functionally, they are going to pull out the contaminated water and then put back in clean water.

That would be a comparable cost that could be subject to more traditional imprudence analysis. So yes, there -- I hope I answered that question. Yes, there will continue to be costs that fall into this category.

Q. And so going back to your testimony on page 8, is that part of what you -- and correct me if it's not, you know, your way of seeing it, but what you would deem to be unfair in that there is remediation that is the responsibility of the Company that goes beyond mere closing and shutting down of facilities?

A. Yes. And I just I hope I'm being clear that some of these are not clearly delineated from the requirements of CAMA and the CCR rule. And so those fall into our equitable sharing and support that environmental piece of that equitable share.

Q. All right. And on page 9, line 4, there you talk about the difficulty in identifying cost of corrective actions for environmental violations.

So you're saying it's difficult to identify the costs. Is if difficult or also to identify the actions?

A. Yes. And that's the delineating the actions. Because like, for example, digging up this coal ash in some of the impacted soils changes what would have been the corrective action if perhaps they stayed in place or if that was required through an existing regulation. The CAMA and CCR are much more prescriptive, and so, again, it kind of supersedes the existing regulations that the Company's been shown to be out of compliance with.

Q. Do you not know the actions that need to be taken? Can those not be identified, even if you can't distinguish the costs?

A. Well, I think part of the problem is that it has changed or determined what actions are being taken. And so that's where excavation eliminates perhaps a string of actions that would have been taken alternatively.

Q. That's once that has occurred, correct? Once that excavation; is that what you mean? I mean, more perspectively. I'm asking you about more perspectively. You go in, you're developing a corrective action plan; is that not something that's fairly easy to identify? And there may be several methods to do that, but the actions that need to be taken are, in a general way at least, known?

A. Well, I would say to that, that had these been, let's say, capped in place, the corrective actions to manage that would have been different than in a situation where you excavate. While there may be overlap and some similarities, there is a different approach. So to kind of create these cost alternatives, that creates the complexity.

Q. So in the terms of the use of the word "difficulty," there's difficulty in determining cost, as I understand it, because we're going back in time?

A. Yes.

Q. And we don't know what was available in terms of cost; we can't find the cost numbers now or no one will provide them; we have to update the costs to today's dollars; or we have to push today's dollars back to yesterday's dollars, whatever that may be. So there's a whole magnitude of difficulty around the cost.

Is there equal difficulty in determining the actions, or does science -- state of science then and now know -- is it easier to quantify, define what the -- what corrective actions are?

A. So yes, there is equal difficulty if not more difficulty in determining the possible actions because -- and that's where we talked about materializing information. Because you didn't do the groundwater monitoring and assessment, you didn't know which would be the best methods for corrective action historically. And then, even if you did implement some of that corrective action, we don't know how effective it would have been. Would it have required additional corrective action? Would at that point, while you're continuing to monitor, would you have determined that closure is required, or you're going to switch to dry ash handling? There's so many different possibilities that that's where you get into kind of the impossibility.

Q. All right. And also -- I think we're on page 9, down around line 18, there you refer to 62-133(d). And realizing that you're not an attorney, but this is part of your testimony, and I believe Mr. Maness has brought it up as well.

Is it the Public Staff's position, to your knowledge, that 33-D allows the Commission discretion, I guess, in how it reaches the just and reasonable rates?

A. Yes. It is within the Commission's discretion to consider these material facts, and then, in that determination of reasonable and just rates, that equitable sharing fits that. And I'd be happy if Mr. Maness has anything to add.

A. (Michael C. Maness) I agree with what Mr. Junis has said.

Q. But in doing so, the Commission always has to be mindful, do you agree, of any constitutional requirements against unlawful taking of property; is that a limitation on the Commission's discretion?

A. (Charles Junis) So I recall a discussion about that in the motion for reconsideration, I believe, by Dominion. That is certainly a consideration that the Commission has to take. Obviously, in our equitable sharing, it is the recovery of the costs, except it is a disallowance of the return on that and a certain amortization period. I just want to say they're still recovering the full amount of the coal ash expenditures.

Q. All right. Now, is your 50/50 in here, I guess, in general, the Public Staff's position you brought to us three or four times now is equitable -- you call it equitable sharing. And in this case, in fact, it's proposed as equal sharing, correct, 50/50?

A. Correct. We believe that that is both equitable, and in this case it is equal, and that has been our recommendation in all four Duke Energy rate cases dealing with coal ash closure costs, remediation and closure costs.

Q. And is that 50/50, is that more -- what's the basis for the 50/50? Is that more than speculative or arbitrary? What supports 50/50 versus 60/40, 70/30? How is the Public Staff determining that exact sharing amount, and what's that based on?

A. Yes, ma'am. So that is a qualitative figure that is based on both Mr. Maness' testimony regarding the abandonment of nuclear plants, and the cleanup remediation of manufactured gas plants that historically this Commission has done a sharing. So there's a baseline based on the magnitude of the cost in Mr. Maness' testimony, and then we are adding a piece to that regarding this environmental culpability for their noncompliance. And that's how we get to the 50/50.

And then with the difference of the environmental records of the Companies, you see this shift, and in Dominion we recommended a 40/60.

A. (Michael C. Maness) Commissioner Brown-Bland, would it be all right if I added a little bit to --

Q. Yes, I was going to ask you to, so right on time.

A. Well, it seems that from -- and I can't remember if it was the DEP or DEC order in the last two rate cases, but there seemed to be a misunderstanding perhaps of my testimony. I clearly -- and I think my testimony on close reading reflects this, equitable definitely does not mean equal. And I have tried to reiterate that point in the Dominion and in these two current rate cases.

In fact, if you look back in the history of the Commission orders dealing the nuclear costs, abandonment costs, there have been many references to the Commission's decision in those cases being equitable or to equitably share. And in those cases, it referred and used the 10-year amortization with no return on rate base, which in those days, with those rates of return, was somewhere in the neighborhood of a 30 percent sharing to the -- being imposed upon the shareholders.

So it can differ from case to case, depending on the nature of the facts and circumstances in each case, and it is -- it is a judgment. It is not something that can be defined by a mathematical formula. It is, by necessity, a qualitative judgment, but it's one that the Commission has used many times in the past.

Q. And so when you say there's a judgment that both you and Mr. Junis -- I hear in there that there's, you know, subjectivity, that there's some objectivity based on some calculations and what's at stake, and then on top of that there's some subjectivity applied based on behaviors, actions coming, whatever it may be; is that accurate, and do you have something else to fill it out with?

A. Well, I think we also look at it in the context of history. What has the Commission done historically when it has approved its sharing, even when there's been no evidence of wrongdoing or culpability, such as with some of those nuclear cases and a couple of other nonnuclear cases? And saying -- and sort of looking that as a qualitative baseline. You know, what do you do, then, when you have a case like this in which we believe culpability is present.

In the end, though, it is a judgment. Using the word subjective, I don't want to make it appear that it's an arbitrary judgment, but it is a qualitative judgment.

Q. And so qualitative is the way of saying there's not a hard and fast way to know to settle on the exact proportion of sharing; is that accurate?

A. (Charles Junis) Yes.

A. (Michael C. Maness) Yes. Not in a mathematical or -- I use the word quantitative way.

Q. All right. So, Mr. Junis, on page 12, line 19, there you reference past management of coal ash, and I would take that to mean past decisions and past activities taken, has resulted in risk of future contamination. I take it that addresses the ongoing nature, the contamination continues?

A. (Charles Junis) Yes. And so that -- that sentence is regarding the framework. And so the Company's actions and omissions of actions resulted in a regulatory environment that the EPA and North Carolina addressed. That they created this risk, and the contamination could continue to spread. And so one way to fix that is excavation and then corrective action.

