REDACTED

PLACE: Held via Videoconference

DATE: Thursday, September 3, 2020

TIME: 9:00 A.M. - 12:30 P.M.

DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

Application of Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable

to Electric Utility Service in North Carolina

Noteworthy Reporting Services, LLC

DOCKET NO. E-7, SUB 1213

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

Application of Duke Energy Carolinas, LLC,

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

VOLUME 11

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

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E X H I B I T S

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P R O C E E D I N G S

CHAIR MITCHELL: All right. Good morning everyone. It's 9:00, so we will go ahead and begin. Let's come to order and go on the record, please. I'm Charlotte Mitchell, Chair of the North Carolina Utilities Commission. With me this morning are the following Commissioners. When I announce your name, please indicate your presence.

Commissioner ToNola D. Brown-Bland.

COMMISSIONER BROWN-BLAND: Present.

CHAIR MITCHELL: Commissioner Lyons Gray?

COMMISSIONER GRAY: Good morning.

CHAIR MITCHELL: Commissioner Daniel G. Clodfelter.

COMMISSIONER CLODFELTER: Good morning.

CHAIR MITCHELL: Commissioner Kimberly W. Duffley.

COMMISSIONER DUFFLEY: Good morning.

CHAIR MITCHELL: Commissioner Jeffrey A. Hughes.

COMMISSIONER HUGHES: Good morning, I'm here.

CHAIR MITCHELL: And Commissioner Floyd B. McKissick, Jr.

COMMISSIONER McKISSICK: Present. Good morning.

CHAIR MITCHELL: All right. I now call for hearing Docket Number E-7, Sub 1214, the application of Duke Energy Carolinas, LLC for an adjustment of rates and charges applicable to electric utility service in North Carolina; Docket Number E-7, Sub 1213, which is the petition of Duke Energy Carolinas, LLC for approval of its prepaid advantage program; and Docket Number E-7, Sub 1187, which is the application of Duke Energy Carolinas, LLC for an accounting order to defer incremental storm damage expenses incurred as a result of Hurricanes Florence and Michael and Winter Storm Diego.

The latter two dockets have been consolidated for hearing with the general rate case docket by orders of the Commission.

On September 30, 2019, DEC filed an application with the Commission in Docket Number E-7, Sub 1214 requesting authority to adjust and increase its rates for retail electric service in

North Carolina.

On October 29, 2019, the Commission issued a scheduling order establishing the general rate case, suspending rates, scheduling hearings, and requiring public notice. Pursuant to the scheduling order, the Commission held several public witness hearings in DEC's service area in order to receive evidence in the form of testimony from DEC's customers. The scheduling order also set an expert witness hearing to commence on March 23, 2020.

Due to the state of emergency that has been declared in North Carolina to coordinate the response and protective actions to prevent the spread of the novel coronavirus and the associated restrictions on mass gatherings, the expert witness hearing was postponed by order of the Commission dated March 16, 2020.

On March 25, 2020, DEC and the Public Staff filed their first agreement and stipulation of partial settlement in this proceeding.

On June 17, 2020, the Commission ordered that the expert witness hearing in DEC's rate case and the expert witness hearing in the rate case of

Duke Energy Progress, LLC, which was filed on October 30, 2019, in Docket Number E-2, Sub 1219, be consolidated for the purpose of receiving expert witness testimony on several specific topics. The consolidated hearing was initially scheduled to commence on Monday July 27, 2020, but by subsequent orders of the Commission, the consolidated DEC and DEP hearing was rescheduled to begin on Monday, August 24, 2020.

On July 31, 2020, DEC and the Public Staff filed their second agreement and stipulation of partial settlement along with supporting testimony.

On August 6, 2020, the Commission issued an order approving DEC's public notice and financial undertaking relating to DEC's exercise of its statutory right under North Carolina General Statute 62-135 to place into effect temporary rates pending a final order by the Commission approving permanent rates.

From August 24th through August 31, 2020, the Commission held the consolidated DEC and DEP hearing and received evidence from expert witnesses on several specific topics.

On August 31, 2020, the Commission issued an order setting the separate DEC expert witness hearing to begin on September 3rd at 9:00 in the morning.

The Commission has allowed intervention in these dockets upon petitions filed by each of the following parties:

Harris Teeter; the North Carolina Clean Energy Business Alliance; the North Carolina League of Municipalities; Apple, Facebook, and Google; the Carolina Industrial Group for Fair Utility Rates III; the Center for Biological Diversity and Appalachian Voices; Carolina Utility Customers Association, Inc.; the Commercial Group; the North Carolina Justice Center; the North Carolina Housing Coalition; the Natural Resources Defense Council; and Southern Alliance for Clean Energy; NC WARN, Inc.; the North Carolina Sustainable Energy Association; the Sierra Club; and Vote Solar.

DEC has entered into partial settlements with Harris Teeter; the Commercial Group, CIGFUR; Vote Solar; and jointly with NCSEA, the

North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy. In addition, numerous statements of position from DEC's customers have been received by the Commission and filed in the official file for each of the DEC dockets.

That brings us to today.

Before we get started, I want to make a few points on the record in light of the fact that this hearing is being conducted remotely. This hearing has been made accessible to the public by way of a link to a video stream that's provided on the Commission's website. Each of the parties has consented to the Commission's conducting this hearing by remote means, as evidenced by the parties' filings in these dockets.

In the interest of ensuring the efficient use of hearing time and minimizing the potential for technical difficulties, the Commission has provided multiple opportunities for the parties to verify that they're able to access the remote technology utilized by the Commission for this hearing, including technology checks conducted on July 21st, 22nd, and 24th.

Due to the fact that this hearing is being held remotely, parties have been asked to avoid the use of confidntial information to the greatest extent possible. In the event that a party must reference confidential information during testimony, we will leave the video conference and join a teleconference line. The party whose confidential information is discussed is responsible for ensuring that only those parties who have executed confidentially agreements are on the teleconference line. When discussion of the confidential information is complete, we will leave the teleconference line and go back on videoconference.

Okay. Let's begin.

Pursuant to the State Ethics Act, I remind all members of the Commission of their duty to avoid conflicts of interest and inquire at this time as to whether Commissioner has a known conflict of interest with respect to the matters coming before us this morning.

(No response.)

CHAIR MITCHELL: The record will reflect

that no conflicts have been identified, so we will proceed.

I call upon the parties to indicate their presence this morning, beginning with the applicant.

MR. ROBINSON: Yes. Good morning, Chair Mitchell, members of the Commission. My name is Camal Robinson appearing on behalf of Duke Energy Carolinas. Chair Mitchell, would you like me to introduce the attorneys again?

CHAIR MITCHELL: Please do so, Mr. Robinson, simply for the purpose of allowing everyone to know who is on the line and who will be present for the Company.

MR. ROBINSON: Absolutely. So also appearing with me, Chair Mitchell, from Duke are Mr. Bo Somers and Mr. Brian Heslin. Additionally, we have appearing with us from the law firm of Troutman Pepper, Kiran Mehta, Molly Jagannathan, and Brandon Marzo. Mr. Marzo is a member of the Georgia bar and has pro hac vice motions granted for appearance in this proceeding. We also have appearing from the law firm of McGuireWoods, Jim Jeffries and Andrea Kells. All of our attorneys have filled out appearance sheets and have provided them to the court reporter.

CHAIR MITCHELL: All right. Thank you, Mr. Robinson. All right. Turning to the intervenors, Public Staff.

MS. DOWNEY: Good morning, Chair Mitchell, Dianna Downey, chief counsel of the Public Staff, appearing on the Using and Consuming Public. Appearing during the course of this hearing will be Elizabeth D. Culpepper, Layla Cummings, Tim R. Dodge, Lucy E. Edmondson, William E. Grantmyre, Gina C. Holt, Megan Jost, John D. Little, and Nadia L. Lure.

CHAIR MITCHELL: Thank you, Ms. Downey. The Attorney General's Office.

MS. FORCE: Good morning, Madam Chair. This is Margaret Force with the Attorney General's Office. And also appearing with me is Teresa Townsend on behalf of the Using and Consuming Public.

CHAIR MITCHELL: All right. Thank you, Ms. Force.

CUCA.

MR. PAGE: Good morning,

Chairman Mitchell and Commissioners. Bob Page appearing for Carolina Utility Customers Association.

CHAIR MITCHELL: Good morning, Mr. Page. CIGFUR.

MS. CRESS: Good morning, Chair Mitchell. This is Christina Cress with the law firm of Bailey & Dixon. I am appearing on behalf of the Carolina Industrial Group for Fair Utility Rates III, otherwise known as CIGFUR III, or for short, CIGFUR.

CHAIR MITCHELL: Thank you, Ms. Cress. Center for Biological Diversity and Appalachian Voices.

MS. SU: Good morning, Chair Mitchell and Commissioners. My name is Jean Su with the Center for Biological Diversity appearing on behalf of the Center for Biological Diversity and Appalachian Voices. Appearing with me today is my co-counsel Howard Crystal, also with the Center for Biological Diversity.

CHAIR MITCHELL: Good morning, Ms. Su.

MS. SU: Good morning.

CHAIR MITCHELL: Commercial Group.

MR. JENKINS: Good morning, Chair Mitchell and Commissioners. Alan Jenkins for the Commercial Group.

CHAIR MITCHELL: Good morning, Mr. Jenkins.

Harris Teeter.

(No response.)

CHAIR MITCHELL: All right. The North Carolina Justice Center.

MR. NEAL: Good morning, Chair Mitchell. My name is David Neal at the Southern Environmental Law Center appearing on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Appearing with me, also from the Southern Environmental Law Center, Gudrun Thompson and Tirrill Moore.

CHAIR MITCHELL: Good morning, Mr. Neal.

All right. NC WARN.

MR. QUINN: Good morning, Chair Mitchell and Commissioners. This is Matthew Quinn. I am here on behalf of NC WARN.

CHAIR MITCHELL: Good morning,

Mr. Quinn.

NCCEBA.

(No response.)

CHAIR MITCHELL: All right. north Carolina League of Municipalities.

(No response.)

CHAIR MITCHELL: NCSEA.

MR. LEDFORD: Good morning, Chair Mitchell. Peter Ledford on behalf of NCSEA. With me is my co-counsel, Ben Smith.

CHAIR MITCHELL: Good morning, Mr. Ledford.

The Sierra Club.

MS. LEE: Good morning, Chair Mitchell and Commissioners. Bridget Lee of the Sierra Club appearing on behalf of the Sierra Club. And with me today, Catherine Cralle Jones of the Law Offices of Bryan Brice.

CHAIR MITCHELL: Good morning, Ms. Lee.

Tech Customers.

MR. TRATHEN: Good morning, Chair Mitchell and Commissioners. I am Marcus Trathen with the law firm of Brooks Pierce appearing on behalf of The Tech Customers: Apple, Facebook, and Google. Also with me are my colleagues, Craig Schauer and Matt Tynan.

CHAIR MITCHELL: All right. Good morning, Mr. Trathen.

And Vote Solar.

MS. CULLEY: Good morning, Chair Mitchell. Thad Culley appearing on behalf of Vote Solar.

CHAIR MITCHELL: Good morning, Mr. Culley.

All right. Any preliminary matters that the Commission should take up prior to moving into the hearing?

MR. ROBINSON: Yes, Chair Mitchell, the Company has about five matters to bring up, so I'll start from the beginning.

CHAIR MITCHELL: All right. You made proceed, Mr. Robinson.

MR. ROBINSON: Thank you. So, Chair Mitchell, out of an abundance of caution, the Company renews its motion from the consolidated phase of the hearings to enter into the DEC record the Company's application, Appendix A, as well as Exhibits A through D. In addition, E-1 items, including the corrections to items 14, 23, 33, and 38. In addition, the settlement agreements for DEC-specific, as well as the prefiled testimony of excused witness John Panizza. Also, the prefiled testimony and exhibits of the following witnesses who appeared during the consolidated hearing:

Dylan D'Ascendis, Karl Newlin, Steve Young, Jane McManeus, Jay Oliver, and Conitsha Barnes.

CHAIR MITCHELL: All right. Mr. Robinson, hearing no objection to your motion, it will be allowed. And I will let -- for purposes of the record, the testimony of the DEC witnesses that was admitted during the consolidated hearing will be copied into the record at this time.

MR. ROBINSON: Thank you, Chair Mitchell.

(DEC Application; NCUC Form E-1,
Confidential Items, and Corrected Items;
DEC Agreements and Stipulations;
D'Ascendis Direct, Rebuttal,
Supplemental Rebuttal, and Settlement
Exhibits; Young Rebuttal Exhibits;
McManeus Direct, Supplemental, Rebuttal,

Supplemental Rebuttal, Second
Supplemental, and Second Settlement
Exhibits; Oliver Direct and Rebuttal
Exhibits; and Oliver and McManeus GIP
Exhibits were admitted into evidence.)
(Whereupon, the prefiled direct
testimony of John Panizza; prefiled
direct, rebuttal and Appendix A,
supplemental rebuttal, and settlement
supporting testimony of Dylan
D'Ascendis; prefiled direct, rebuttal,
and settlement supporting testimony of
Karl W. Newlin; prefiled rebuttal
testimony of Steven K. Young; prefiled
direct, corrected direct, supplemental
direct, rebuttal, settlement,
supplemental rebuttal, second
supplemental direct, and second
settlement testimony of
Jane L. McManeus; prefiled direct,
corrected direct, and rebuttal testimony
of Jay W. Oliver; prefiled joint
testimony of Jay W. Oliver and
Jane L. McManeus; and prefiled rebuttal

testimony of Conitsha B. Barnes were copied into the record as if given orally from the stand.)

(Corrections provided by the witnesses during live testimony are not reflected in the prefiled testimony.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is John Panizza, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am employed by Duke Energy Business Services LLC ("DEBS") as Director, Tax Operations. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the Company) and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Science degree in Accounting from Montclair State University and a Master's in Taxation from Seton Hall University. I am a Certified Public Accountant in the state of New Jersey. My professional work experience began in 1989 as an auditor with KPMG. From 1993 to 2002, I held several financial positions primarily at two companies, in telecommunications and automotive (AT&T Corp., and Collins & Aikman Inc.). In 2002, I joined Duke Energy and have held several financial positions of increasing responsibilities, including various accounting and tax related positions. In March 2018, after a three year rotation primarily in Corporate Accounting, I moved back into the role of Director, Tax Operations, a position that I had previously held.

Q. PLEASE DESCRIBE YOUR DUTIES AS DIRECTOR, TAX OPERATIONS.

A. As Director, Tax Operations, I have overall responsibility for corporate tax compliance and accounting for Duke Energy. The Duke Energy Tax Operations Department is responsible for all federal, state, and local income tax returns for Duke Energy including various joint ventures if Duke Energy is the designated tax matters partner. The Tax Department is responsible for maintaining and reconciling Duke Energy's tax accounts and for the reporting and disclosure of tax-related matters, to the extent required.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR OTHER STATE PUBLIC UTILITY COMMISSIONS?

A. I have not testified before this Commission, but I have filed testimony on behalf of Duke Energy in proceedings before the South Carolina, Indiana, and Kentucky utility commissions.

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

A I address the recently enacted federal tax reform legislation, the Tax Cuts and Jobs Act (the "Tax Act"), which became law on December 22, 2017.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. While the headline change brought by the Tax Act is a reduction of the statutory corporate tax rate from 35 to 21 percent, this reduction in rate is accompanied by many other provisions. The varying impacts of the Tax Act on the revenue requirement all must be considered, as the Company has done in its proposal for how best to address the Tax Act for the benefit of customers in North Carolina. Customers should – and will through the Company's proposal in this case – benefit from the overall reduction in the revenue requirement, but it is appropriate to also consider other, non-tax impacts of the legislation, particularly as it relates to cash flow. This need was highlighted by Moody's Investors Service ("Moody's") in an article it published on January 24, 2018,[1] approximately a month after the Tax Act became law which highlights the Tax Act effect of putting pressure on cash flow and the possibility of an overall negative credit impact on utilities. This was, of course, an industry-wide analysis where some issuers will be affected by a greater amount, some by a lesser amount. However, I wish to highlight in my testimony that the implementation of the Tax Act has the potential to adversely affect the Company's cash flows and credit metrics. These negative impacts must be considered, and makes having a strong equity to debt capital structure even more important post-Tax Act reform.