Q. So today, are there new and discrete instances of contamination, would you say, as opposed to past contamination?

A. Yes. The -- until there is clean closure, there will be the continued risk of the spread of contamination. And I think that speaks to partially why the legislature required alternative water sources. That there was this untenable risk to surrounding neighbors' water quality.

Q. And you indicated risk, but I guess my question is, to your knowledge, are there actual new instances of contamination that occurs today, or you would not -- or you would consider it past contamination, or is it new contamination?

A. So at certain sites where ash is still in the impoundments, there continues to be seepage and the spread of, I would say, new contamination. If the plume grows, I would say that growth is new contamination.

Q. So contamination is not all historical?
A. That's correct.
Q. All right. On -- and on page 13 there, you talk about traditional imprudence leads to 100 percent disallowance of cost.
Is that 100 percent disallowance for instances? In other words, in this situation we have, you know, a global big picture of coal ash handling activities; could it be that there are instances within that? Is that what you mean when you say 100 percent disallowance?
A. Yes. Discrete disallowances of cost.
Q. So traditional imprudence would not require that all the global costs be disallowed?
A. Correct.
Q. So if you found discrete instances that you could address and show imprudence, it would be 100 percent of that discrete piece that would be disallowed? But other portions of remedial cleanup and those kinds of things, if they weren't found to be imprudent, they would still be allowed; is that correct?
A. Correct. And I think this is more catered to just the big picture view of the complexity of

identifying the costs and actions and the potential alternatives. And so we're saying, we didn't have that opportunity to make the imprudence adjustment on a significant portion of these costs. And so that's what -- where we've then relied on the equitable sharing.

Q. All right. And on page 66 of your testimony, somewhere on there you refer to surface water discharges as violations.

And my question is, when you say that, are you referring to specific discharges that are -- that have been discussed somewhere else in your testimony or in your incorporated testimony, or are you referring to something else?

A. So you're referring to the sentence that starts on line 4 of page 66:

"For example, there are violations of NC Gen Stat 143-214.1"?

Q. Yes.

A. Okay. Those would be seeps, specifically. So those are the engineered, deliberately constructed seeps, those are the nonconstructed seeps, those are surface discharges, unpermitted surface discharges of coal ash wastewater.

Q. And those that relate to surface water, you know, as opposed to speaking to groundwater, those are in your testimony or in the record?

A. Yes. And then you have the complexity, which might have insinuated intentionally or unintentionally, the Hawaii case before the Supreme Court dealing with seepage into the groundwater that then reaches surface water. That is not accounted for in our testimony, because that was still a very, lack of better words, fluid situation.

Q. And back for a minute to the concept of imprudence. So cost of cleaning and remediation, the actual activities necessary to do that, the cost associated with it could be reasonable in that not a single cent spent was improper or unnecessary to do the job, correct?

A. Correct. So I would say the Belews Creek extraction treatment was necessary to correct that groundwater contamination, and they appropriately incurred that cost; but it was imprudent from the very beginning to have created a situation where that was necessary, that remediation.

Q. All right. So imprudence is about both the cost and the actions or the decisions?

A. Yes.

Q. One could be prudent, but the other imprudent?

A. That's correct.

Q. They don't have to be the same?

A. I agree.

Q. Okay. Mr. Maness, on page 18 of your testimony there, you use a phrase "speculative to some degree."

A. (Michael C. Maness) Hold on, let me -- if I can pull that up, hold on just a second.

Q. Sure.

A. (Witness peruses document.)

Yes, I see.

Q. Does that imply or do you mean to imply that there is some degree to which -- to which some are not speculative?

A. I actually there am just referring to what Mr. Junis testifies to. Mr. Junis also testifies that it's 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. And I don't know if I was directly quoting a word from his testimony or just paraphrasing, but it was meant to convey the meaning of Mr. Junis' testimony as to when equitable sharing would be the path to take.

Q. I believe, and Mr. Junis can correct me if I'm wrong, but I believe, in general, his testimony was said more conjecture, as I said, more global. So I think he used phrases sort of more along the lines of 100 percent, or impossible to quantify, or more speculative. And so I'm asking you, I guess, was this a full (sound failure) --

A. I'm sorry. Commissioner Brown-Bland is frozen on my computer.

CHAIR MITCHELL: Commissioner Brown-Bland is having connectivity issue at the moment. Let's give her a few seconds. It may resolve itself.

(Pause.)

CHAIR MITCHELL: All right. Commissioner Brown-Bland, are you back? Can you hear us?

(No response.)

CHAIR MITCHELL: Okay. At this point in time, let's proceed with Commissioner Gray, questions from you.

COMMISSIONER GRAY: No questions at this

time. Thank you.

CHAIR MITCHELL: All right. Thank you, sir.

Commissioner Clodfelter?

COMMISSIONER CLODFELTER: I do not have questions for the panel.

CHAIR MITCHELL: Okay.

MS. LUHR: Chair Mitchell, I apologize for interrupting. It appears that Mr. Grantmyre had some redirect questions for Mr. Maness but was having some technical difficulties and was unable to alert you at the time. Would it be acceptable for him to ask those redirect questions now or at a later time?

CHAIR MITCHELL: All right. We now have Commissioner Brown-Bland back, so let's let her finish her with her questions.

COMMISSIONER BROWN-BLAND: All right. I'm just about at the end.

Q. So I was asking, Mr. Maness, is there some degree there of indication that there's something built in that's not so speculative?

A. Into equitable sharing or just in general?

Q. Just in general as to your testimony there at the bottom of page 18.

A. Well, I think the implication is, you know, there have been specific adjustments recommended in the case to be disallowed from Mr. Garrett, Mr. Moore and Mr. Junis. And so those would not be speculative. So -- but the speculative here is meant to refer to the difficulty to quantify costs to the extent that we don't believe that the evidence can be generated to determine a specific dollar amount prudence disallowance. And therefore, it goes into -- I guess in terminology we typically use, into the equitable sharing bucket where we believe there's some culpability but we can't identify the evidence to generate a specific dollar amount for a prudence disallowance.

Q. And on page 25 of your testimony, you indicate there -- let me see if I have a line number. Line up at the top, 1 through 4, you say it is your understanding that equitable sharing of prudently incurred utility costs has been ruled to be lawful in past cases. I point you there to your use of the word "prudently."

Does that indicate that you still need to make some determination of prudence in order to determine what costs can be shared?

A. Yes. And I think I would point to the nuclear abandonment cases. And I can't recall in every one of those cases. I know that, for example, in the Harris unit 1 case, E-2, Sub 537, the Public Staff and its consultants made assertions of imprudence that the Commission eventually chose to share between the customers rather than talking about the whole amount being imprudent.

But in the earlier cases, there are several cases where at least the Public Staff and the Commission did not make allegations of imprudently incurred costs, but instead said that those costs should be equitably shared between the customers and the stockholders of Duke CP&L at that time, or Virginia Electric and Power Company. We would say -- and the Commission's orders would reflect that the use, for example, in those cases of the 10-year amortization with no inclusion in rate base of the unamortized balance would more equitably share the burden of those costs between the ratepayers and the shareholders. So that existed without any finding of imprudence on the part of the companies.

Q. If the record supported some showing of imprudence, and those costs could be pinned down in a way that went beyond speculation, would it be, under equitable sharing, that those imprudent portions of cost, discrete items or what have you, would be pulled out first before you would even look at the equitable sharing --

A. Yes.

Q. -- what would be equitably shared?

A. Yes. And that, in fact, is our proposal, our recommendation in this case, that the imprudence adjustments recommended by other Public Staff witnesses be removed from the balance and disallowed in their entirety, and then the remainder be equitably shared.

Q. All right. That's all my questions.

CHAIR MITCHELL: All right.

Mr. Grantmyre, you may proceed with your redirect.

MR. GRANTMYRE: Yes, on redirect --

MR. MEHTA: Chair Mitchell, before we get there, I believe that the proper procedure is for the Public Staff to get all of its redirect questions out and then we go to Commission's questions. And I can certainly appreciate that somebody can have technical difficulties, but there's lots of people on the Public Staff that could have drawn this to the Commission's intention much earlier than right now. And I believe it's improper for Mr. Grantmyre, having heard a whole bunch of questions from Commissioner Brown-Bland, to now go into redirect.

CHAIR MITCHELL: All right. Mr. Mehta, I hear your objection. I'm going to allow Mr. Grantmyre to proceed nevertheless. Mr. Grantmyre, please -- going forward -- this goes for all counsel. Going forward, given that we are connected remotely and there are connectivity issues from time to time here, if it is your turn to present during the course of the proceeding and you are unable to because you are not connected, you must take action to alert me to that fact, whether through co-counsel or waving your hands around wildly so I can see you or some other manner.

But, Mr. Grantmyre, we are going to allow you to proceed here, and I would ask that you please make efficient use of this time.

MR. GRANTMYRE: Yes.

REDIRECT EXAMINATION BY MR. GRANTMYRE:

Q. This is to Mr. Maness. You were asked also by Commissioner Brown-Bland how the 50/50 split was devised. And in your direct testimony --

CHAIR MITCHELL: Mr. Grantmyre, I'm going to interrupt you here. We are on redirect -- I'm allowing you to proceed with redirect examinations, not questions --

MR. GRANTMYRE: Okay. Mr. Mehta also asked this same question, how did they arrive at 50/50, so I'll go on redirect.

Q. Did you say in your testimony one is the large amount of the coal ash costs they're trying to recover?

MR. MEHTA: Objection. Leading.

CHAIR MITCHELL: Restate the question, please.

Q. Did you or did you not refer to the large amount of coal ash cost?

MR. MEHTA: Objection.

CHAIR MITCHELL: Basis for the objection?

MR. MEHTA: Well, "did you or did you not" is basically leading, Chair Mitchell.

CHAIR MITCHELL: All right. Mr. Grantmyre, let's restate the question, please.

Ask it in a nonleading way.

Q. What were the other factors that you pointed out in your direct testimony that contributed to the 50/50 split?

A. (Michael C. Maness) In addition to the position of Mr. Junis regarding culpability, we talked about -- I talked about the -- in general, there's a history of approval of sharing for extremely large costs that do not result in any new generation of electricity for others. And that 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, uncanceled nuclear generation facilities, would be appropriate and reasonable for DEC's coal ash costs.

Q. Can you --

A. And one of the reasons for that -- I'm sorry?

Q. Go ahead.

A. The total amount of costs is extraordinarily large, and this is referring to my original testimony, so the balances have changed somewhat since then. But the total amount of costs that were incurred during the January 2018 through January 2020 period were approximately $330 million a system basis. North Carolina retail amount that the Public Staff is presenting, or the Company is presenting for amortization was approximately $243 million, which would be about $104 per North Carolina retail customer.

So even without -- even without the removal of the unamortized amount from rate base, I would think that a five-year period would be much too short for an expense of this magnitude.

We also have to consider the fact that this is just a small piece of the pie, so to speak, the Company will most likely be asking for. In the next few years we'll talking about billions of dollars that most likely will come up in future rate cases related to coal ash sharing.

Additionally, you have to keep in mind that the incurrence of these costs is not really providing any additional benefits to customers in terms of additional electric service or improvements of service. You also have to consider that these costs -- incurrence of these costs has not been the result of an economic analysis that pointed toward an action that will be economically advantageous to the ratepayers.

And finally we have to take into effect that equitable sharing helps mitigate the intergenerational inequity of present and future customers paying for costs that, to the extent you can say that they were the result of, at least you can say they were related to service to customers in past decades. And it would just not be fair to impose all of those costs on present and future customers.

Q. Also, what, if anything, did you say in your direct testimony about coal ash costs being used and useful?

A. Well, the coal ash costs we're talking about here, as I've testified previously, they're expenses, and they're not property that would be used and useful under 62-133(b). They're costs related to service that was provided in the past. And for that reason, they should be widely regarded as expenses related to past service, and not in any way assets related to future service to the customers.

Q. Now, you were asked about the Sub 142 Duke Carolinas case, and if I were to summarize your testimony, you respectfully disagreed with the Commission's decision; is that correct?

A. The 1146 rate case?

Q. Yes, Duke Carolinas.

A. Yes, I did.
Q. And would it be fair to say that you agree with -- that the Commission got it right in the Dominion case, as far as the end result not necessarily deciding on equitable sharing?
A. Well, I think that, personally, I was pleased that the Commission did decide, in that case, that it was within its discretion to exclude the unamortized balance from rate base and not allow it to earn a return. Of course, we believed that the amount of sharing as an end result should have been higher in that case, that it should have been 40 percent. I think the Commission's order, in effect, shared about 26 percent with the shareholders.
But I would say that I was pleased that they did deduct -- find it within their discretion to deduct that amount from rate base and did, in fact, take that action.
Q. Thank you. I have no further redirect.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good afternoon, Mr. Maness. Most of my questions will be for you today. If I could have you turn to your second supplemental testimony, please; and specifically page 7.

A. (Michael C. Maness) The second supplemental?

Q. Correct.

A. Let me pull that up. Hold on one second.

(Witness peruses document.)

I apologize. I have the first and third up but not the second. Let me grab it real quick.

Q. That's okay.

A. (Witness peruses document.)

Q. And you probably don't need it. If you do, you can -- you can -- we can stop and you can find it.

But according to your testimony on page 7, you state:

"The Public Staff is in agreement with allowing the Company to obtain a carrying charge or carrying cost on coal ash expenditures incurred between rate cases"; is that correct?

A. That's correct.

Q. And in the present case, the Public Staff is in agreement with the sum of approximately $26 million, which represents the carrying charges for coal ash costs incurred between January of 2018 through January of 2020; is that correct?

A. Yes, approximately $26 million. I will say, and I don't know if it's in this supplemental testimony or the original testimony, but I do at least raise the possibility that perhaps the Commission should take those carrying costs into account in future cases in determining the overall amortization period.

Q. Correct. And you came to my next question, which is, is that a new request from the Public Staff from the last rate case?

A. Yes. I don't remember if we made that recommendation in Dominion or not. I'm thinking not, but definitely it's new for the DEC and DEP cases.

Q. Okay. And going back to the $26 million, and if the Commission defers the future ARO coal ash costs beginning in February of 2020, the Public Staff is in agreement for allowing a return or this carrying cost between this rate case and the next rate case; is that correct?

A. If I stated that -- I think I did state that starting from the new point that we would be -- that we would want it potentially taken into account in determining the -- looking at the amortization period. I guess that a part of this is because since the costs are so large, and going from case to case like we have, at least at the beginning, we -- the Commission has started down a certain path. But we don't know if they're going to continue on that path, and then we had the appeal to deal with and other facts and circumstances.

So there might come a time when we would say, we know what's going on happen now, and maybe it will be set up in a way that allowing those carrying costs might not be necessary. But for the time being, we're not opposing that as we go forward until a decision is made on the particular costs considered in each case. Once things settle down a bit and it's been pretty settled how it's going to be handled, then we might

make a different proposal.
Q. Right. But sitting here today, if the Commission defers these future coal ash costs, your testimony indicates that the Public Staff is in agreement with allowing a return or carrying charges, because your testimony states it potentially will allow the Company to stay out longer between rate cases; is that an accurate summary?
A. That's one of the reasons, yes, along with the not knowing what the Commission's final determination will be with regard to those costs in that case.
Q. Okay. Thank you. Now if I could have you turn to your third supplemental and settlement testimony.
A. (Witness peruses document.)
Yes.
Q. And if you could go to page 10, and specifically footnote 2.
A. Yes.
Q. If you could help me out here and more fully spell out -- and I think you were doing it with Mr. Mehta this morning somewhat -- what you're trying to say in footnote 2. And specifically, are you saying

something different than what you state in the sentences beginning right after footnote 2 to the end of that section which ends on the next page on line 17? Are you saying something different?