Further detail concerning the credit quality impact of the Tax Act is provided in the pre-filed direct testimony of Witness Karl Newlin and additional details on the effect of the Tax Act on revenue requirements are included in the testimony of Witness Jane McManeus. My testimony reviews the Company's plan. I conclude in my testimony that the Company's plan to

[1] Moody's Investors Service, Sector Comment, "Tax Reform is Credit Negative for Sector, but Impact Varies by Company," January 24, 2018. This article notes (at p. 2) that "[f]or the investor-owned utilities sector, the 2017 tax reform legislation will have an overall negative credit impact on operating companies and their holding companies." Moody's estimates that the Tax Act "will dilute a utility's ratio of cash flow before changes in working capital to debt [FFO/Debt] by approximately 150-250 basis points on average, depending to some degree on the size of the company's capital program."

incorporate the benefits of the Tax Act for the benefit of customers is balanced, appropriate, and consistent with the Commission's direction to defer tax benefits and incorporate them into DE Carolinas' next rate case.

II. TAX REFORM

Q. WHAT ARE THE KEY PROVISIONS OF THE TAX ACT AS IT RELATES TO DE CAROLINAS?

A. Most changes to the corporate tax code apply to all U.S. corporations equally, while a limited set of others affect regulated utilities uniquely. For utilities in general, and DE Carolinas in particular, the key provisions of the Tax Act that will affect customer rates are as follows: (1) reduction of the corporate tax rate from 35 percent to 21 percent; (2) retention of net interest expense deductibility; (3) elimination of bonus depreciation; (4) elimination of the manufacturing deduction; and (5) normalization of excess accumulated deferred income taxes resulting from the Tax Act.

Q. PLEASE SUMMARIZE HOW THESE KEY PROVISIONS COULD IMPACT DE CAROLINAS AND CUSTOMER RATES.

A. <u>REDUCTION IN CORPORATE TAX RATE</u>: The new statutory income tax rate of 21 percent represents a 40 percent reduction from the previous rate of 35 percent. This will lower a key component of cost of service, i.e., income taxes. In contrast to this lower cost of service impact, however, rate base will be higher in future rate proceedings due to the elimination of bonus depreciation (see below) and the reduced value of accelerated depreciation due to the lower federal income tax rate.

INTEREST EXPENSE DEDUCTIBILITY: The Tax Act generally provides that net interest expense is deductible only to the extent it does not exceed a stated percentage of an adjusted taxable income calculation, a calculation that becomes even more restrictive four years hence. However, regulated utilities are exempt from this limitation provision and may deduct their interest expense without limitation. Duke Energy and EEI (the regulated electric utility trade association) fought hard to achieve this important exemption, and our customers will retain the significant benefits that flow from it.

DEPRECIATION AND EXPENSING OF CAPITAL: The Tax Act generally provides that corporations may immediately expense capital as it is placed in service, akin to 100 percent bonus depreciation. However, the Tax Act specifically prohibits the immediate expensing of capital by regulated utilities. Instead, utilities are directed to use MACRS (modified accelerated cost recovery system) depreciation for capital investment placed in service. Though no longer accompanied by "bonus" depreciation, MACRS still represents a significantly accelerated rate of depreciation compared to book depreciation. As a result, deferred taxes will continue to accrue under MACRS, but will do so at a slower rate compared to bonus depreciation and at a much slower rate under the lower 21 percent corporate tax rate (see above)—this will cause a more rapid increase to rate base relative to pre-Tax Act.

MANUFACTURING DEDUCTION: Prior to the Tax Act, domestic manufacturers were granted a tax deduction based on a certain percentage of qualifying manufacturing income, and the production of electricity qualified for this tax benefit. To avail itself of this deduction, a corporation had to be in a taxable income position—this was often not the case recently for most regulated utilities because of the impact of bonus depreciation. Unfortunately, the elimination of bonus depreciation for utilities in the Tax Act coincided with the elimination of this tax deduction for all manufacturers, which is directionally detrimental to customer rates.

EXCESS DEFERRED INCOME TAXES: At the end of 2017, DE Carolinas has a significant net deferred tax liability, booked at a 35 percent corporate tax rate and driven overwhelmingly by accelerated and bonus depreciation of fixed assets for tax purposes. Because a deferred tax liability represents taxes collected from customers but not yet paid to taxing authorities, and because the ultimate payment of these taxes will now occur at a 21 percent corporate tax rate (down from 35 percent), the balance of deferred tax liability must be remeasured. The resulting "excess" deferred tax balance becomes a regulatory liability. The Tax Act requires that excess deferred taxes generally associated with property, and specifically connected to the accelerated depreciation of property, must be normalized into customers rates in a highly-prescribed manner that mimics the remaining life of the underlying assets. These are known as "protected" excess deferred taxes. All other excess deferred taxes may be treated by the Commission like any other regulatory liability in the rate-setting process.

Q. PLEASE DISCUSS THE CONCEPT OF BONUS DEPRECIATION.

A. Bonus depreciation is an enhanced form of accelerated depreciation for tax purposes. Congress has used bonus depreciation for well over a decade to encourage capital investment, at varying times renewing the provision just as it is set to expire and modifying the degree to which depreciation in the first year (the "bonus") could be claimed. Prior to the Tax Act, existing bonus depreciation laws were scheduled to sunset in 2020, but could very well have been extended as in years past. In 2017, prior to the Tax Act, bonus depreciation was 50 percent—this means that corporate taxpayers could depreciate 50 percent of capital placed in service in the first year *in addition to* a normal level of tax depreciation (MACRS) on the remaining 50 percent.

Bonus depreciation has the effect, generally, of reducing taxable income, and therefore deferring associated cash taxes. However, utilities, being very capital-intensive businesses, were often put into tax loss positions (net operating losses, or NOLs) from an abundance of bonus depreciation and therefore were limited in their ability to incrementally delay cash taxes. To the extent that a utility could defer cash taxes due to bonus depreciation, however, a net deferred tax liability was established. The cash collected from customers but deferred from the taxing authorities was used to fund the operations and investments of the utility and avoided a commensurate level of third-party financings that would otherwise have been necessary but for the additional deferred income taxes.

Q. PLEASE DISCUSS THE CONCEPT OF ACCUMULATED DEFERRED INCOME TAXES ("ADIT")

A. Many timing differences exist between when income taxes are collected from customers in rates and when the Company pays those taxes in cash to the IRS. Sometimes the taxes are paid sooner than when they are collected from customers (which creates a deferred tax asset on the Company's books), and sometimes they are paid later (creating a deferred tax liability). Deferred taxes balances, therefore, result from book/tax timing differences between the recognition of income and expenses. All deferred tax balances, whether they are assets or liabilities, reverse over time and converge to zero over the life of the underlying item giving rise to the deferred tax balance.

To illustrate, see the table below. In this example, I assume the Company invests $1,000 in an asset with a useful life of ten years. Because the useful life is ten years, the initial cost of the asset will be spread out evenly over the ten-year period such that the depreciation expense for book purposes is $100 per year. Another assumption in this example is that the Company can accelerate the depreciation of the investment over a much shorter life for tax purposes—five years in my example (the IRS provides tables that are used to calculate the annual tax depreciation expense).

In this example, DE Carolinas can depreciate $200 of its investment for calculating its current year tax liability, but only $100 for calculating its book tax expense. Because of that difference, the Company's income taxes paid is $35 less (at the 35 percent tax rate) than it would have been using the useful life as the basis for calculating taxes. In the example below, it shows that by end of year six the Company will have fully depreciated its investment for tax purposes but is still recording depreciation expense for book purposes. The benefit to the Company and customers is apparent in the "accumulated" column. The figures in this column represent cash available to the Company from what amounts to a zero-cost loan from the government. This balance benefits customers by providing an offset to rate base.

Table 1					
	Depreciation Expense			Deferred Tax	
Year	**Per Books**	**Per Tax**	**Difference**	**Current Year**	**Accumulated**
1	$100	$200	$100	$35	$35
2	100	320	220	77	112
3	100	192	92	33	145
4	100	115	15	5	150
5	100	115	15	5	155
6	100	58	(42)	(15)	140
7	**100**	**-**	**(100)**	**(35)**	**105**
8	100	-	(100)	(35)	70
9	100	-	(100)	(35)	35
10	100	-	(100)	(35)	0
	$1,000	$1,000	$0	$0	$0

III. THE COMPANY'S PROPOSAL

Q. HOW DOES THE COMPANY'S APPLICATION IN THIS RATE CASE REFLECT THE IMPACTS OF THE TAX ACT?

A. Witness McManeus describes how the Company has incorporated into the base rate revenue requirements in this case the reduction in the corporate income tax rate from 35 to 21 percent. For the remaining benefits of the Tax Act, the Company is proposing to create an Excess Deferred Income Tax ("EDIT") Rider (the "EDIT Rider"). It is my understanding that the EDIT

Rider (also referred to as "EDIT-2" in Rate Design exhibits) contains the following five categories of benefits for customers:

1. Federal EDIT – Protected
2. Federal EDIT – Unprotected, PP&E related
3. Federal EDIT – Unprotected, non PP&E related
4. Deferred Revenue
5. NC EDIT

While Witness McManeus describes the structure and mechanics of the EDIT Rider, my testimony addresses the categories of federal EDIT that are included in the rider.

Q. PLEASE DESCRIBE THE THREE BUCKETS OF FEDERAL EDIT.

A. To understand the Company's proposal, it is necessary to understand the different types of assets from which EDIT is derived, and their differing treatment by the Tax Act. The $2,175 million of EDIT, as of the end of 2018, is in three different buckets. In one is approximately $1,193 million as of the end of 2018 of what is called "protected EDIT" – that is, EDIT related to the Company's investment in property, plant and equipment, whose flow back treatment is expressly made subject to IRS normalization rules by the Tax Act. The normalization rules – specifically, Section 13001(d)(3)(B) of the Tax Act – require protected EDIT to be flowed back over the remaining lives of the property giving rise to the deferred tax balance.

The remaining EDIT, totaling approximately $982 million, as of the end of 2018, is "unprotected" under IRS rules, and, therefore, subject to flow back in a timeframe open to discretionary action by the Commission. But the lion's share of unprotected EDIT, totaling more than $783 million still relates to the Company's investment in property, plant, and equipment, and is the second bucket of EDIT. This portion of unprotected EDIT is not required to be normalized under the Tax Act. Although both buckets are property-related, the Internal Revenue Code protects one but not the other. However, the rationale for normalization applies to this portion of EDIT as much as it applies to protected EDIT, and so normalization at some level is appropriate. The assets represented in this bucket have an average life of approximately 23 years for DE Carolinas, although, as discussed below, the Company's proposal uses a shorter 20-year period over which to accomplish this flow-back.

The third and final bucket, totaling approximately $199 million, as of the end of 2018, is unprotected EDIT. For DE Carolinas, the assets in this bucket are a variety of things, including certain regulatory assets with a two-year life, pension-related excess deferred taxes with 12- to 20-year lives, and EDIT that transitioned from Protected to Unprotected during 2018. Their average life is 6½ years.

Again, these balances are as of the end of 2018. The Company has made and may make additional adjustments to these amounts in 2019, as protected amounts ultimately become unprotected over time.

Q. WHAT IS THE FLOW BACK PERIOD FOR PROTECTED EDIT?

A. These amounts are generally related to Property, Plant & Equipment ("PP&E") and there are specific IRS requirements that require that this amount be returned to customers no more quickly than the prescribed method. For protected EDIT, the Company applies the Tax Act-prescribed IRS normalization rules. The amortization period the Company is using here is called the Average Rate Assumption Method ("ARAM"). ARAM is the method under which the excess in the reserve for deferred taxes is reduced over the remaining lives of the property as used in its regulated books of account which gave rise to the reserve for deferred taxes. Under such method, during the time period in which the timing differences for the property reverse, the amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying—(i) the ratio of the aggregate deferred taxes for the property to the aggregate timing differences for the property as of the beginning of the period in question, by (ii) the amount of the timing differences which reverse during such period.

Q. WHY IS THE COMPANY PROPOSING TO FLOW BACK THE CLASS OF UNPROTECTED PROPERTY-RELATED EDIT OVER 20 YEARS?

A. The 20-year period is appropriate because it is tied directly to the underlying assets that created the deferred tax balances that became EDIT when the Tax Act dropped the corporate tax rate to 21 percent. Protected and unprotected property related deferred taxes are no different except for the fact that they come from two places in the Internal Revenue Code and the statute protects one and it does not the other. The flow-back of excess deferred taxes over the life of the underlying assets makes sense, as does normalization concept underlying the 20-year flow-back proposal. Normalization, or the gradual return of EDIT over the life of the capital asset being depreciated, balances the customer and the Company's interests; it protects the Company's cash flow and protects the customer against rate volatility, because the deferred balance acts as an offset to rate base, and, therefore, a reduction in rates.

Matching the flow-back period to the timeframe over which the flow-back would have occurred absent the Tax Act is important in other ways. Deferred taxes represent an interest-free loan from the government. The Company then used these funds, at no cost to customers, to invest in its business. By doing so, the Company avoided having to go to the capital markets to raise this portion of the funds that it invested, and customers saved the capital cost of its being able to use the interest-free loan from the government instead of investor-supplied capital. But having invested in the business, there is not a readily available reserve pool from which the cash needed to return EDIT can be drawn. Flow-back over the 20-year period that more closely matches the asset lives smooths out the cash flow hit that the Company must take as it returns EDIT to customers and lessens the need for the Company to raise those funds from investors and third parties.

Q. PLEASE SUMMARIZE HOW CUSTOMERS BENEFIT FROM THE CHANGES IN THE COMPANY'S COST TO SERVE AS A RESULT OF THE TAX ACT?

A. As this Commission is well aware, electric utilities are one of the most capital intensive industries in the country. The Company invests in infrastructure not because of federal tax policy, but because it is critical, necessary, and often legally required that it do so. The Company's privilege and obligation to serve customers requires the financial wherewithal to support operational commitments on a reliable and cost-effective basis. Credit quality drives access to affordable capital, and for this reason it is in the best interest of customers to prevent a weakening of the Company's cash flow and credit quality from pre-Tax Act levels.

The Company's proposal included in this case both provides immediate benefit from the Tax Act and continues benefitting customers through the return of deferred taxes over time, as explained by Witness McManeus. The Company's proposal further complies with accounting requirements while preserving the Company's credit rating by not creating undue pressure on cash flows.

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

A. Yes.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony ("Direct Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Company, doing business in North Carolina as Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I also hold a Masters of Business Administration from Rutgers University with a concentration in Finance and International Business, which was conferred with high honors. I am a Certified Rate of Return Analyst ("CRRA") and a Certified Valuation Analyst ("CVA").

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I offer expert testimony on behalf of investor-owned utilities on rate of return issues and class cost of service issues. I also assist in the preparation of rate filings, including but not limited to revenue requirements and original cost and lead/lag studies. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included as Attachment A to my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present evidence and provide the Commission with a recommendation regarding the Company's return on equity ("ROE").[1] My analysis and conclusions are supported by the data presented in Exhibit DWD-1 through Exhibit DWD-7, which have been prepared by me or under my direction.

II. SUMMARY OF KEY CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF EQUITY FOR THE COMPANY?

A. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, I conclude that an ROE in the range of 10.00 percent to 11.00 percent represents the range of equity investors' required return for investment in electric utilities like DE Carolinas in today's capital markets. Within that range, I believe an ROE of 10.50 percent is reasonable and appropriate. As described in greater detail later in my testimony, that recommendation is based on the use of several widely accepted methods, and reflects the results of several analyses I have undertaken to estimate the effect of DE Carolinas' business risks on its Cost of Equity.

[1] Throughout my testimony, I interchangeably use the terms "ROE" and "Cost of Equity."

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR ROE DETERMINATION.

A. Because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. I therefore relied on three widely accepted approaches to develop my ROE determination: (1) the Constant Growth Discounted Cash Flow ("DCF") model; (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. Those analyses indicate the Company's Cost of Equity currently to be in the range of 10.00 percent to 11.00 percent. That range is corroborated by the Expected Earnings approach which, as I discuss later in my Direct Testimony, is supported by recent FERC Orders.

In addition to the methods noted above, I considered: (1) the risks associated with certain aspects of the Company's generation portfolio and (2) the Company's significant capital expenditure plan. In addition to the methods noted above, I calculated the costs of issuing common stock (that is, "flotation" costs), and considered evolving capital market and business conditions, including changes in Federal Reserve monetary policy. Although those factors are very relevant to investors, their effect on the Company's Cost of Equity cannot be directly quantified. Therefore, although I did not make explicit adjustments to my ROE estimates, I considered those factors in determining where the Company's Cost of Equity falls within the range of analytical results.

In light of those analyses, I believe that my recommended range is reasonable and appropriate.