A. You're talking about the end of -- oh, to the end of on line 17?

Q. Right. So you see where footnote 2 --

A. Yes.

Q. -- is on line 18?

So in the footnote, are you saying something different than what you state in those next three sentences?

A. No. I think it's just variations of the same. The point of footnote 2 was just to point out that through discovery in this case it's become clear that the -- specifically clear that the Commission -- I mean the Company is deferring expenses that are recorded on its books for purposes of ARO treatment. That they're doing a regulatory deferral of those ARO depreciation expenses. Those -- as the footnote states, a portion of those costs that would have otherwise already been written off to expense absent the Commission's approval of deferral.

So in other words, to illustrate, if they recorded in 2019 a certain amount of ARO depreciation expense, what they do for regulatory purposes for this Commission's jurisdiction is to reverse that entry and record the amount in a regulatory asset, instead, that they don't propose for rate base inclusion, but then when they actually spend money, they reclassify part of that regulatory asset to another regulatory asset representing monies spent that they do propose for rate base inclusion.

And so the genesis of all that is a recording of a regulatory asset that defers ARO depreciation expenses that are recorded on their GAAP and FERC books, and not deferring a piece of the ARO asset, itself.

Q. Okay. Thank you. So I don't plan on asking you detailed questions regarding coal ash recovery. Those have been sufficiently stated in this case, as well as through various briefs of the parties. But I did want to ask you one hypothetical. So -- and it's based upon the positions that the Public Staff has taken.

So, hypothetically, if the Commission were to allow the Company to defer ARO-related coal ash costs amortized over five years -- so, in this case, allow all of the cost, defer over five years with a return like the Company is asking for -- would you agree that the Commission has the authority to do so based upon the positions taken by the Public Staff? Although you might not agree with the decision, would you agree that the Commission has the authority and discretion to make such a determination if supported by the evidence in the record?

A. I believe so. From the point of view of being a regulatory accountant, I believe so. And it sounds to me it would pass legal muster, although I would leave that to our attorneys to make a final conclusion there. But it seems like, to me, that the Commission would have that discretion to do so.

Q. Okay. And --

A. (Charles Junis) I apologize, Commissioner Duffley. Is it okay if I add to that?

Q. Of course. Please add what -- your thoughts.

A. So -- and I agree with Mr. Maness with the exception of that the Commission must take into consideration all of the other material facts. We strongly believe, and this is laid out in the appeal, that the environmental record was not appropriately considered as part of that previous decision.

Q. Okay. Thank you. Turning back to Mr. Maness, if I could change subjects here. So there were some questions and some discussions in this proceeding related to the creation of a run rate for future, you know, coal ash expenditures. And it was in response to DEC's testimony that, if the Commission ruled the same way that it did in the last Dominion Energy North Carolina rate case regarding coal ash recovery, that DEC's credit metrics would suffer and that the Company would be downgraded.

In the last rate case, the Public Staff was opposed to the run rate because of the uncertainty of costs involved, and I've also heard you state this morning -- or this morning with Mr. Mehta, it would complicate the equitable sharing position of the Public Staff.

Do you agree that the cost -- or the coal ash costs and future expenditures are more certain now than at the time of the last rate case?

A. (Michael C. Maness) With regard to future expenditures?

Q. Correct.

A. Well, I'm certain that there's probably still a degree of volatility. We have had some legal decisions by DEQ that have maybe made it a little more certain. But I hesitate to say it's a whole lot more certain, because we still don't know what we're going to run into in terms of technical and maybe legal issues in future years.

Q. But at the time of the last rate case, we did not know the closure plans for any of the basins, correct? We did not know whether it would be cap in place or some other type of closure plan or excavation, correct?

A. I think there have been some preliminary decisions made, but those were still subject to change and, in fact, have been changed since that last case.

Q. And since the last case, Duke has entered into agreement with DEQ, correct?

A. Yes.

Q. Okay. Thank you. So there probably -- I heard you say that you think there's still some volatility there, but in the sense of rate volatility between cap in place versus excavation, those decisions have been made between the two rate cases, correct?

A. I think that's generally true. That would still leave volatility over time as different projects get started and finished.

Q. So in your opinion, should the run rate -- should the Commission revisit the run rate at this point, or should the Commission just continue with the spend, defer, and recover mechanism?

And specifically what I'd like to hear when you answer, whether the Commission should look at this other type of recovery mechanism and compare the two recovery mechanisms, like, what would be some of the benefits of allowing some portion of the ongoing coal ash costs to be collected as an expense in base rates, and then what would be some of the challenges, concerns, or pitfalls of allowing such a mechanism?

A. Well, preliminarily, I would state, as sort of an overall statement, that had the Public Staff still does not support a run rate. And I can't see us changing that position or even considering changing it prior to the previous cases coming back with a decision or a remand from the Supreme Court and then getting put back before the Commission to decide if anything needs to be done in regard to the Supreme Court's opinion.

After that, it -- I don't think it can be denied that if it is known what the expense or the pattern of recovery of costs should be from the customers, that there is some benefit to having that being recovered in a timely manner. That that is some benefit. I would say that I don't think we should -- or I don't think the Commission should consider doing that without some sort of true-up and deferral mechanism at this point, because I don't think the costs are certain enough to -- and, I mean, just expressing my personal opinion now. I don't think the costs are certain enough or level enough over time to simply have a run rate that wouldn't take in -- wouldn't look at looking at having that trued up through some sort of annual mechanism, or at least something that would occur in a rate case.

I do think also that to the extent that the Commission does make a decision in Duke in these cases eventually similar to what the Public Staff has recommended or similar to what Dominion has recommended, that we're going to have to take great care if there is going to be any sort of run rate to factor in what sort of sharing or other adjustments would need to be made to fairly divide that cost between the shareholders and the ratepayers.

It will be, I believe, more complicated if we are going to have some sort of sharing or disallowance of costs, that it's more complicated to do that with a run rate. Probably not impossible, but it's more complicated, and I think in that case you would almost certainly have to have some sort of true-up -- tracking and true-up mechanism to make sure that the customers and the shareholders came out where the Commission wanted them to come out.

Q. Okay. And you stated at the beginning of your answer that you felt like the Public Staff would be opposed to the run rate, and I've heard the reason for the complications that would make the whole process more complicated from the aspect of this equitable sharing, but are there other concerns or challenges besides that one challenge?

A. Well, I think also, and maybe you may have meant to include this in sort of that universe of equitable sharing, but also from the perspective of what the Commission did in the Dominion case. If that was the way the Commission went in the Duke cases and after all the appeals, I think you would have the same sort of complications.

Other than that, sitting here today, I think the main complication, once everything has been settled, other than what I've spoken to before, is you'd need to decide whether to have a tracking mechanism, a true-up, what sort of carrying costs, if any, would be allowed, what sort of return on refunds, true-up refunds to the customers would be set in place. None of those, I think, are insurmountable, but they are issues that the Commission and the intervenors would have to deal with.

A. (Charles Junis) Commissioner, if I could just add. A complication would be -- and Mr. Maness has kind of hit on it with the possible true-up -- is the review of those cost expenditures and that, while these are identified as expenses, this is not a repetitive incurrence of the same cost year after year like you would think of as testing or sludge hauling. This is a group -- a complex grouping of costs tied to excavation, corrective action, liners, landfills.

I mean, there are so many different costs grouped into this ARO, an opportunity to review not only that the actions but also the costs are prudently incurred, that's where I think Mr. Maness was hitting on with the true-up, that that would be a necessary part of a potential run rate, which I don't think either party has appropriately addressed in this proceeding as opposed to the previous rate cases.

Q. Okay. Thank you, Mr. Junis.

And, Mr. Maness, could you quickly put your hands on -- Duke filed a late-filed exhibit on September 2nd of this year.

A. (Michael C. Maness) I might have to ask for help from counsel as to where to find that on our server.

Q. Might be easiest just to go to the docket. Or the --

A. You're right. All right. I'll pull it up that way.

(Witness peruses document.)

Q. And it was filed September 2nd.

A. All right. Hang on just a minute.

(Witness peruses document.)

In this case?

Q. Correct.

A. (Witness peruses document.)

All right. Late-filed Exhibit Number 1?

Q. Correct. And so this is a late-filed exhibit that DEC provided regarding the impact on the Company's credit metrics when various hypothetical scenarios are put upon them, correct?

A. Yes.

Q. Have you had a chance to look at this late-filed exhibit?

A. I have reviewed it very generally. Not in any detail.

Q. Okay. If you could --

A. It probably -- it would be something that Mr. Hinton would probably pay more attention to than I would in the normal course of our division of labor.

Q. Okay. So if you could go to the last page.

A. Yes.

Q. And so my question is with respect to the last two lines. In the third to the last line, it says:

"Approximate average retail rate impact."

Do you see that on the left-hand side?

A. Yes.

Q. Third full column. And it has for DEC and DEP. And then across the top there are five different scenarios. The first is the existing, as Mr. Mehta called it, spend, defer, and recover mechanism.

A. Yes.

Q. And it looks like the impact to the customer -- or sorry, retail rate impact is 2 percent for DEC and 3 percent for DEP.

A. I see that, yes.

Q. And then it goes across. So my -- and do you see with the second scenario there's a run rate component, and that third scenario is a run rate component. And you see how those rate impacts -- retail rate impacts pretty much double. And then the very last scenario is the Dominion scenario where the -- there's a 10-year no return, and you see the rate impacts there.

So I'm asking this of the Public Staff. You represent the using and consuming public. And I guess you said there was some benefit to allowing these rates to be part of ongoing payment versus a deferred scenario. But in looking at these, how do you feel about which scenario seems to -- that the Public Staff -- understand your scenario is not on here, but the scenario that works best for the using and consuming public?

A. Well, I'm assuming that what we're seeing here is that 5.1, and, 6.0, and 5.0, and 6.1 is -- and I don't know what -- one of the things that was interesting about this was there seemed to be some sort of counterintuitive impacts on credit from having a run rate, and I don't know what -- well, there it is. I see that.

Q. Right. It's the -- but it looks like the credit metrics remain above the downgrade threshold for each of them --

A. Right.

Q. -- except for scenario number 5.

A. Okay. I just wasn't sure whether it took into account any impacts on cost of debt or equity in that -- those average retail rate impacts. So I'm assuming, from what I see here -- and I haven't dug into these numbers at all -- is that you're seeing the year-one impact when -- and in the early years, you would have somewhat what we would call a doubling up of both the amortization of what had been spent before, and then the attempt to recover in current rates on a more contemporaneous basis the costs as they were being incurred over time.

So I'm getting just some general almost speculation here, but I would expect that after a few years, let's say five years, you would have a drop so that you'd no longer be picking up amortization of costs before 2020, but you would just begin doing the run rate with hopefully a smaller true-up each year.

And then the other benefit is that you'd be done with it sooner. You wouldn't have a five-year run-out after the last year of amortizing the last one or two years of cost, you would just hopefully recover it in the last year that the monies were expended and then have a very -- hopefully a very small true-up to be amortized.

So there's benefits. There's a higher cost of switching in these early years and then a lower cost in the later years. So that's the benefit, and I think it's a benefit to the Company for the most part. To the customers, I guess, in a general sense, they would rather have the recovery stretched out further. But then you also -- if the Commission isn't going to disallow any sort of return, you're going to have additional return that's going to be built in to stretching that out further, so --

Q. And what -- sorry to interrupt. Please continue.

A. So I think there's pluses and minuses. It's probably -- that switch is going to cause an impact. Unless you somehow sort of phase it in, it's going to cause a pretty significant impact in the first four or five years, which then should level out at a lower number over time.

Q. And let's assume a perfect scenario that we did know the exact costs. From a Public Staff position, is it more beneficial -- and let's assume that the Commission would grant a return on the unamortized balance.

Is it more beneficial to the customer to have a run rate where it could be higher up front, or is it more beneficial to the customer -- it's kind of a 15-year mortgage versus a 30-year mortgage. From a Public Staff perspective, which do you find is more beneficial to the customer; to pay a return and stretch out these large costs over a period of time, or to put these costs in as an expense and, as you said, get through them more quickly?

A. I think that's -- and again, it's sort of a multilayered question and answer. To the extent that you're only looking at what would provide the lowest rates to the customers stretching it out, at least at first glance would provide for lower rates for a period of time. But if you stretch things out too far, then you may impact the Company's credit ratings to a certain extent, or the metrics at least to -- it might cause some unexpected effects down the road if you have too many regulatory assets on the books that are being put off, and put off, and put off.

If you're talking about a longer base amortization period, let's say something like the Public Staff is proposing but even with a return, then the -- that 5.1, 6.0 percent impact is not going to be quite as large, and it's more comfortable to me to talk about a transition to some sort of run rate. If you're talking about a five-year amortization period, it's not so comfortable, because then you are -- the shorter you make that amortization period, the higher this 5.1, 6.0 percent is going to be.

Q. Okay. Thank you. And did you have anything else you wanted to add, benefits or concerns regarding a potential run rate?

A. Not that I can think of here at the minute.

Q. Okay.

A. Excuse me.

Q. So if we could move to -- let's just go to your testimony summary, page 4.

A. (Witness peruses document.)

Okay.

Q. Okay. So on page 4, you state:

"The automatic right to defer capital costs associated with these non-ARO projects should not continue."

And you continue and you say -- and if you could help me understand, you say 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."

And my questions are, which request are you referring to? And what costs were being sought to be deferred? And did the Commission grant these deferral requests?

A. So you're saying which requests -- you're referring to what I refer to other generation projects?

Q. Correct.

A. In the past.

Q. Right. You're saying that these non-ARO costs are more similar to that type of deferral request that you've seen in the recent past related to other generation projects. So which -- I'm just trying to figure out which projects, which deferral requests are you speaking of? And what were the costs that were sought to be deferred? And what's the Commission's decision?

A. I don't have a list in front of me. I know -- I believe, with regard to Duke, the most recent one may have been the Lee combined-cycle plant. But these are fairly frequent, when the Commission comes in for rate cases, that they'll have a plant that's going into service a few months before the rate case -- rates are going into effect, and they will request that the capital costs, meaning the depreciation return on investment between the date that the plant goes into service and the date that the rates go into effect, that they be allowed to defer those and then amortize them over some period after the rates have gone into effect.

Q. Correct. And usually those are granted by the Commission, correct?

A. They are. Sometimes the Public Staff and the Company or another intervenor in the Company might have concerns about the amount of costs. There may be particular items where we may raise concerns, sometimes to the Commission, sometimes just internally about should this be included, should this not be included.

There have been a few cases in the past where the Public Staff has opposed deferral altogether because we didn't think that the magnitude rose to the level which would justify deferral. I believe in the case that I'm thinking about, which was a Duke case, the Commission disagreed with us and allowed the deferral over our objection.

So I would say, except for that when there -- a lot of times we may be nibbling around the edges to try to settle what should be included and what should not be included, but generally, I think the Commission has a history of approving those.