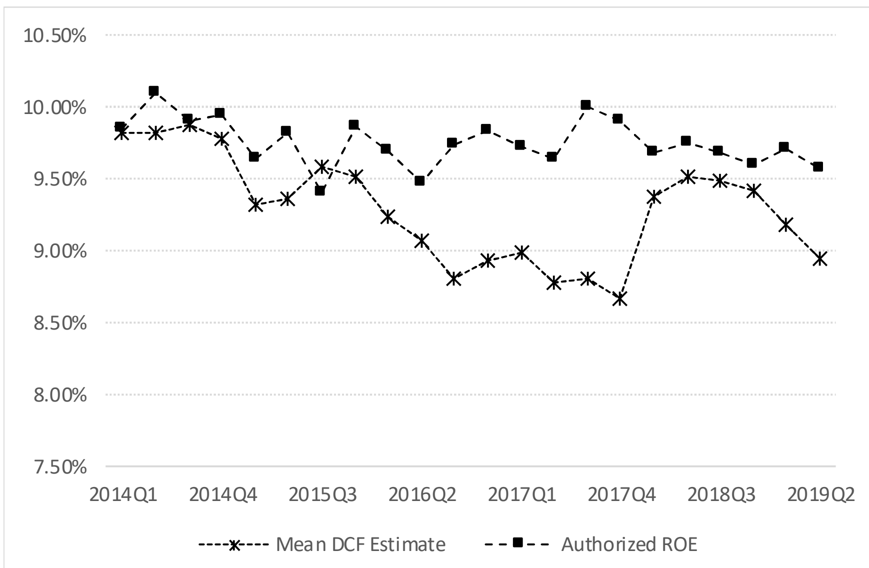
My analyses recognize that estimating the Cost of Equity is an empirical, but not entirely mathematical exercise; it relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that inevitably must be applied. No single model is more reliable than all others under all market conditions, and all require the use of reasoned judgment in their application, and in interpreting their results. Therefore, the results of each ROE model must be assessed in the context of current and expected capital market conditions, and relative to other appropriate benchmarks.

In developing my recommendation, I recognized that the low end of the range of results (set by the low end of the range of Constant Growth DCF model results) is not likely to be a reasonable estimate of the Company's Cost of Equity. In large measure, that is the case because those results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions. Because Risk Premium-based methods directly reflect measures of capital market risk, they are more likely than other approaches (such as the Constant Growth DCF method) to provide reliable estimates of the Cost of Equity during periods of market instability.

Q. WHAT IS THE BASIS OF YOUR VIEW THAT THE CONSTANT GROWTH DCF METHOD RECENTLY HAS FAILED TO PROVIDE RELIABLE ROE ESTIMATES?

A. Since 2014, the model has produced results (*i.e.*, mean results) consistently and meaningfully below authorized returns (*see*, Chart 1, below). That data suggests state regulatory commissions have recognized the model's results are not necessarily reliable estimates of the Cost of Equity, and that other methods should be given meaningful weight in determining the ROE.

Chart 1: Mean DCF Results vs. Authorized ROE Over Time[2]



For example, in Baltimore Gas and Electric Company's 2016 rate case, the Maryland Public Service Commission discussed the importance of

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[2] DCF results based on quarterly average stock prices, Earnings Per Share growth rates from Value Line, Zacks, and First Call; assumes my proxy group. Authorized ROEs are quarterly averages for vertically integrated electric utilities; source: S&P Global Market Intelligence. Please note that 2016 Q2 and 2017 Q3 included only one ROE decision.

considering multiple analytical methods, given the complexity of determining the investor-required ROE:

> The ROE witnesses used various analyses to estimate the appropriate return on equity […] including the DCF model, the IRR/DCF, the traditional CAPM, the ECAPM, and risk premium methodologies. Although the witnesses argued strongly over the correctness of their competing analyses, we are not willing to rule that there can be only one correct method for calculating an ROE. Neither will we eliminate any particular methodology as unworthy of basing a decision. The subject is far too complex to reduce to a single mathematical formula. That conclusion is made apparent, in practice, by the fact that the expert witnesses used discretion to eliminate outlier returns that they testified were too high or too low to be considered reasonable, even when using their own preferred methodologies.[3]

The Federal Energy Regulatory Commission ("FERC") also has addressed its longstanding focus on the DCF method. In its November 15, 2018 *Order Directing Briefs*, FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE."[4] In its October 16, 2018 *Order Directing Briefs*, FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness…", it is "…concerned that relying on that methodology alone will not produce just and reasonable results."[5] As FERC explained, it is important to understand "how investors

[3] *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates, Public Service Commission of Maryland*, Case No. 9406, Order No. 87591, at 153. Citations omitted.

[4] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs,* 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

[5] Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

analyze and compare their investment opportunities."[6] FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods…"[7] Those methods include the CAPM and the Risk Premium method, which I have applied in this proceeding.

Since the FERC issued its *Orders Directing Briefs*, the South Carolina Public Service Commission came to a similar finding, explaining that "it is appropriate and reasonable to consider a range of estimates under various methodologies in order to more accurately estimate [South Carolina Electric & Gas's] cost of equity", and relying on a single analytical method is "inconsistent with decisions reached by regulatory commissions over the past several years and departs from the normal practice of estimating the Cost of Equity for utilities."[8]

Q. HAS THE COMMISSION PREVIOUSLY DECLINED TO RELY ON THE DCF MODEL RESULTS?

A. Yes. In the Commission's June 2018 *Order Accepting Stipulation* for the Company, the Commission noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged from 8.45 percent to 8.80 percent) and determined that "all of these DCF analyses in the current

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6 *Ibid*., at para. 33.

7 *Ibid*., at para. 35. *See*, also, Docket No. PL19-4-000, *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, March 21, 2019.

8 Public Service Commission of South Carolina, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, Order No. 2018-804, Order Addressing South Carolina Electric & Gas Nuclear Dockets, at 89-90. [clarification added].

market produce unrealistically low results."[9]

Q. ARE THERE ASPECTS OF THE CONSTANT GROWTH DCF MODEL THAT MAY EXPLAIN WHY REGULATORY COMMISSIONS CURRENTLY DO NOT RELY PRINCIPALLY ON IT WHEN DETERMINING THE COST OF EQUITY?

A. Yes. Quite simply, the model's underlying structure and assumptions are not compatible with the recent capital market and economic environment. That can most easily be seen by recognizing that the model's fundamental structure requires the assumption of constancy in perpetuity. It assumes there will be no change in growth rates, dividend payout ratios, Price/Earnings ratios, Market/Book ratios, or in the economic and market conditions that support those variables. Equally important, the model assumes the Cost of Equity estimated today will remain unchanged, also in perpetuity. That is, the model requires that the Cost of Equity estimate produced today will be the same forward-looking return equity investors will require every day in the future, in perpetuity.

At issue is whether we reasonably can assume the market conditions created by those policies will stay in place over the long run. For example, we know that the Federal Reserve is continuing to "assess" market information as

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[9] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1146, *In the Matter of 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, at 62.

it evaluates future monetary policy decisions.[10] Regardless of its eventual disposition, neither the Federal Reserve's unconventional monetary policy initiatives, nor the capital market conditions they supported, will remain in place in perpetuity, as the Constant Growth DCF model requires. On that basis alone, we should be cautious about the weight given the DCF method.

The model also assumes investors use its fundamental structure to find the "intrinsic" value of stock, that is, the price they are willing to pay.[11] In practice, investors also consider relative valuation multiples – Price/Earnings, Market/Book, Enterprise Value/EBITDA[12] – in their buying and selling decisions. They do so because no single financial model produces the most accurate measure of fundamental value, or the most reliable estimate of the Cost of Equity, at all times.

Q. IS IT YOUR VIEW THAT THE DCF MODEL SHOULD BE GIVEN NO WEIGHT IN DETERMINING THE COMPANY'S COST OF EQUITY?

A. No. It is not. It is my view, however, that we should carefully consider the range of results the model produces in arriving at ROE recommendations. As discussed later in my Direct Testimony, doing so fully supports my ROE range and recommendation.

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10 Minutes of the Federal Open Market Committee, July 30-31, 2019, at 13.

11 *See*, Equations [4] and [5], in Appendix A below. *See also*, finance.zacks.com/difference-between-market-value-intrinsic-value-2991.html.

12 Earnings Before Interest, Taxes, Depreciation, and Amortization.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ANALYSES, AND HOW THEY CONTRIBUTED TO YOUR ROE RECOMMENDATION.

A. The range of results produced by the three primary approaches noted above are summarized in Tables 1a and 1b, below.

Table 1a: Summary of Discounted Cash Flow Model Results[13]

	Mean	Mean High
30-Day Average	8.86%	9.73%
90-Day Average	8.95%	9.82%
180-Day Average	9.09%	9.96%

Table 1b: Summary of Risk Premium Results[14]

CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	8.73%	8.68%
Near Term Projected 30-Year Treasury (2.70%)	8.80%	8.75%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	9.74%	9.69%
Near Term Projected 30-Year Treasury (2.70%)	9.81%	9.75%
Empirical CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	10.27%	10.21%
Near Term Projected 30-Year Treasury (2.70%)	10.34%	10.28%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	11.03%	10.96%
Near Term Projected 30-Year Treasury (2.70%)	11.10%	11.03%
Bond Yield Plus Risk Premium Approach		
Current 30-Year Treasury (2.63%)	9.90%	
Near Term Projected 30-Year Treasury (2.70%)	9.90%	
Long-Term Projected 30-Year Treasury (3.70%)	10.06%	

13 *See also*, Exhibit RBH-1, which includes the Mean Low estimates.
14 Exhibit RBH-4 and Exhibit RBH-5.

Based on those estimates, it is my view that a reasonable range of estimates is from 10.00 percent to 11.00 percent, and within that range, an ROE of 10.50 percent is reasonable and appropriate. That range is supported by the Expected Earnings approach, which results in an average ROE estimate of 10.44 percent and a median ROE estimate of 10.54 percent.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized as follows:

- Section III – Provides an overview of the Cost of Equity analyses;
- Section IV – Provides a discussion of specific business risk and other considerations that have a direct bearing on DE Carolinas' Cost of Equity;
- Section V – Discusses the economic conditions in North Carolina;
- Section VI – Highlights the current capital market conditions and their effect on DE Carolinas' Cost of Equity;
- Section VII – Summarizes my conclusions; and
- Section VIII – Appendix A provides the technical details of my analytical approaches.

III. COST OF EQUITY ESTIMATION

Regulatory Guidelines and Financial Considerations

Q. BEFORE ADDRESSING THE SPECIFIC ASPECTS OF THIS PROCEEDING, PLEASE PROVIDE AN OVERVIEW OF THE ISSUES SURROUNDING THE COST OF EQUITY IN REGULATORY PROCEEDINGS, GENERALLY.

A. In general terms, the Cost of Equity is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk. In that important respect, the returns required by debt and equity investors represent a cost to the Company.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities.[15] The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders. In that basic sense, equity and debt investors differ: they invest in different securities, face different risks, and require different returns.

Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated or inferred based on market data and various financial models. As discussed throughout my Direct Testimony, each of those models is subject to specific assumptions, which may be more or less applicable under differing market conditions. In addition, because the Cost of Equity is premised on opportunity costs, the models typically are applied to a group of "comparable" or "proxy" companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of the model results all require the application of reasoned judgment. That judgment should

[15] The observed interest rate may be adjusted to reflect issuance or debt directly observable costs.

consider data and information that is not necessarily included in the models themselves. In the end, the estimated Cost of Equity should reflect the return that investors require in light of the subject company's risks, and the returns available on comparable investments.

Practitioners and academics recognize that financial models are approximations of investor behavior, not precise quantifications of it. They appreciate that models are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions. That position is consistent with the *Hope* and *Bluefield* principle that it is the analytical result, as opposed to the method employed, that is controlling in arriving at just and reasonable rates. A reasonable ROE estimate therefore appropriately considers alternative methods and the reasonableness of their individual and collective results in the context of observable, relevant market information.

As discussed earlier, FERC has found that no individual model is more reliable than all others under all market conditions, and that the application of judgment is important in developing ROE estimates. Commissions in other regulatory jurisdictions, such as Hawaii, Maryland, Massachusetts, and South

Carolina have made similar findings.[16] As those decisions suggest, it is both prudent and appropriate to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. I therefore have considered the results of the Constant Growth DCF model, the traditional and empirical forms of the Capital Asset Pricing Model, and the Bond Yield Plus Risk Premium approach. I also have provided an Expected Earnings analysis, which I have applied as a corroborating method.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE GUIDELINES ESTABLISHED BY THE UNITED STATES SUPREME COURT (THE "COURT") FOR THE PURPOSE OF DETERMINING THE RETURN ON EQUITY.

A. The Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* ("*Bluefield*");[17] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[18] In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn

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16 *See*, for example: (1) Public Utilities Commission of the State of Hawaii, Docket No. 7700, Order No. 13704 in Docket No. 7700, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules*, December 28, 1994 at 92; (2) The Public Service Commission of Maryland, Case No. 9418, *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, Order No. 87884, at 97; (3) The Commonwealth of Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities*, Docket D.P.U. 15-155, September 30, 2016, at 376-378; and (4) Public Service Commission of South Carolina, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, Order No. 2018-804, Order Addressing South Carolina Electric & Gas Nuclear Dockets, at 88-89.

17 *See, Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679, 692 (1923).

18 *See, Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

> a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[19]

The Court therefore recognized that: (1) a regulated public utility cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the Cost of Capital (the principle relating to the demand for capital); and (2) a regulated public utility will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In *Hope*, the Court reiterated the financial integrity and capital attraction principles of the *Bluefield* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to

[19] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679, 692 (1923).

maintain its credit and to attract capital.[20]

In summary, the Court clearly has recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Q. HAS THE COMMISSION ALSO LOOKED TO THE HOPE AND BLUEFIELD STANDARDS AS GUIDANCE FOR SETTING RATES?

A. Yes. It has. For example, in Docket No. E-7, Sub 1026, the Commission noted:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):
>
> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S. E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. *Id*.[21]

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[20] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[21] North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, September 24, 2013, at 23; *see also*, State of North Carolina Utilities

Based on those standards, the authorized ROE should provide the Company with the opportunity to earn a fair and reasonable return, and should enable efficient access to external capital under a variety of market conditions.

Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO EARN A RETURN ADEQUATE TO ATTRACT CAPITAL AT REASONABLE TERMS?

A. A return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. The consequence of the Commission's order in this case, therefore, should be to provide DE Carolinas with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent DE Carolinas is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders should be disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables DE Carolinas to provide safe, reliable electric utility service while maintaining its financial integrity, all to the benefit of both investors and ratepayers.

Commission, Docket No. E-22, Sub 479, Order on Remand, July 23, 2015, at 12-16 (discussing the *Hope* and *Bluefield* decisions) ("Dominion Remand Order").

Proxy Group Selection

Q. AS A PRELIMINARY MATTER, WHY IS IT NECESSARY TO SELECT A GROUP OF PROXY COMPANIES TO DETERMINE THE COST OF EQUITY FOR DE CAROLINAS?

A. First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of the individual business units reflects the risks and opportunities inherent in the business sectors in which those units operate. In this proceeding, we are focused on estimating the Cost of Equity for the North Carolina operations of DE Carolinas, whose parent is Duke Energy Corporation ("Duke Energy"). Because the ROE is a market-based concept, and DE Carolinas is not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if the Company were a publicly traded entity, short-term events could bias its market value during a given period of time. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. DOES THE SELECTION OF A PROXY GROUP SUGGEST THAT ANALYTICAL RESULTS WILL BE TIGHTLY CLUSTERED AROUND AVERAGE (*I.E.*, MEAN) RESULTS?

A. Not necessarily. For example, the Constant Growth DCF approach defines the Cost of Equity as the sum of the expected dividend yield and projected long-term growth. Despite the care taken to ensure risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. Consequently, at issue is how to estimate the Cost of Equity from within that range. Such a determination necessarily must consider a wide range of both quantitative and qualitative information.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF DE CAROLINAS.

A. DE Carolinas, which is a wholly owned subsidiary of Duke Energy, provides electric generation, transmission and distribution services to approximately 2.60 million residential, commercial, and industrial customers in portions of North Carolina and South Carolina.[22] Duke Energy's long-term issuer credit ratings are A- (Outlook: Negative) from Standard & Poor's ("S&P") and Baa1 (Outlook: Stable) from Moody's Investors Service ("Moody's"). The Company's long-term and senior unsecured credit ratings are A- (S&P, Outlook:

[22] Duke Energy Corp., SEC Form 10-K for the fiscal year ended December 31, 2018, at 23.

Negative) and A1 (Moody's, Outlook: Stable).[23]

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. I began with the universe of companies that Value Line classifies as Electric Utilities, and applied the following screening criteria:

- I excluded companies that do not consistently pay quarterly cash dividends;
- I excluded companies that were not covered by at least two utility industry equity analysts;
- I excluded companies that do not have investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- I excluded companies that were not vertically-integrated, i.e. utilities that own and operate regulated generation, transmission and distribution assets;
- I excluded companies whose regulated operating income over the three most recently reported fiscal years composed less than 60.00 percent of the respective totals for that company;
- I excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 60.00 percent of total regulated operating income; and

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[23] Source: S&P Global Market Intelligence.

- I eliminated companies that are currently known to be party to a merger or other significant transaction.

Q. DID YOU INCLUDE DUKE ENERGY IN YOUR ANALYSIS?

A. No. To avoid the circular logic that otherwise would occur, it is my practice to exclude the subject company, or its parent holding company, from the proxy group.

Q. WHAT COMPANIES MET THOSE SCREENING CRITERIA?

A. The criteria discussed above resulted in a proxy group of the following 19 companies:

Table 2: Proxy Group Screening Results

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avangrid, Inc.	AGR
CMS Energy Corporation	CMS
DTE Energy Company	DTE
Evergy, Inc.	EVRG
Hawaiian Electric Industries, Inc.	HE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

Cost of Equity

Q. HOW HAVE YOU DETERMINED THE INVESTOR-REQUIRED ROE?

A. As noted earlier, because the Cost of Equity is not directly observable, it must be estimated based on both quantitative and qualitative information. Although several empirical models have been developed for that purpose, all are subject to limiting assumptions or other constraints. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity, as discussed in Appendix A.[24] When faced with the task of estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed and, therefore, rely on multiple analytical approaches. As noted earlier, the use of multiple methods, and the consideration given to them, recently was addressed by FERC.

Consistent with that approach, I have considered the results of the Constant Growth DCF model, the traditional and empirical forms of the Capital Asset Pricing Model, and the Bond Yield Plus Risk Premium approach. I also have provided an Expected Earnings analysis, which I have applied as a corroborating method. FERC has provided similar guidance, using the Expected Earnings analysis in its determination of the "zone of reasonableness", observing that "*investors use those models.*"[25]

Q. PLEASE BRIEFLY DESCRIBE THE CONSTANT GROWTH DCF MODEL.

A. The Constant Growth DCF approach defines the Cost of Equity as the sum of (1) the expected dividend yield, and (2) expected long-term growth. As explained in Appendix A, the model often is expressed in the familiar form $k = \frac{D(1+g)}{P_0} + g$, where the expected dividend yield generally equals the expected annual dividend divided by the current stock price, and the growth rate is based

[24] *See, e.g.*, Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd ed., 2000, at 214.

[25] Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 44 (italics in original).

on analysts' expectations of earnings growth. The Constant Growth DCF formula, which falls from the longer "present value" structure,[26] requires several simplifying assumptions, including the constancy of inputs in perpetuity.

Under the model's strict assumptions, the growth rate equals the rate of capital appreciation (that is, the growth in the stock price).[27] Given that assumption, it does not matter whether the investor holds the stock in perpetuity, or whether they hold the stock for some period of time, collect the dividends, then sell at the prevailing market price. That result also requires that the ROE result reached today will remain unchanged in perpetuity. So, if market conditions are such that the model produces an unreasonably low (or high) ROE estimate today, it assumes that estimate will be the same ROE investors require every day in the future, regardless of whether or how market conditions change.

Q. PLEASE BRIEFLY DESCRIBE THE CAPITAL ASSET PRICING MODEL.

A. Whereas DCF models focus on expected cash flows,[28] Risk Premium-based models such as the CAPM focus on the additional return that investors require for taking on greater risk. In finance, "risk" generally refers to the variation in

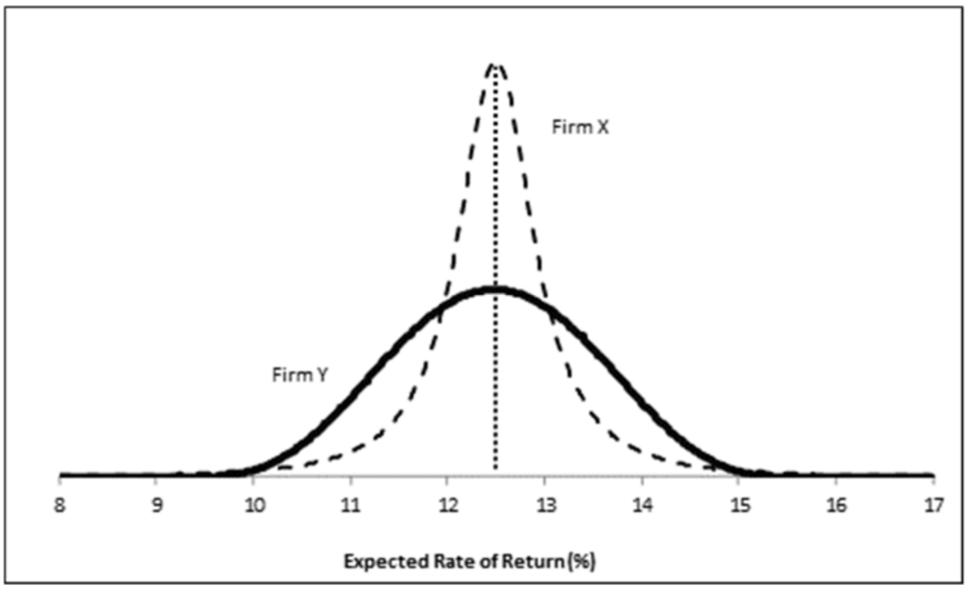
26 *See,* Appendix A, part A.

27 As discussed in Appendix A, part A, the model assumes that earnings, dividends, book value, and the stock price all grow at the same constant rate in perpetuity. Additionally, academic research has indicated that analysts forecasts of growth are superior to other measures of growth (*see,* Appendix A, part A).

28 *See,* Appendix A, part A.

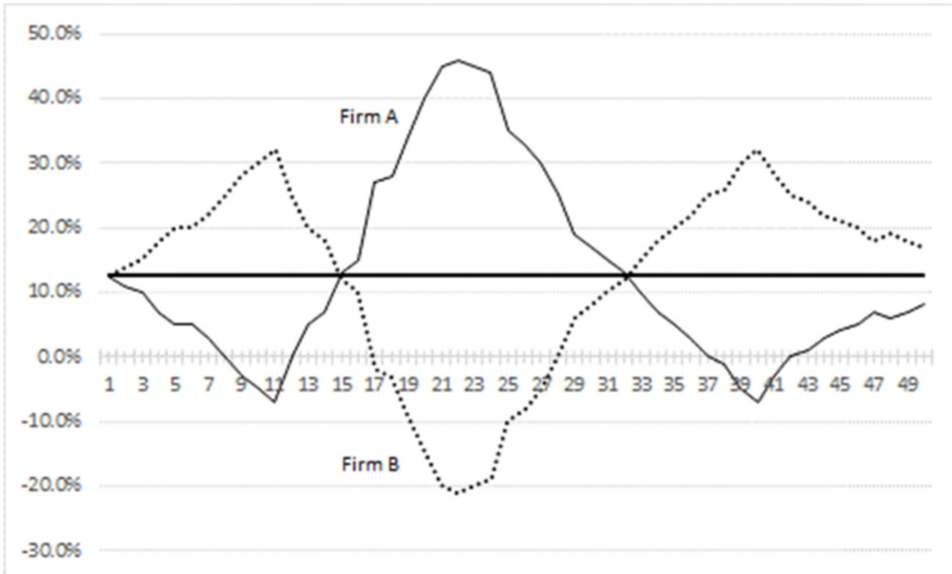
expected returns, rather than the expected return, itself. Consider two firms, X and Y, with expected returns, and the expected variation in returns noted in Chart 2, below. Although the two have the same expected return (12.50 percent), Firm Y's are far more variable. From that perspective, Firm Y would be considered the riskier investment.

Chart 2: Expected Return and Risk



Now consider two other firms, Firm A and Firm B. Both have expected returns of 12.50 percent, and both are equally risky as measured by their volatility. But as Firm A's returns go up, Firm B's returns go down. That is, the returns are negatively correlated.

Chart 3: Relative Risk



If we were to combine Firms A and B into a portfolio, we would expect a 12.50 percent return with no uncertainty because of the opposing symmetry of their risk profiles. That is, we can diversify the risk away. As long as two stocks are not perfectly correlated, we can achieve diversification benefits by combining them in a portfolio. That is the essence of the Capital Asset Pricing Model – because we can combine firms into a portfolio, the only risk that matters is the risk that remains after diversification, *i.e.*, the "non-diversifiable" risk.

The CAPM defines the Cost of Equity as the sum of the "risk-free" rate, and a premium to reflect the additional risk associated with equity investments. The "risk-free" rate is the yield on a security viewed as having no default risk, such as long-term Treasury bonds. The risk-free rate essentially sets the baseline of the CAPM. That is, an investor would expect a higher return than the risk-free rate to purchase an asset that carries risk. The difference between that higher return (*i.e.*, the required return) and the risk-free rate is the risk premium:

Risk-Free Rate + Risk Premium = Cost of Equity [1]

The risk premium is defined as a security's Beta coefficient multiplied by the risk premium of the overall market (the "Market Risk Premium" or "MRP").[29] The Beta coefficient is a measure of the subject company's risk relative to the overall market, *i.e.*, the "non-diversifiable" risk. A Beta coefficient of 1.00 means the security is as risky as the overall market; a value below 1.00 represents a security with less risk than the overall market, and a value over 1.00 represents a security with more risk than the overall market. In general, the CAPM is expressed as follows:

Risk-Free Rate + (Beta Coefficient x MRP) = Cost of Equity [2]

As with the Constant Growth DCF model, it is important to understand the CAPM's inputs, assumptions, and results in the context of observable market data. Appendix A, part B explains that Beta coefficients reflect two aspects of stock price movements: (1) the variability of the subject company's returns relative to the market; and (2) the correlation of the subject company's returns to the market's returns. Both are important factors. When utility stock prices fall but the overall market increases, the correlation will fall. When that

[29] As discussed in Appendix A, part B, I have relied on a forward-looking measure of the MRP, using inputs from Value Line and Bloomberg to derive an *ex-ante* market return estimate.

happens (all else remaining equal), Beta coefficients also will fall. That is especially the case when they are calculated over relatively short periods, as Bloomberg does. The question then becomes whether those Beta coefficients are likely to reflect investors' views of utility risk going forward. Here again, a certain amount of judgment must be applied.

Because the correlation between the proxy group companies and the S&P 500 has declined since 2014, even as their relative risk increased,[30] the CAPM in the form presented here may not adequately reflect the expected systematic risk, and therefore, the returns required by investors in low-Beta companies. To address that concern, I considered the Empirical CAPM ("ECAPM") approach, which is a variant of the CAPM approach. The ECAPM adjusts for the CAPM's tendency to under-estimate returns for companies that (like utilities) have Beta coefficients less than one, and over-estimate returns for relatively high-Beta coefficient stocks.

Q. PLEASE BRIEFLY DESCRIBE THE BOND YIELD PLUS RISK PREMIUM APPROACH.

A. This approach is based on the basic financial principle that equity investors bear the risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that additional risk (that difference often is referred

[30] *See*, Chart 15 in Appendix A, part B.

to as the "Equity Risk Premium"). Bond Yield Plus Risk Premium approaches estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.[31]

Bond Yield + Equity Risk Premium = Cost of Equity [3]

Q. WHAT ARE THE RESULTS OF THE CONSTANT GROWTH DCF ANALYSIS?

A. The results of the Constant Growth DCF analysis described above is provided in Table 3, below.[32]

Table 3: Summary of DCF Results[33]

	Mean	**Mean High**
30-Day Average	8.86%	9.73%
90-Day Average	8.95%	9.82%
180-Day Average	9.09%	9.96%

Q. WHAT ARE THE RESULTS OF THE RISK PREMIUM-BASED ANALYSES?

A. The Risk Premium-based results, including the CAPM and Bond Yield Plus Risk Premium methods, are provided in Table 4 below.

31 Prior research has shown that the Equity Risk Premium is inversely related to the level of interest rates (*see*, Appendix A, part C).

32 *See*, Appendix A for a more detailed description of the models, assumptions, and inputs described in Section III.

33 Exhibit RBH-1.

Table 4: Summary of Risk Premium Results[34]

CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	8.73%	8.68%
Near Term Projected 30-Year Treasury (2.70%)	8.80%	8.75%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	9.74%	9.69%
Near Term Projected 30-Year Treasury (2.70%)	9.81%	9.75%
Empirical CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	10.27%	10.21%
Near Term Projected 30-Year Treasury (2.70%)	10.34%	10.28%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	11.03%	10.96%
Near Term Projected 30-Year Treasury (2.70%)	11.10%	11.03%
Bond Yield Plus Risk Premium Approach		
Current 30-Year Treasury (2.63%)	9.90%	
Near Term Projected 30-Year Treasury (2.70%)	9.90%	
Long-Term Projected 30-Year Treasury (3.70%)	10.06%	

Q. PLEASE BRIEFLY DESCRIBE THE EXPECTED EARNINGS ANALYSIS.

A. The Expected Earnings analysis is based on the principle of opportunity costs. By taking historical returns on book equity and comparing those authorized

[34] Exhibit RBH-4 and Exhibit RBH-5.

ROEs, investors are able to directly compare returns from investments of similar risk. In addition to historical returns, Value Line also provides projected returns on book equity. Because the Cost of Equity is forward-looking, I relied solely on forward-looking projections in the Expected Earnings analysis.[35] The Expected Earnings analysis results in an average ROE estimate of 10.44 percent and median ROE estimate of 10.54 percent.[36] As noted earlier, I used those results to assess the reasonableness of the DCF, CAPM, and Bond-Yield Plus Risk Premium results.[37]

Flotation Costs

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance.

Q. ARE FLOTATION COSTS PART OF THE UTILITY'S INVESTED COSTS OR PART OF THE UTILITY'S EXPENSES?

A. Flotation costs are part of capital costs, which are properly reflected on the balance sheet under "paid in capital" rather than current expenses on the income statement. Like investments in rate base or the issuance costs of long-term debt,

35 As described more fully in Appendix A, part D, an adjustment is necessary to accurately reflect the average invested capital over the period in question.
36 Exhibit RBH-6.
37 *See also*, Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018).

flotation costs are incurred over time. As a result, the great majority of flotation costs are incurred prior to the test year, but remain part of the cost structure during the test year and beyond.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS ELIMINATED BECAUSE DE CAROLINAS IS A WHOLLY OWNED SUBSIDIARY OF DUKE ENERGY?

A. No. Although the Company is a wholly owned subsidiary of Duke Energy, it is appropriate to consider flotation costs because wholly owned subsidiaries receive equity capital from their parents and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based on the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately would penalize the investors that fund the utility operations and would inhibit the utility's ability to obtain new equity capital at a reasonable cost. This is important for companies such as DE Carolinas, that are planning continued capital expenditures in the near term, and for which access to capital to fund such required expenditures will be critical.

Q. HOW DID YOU ESTIMATE THE SIZE OF THE EFFECT OF FLOTATION COST ON INVESTOR RETURNS?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. The estimate of flotation costs recognizes the costs of issuing equity that were incurred by Duke Energy and the proxy companies in their most recent two issuances. As shown in Exhibit DWD-7, an adjustment of 0.08 percent (*i.e.*, eight basis points) reasonably represents flotation costs for the Company.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS RECOGNIZED BY THE ACADEMIC AND FINANCIAL COMMUNITIES?

A. Yes. The need to reimburse investors for equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. For example, Dr. Morin notes that "[t]he costs of issuing [common stock] are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs."[38] Dr. Morin further notes that "equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely."[39] This treatment is consistent with the philosophy of a fair rate of return. As explained by Dr. Shannon Pratt:

> Flotation costs occur when a company issues new stock. The business usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the business. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the business's required returns must be greater to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the net cash flow to discount, or by incorporating the cost into the cost of equity capital. Since

38 Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 321.
39 *Ibid.*, at 327.

> flotation costs typically are not applied to operating cash flow, they must be incorporated into the cost of equity capital.[40]

Similarly, Morningstar has commented on the need to reflect flotation costs in the cost of capital:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[41]

Q. ARE YOU PROPOSING TO ADJUST YOUR RECOMMENDED ROE BY EIGHT BASIS POINTS TO REFLECT THE EFFECT OF FLOTATION COSTS ON THE COMPANY'S ROE?