I'm thinking there was one back several years ago regarding a Dominion plant where the plant had really gone into service quite a bit of time before the rate case came about. And I'm struggling to remember the outcome of that. I can't remember if the Commission allowed it or not, but then they tried to put some boundary lines around when these types of things -- deferral requests would be acceptable and when they would not.

There was one case in which we opposed, but then based on, I believe, the Commission order, we came back. Or actually it was based on data that we had misinterpreted from the Company, we came back in, supplemental testimony, and agreed with the deferral.

Q. I think that was Warren County?

A. It may have been. That sounds like it may have been it, yes.

Q. So I'm just trying to seek your position here. And what I think I've heard is the effect -- with it -- hypothetically, let's assume that most cases the Commission does allow for this deferral. Clearly, both mechanisms lead to the same result, but what I heard you state in your testimony is that Public Staff would like just like the option to be able to oppose this type of deferral; is that a correct assumption, or are you saying something else?

A. I think that is generally the correct assumption. As I state more completely in one of my testimonies, whether it was the initial or supplemental that's summarized here, the Public Staff was a bit surprised when, in this case for the first time, DEC proposed deferral and amortization of these types of cost, which were not ARO related but were related to facilities being constructed to deal with the ongoing production ash.

When we read the terms of the Commission's order -- the Company's request and the Commission's order in Sub 1110, we -- and the 1146 rate case -- we felt like that they were within the bounds of the Commission's order. And so we didn't oppose it in this case. But we would like action by the Commission to say that non-ARO projects should, in the future, be considered like other generation and deferral requests where it wouldn't be automatically covered by the Commission's order in Sub 1110 and 1146.

COMMISSIONER DUFFLEY: Okay. And that is all of the questions that I have. I will give you, Public Staff, the opportunity to file a late-filed exhibit. I don't need to see all of the cases like Warren County where that deferral was granted by the Commission, but if there are any cases out there where the Commission did not allow for the deferral of those types of expenses, feel free to submit those as a late-filed exhibit.

Thank you, Chair Mitchell. Thank you, gentlemen.

THE WITNESS: If I could just clarify, Commissioner Duffley, that would be cases where the Commission disallowed the request for deferral in its entirety?

COMMISSIONER DUFFLEY: No. Well, it would be the cases to which you were referring as support to your position that these non-ARO costs are similar to requests that have been brought forth frequently related to new generation projects.

THE WITNESS: Okay. So it would be all of the cases, not just the ones -- I misunderstood. And thought you were just asking about ones that the Commission had disallowed. But you're saying you'd sort of like to see all of the --

COMMISSIONER DUFFLEY: No, you did hear me correctly. I don't need to see the ones where the Commission granted the deferral.

THE WITNESS: Okay. All right.

CHAIR MITCHELL: All right. Anything further, Commissioner Duffley?

COMMISSIONER DUFFLEY: No, Chair Mitchell. Thank you, gentlemen.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: No additional questions. Thanks.

CHAIR MITCHELL: Okay. And Commissioner McKissick?

COMMISSIONER McKISSICK: Just one or two questions, Madam Chair.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. First I want to thank the witnesses for providing such insightful testimony. I think so many of the questions that were in my mind already may have been asked and answered. And so it leaves me with very little to really try to get some clarity on.

But I guess one issue I'm still wrestling with somewhat is the equitable sharing and trying to understand exactly when -- what the standards would be for culpability. I mean, we know what the standards are for imprudence, and we understand why in this case there would not be grounds for finding imprudence.

But in terms of culpability, what I'm looking for is what could be articulated as a standard that applies not simply to the facts of this case, but to other cases that the Commission might consider if they're going down the path of equitable sharing. And I understand that there's the nuclear power plant issues that were out there, and things of that sort, and other projects that have been large that, you know, there was a basis for the Commission to take some action employing a similar kind of concept.

But can the two of you help me articulate what this standard should be in clear, concise terms which are applicable on a broad-base basis, not just based on the facts of this case in terms of what was known or reasonably should have been known, and what actions they might have failed to have taken, you know, in terms of environmental measures to mitigate things somewhere many, many decades ago? That's it.

A. (Charles Junis) Mr. Maness, do you want to start or me?

A. (Michael C. Maness) Well, I was going to say, if you're specifically talking about culpability, it probably does start with you. If we're talking more generally about sharing, it would probably start with those cases in the early '80s, in 1983 forward where the Commission first, to my knowledge, started discussing unequitable sharing of those abandonment costs. Those did not involve the concept of culpability.

A. (Charles Junis) And, Commissioner McKissick, if I understand, your question is geared towards culpability; is that correct?

Q. Correct. Because I gather here there has been discussion about there being culpability, that Duke did not intervene at an appropriate time knowing that information was out there in dealing with the impoundment facilities for coal ash, and that they did not take appropriate measures. There were the exceedances that were out there; there was the reports that were being done; there were measures that were out there that it really would have, you know, informed them that they needed to do something other than what they did. Okay?

So, I mean, I understand what it looks like here in terms of what you're arguing, but when you start using a term like "culpability," which is broad and rather expansive, I'd like to know that it's more than just a subjective feeling that could be arbitrary based upon the way you see and feel it.

So help me try to put my arms around what that term -- what are the standards, A, B, C, and D? I mean, we know what they are for imprudence; we've got A, B, C, and D. What are they for culpability? If that's a concept that we're embracing more than just the concept of equitable sharing. But that's what's being contented here; is that not correct?

A. Correct. So you have a kind of baseline sharing that Mr. Maness covered dealing with the magnitude of the costs, and then you have kind of further adjustment, this qualitative adjustment based on culpability. And this may require some refinement, but on the spot here, I think the true key is that there were environmental regulations in place. The Company violated those regulations.

And with that, they were going to incur costs tied to these impoundments to correct this issue. That there were already in place corrective-action measures required by 2L. There were already regulations in place that did not allow the unpermitted discharge of wastewater. Those impacts, tied to that noncompliance, drives up costs. And like I said, would have required some corrective action or remediation. And now you have this overlap with these new laws and regulations regarding the actual closure of these impoundments. And that's where this becomes complicated. And we've talked about impossible or speculative. That you have kind of precluded a traditional imprudence analysis because this covers such a long period of time. And that you cannot reasonably create an alternative or feasible alternative throughout this period of time.

You would have to materialize so much information and create all sorts of -- and you can't create one path. There are tens if not hundreds of thousands of paths, because you have multiple sites, different corrective actions, different storage options, and at what point in time determines how much ash is in each of those impoundments or storage units.

So the possibilities are endless, and that's what really complicates this. And so if you had to boil it down, okay, is there -- and maybe this is even still too suited to this case, but was there an environmental or regulatory requirement in place over this period of time; has it been shown that they did not adhere to that requirement; and does that significantly impact the costs that are being sought for recovery today; and would there have been an alternative route of actions that could have been taken in the past that would change the costs incurred today?

Now, I recognize that, if they had done something differently in the past, there would have been costs associated with that and recovery of those costs through rates. But you would also recognize that those costs would be either mostly or entirely recovered already to this point and tied to customers that actually benefitted from that electric generation. And that's another disconnect in this case, that a majority of these costs are tied to previous customers that will be fielded by present and future customers.

Does that help? And we can kind of go back and forth if this requires some further refinement, or maybe we're given an opportunity to provide a late-filed exhibit to maybe lay this out more succinctly.

A. (Michael C. Maness) If I could --

Q. Sure, go ahead.

A. -- add a little bit of that. I think also, in addition to what Mr. Junis said with regard to some of these costs would have been already in rates, already been recovered from the correct customers, that's certainly true. But I think you also have to recognize that, so to speak, the chickens are coming home to roost now. That these costs are going to be incurred now, and they're the result of actions or inactions in the past that we can't -- as Mr. Junis says, we can't describe the alternative path, but we can certainly see where exorbitant costs are being charged to the customers now or requested to be charged.