A. No. Rather I have considered the effect of flotation costs, in addition to the Company's other business risks (discussed below) in determining where the Company's ROE falls within the range of results.

IV. BUSINESS RISKS AND OTHER CONSIDERATIONS

Q. DO THE MEAN MODEL RESULTS FOR THE PROXY GROUP PROVIDE AN APPROPRIATE ESTIMATE FOR THE COST OF EQUITY FOR DE CAROLINAS?

A. No. The mean results of these models do not necessarily provide an appropriate estimate of DE Carolinas' Cost of Equity. In my view, there are additional factors that must be taken into consideration when determining where DE

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40 Shannon P. Pratt, Roger J. Grabowski, Cost of Capital: Applications and Examples, 4th Ed. (John Wiley & Sons, Inc., 2010), at 586.

41 Morningstar, Inc. Ibbotson SBBI 2013 Valuation Yearbook, at 25.

Carolinas' Cost of Equity falls within the range of results. Those factors include: (1) the risks associated with certain aspects of the Company's generation portfolio and (2) the Company's significant capital expenditure plan. Those factors, which are discussed below, should be considered in terms of their overall effect on the Company's Cost of Equity.

A. Environmental Regulations

Q. HOW DO THE RISKS OF ENVIRONMENTAL REGULATIONS AFFECT DE CAROLINAS' ACCESS TO AND COST OF CAPITAL?

A. Environmental regulations, in particular those relating to coal-fired generation (including coal-ash basin closure), nuclear generation, and regulations motivating distributed generation and net metering, have a direct bearing on the Company's operating and financial risk, and therefore, its Cost of Equity. In general, capital-intensive generation assets, such as coal-fired or nuclear generation facilities, are subject to certain risks including the recovery of investors' capital in the event of a change in market structure or a plant failure, and the recovery of replacement power and repair costs in the event of extended or unplanned outage. I discuss each of those issues in turn, below.

Coal-Fired Generation

Q. PLEASE PROVIDE AN OVERVIEW OF THE RISKS ASSOCIATED WITH DE CAROLINAS' GENERATION PORTFOLIO AND CURRENT ENVIRONMENTAL REGULATIONS.

A. DE Carolinas' operations are dependent on coal-fired generation, which represented approximately 33.50 percent of its 2018 reported owned operating capacity.[42] In particular, DE Carolinas and its investors face the risk that environmental regulations will require them to invest additional capital or face closure or curtailment of generating capacity. These risks are compounded in the current regulatory environment as a result of the uncertainty investors, utilities, and the economy as a whole, face in light of the change in administration following the 2016 election, and, in particular, the uncertain fate of Obama-era environmental regulations targeting greenhouse gas emissions and climate change in general, such as the Clean Power Plan, which is currently being challenged in the courts.

Most recently, the U.S. Environmental Protection Agency ("EPA") unveiled a proposal to replace the Clean Power Plan with the Affordable Clean Energy ("ACE") rule. The ACE rule would allow utilities to make heat efficiency upgrades to coal-fired power plants without triggering further environmental controls and would exclude natural gas-fired power plants from

[42] Duke Energy Corporation., SEC Form 10-K for the Period Ending December 31, 2018, at 33.

emissions limits.[43] Because investors consider those risks when establishing their return requirements, the Commission likewise should consider the effect of the additional risk associated with DE Carolinas' generating portfolio in determining its authorized ROE.

Q. PLEASE SUMMARIZE THE IMPLICATIONS OF COAL ASH BASIN CLOSURE AND COMPLIANCE ACTIVITIES IN DUKE ENERGY'S CAROLINA OPERATIONS FOR THE COMPANY'S COST OF EQUITY.

A. By way of background, on September 20, 2014, the North Carolina Coal Ash Management Act ("CAMA") became law. CAMA (as subsequently amended) was supplemented by the EPA's rule, published on April 17, 2015, which regulated the disposal of coal combustion residuals ("CCRs") from electric utilities as solid waste. The EPA's CCR rule established requirements regarding operational and reporting procedures to ensure the safe disposal and management of CCRs.[44] CAMA and the EPA CCR rule subjected most of Duke Energy's coal ash impoundments in North Carolina to scrutiny.

Pursuant to CAMA, Duke Energy was ordered to take immediate action, and to excavate and close four high-priority sites with multiple coal ash basins around the state (including two DE Carolinas sites) by August 2019. In addition, DE Carolinas and the South Carolina Department of Health and

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43 S&P Global Market Intelligence, "EPA's Affordable Clean Energy rule: How it would work," August 21, 2018.

44 Duke Energy Corporation., SEC Form 10-K for the Period Ending December 31, 2018, at 80.

Environmental Control executed a consent agreement requiring the excavation of an inactive ash basin and ash fill area at the W.S. Lee Steam Station. Following publication of the EPA CCR rule in April 2015, DE Carolinas also entered into a consent agreement with conservation groups Upstate Forever and Save Our Saluda, similarly requiring the Company to deal with all active and inactive ash storage areas at that plant.[45] In a petition to the North Carolina Commission on December 30, 2016, Duke Energy indicated that it had recorded asset retirement obligations ("AROs") of $2.1 billion for DE Carolinas, and $2.4 billion for Duke Energy Progress' ("DE Progress") consolidated operations in compliance with CAMA, the CCR rule and the consent agreements.[46]

In the Company's last rate case, the Commission approved recovery of $545.70 million of AROs, and allowed the Company to defer costs recorded after January 1, 2018 until its next general rate case.[47] However, the North Carolina Attorney General filed an appeal challenging the Commission's Order allowing the Company to recover those costs.[48] I also understand that on April 1, 2019, the North Carolina Department of Environmental Quality ("NCDEQ")

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45 Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for an accounting Order to Defer Certain Coal Ash Remediation Costs, December 30, 2016, Paragraph 8.

46 *Ibid.*, Paragraph 11.

47 State of North Carolina Utilities Commission, Docket No. E-7, Sub 1146, *In the Matter of 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, July 25, 2017, at 23-24.

48 *See,* S&P Global Market Intelligence, "NC attorney general appeals orders allowing Duke to recover coal ash costs," April 29, 2019.

ordered Duke Energy to excavate all remaining coal ash impoundments in North Carolina, and to submit final excavation closure plans to the NCDEQ by August 1, 2019.[49] The uncertainty surrounding the Attorney General's appeal, the eventual cost of deferred coal ash compliance costs, and the timing and extent of recovery of those costs therefore remains a significant risk to investors.[50]

Q. ARE THERE ANY OTHER CONCERNS FOR INVESTORS WITH RESPECT TO COAL GENERATION?

A. Yes. On January 25, 2016, California Insurance Commissioner Dave Jones introduced a new requirement for the disclosure of carbon-based investments held by insurance companies, and called on California insurance companies to divest investments in coal and companies that use coal, including electrical utilities.[51] Although California's is the first insurance commission to call for such divestitures, it is the largest insurance commission in the United States, and sixth largest insurance commission in the world.[52] Given the large percentage of institutional ownership among the proxy companies,[53] the potential of divestiture represents a significant source of risk for investors.

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[49] *See*, North Carolina Department of Environmental Quality, Press Release, "DEQ Orders Duke Energy to Excavate Coal Ash at Six Remaining Sites," April 1, 2019.

[50] *See*, Duke Energy Corporation., Cautionary Statement Regarding Forward-Looking Information, SEC Form 10-K for the Period Ending December 31, 2018 at 5.

[51] *See*, California Department of Insurance, January 25, 2016 Press Release

[52] *Ibid*.

[53] The average institutional ownership for the proxy group is 73.38 percent. Duke Energy Corporation's institutional ownership is 60.73 percent. Source: S&P Global Market Intelligence.

Nuclear Generation Portfolio

Q. PLEASE BRIEFLY DESCRIBE THE RISKS ASSOCIATED WITH THE OWNERSHIP OF NUCLEAR GENERATING RESOURCES.

A. Nuclear generating resources are regulated by the U.S. Nuclear Regulatory Commission ("NRC"). As such, DE Carolinas is subject to NRC mandates to meet licensing and safety related standards that may require increased capital spending and incremental operating costs. As Duke Energy noted:

> Revised security and safety requirements promulgated by the NRC, which could be prompted by, among other things, events within or outside the control of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, such as a serious nuclear incident at a facility owned by a third-party, could necessitate substantial capital and other expenditures, as well as assessments to cover third-party losses. In addition, if a serious nuclear incident were to occur, it could have a material adverse effect on the results of operations and financial condition and reputation of the Duke Energy Registrants.[54]

Q. DOES THE COMPANY'S GENERATION PORTFOLIO INCLUDE NUCLEAR GENERATING ASSETS?

A. Yes. DE Carolinas' generation portfolio includes 5,315 megawatts ("MW") of owned nuclear generating capacity. Specifically, the Company owns 2,316 MW at the McGuire facility in North Carolina, 2,554 MW at the Oconee facility in South Carolina, and 445 MW at the Catawba facility in South Carolina.[55]

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54 Duke Energy Corporation., SEC Form 10-K for the Period Ending December 31, 2018, at 31.

55 *See*, DE Carolinas owns 5,315 MW of nuclear capacity out of a total owned capacity of 20,209 MW, or 26.30 percent of the total. *See*, Duke Energy Corp., SEC Form 10-K for the fiscal year ended December 31, 2018, at 33.

Q. ARE THERE EXAMPLES OF THE INCREASED RISK OF NEW REGULATORY REQUIREMENTS THAT NUCLEAR GENERATION PLANT OPERATORS FACE?

A. Yes. One example is the increased oversight and regulatory requirements put in place following a March 11, 2011 earthquake and tsunami, which caused significant damage to the Fukushima Daiichi nuclear complex and threatened the public health. After the Fukushima accident, the NRC assembled a task force to assess current regulation and determine if new measures were required to ensure safety. The task force issued a report in July 2011 that included a set of recommendations for NRC consideration. Those recommendations continue to be modified and expanded by the NRC staff, and the first related regulatory requirements were issued in March 2012 with implementation guidance issued on August 30, 2012.[56] The evolving nature of these requirements from the NRC put nuclear operators at risk of incurring costly future capital expenditures.

Another example of nuclear risk is the ongoing and long-term uncertainty regarding nuclear waste disposal. On June 8, 2012, the U.S. Court of Appeals vacated the NRC's rulemaking regarding storage and permanent disposal of nuclear waste. The Court of Appeals found the NRC rulemaking was deficient in that: (1) it "did not calculate the environmental effects of failing to secure permanent storage," and (2) "in determining that spent fuel can safely be stored on site at nuclear plants for sixty years after the expiration of a plant's

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56 *See*, www.nrc.gov/reactors/operating/ops-experience/japan-info.html.

license, the [NRC] failed to properly examine future dangers and key consequences."[57] Nuclear operators therefore face future capital expenditures related to expansion of nuclear waste storage, and may face additional costs to meet safety standards that may be required when the NRC addresses the Court of Appeal's ruling.

To the extent further mandates are promulgated by the NRC, additional spending may be required. Absent full and timely recovery, increases in the Company's capital investment requirements will place additional pressure on its free cash flow and credit metrics.

North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("REPS")

Q. IS RETAIL NET METERING AVAILABLE TO DE CAROLINAS' CUSTOMERS IN NORTH CAROLINA?

A. Yes. The Company has effective North Carolina retail net metering tariffs, and there is no aggregate limit on participation by retail customers.

Q. PLEASE DESCRIBE RETAIL NET METERING.

A. Simply put, net metering is a billing mechanism whereby, through the use of a bidirectional meter, the customer's usage of electricity and the production of electricity from the customer's generator are combined and netted on the customer bill. Under retail net metering, customers sell their generated electricity to the utility at the same price that the utility charges to the customer

57 U.S. Court of Appeals for the District of Columbia Circuit, *On Petitions for Review of Orders of the Nuclear Regulatory Commission*, Case No. 11-1045, Decided June 8, 2012, at 3.

(a 1:1 ratio). This type of net metering is an embedded incentive to customers to invest in distributed generation in North Carolina.

Q. PLEASE EXPLAIN THE NORTH CAROLINA REPS AND THE COMPANY'S COMPLIANCE REQUIREMENTS.

A. Pursuant to North Carolina Session Law 2007-197 ("Senate Bill 3"), since 2012, utilities and other power suppliers have been required to meet stated percentages of their retail customers' energy needs (which escalates over time to 12.50 percent in 2021) through a combination of renewable energy resources, and energy reductions or savings from the implementation of energy efficiency and demand-side management programs. On July 27, 2017, North Carolina Governor Cooper signed HB 589 into law, which calls for a competitive procurement process by which the Company will pursue additional solar resources in both its North Carolina and South Carolina service territories. HB 589 targets 2,660 MW of competitively procured renewable resources over a 45-month period. The Company's "Base Case" forecast projects that the Company will have approximately 3,500 MW of renewable capacity by 2033 to comply with REPS and HB 589.[58]

58 Duke Energy Carolinas North Carolina 2018 Integrated Resource Plan, Docket No. E-100, Sub 157, September 5, 2018, at 29. Represents an incremental capacity of approximately 2,150 MW over 2019 renewable capacity of 1,300 MW.

Q. IS DE CAROLINAS ALSO EXPERIENCING GROWTH IN RENEWABLE ENERGY PROJECTS IN NORTH CAROLINA RELATED TO ITS PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 ("PURPA") COMPLIANCE REQUIREMENTS?

A. Yes. It is. According to the Company's Joint Comments to the Federal Energy Regulatory Commission's Technical Conference Concerning Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, submitted in Docket No. AD16-16-000 on June 7, 2016, "Duke Energy's utilities lead in and continue to grow deployment levels of PURPA qualifying facilities ("QF")…the Duke Progress and Duke Carolinas service territories are the nation's largest PURPA market, 'accounting for 60% of U.S. PURPA projects.'"[59] The following excerpt from the same filing further illustrates the PURPA compliance issues the Company faces in the Carolinas:

> From 2010 through 2015, 621 projects and 1246 MWs of QF generation have come online in the Carolinas, the vast majority of which are intermittent solar facilities. These mandatory purchases have resulted in over $1 billion in costs on customers – to date – and customers will continue to incur costs associated with these QF projects. Across Duke Energy's service territory in the Carolinas alone, transmission and distribution engineers have and are grappling with over 1,700 projects totaling over 9000 MWs of additional intermittent QF capacity. Engineers have to study all these projects, and they may not all be built. However, at this time there are over 1200 projects in the interconnection process that are viable and/or being built, totaling over 4400 MWs of additional intermittent capacity. These 1200 projects will mandate approximately $400 million

[59] Colin Smith, Analyst, GTM Research, The Next Wave of U.S. Utility Solar, Procurement Beyond the RPS (Feb. 2016) at 28 (emphasis supplied).

> in costs each year or $6 billion in costs over a 15-year commitment period. The above do not include the QFs in the Carolinas that are interconnected with other systems and municipal/cooperative utilities that are selling or seeking to sell their output to Duke Progress and Duke Carolinas.[60]

The Company's North Carolina 2018 Integrated Resource Plan filed in Docket No. E-100, Sub 157 identified 307 projects totaling 13,037 MW in its combined Carolinas service territories, with 159 pending projects totaling 5,957 MW in capacity being located in North Carolina.[61]

Q. WHAT ARE THE POTENTIAL IMPLICATIONS OF RETAIL NET METERING FOR THE COMPANY'S BUSINESS RISK?

A. The Company currently is experiencing low growth in demand, and is projected to do so into the future.[62] The extension of retail net metering incentivizes continued or increased investment in distributed generation, which can begin a cycle in which customers with means leave the system, and the pool of remaining customers are left with increasing fixed costs until, ultimately, the utility has difficulties recovering its full cost of service.[63] At that point, credit quality may come under pressure.

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60 Comments of Duke Energy Corporation to the Federal Energy Regulatory Commission's Technical Conference Concerning Implementation Issues Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Docket No. AD16-16-000, at 5.

61 Duke Energy Carolinas North Carolina 2018 Integrated Resource Plan, Docket No. E-100, Sub 157, September 5, 2018, at 206.

62 Duke Energy Corporation, SEC Form 10-K for the Period Ending December 31, 2018, at 10.

63 I understand that under House Bill 589, §62-126.4, utilities will file revised net metering rates for customers that own a renewable energy facility for their primary use, or are customer generator lessees, and that the Commission should establish non-discriminatory rates ensuring that retail net metering customers pay their full fixed costs. Those rates, and the Commission's analysis of the rates, are yet to be determined.

Q. DO CREDIT RATING AGENCIES RECOGNIZE RISKS ASSOCIATED WITH AN INCREASE IN DISTRIBUTED GENERATION RESOURCES?

A. Yes. They do. Although S&P noted the competitive threat from rooftop solar panels has not been significant enough to have an effect on credit quality to date, it has outlined the potential risks to the electric utility sector:

> …should solar rooftop use suddenly increase, a utility would be forced to recover its excess electric capacity costs from its remaining customers. The resulting higher bills to the remaining utility customers would only further drive those customers to install solar panels. This could, again, prevent the utility from fully recovering its costs and investments in a timely manner, potentially harming its credit quality.[64]

Moody's likewise noted that under certain conditions, there could be "large negative consequences" for utilities as a result of the widespread deployment of distributed generation resources. Under those conditions, when the regulatory structure does not address the effect of distributed generation, Moody's suggests that "the likelihood of negative credit events would rise due to the technological disruption."[65]

Similarly, a July 2014 article quoted Bernstein Research analysts regarding the risk of distributed generation from a utility's perspective, stating that "'[f]or the foreseeable future, distributed solar will exist in a parasitic

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64 Standard and Poor's Research, "Why U.S. Electric Utilities' Credit Quality Can Withstand the Rise of Rooftop Solar," November 15, 2013, at 6.

65 Moody's also refers to distributed generation as a "form of technology event risk, where event risk is low or remote, but with high severity implications should the event actually materialize." *See,* Moody's Investors Service, *Regulatory framework holds keys to risk and rewards associated with distributed generation*, April 23, 2014, at 2.

relationship to the grid, absorbing its revenues while continuing to rely upon it for economic viability,' the analysts said, noting two specific challenges distributed solar creates for utilities: lost sales volume and a 'foregone' need for new capacity."[66]

Q. ARE YOU AWARE OF ANY REGULATORY OFFICIAL THAT HAS QUANTIFIED THE POTENTIAL EFFECT OF DISTRIBUTED ENERGY SYSTEMS ON ELECTRIC UTILITIES?

A. Yes. On January 19, 2017, Commissioner Picker of the California Public Utilities Commission commented on the state of distributed energy in that state.[67] Commissioner Picker described an important development involving retail community clean aggregators ("CCA"), which are established by local governments. At the time of his comments, there were five operational, and fifteen CCAs in planning in California. Commissioner Picker noted that San Diego City's CCA would reduce San Diego Gas & Electric's customer base by 44.00 percent, and that Pacific Gas & Electric, where most of the existing CCAs are operational, was expected to see additional customer losses of 21.00 percent in 2017, alone. As described by Commissioner Picker, distributed energy is a very disruptive technology, with significant risks to incumbent electric utilities such as DE Carolinas.

[66] Copley, Michael, "Despite distributed generation's buzz, grid power 'here to stay,' Bernstein says," SNL Financial, July 21, 2014.

[67] *See*, Commissioner Picker Comments at the Start of the New Year, January 19, 2017.

B. Capital Expenditures

Q. PLEASE SUMMARIZE DE CAROLINAS' CAPITAL EXPENDITURE PLANS.

A. Based on Duke Energy's Summer 2019 Update, DE Carolinas plans to deploy approximately $13.83 billion in capital over the period 2019-2023.[68]

Q. WHAT ARE THE RISKS ASSOCIATED WITH THAT LEVEL OF INVESTMENT?

A. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. S&P has noted several long-term challenges for utilities' financial health including: heavy construction programs to address demand growth; declining capacity margins; and aging infrastructure and regulatory responsiveness to mounting requests for rate increases.[69] More recently, S&P noted that:

> We assume that capital spending will remain a focus of most utility managements and strain credit metrics. It provides growth when sales are diminished by ongoing demanded efficiency from regulators and other trends, and it is welcomed by policymakers that appreciate the economic stimulus and the benefits of safer, more reliable service. The speed with which the regulatory process turns the new spending into higher rates to begin to pay for it is an important factor in our assumptions and the forecast. Any extended lag between spending and recovery can exacerbate the negative effect on credit metrics and

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[68] Duke Energy Corporation, Summer Update 2019, at 29.

[69] *See* Standard & Poor's, *Industry Report Card: Utility Sectors in the Americas Remain Stable, While Challenges Beset European, Australian, and New Zealand Counterparts*, RatingsDirect, June 27, 2008, at 4.

therefore ratings.[70]

The allowed ROE should enable the subject utility to finance capital expenditures and working capital requirements at reasonable rates, and to maintain its financial integrity in a variety of economic and capital market conditions. As discussed earlier in my Direct Testimony, a return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness. To the extent a utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders should be disadvantaged.

The ratemaking process is based on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, their decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of the utility and its ratepayers.

Further, the financial community carefully monitors the current and expected financial condition of utility companies, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and

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70 *See* Standard & Poor's Rating Services, *Industry Top Trends 2017: Utilities*, RatingsDirect, February 16, 2017, at 4.

equity investors' assessments of risk. That is especially important during periods in which the utility expects to make significant capital investments and, therefore, may require access to capital markets.

V. ECONOMIC CONDITIONS IN NORTH CAROLINA

Q. DID YOU CONSIDER THE ECONOMIC CONDITIONS IN NORTH CAROLINA IN ARRIVING AT YOUR ROE RECOMMENDATION?

A. Yes. I did. As a preliminary matter, I understand and appreciate that the Commission must balance the interests of investors and customers in setting the Return on Equity. As the Commission has stated, it "…is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[71] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the *Hope* and *Bluefield* Comparable Risk, Capital Attraction, and Financial Integrity standards.

The Commission also has found the role of Cost of Capital experts is to determine the investor-required return, not to estimate increments or decrements of return in connection with consumers' economic environment:

> … adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an

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[71] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Sept. 24, 2013 at 25; *see also,* North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, at 31 ("the Commission in every case seeks to comply with the N.C. Supreme Court mandate that the Commission establish rates as low as reasonably possible within Constitutional limits.").

> unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the "end result" test of Hope. This the Commission has done.[72]

The Supreme Court agreed, and upheld the Commission's Order on Remand.[73] The Supreme Court also made clear, however, that "in retail electric service rate cases the Commission must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[74] The Commission made such additional findings of fact in its Order on Remand.[75] In light of the Cooper I decision, I appreciate the Commission's need to consider economic conditions in the state and, as such, I have undertaken several analyses to provide such a review.

Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.

A. In its Order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the Cost of Equity.[76] As discussed below, those relationships still hold: Economic

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72 State of North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, October 23, 2013, at 34 - 35; *see also,* Dominion Remand Order, Docket No. E-22, Sub 479 at 26 (stating that the Commission is not required to "isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity").

73 *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484,739 S.E.2d 541 (2013) ("Cooper I").

74 *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484,739 S.E.2d 541 (2013) ("Cooper I") at 8.

75 State of North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, October 23, 2013, at 13-16.

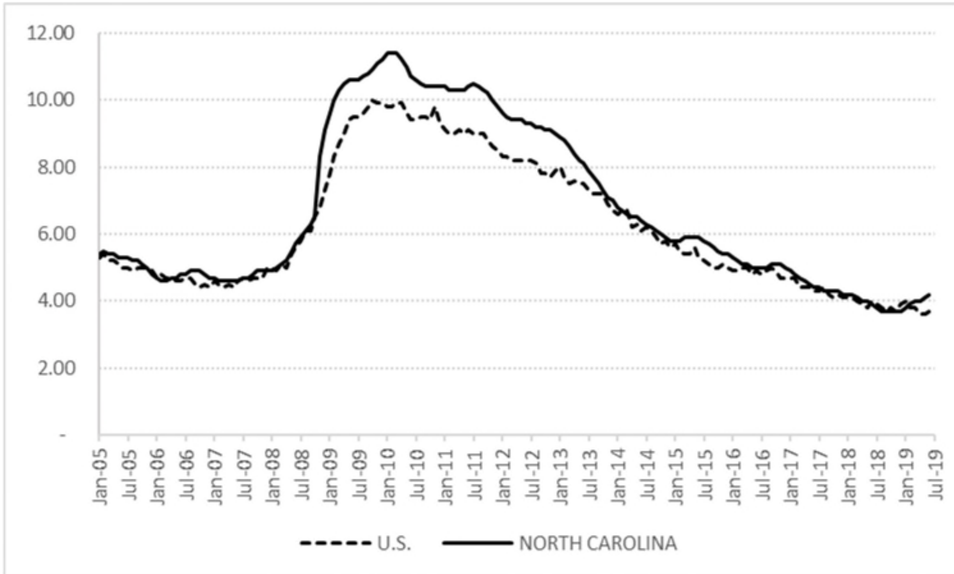
76 *See,* State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, Order on Remand, July 23, 2015, at 39.

conditions in North Carolina continue to improve from the recession following the 2008/2009 financial crisis, and they continue to be strongly correlated to conditions in the U.S., generally. In particular, unemployment, at both the state and county level, continues to fall and remains highly correlated with national rates of unemployment; real Gross Domestic Product ("GDP") also remains fairly well correlated with U.S. GDP growth; and median household income in North Carolina has grown at a rate consistent with the rest of the U.S., and remains strongly correlated with national levels. On balance, the correlations between state-wide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain in place and, as such, they continue to be reflected in the models and data used to estimate the Cost of Equity.

Q. PLEASE NOW DESCRIBE THE SPECIFIC MEASURES OF ECONOMIC CONDITIONS THAT YOU REVIEWED.

A. Turning first to the rate of unemployment, as noted above it has fallen substantially in North Carolina and the U.S. since late 2009 and early 2010, when the rates peaked at 10.00 percent and 11.40 percent (seasonally adjusted), respectively. Although the unemployment rate in North Carolina exceeded the national rate during and after the 2008/2009 financial crisis, by the latter portion of 2013, the two were largely consistent. By June 2019, the unemployment rate (seasonally adjusted) had fallen by approximately two-thirds of those peak levels: 3.70 percent nationally and 4.20 percent in North Carolina. (*see* Chart 4, below).

Chart 4: Unemployment Rate[77]



Since the Company's last rate filing in August 2017, the unemployment rate (seasonally adjusted) in North Carolina has fallen from 4.30 percent to 4.20 percent. Over the entire period of 2005 through 2019, the correlation between North Carolina's unemployment rate and the national rate was 99.32 percent. More broadly, economic growth at the national level is projected to generate 8.40 million new jobs from 2018-2028 (*i.e.*, 5.22 percent growth over that period).[78]

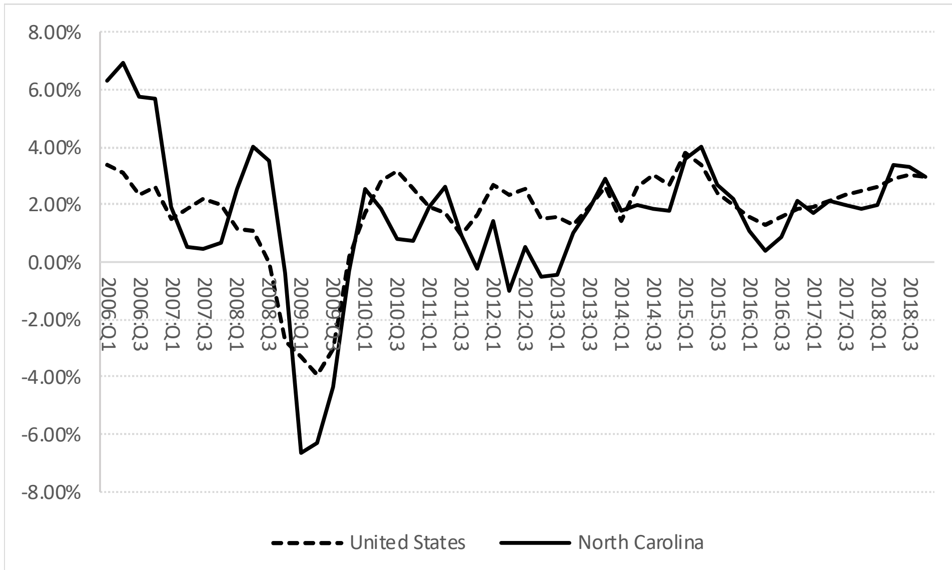
Looking to real Gross Domestic Product growth, there also has been a relatively strong correlation between North Carolina and the national economy (approximately 75.00 percent). Since the financial crisis, the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina.

[77] Source: Bureau of Labor Statistics. Seasonally adjusted.

[78] *See,* U.S. Bureau of Labor Statistics, *Employment Projections: 2018-2028*, September 4, 2019.

Since the first quarter of 2015, however, North Carolina's economic growth has been relatively consistent with U.S. economic growth.

Chart 5: Real Gross Domestic Product Growth Rate (Year over Year)[79]



As to median household income, the correlation between North Carolina and the U.S. is relatively strong (91.00 percent from 2005 through 2018). Since 2009 (that is, the years subsequent to the financial crisis), median household income (in nominal dollars) in North Carolina has grown at approximately the same annual rate as the national median income (2.72 percent vs. 2.68 percent, respectively; *see* Chart 6, below). To put household income in perspective, the Missouri Economic Research and Information Center reports that in the second quarter of 2019, North Carolina had the 20th lowest cost of living index among the 50 states and the District of Columbia.[80]

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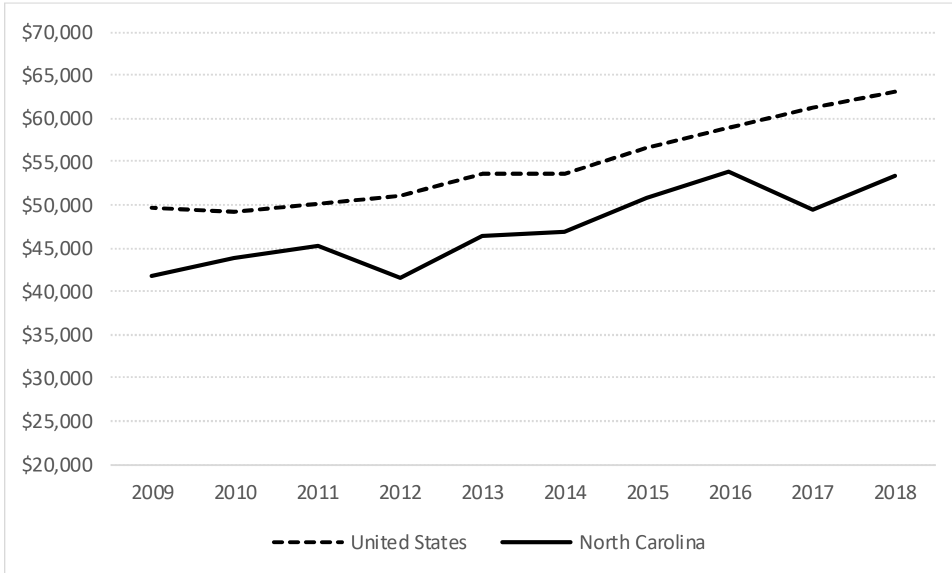
79 Source: Bureau of Economic Analysis.

80 Source: https://meric.mo.gov/data/cost-living-data-series accessed September 18, 2019.

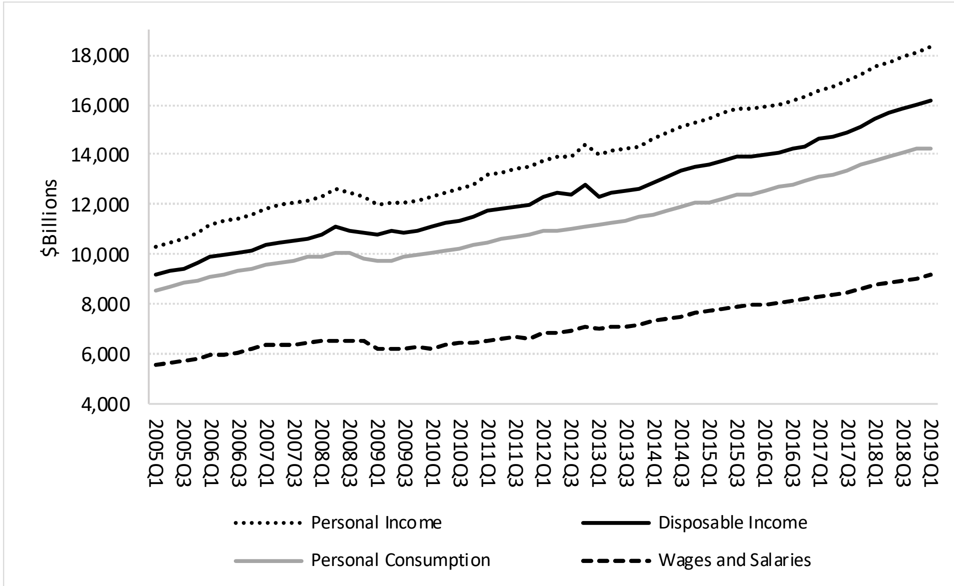
Chart 6: Median Household Income[81]



Similarly, as shown in Chart 7, below, since 2009 total personal income, disposable income, personal consumption, and wages and salaries have generally been on an increasing trend at the national level.