Q. Well, I appreciate those thoughts. Perhaps if there could be a late-filed exhibit that provides as much clarity and specificity as possible that, you know, establishes kind of a bright line not just for the facts of this case. And I understand it may well be that you're -- we have whether there's, you know, regulations that existed that were violated and, you know, going into all the details as to what could or could not have been done. I guess I'm just trying to analyze this as objectively as I can based upon the facts that are not only applicable to this particular case but to what we, as a Commission, might do moving forward in the future, or with equitable sharing as what should be done as recommended by the Public Staff.

COMMISSIONER McKISSICK: Thank you, Madam Chair, I don't have any further questions. I think you guys did a great job over the last two days. It's been very helpful and insightful. And I think Commissioner Brown-Bland clearly earlier asked you a number of questions that were in the back of my mind, so I look forward to reviewing that late-filed exhibit. Thank you.

THE WITNESS: (Charles Junis) Thank you, sir.

MR. MEHTA: Chair Mitchell, before we get to questions on Commissioner questions, may I just follow up with Commission McKissick on his late-filed exhibit request? To the extent that the Public Staff takes him up and makes a late-filed exhibit, the Company would like the opportunity, Commissioner McKissick, to respond to that particular filing to the extent that we feel it necessary. And if that is acceptable, we will certainly do so.

CHAIR MITCHELL: Commissioner McKissick's on mute, but I will go ahead and respond as I believe he did, which is that would be acceptable, Mr. Mehta.

MR. MEHTA: Thank you, Madam Chair.

CHAIR MITCHELL: And I actually have a question for Mr. Maness. I'm going to request an exhibit of you, of the Public Staff, and, Mr. Mehta, I'm going to make the same request of the Company and encourage you-all to work together in developing this exhibit if it is possible and it saves everyone some time and effort.

But, Mr. Maness, you have testified today about the accounting treatment for the ARO-related coal ash associated costs, and it would be helpful for the Commission and for the Commission staff to see an exhibit that shows the various journal entries associated with the accounting -- the accounting that you have described today. We don't need to see actual dollar amounts, but rather, just sort of an illustration of how these -- how the entries have been made. An example -- just to be a little bit clearer, an example that shows the debits and credits to the applicable FERC accounts from the original recordation of the ARO to the ultimate recovery of these amounts.

Let me know if you have any questions about what I've asked for. And again, I will make the same request of the Company. So to the extent that it makes sense for y'all to work together on that, please do so.

THE WITNESS: (Michael C. Maness) I think it does, Madam Chair. I think that does make sense. We have gotten some information from the Company of this during discovery, and I'm confident we could get together and provide that.

CHAIR MITCHELL: Okay. All right. Thank you very much, Mr. Maness.

MR. MEHTA: I concur with Mr. Maness, Chair Mitchell, I'm sure we can work together on that.

CHAIR MITCHELL: Okay. Thank Mr. Mehta. All right. We will now -- we will turn to questions on the Commissioners' questions. Questions from any of the -- from any of the intervenors?

(No response.)

CHAIR MITCHELL: All right. Questions from Duke?

MR. MEHTA: No questions.

CHAIR MITCHELL: Okay. Any questions from the Public Staff on Commissioners' questions?

MR. GRANTMYRE: No questions from Grantmyre.

MS. LUHR: No questions for me.

CHAIR MITCHELL: All right. At this point the in time, witnesses may step down. I will entertain motions from counsel.

MS. LUHR: Thank you. And I would also note that the following exhibits entered into evidence in the Duke Energy Carolinas proceeding be moved into the record. DEC Junis/Maness Cross Examination Exhibit Numbers 1 through 5, and Public Staff Junis/Maness Redirect Exhibit Number 1.

COMMISSIONER CLODFELTER: All right. They will be so designated for purposes of this record.

(DEC Junis/Maness Cross Examination Exhibit Numbers 1 through 5, and Public Staff Junis/Maness Redirect Exhibit Number 1 were admitted into evidence.)

MS. LUHR: Thank you. And the panel is now available for cross.

COMMISSIONER CLODFELTER: All right. Ms. Force?

MS. FORCE: No questions. Thank you.

COMMISSIONER CLODFELTER: No questions. All right. Mr. Mehta, we are at 12:17. We can begin you now, knowing that you'll have to break, or we can take an early lunch break and come back earlier. I offer you the choice.

MR. MEHTA: I think, frankly,

Commissioner Clodfelter, with the stipulations, we might be able to finish by 12:30.

COMMISSIONER CLODFELTER: Let's give that a try. Mr. Mehta, you are recognized.

MR. MEHTA: And on the lunch break score, Commissioner Clodfelter, I was wondering if we could actually add a few minutes to the lunch break so that the parties could discuss the issue that was raised this morning during the panel.

COMMISSIONER CLODFELTER: I'm not sure that will be necessary, but I'll tell you what, I will honor that request. I will honor that request. We'll add a few extra minutes, because I'll also want to tell you some things about the schedule going forward, and you may want to think about that and how you want to make your plans accordingly. So let's go ahead with your cross examination. Okay?

MR. MEHTA: Okay.

CROSS EXAMINATION BY MR. MEHTA:

Q. Mr. Lucas, in this case, the Public Staff's prudence review of the costs actually sought for recovery by DEP in this case was undertaken by witnesses Garrett and Moore; is that correct?

A. (Jay Lucas) In my testimony, I do also have some specific disallowances.

Q. Yes. And apart from those specific disallowances, the prudence review by the Public Staff was conducted by Garrett and Moore, correct?

A. Yes, yes.

Q. And what you call -- or what the Public Staff calls, quote, equitable, close quote, sharing is premised not on a prudence review of the incurred costs, but rather on what you call your culpability analysis; is that correct?

A. Yes. Public Staff -- I believe Duke Energy Progress was culpable for the environmental contamination it created. So we believe that the Company should share the re- -- excuse me, the remediation costs with its customers.

Q. And the sharing that you propose is of incurred costs for which a specific imprudence disallowance has not been recommended by the Public Staff; is that correct?

A. Yes. That equitable sharing is not based upon imprudence analysis.

Q. And you did not do a prudence evaluation, because to go back and recreate the costs that DEP could have incurred in the past was too speculative an exercise even for the Public Staff to engage in; is that correct?

A. Yeah. The Public -- well, the Public Staff did not have the resources or means to be able to reproduce costs from decades ago.

Q. And therefore, the Public Staff concluded that it would be too speculative to do that kind of analysis, correct?

A. Yes.

MR. MEHTA: Commissioner Clodfelter, I have no further questions of this panel.

COMMISSIONER CLODFELTER: All right. Let me inquire at this point, does any other party have any cross examination for this panel?

(No response.)

COMMISSIONER CLODFELTER: If not, Ms. Luhr, do you think you can get your redirect in?

MS. LUHR: I do. Thank you.

COMMISSIONER CLODFELTER: All right.

REDIRECT EXAMINATION BY MS. LUHR:

Q. Mr. Lucas, I just have one question. Mr. Mehta asked you about the difficulty of quantifying costs -- or the Public Staff's assessment of the difficulty of quantifying costs in this case. Can I please have you refer to Public Staff Redirect Exhibit 78?

A. (Jay Lucas) Okay.

Q. And this is a Duke Energy Progress response to a Public Staff data request.

MS. LUHR: And, Commissioner Clodfelter, I would like for Public Staff Redirect Exhibit Number 78, which starts on page 2362, to be identified as Lucas/Maness Public Staff Redirect Exhibit Number 2. I say 2 because there was a Junis/Maness Redirect Exhibit Number 1 in the DEC case.