[81] Source: U.S. Census Bureau, Current Population Survey.

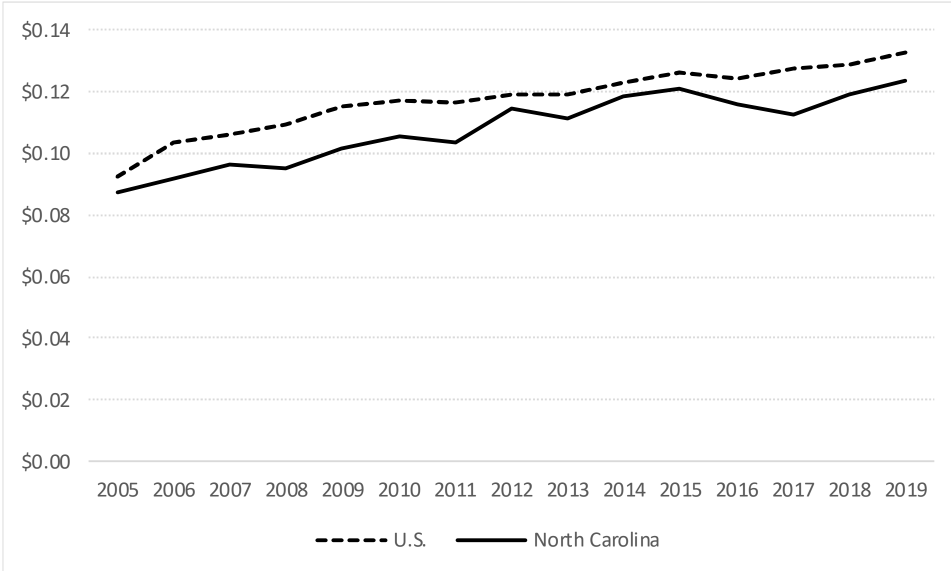
Chart 7: United States Income and Consumption[82]



Since 2005, residential electricity costs (measured in cents/kWh) in North Carolina remained approximately 8.28 percent below the national average. Even looking to the years 2012 through 2019, residential rates in North Carolina have been (on average) approximately 6.53 percent below the national average (*see* Chart 8, below). Over the longer period, residential rates remained highly correlated with the national average (approximately 95.40 percent).

[82] Source: Bureau of Economic Analysis.

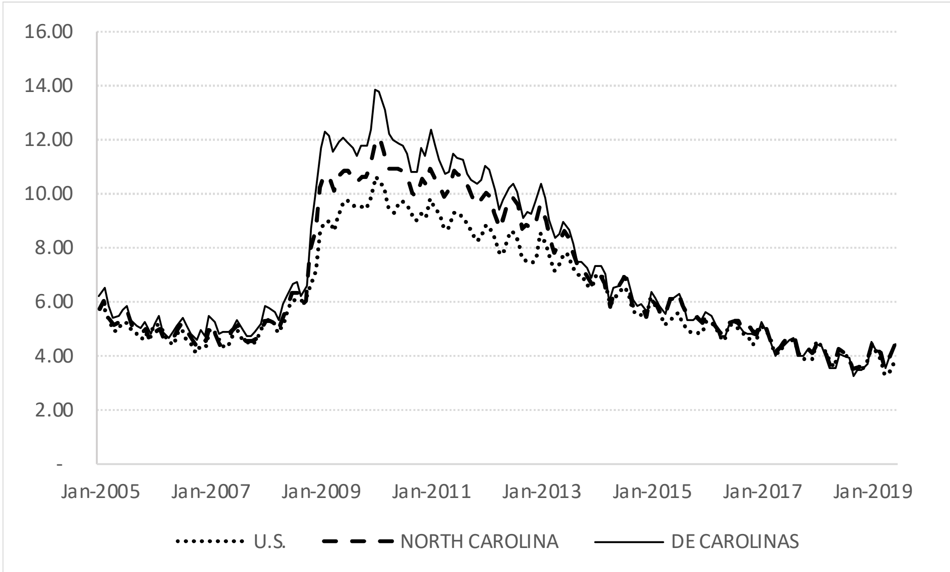
Chart 8: Residential Electricity Rates ($/kWh)[83]



Lastly, I reviewed (seasonally unadjusted) unemployment rates in the counties served by DE Carolinas. At its peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 13.80 percent (1.80 percentage points higher than the state-wide average); by June 2019 it had fallen to 4.41 percent (approximately equal to the state-wide average). Since the Company's last rate filing in August 2017, the counties' unemployment has fallen by 0.22 percentage points. From 2005 through 2019, the correlation in unemployment rates between the counties served by DE Carolinas, and the U.S. and North Carolina, respectively, were approximately 99.00 percent and 99.70 percent. In summary, county-level unemployment has fallen considerably since its peak in early 2010 and now is approximately equal to the state average.

[83] Source: Energy Information Administration. As of April, each year.

Chart 9: Seasonally Unadjusted Unemployment Rates[84]



Based on the data presented above, I observe the following:

- North Carolina's unemployment rate has fallen by two-thirds since its peak in the 2009-2010 period; as of June 2019, it stood at 4.20 percent (seasonally adjusted). Although the current rate is slightly higher than the national average, it fell by 7.20 percentage points from its peak, whereas the national average rate fell by 6.30 percentage points.
- The unemployment rate in the counties served by DE Carolinas now is approximately equal to the state-wide average, and has fallen considerably since its peak in early 2010.[85]
- The State's Gross Domestic Product remains highly correlated with national GDP.

84 Source: Bureau of Labor Statistics, St. Louis Federal Reserve.
85 Seasonally unadjusted. Source: Bureau of Labor Statistics, St. Louis Federal Reserve.

- Similarly, since 2005, median household income has grown in North Carolina and has grown at a rate consistent with the national average. Additionally, the overall cost of living in North Carolina also is below the national average. Furthermore, at the national level, income has generally been increasing since the financial crisis.
- Residential electricity rates have been approximately 8.28 percent below the national average over the last fifteen years.

Q. HOW WOULD YOU SUMMARIZE THE ECONOMIC INDICATORS THAT YOU HAVE ANALYZED AND DISCUSSED IN YOUR TESTIMONY?

A. Based on the indicators discussed above, it is my opinion that North Carolina, and the counties contained within DE Carolinas' service area, continue to steadily emerge from the economic downturn that prevailed during 2009-2010, and have experienced significant economic improvement during the last several years. As also discussed above, that improvement is projected to continue.

Q. IN YOUR OPINION, IS AN ROE OF 10.50 PERCENT FAIR AND REASONABLE TO DE CAROLINAS, ITS SHAREHOLDERS, AND ITS CUSTOMERS, AND NOT UNDULY BURDENSOME TO DE CAROLINAS CUSTOMERS CONSIDERING THE IMPACT OF THESE CHANGING ECONOMIC CONDITIONS?

A. Yes. Based on the factors I have discussed here, I believe that an ROE of 10.50 percent is fair and reasonable to DE Carolinas, its shareholders, and its customers in light of the effect of those changing economic conditions.

VI. CAPITAL MARKET ENVIRONMENT

Q. DO ECONOMIC CONDITIONS INFLUENCE THE REQUIRED COST OF CAPITAL AND REQUIRED RETURN ON COMMON EQUITY?

A. Yes. As discussed in Appendix A, the models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. Therefore, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent a given model's assumptions are misaligned with such data, or its results are inconsistent with basic financial principles, it is important to consider whether other methods likely provide more meaningful and reliable results.

Q. DOES YOUR RECOMMENDATION CONSIDER THE CAPITAL MARKET ENVIRONMENT?

A. Yes. It does. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst, and the capital market environment in which the analyses were undertaken.

Q. HAS MARKET VOLATILITY INCREASED IN RECENT MONTHS?

A. Yes. It has. A visible and widely reported measure of expected volatility is the Cboe Options Exchange ("Cboe") Volatility Index, often referred to as the VIX. As Cboe explains, the VIX is a calculation designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-time, mid-quote prices of S&P 500® Index call and put options.[86] Simply, the VIX is a market-based measure of expected volatility. Because volatility is a measure of risk, increases in the VIX, or in its volatility, are a broad indicator of expected increases in market risk.

Although the VIX is not expressed as a percentage, it should be understood as such. That is, if the VIX stood at 15.00, it would be interpreted as an expected standard deviation in annual market returns of 15.00 percent over the coming 30 days. Since 2000, the VIX has averaged about 19.22, which is highly consistent with the long-term standard deviation on annual market returns (19.80 percent, as reported by Duff & Phelps).[87]

Table 5, below, demonstrates the increase in market uncertainty from 2017 to 2019. As that table notes, the standard deviation (that is, the volatility of volatility) from 2018 through 2019 is about 3.25 times higher than its 2017 level (1.36).

86 Source: www.cboe.com/vix.
87 Source: Duff & Phelps, 2019 SBBI Yearbook, at 6-17.

Table 5: VIX Levels and Volatility[88]

Long-Term Average	19.22
2018-2019 Average	16.37
2018-2019 Maximum	37.32
2018-2019 Minimum	9.15
2018-2019 Standard Deviation	4.41
2017 Average	11.09
2017 Maximum	16.04
2017 Minimum	9.14
2017 Standard Deviation	1.36

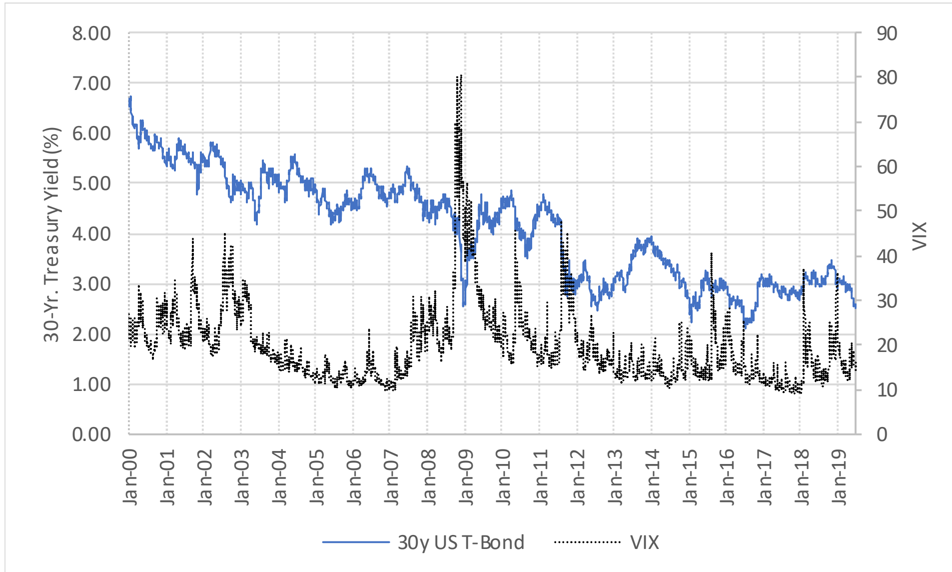
The increase in volatility is not surprising as market participants reassess the Federal Reserve's long-term objective of monetary policy normalization, and the increasing risks associated with federal trade policy initiatives.

Q. IS THERE A RELATIONSHIP BETWEEN EQUITY MARKET VOLATILITY AND INTEREST RATES?

A. Yes. There is. Significant and abrupt increases in volatility tend to be associated with declines in Treasury yields. That relationship makes intuitive sense; as investors see increasing risk their objectives may shift principally to capital preservation (that is, avoiding a capital loss). A means of doing so is to allocate capital to the relative safety of Treasury securities, in a "flight to safety." Because Treasury yields are inversely related to Treasury bond prices, as investors bid up the prices of bonds, they bid down the yields (see Chart 10, below, showing decreases in the 30-year Treasury yield coincident with significant increases in the VIX).

88 Source: Yahoo! Finance.

Chart 10: 30-Year Treasury Yields vs. VIX[89]



In those instances, the fall in yields does not reflect a reduction in required returns, it reflects an increase in risk aversion and, therefore, an increase in required equity returns.

Q. IS MARKET VOLATILITY EXPECTED TO INCREASE FROM ITS CURRENT LEVELS?

A. Yes. It is. One means of assessing market expectations regarding the future level of volatility is to review Cboe's "Term Structure of Volatility." As Cboe points out:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of

[89] Source: S&P Global Market Intelligence, Yahoo! Finance.

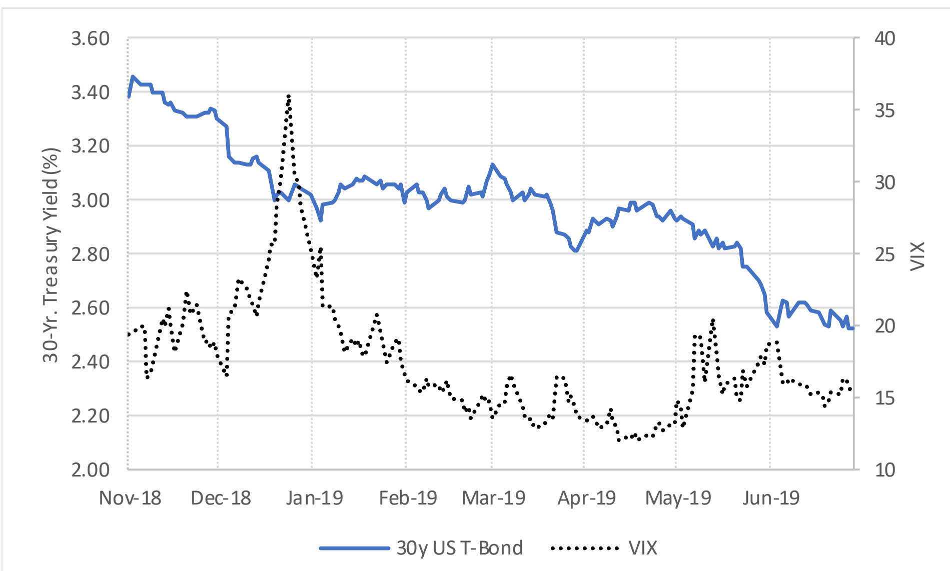
the SPX implied volatility term structure.[90]

Cboe's term structure data is upward sloping, indicating market expectations of increasing volatility. The expected VIX value in December 2020 is about 20.29, suggesting investors see a reversion to long-term average volatility over the coming months.[91]

Q. HAVE RECENT DECLINES IN THE TREASURY YIELD BEEN ASSOCIATED WITH INCREASES IN MARKET VOLATILITY?

A. Yes. They have. Since November 2018, the periods during which Treasury yields fell coincided with increases in the VIX (*see* Chart 11, below).

Chart 11: 30-Year Treasury Yields vs. VIX (11/18 – 6/19)[92]



[90] Source: www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

[91] Source: www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, accessed August 30, 2019.

[92] Source: S&P Global Market Intelligence, Yahoo! Finance.

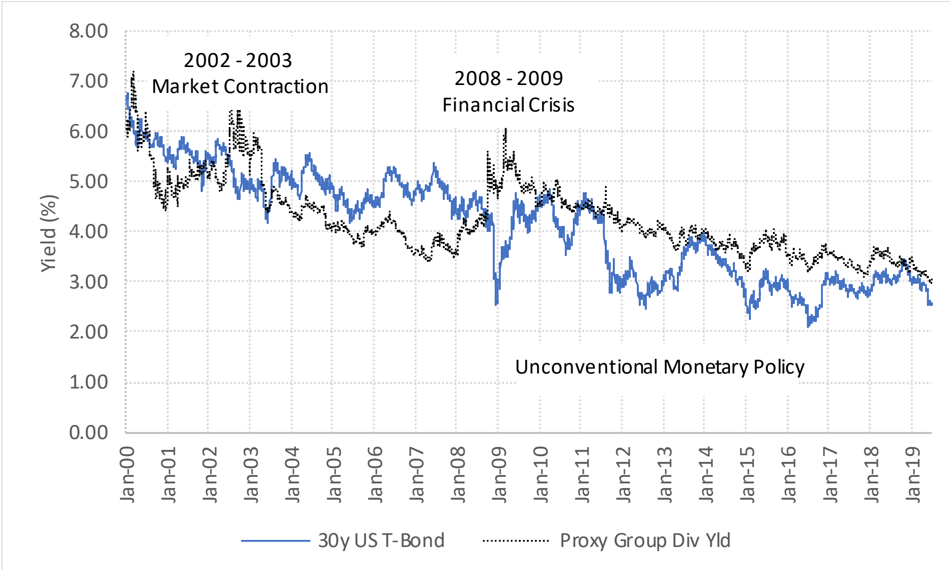
Q. WHAT CONCLUSIONS DO YOU DRAW FROM THOSE ANALYSES?