COMMISSIONER CLODFELTER: Ms. Luhr, you've got it correct. I think we went through this once yesterday in a similar situation, so it will be so designated as Number 2.

MS. LUHR: Thank you.

(Lucas/Maness Public Staff Redirect Exhibit Number 2 was identified as they were marked when prefiled.)

THE WITNESS: And can you give me the exhibit number, please, again?

Q. That was Public Staff Potential Redirect Exhibit 78.

A. (Witness peruses document.)

Okay. I've got it open.

Q. And are you familiar with this document? Have you reviewed this before?

A. Yes. This is a response to a Public Staff data request.

Q. Okay. And if you look at pages 2 through 4 of this document, what information was the Public Staff requesting?

A. Public Staff was requesting Duke Energy to recreate costs from past years: 1979, 1984, 1988, 2000. I know it's costs for doing groundwater monitoring wells, downgradient, upgradients, cost of installing groundwater extraction and treatment systems, dry fly ash handling, as if Duke Energy would try to do dry fly ash handling during those years I mentioned.

Q. Thank you. And if you could for me, please read from the Company's response on page 4 beginning with "the Company agrees with the Public Staff statement."

A. At the very bottom of page 4:

"The Company agrees with the Public Staff's statement above. Estimates of the nature requested by the Public Staff would be speculative and therefore unreliable."

Do you want me to keep reading?

Q. One more sentence.

A. Oh, sure.

"Using 20/20 hindsight to develop site-specific of estimates for activities covering a four-decade span of time would, as Commissioner Clodfelter indicates, require the impossible construction and evaluation of several different alternative histories and realities."

This is from the 2017 DEP rate case order, Clodfelter dissent at 13.

Q. Thank you. So, Mr. Lucas, does it appear from this response that Duke Energy Progress also believes it would be too speculative to attempt to quantify costs related to historical coal ash management practices in this case?

A. Yeah. It comes out to be speculative and therefore unreliable.

Q. Thank you. That's all the questions I have.

COMMISSIONER CLODFELTER: All right. I tell you what, we'll open after lunch with

Commissioners' questions, and we'll take our lunch break now. Let me do a couple of things, though, before everyone scatters.

Based on the progress we have made this morning and trying to look ahead a little bit, and of course that's always a very dangerous thing to do, I do think we probably can adjourn a bit early tomorrow afternoon.

And so current plan would be -- depending on the progress we're making, current plan would be to probably recess for the week at the time we would normally take the afternoon break, which would be sometime around 2:45 to 3:00. For those of you who, like me, have to do anything on US 1, US 64 or I-40 in the late afternoons around this place, that might be a positive thing. So we'll plan to try to adjourn tomorrow roughly 2:45 to 3:00. If we are -- if we're needing to wrap up a witness or something, we might vary that a little bit, but the target would be to try to shorten it a little bit. We will, though -- I would like to come through after lunch and not break at lunch, because we seem to be getting pretty far down the road here.

With respect to schedule, if we do not conclude the case tomorrow, and I have no predictions on that subject, but we would come back on Monday. And again, because of some conflicts that some of the Commissioners have on Monday morning, we won't be able to start on Monday until 1:30 p.m. So we will -- if we continue on Monday, we'll resume at 1:30 p.m. and go through the normal 4:30 in the afternoon. Again, if we do not conclude on Monday, then we'll adopt the normal daily schedule thereafter beginning at 9:00 and running through the day at 4:30.

Let me also say -- and, you know, I reserved ruling this morning on the motion with respect to reconstitution of the rebuttal panel, and I asked the parties to talk among themselves. I do not want to put you to unnecessary efforts and unnecessary labor. Let me say to you that the question of whether witnesses testify individually or as a panel is a matter within the discretion of the Commission. It's not common that we have objections to that, but we have had objections to that, to changing the order of witnesses and the panel designation that's been presented to the parties, and upon which they based their potential questions.

And also, after some consultations among the Commission, I believe the Commission would feel more comfortable also if we preserve the panel as a Wells/Williams panel and had Ms. Bednarcik testify as she was originally designated to testify rebuttal as an individual witness.

So, Mr. Robinson, I'm going to ask that we keep the panel as constituted originally as the parties had planned for and prepared for. Again, as I say, the Commission has a strong preference in that regard as well. If you want to resequence your witnesses -- again, I'm going to assume the parties have done their preparation for the questioning, so it may not be as disruptive for you to resequence if you want to take Ms. Bednarcik in a different order -- I think that would be appropriate.

MR. ROBINSON: Commissioner Clodfelter, may I respond to both of your points? So the first thing that --

COMMISSIONER CLODFELTER: You may.

MR. ROBINSON: Thank you. So just the

first thing with regards to the timing for tomorrow. So just looking at the schedule, in the presumption or the -- if we get to a place today where we are in our rebuttal case, say, by this afternoon and we have either Mr. Steven Fetter or Ms. Marcia Williams up, provided -- given the fact that they are Pacific time, we could -- if, again, we're at that stage, if we could start at 10 a.m. tomorrow instead of 9 a.m. to allow them time to wake up and get themselves together. So that's my first request.

COMMISSIONER CLODFELTER: That's certainly appropriate. We followed that request in the prior case, and we'll do so in this case as well. So if we get to them early in the morning, we'll make that early time be 10 a.m.

MR. ROBINSON: Thank you, sir. And on your second ruling, so obviously, the Company acknowledges it. For the record, Commissioner Clodfelter, just want to say that the Company has the burden of proof here, and in the Company's view, the manner in which that burden is best discharged is to ensure that all of these witnesses, each of whom, as you know, brings a slightly different prospective to the issues in this case, but they testify as a panel so that any question from any perspective can be responded to by the appropriate witness.

Frankly, there are due process concerns that we are seeing where parties are asking questions to one witness that should be directed to another, and then, in my opinion, are intentionally not asking the appropriate witness that same question. Again, these are technical matters, and we owe it to this Commission and the record to ensure that the witness with knowledge is before the Commission at the time the question is asked to provide clear, complete, and comprehensive answers to the questions. That being said --

COMMISSIONER CLODFELTER: I respect your point. I also, though, want to acknowledge that parties in the case are entitled to test the credibility and knowledge of each witness on an unaided basis. That is also an element of due process. To the extent you believe that questions are being asked and are not asked for purposes of strategic advantage, I will grant you the right on additional direct testimony if you wish to bring those questions forward in additional direct testimony by the Company, on redirect testimony by the Company, or if you wish to recall a witness in order to clarify a point that you believe was not correctly addressed by another witness, I will listen to you, and I will be liberal in allowing you those privileges.

But at this point, again, the opportunity to testify as a multiple witness panel is not a right, it is a matter of discretion, and I have so ruled.

MR. ROBINSON: Thank you, Commissioner Clodfelter. And you anticipated my request, so thank you, we'll take that reservation.

COMMISSIONER CLODFELTER: To the extent, again, you believe that there is strategic questioning or nonquestioning as the case may be of a witness, and the testimony was not fully and fairly developed, then I will acknowledge that you may pursue that in an appropriate manner to make your point. But as I say, I also have to acknowledge that other parties are entitled to test the credibility and the knowledge of individual witnesses in the manner that they deem appropriate as well.

So we'll proceed on that basis. And again, I do this now, because I just wanted to save you some time over the lunch.

MR. ROBINSON: Thank you.

COMMISSIONER CLODFELTER: With that said, we'll come back on the record and resume again with Commissioners' questions at 12:40 p.m. -- 1:40, excuse me. I'm in a different time zone here. At 1:40 p.m. Please turn off your video and go on mute. Thank you.

(The hearing was adjourned at 12:33 p.m. and set to reconvene at 1:40 p.m. on Thursday, October 1, 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 8th day of October, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112