A. It is important to consider whether changes in long-term interest rates reflect fundamental changes in investor sentiment, or whether they reflect potentially transitory factors. The recent, sudden decline in interest rates appears to be related to the increase in equity market volatility, which may be event-driven rather than a fundamental change. Because the methods used to estimate the Cost of Equity are forward-looking it is important to consider those distinctions in assessing model results.

Q. HAVE UTILITY DIVIDEND YIELDS CLOSELY FOLLOWED LONG-TERM TREASURY YIELDS?

A. Although they have been directionally related over time, the fundamental relationship between Treasury yields and utility dividend yields changed after the 2008/2009 financial crisis. From 2000 through 2008, Treasury yields generally exceeded dividend yields; the exception was the 2002-2003 market contraction. Then, as in 2008-2009, investors sought the safety of Treasury securities, accepting lower yields in exchange for a greater likelihood of capital preservation. Once the contraction ended (in latter half of 2003), the relationship was restored, and Treasury yields again exceeded dividend yields (*see* Chart 12, below).

Chart 12: Utility Dividend Yields and 30-Year Treasury Yields[93]



In the 2008/2009 financial crisis, Treasury bond prices increased (yields decreased), and utility stock prices decreased (dividend yields increased) such that the prior relationship inverted. As the Federal Reserve implemented and maintained "unconventional" monetary policies in reaction to the financial crisis (i.e., Quantitative Easing) with the intended consequence of lowering long-term interest rates, the now-inverted relationship between Treasury yields and utility dividend yields persisted.

Even though the "yield spread"[94] became inverted after the financial crisis, it has not been static. That is, as Treasury yields fell in response to central bank policies, dividend yields did not fall to the same degree; the yield spread widened (*see* Chart 12, above). That data suggests that, although utility prices

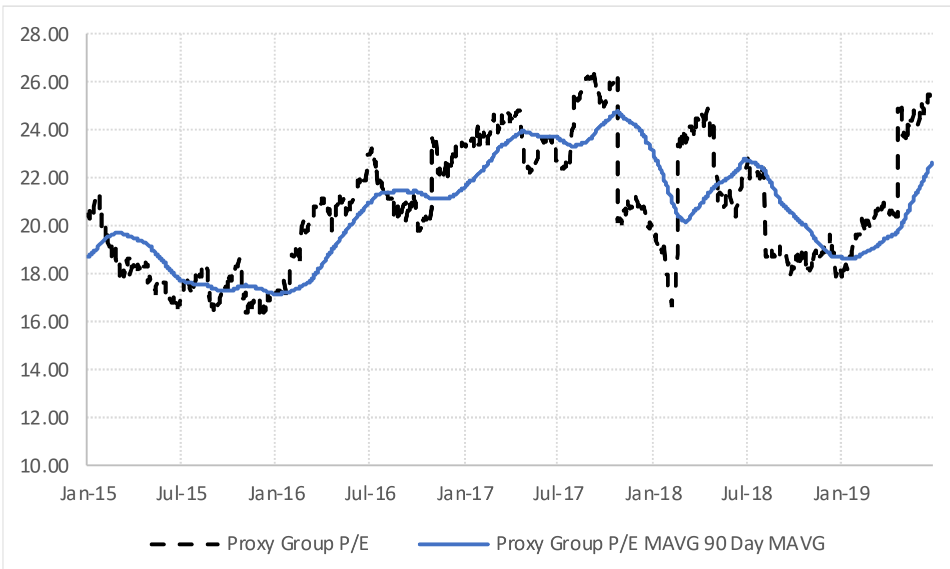
[93] Source: S&P Global Market Intelligence.
[94] Defined here as dividend yields less Treasury yields.

are sensitive to long-term Treasury yields, the relationship is not unbounded.

Q. IS THAT RELATIONSHIP ALSO SEEN IN UTILITY PRICE/EARNINGS RATIOS?

A. Yes. It is. Looking to the period following the Federal Reserve's Quantitative Easing policy, the proxy group's P/E ratio has varied, often reverting once it has largely breached its 90-day moving average.

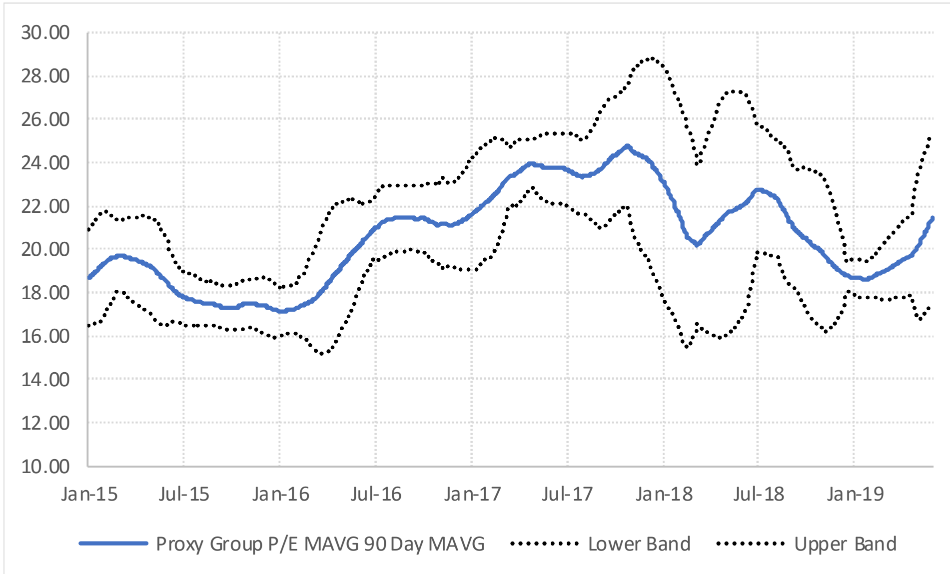
Chart 13: Proxy Group Average Price/Earnings Ratio[95]



From a somewhat different perspective, the proxy group's P/E ratio has traded within a two-standard deviation range, although that range recently has widened, indicating increasing variability in the group's valuation.

95 Calculated as an index. Source: S&P Global Market Intelligence.

Chart 14: Proxy Group Average P/E Ratio Bands[96]



That data supports the conclusion discussed earlier, that utility stock prices are sensitive to changes in interest rates, but only to a degree. The "reach for yield" that sometimes occurs when interest rates fall has a limit; investors will not accept the incremental risk of capital losses when utility valuation levels become "stretched". That also may be the case when investors see interest rates reacting to market volatility that is event-driven, rather than a fundamental change in the capital market environment or investor risk tolerances. The increasing variability can be seen in Chart 14 (above), when the bands around the 90-day moving average P/E ratios widen. During those periods, the risk of capital loss increases, implying a further limit on valuation levels.

96 Calculated as an index. Source: S&P Global Market Intelligence. Bands represent two standard deviations calculated over 90 days.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR ANALYSES OF THE CURRENT CAPITAL MARKET ENVIRONMENT, AND HOW DO THOSE CONCLUSIONS AFFECT YOUR ROE RECOMMENDATION?

A. Because certain models used to estimate the Cost of Equity require long-term assumptions, it is important to understand whether those assumptions hold. The current market environment is one in which changes in interest rates likely are associated with events, more than they are a function of fundamental economic conditions. Further, utility valuations have a limit, even when investors look to them for an alternate source of income as interest rates fall.

On balance, it remains important to consider changes in market conditions, the likely causes of those changes, and how model results are affected by them. Those assessments necessarily involve the application of reasoned and experienced judgment. As discussed throughout my testimony, that judgment supports my recommended range of 10.00 percent to 11.00 percent.

VII. CONCLUSION

Q. WHAT IS YOUR CONCLUSION REGARDING THE ROE FOR DE CAROLINAS?

A. As discussed throughout my testimony, it is important to consider a variety of empirical and qualitative information in reviewing analytical results and arriving at ROE determinations. As a practical matter, the Constant Growth DCF results are well below a highly observable and relevant benchmark, *i.e.*, the returns authorized for vertically integrated electric utilities. A more balanced approach therefore would be to consider the relative strengths and weaknesses of multiple methods, and give the appropriate weight to their results.

Based on that review, I believe that an ROE in the range of 10.00 percent to 11.00 percent represents the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets. Within that range, I conclude that an ROE of 10.50 percent represents the Cost of Equity for DE Carolinas. That conclusion considers the cost associated with issuing common stock and the current capital market environment, as well as DE Carolinas' risk profile relative to the proxy group analytical results with respect to (1) the risks associated with certain aspects of the Company's generation portfolio and (2) the Company's significant capital expenditure plan. In light of those factors, it is appropriate to establish an ROE that is above the proxy group mean results. As such, an ROE of 10.50 percent reasonably represents the return required to invest in a company with a risk profile comparable to DE Carolinas.

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

A. Yes. It does.

VIII. APPENDIX A

A. Constant Growth DCF Model

Q. PLEASE DESCRIBE THE CONSTANT GROWTH DCF APPROACH.

A. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_t}{(1+k)^t} \quad [4]$$

where P_0 represents the current stock price, $D_1 \ldots D_t$ represent expected future dividends, and k is the discount rate, or required ROE. Equation [4] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad [5]$$

Equation [5] often is referred to as the "Constant Growth DCF" model, in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. WHAT ASSUMPTIONS ARE REQUIRED FOR THE CONSTANT GROWTH DCF MODEL?

A. The Constant Growth DCF model assumes: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) the dividend payout ratio remains constant; (3) the Price to Earnings ("P/E") multiple remains constant in perpetuity; and (4) the discount rate is greater than the expected growth rate, and remains constant over time.

Q. WHAT MARKET DATA DID YOU USE TO CALCULATE THE DIVIDEND YIELD IN YOUR DCF MODEL?

A. The dividend yield is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading day periods as of June 28, 2019.

Q. WHY DID YOU USE THREE AVERAGING PERIODS TO CALCULATE AN AVERAGE STOCK PRICE?

A. I did so to ensure the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term. In my view, using 30-, 90-, and 180-trading day averaging periods reasonably balances those concerns.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A. Yes. I did. Because utilities tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield.[97]

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[97] Exhibit RBH-1.

That adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the dividends to be paid during that time.

Q. IS IT IMPORTANT TO SELECT APPROPRIATE MEASURES OF LONG-TERM GROWTH IN APPLYING THE DCF MODEL?

A. Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [5] above) assumes a single growth estimate in perpetuity. Accordingly, to reduce the long-term growth rate to a single measure, we must assume a fixed payout ratio, and the same constant growth rate for earnings per share ("EPS"), dividends per share, and book value per share. Because dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth. That can be accomplished by averaging measures of long-term growth that tend to be least influenced by capital allocation decisions companies may make in response to near-term changes in the business environment. Because such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend growth estimates. For the purposes of the Constant Growth DCF model, therefore, growth in EPS represents the appropriate measure of long-term growth.

Q. PLEASE SUMMARIZE THE FINDINGS OF ACADEMIC RESEARCH ON THE APPROPRIATE MEASURE FOR ESTIMATING EQUITY RETURNS USING THE DCF MODEL.

A. The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[98] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[99]

Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[100] For example, Vander Weide and Carleton state that "[our] results … are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[101] Other research specifically notes the importance of

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98 *See*, Harris, Robert, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

99 Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. ed. 1969).

100 *See, e.g.*, Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

101 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988). The Vander Weide and Carleton study was updated in 2004 under the direction of Dr. Vander Weide. The results of the updated study were consistent with the original study's conclusions.

analysts' growth estimates in determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices."[102] Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[103] Similarly, Brigham, Shome, and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts."[104]

To that point, the research of Carleton and Vander Weide demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[105] Those findings suggest investors form their investment decisions based on expectations of growth in earnings, not dividends. Consequently, earnings growth, not dividend growth, is the appropriate estimate for the purpose of the Constant Growth DCF model.

102 Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986) at 59.

103 *Ibid*.

104 Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management (Spring 1985) at 36.

105 *See,* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

Q. PLEASE SUMMARIZE YOUR INPUTS TO THE CONSTANT GROWTH DCF MODEL.

A. I applied the DCF model to the proxy group of electric utility companies using the following inputs for the price and dividend terms:

- The average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days ended June 28, 2019 for the term P_0; and
- The annualized dividend per share as of June 28, 2019 for the term D_0.

I then calculated the DCF results using each of the following growth terms:

- Zack's consensus long-term earnings growth estimates;
- First Call consensus long-term earnings growth estimates; and
- Value Line earnings growth estimates.

Q. HOW DID YOU CALCULATE THE DCF MODEL RESULTS?

A. For each proxy company, I calculated the mean, mean high, and mean low results. For the mean result, I combined the average of the EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. I calculated the high DCF result by combining the maximum EPS growth rate estimate as reported by Value Line, Zacks, and First Call with the subject company's dividend yield. The mean high result simply is the average of those estimates. I used the same approach to calculate the low DCF result, using instead the minimum of the Value Line, Zacks, and First Call estimate for each proxy company, and calculating the average result for those estimates.

Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSES?

A. The Constant Growth DCF results are summarized in Table 6 below (*see also* Exhibit DWD-1).

Table 6: Constant Growth DCF Results

	Mean Low	Mean	Mean High
30-Day Average	8.03%	8.86%	9.73%
90-Day Average	8.12%	8.95%	9.82%
180-Day Average	8.26%	9.09%	9.96%

Q. DO YOU BELIEVE THAT THE CONSTANT GROWTH DCF MODEL CURRENTLY PROVIDES A REASONABLE ESTIMATE OF THE COMPANY'S COST OF EQUITY?

A. No. I do not. The Constant Growth DCF model is predicated on a number of assumptions, one of which is that the Price/Earnings ratio will remain constant, in perpetuity. Because utility sector P/E ratios have expanded to the point that they recently have exceeded both their long-term average and the market P/E ratio, the Constant Growth DCF model's results should be viewed with caution. As a practical matter, as shown in Chart 1 above, the mean Constant Growth DCF results are below a highly observable and relevant benchmark – the returns authorized for electric utilities.[106] As such, it is more appropriate to consider multiple methods in current market conditions, such as Risk-Premium based

106 The average authorized ROE for vertically-integrated electric utilities since January 2015 is 9.74 percent. Excludes limited issue rider proceedings.

methods and the Expected Earnings approach.

Regardless of the method employed, however, an authorized ROE that is well below returns authorized for other utilities: (1) runs counter to the *Hope* and *Bluefield* "comparable risk" standard, (2) would place the Company at a competitive disadvantage, and (3) would make it difficult for the Company to compete for capital at reasonable terms.

Q. PLEASE SUMMARIZE THE REASONS YOU BELIEVE THE CONSTANT GROWTH DCF MODEL SHOULD NOT BE GIVEN UNDUE WEIGHT IN THIS PROCEEDING.

A. As explained earlier, the model assumes that the return estimated today will be the same return required in the future, even though the Federal Reserve only recently has completed the principal initiatives of its monetary policy normalization and is continuing to assess realized and expected economic conditions as it determines future adjustments,[107] introducing a degree of uncertainty regarding future monetary policy actions. As also discussed later in my Direct Testimony, other methods more directly reflect the risk premium required by investors in response to market and industry risks. On balance, it is my view that the Constant Growth DCF method should be given less weight than other methods in establishing the Company's ROE.

[107] *Federal Reserve FOMC statement*, September 18, 2019.

Q. WITH THOSE POINTS IN MIND, HOW DID YOU REFLECT THE CONSTANT GROWTH DCF RESULTS IN YOUR ROE RANGE AND RECOMMENDATION?

A. I first recognized that the model's mean low results are well below a reasonable estimate of the Company's Cost of Equity. For example, of the 1,593 electric utility rate cases provided by Regulatory Research Associates that disclosed the awarded ROE since 1980, only eleven included an authorized ROE below 9.00 percent.[108] On that basis alone, the mean low results are highly improbable.

I then considered why the Constant Growth model is producing such low estimates of the Company's Cost of Equity. In one sense, relatively low dividend yields should be associated with relatively high growth rates. That is, low dividend yields are the result of relatively high stock prices which, in turn, should be associated with relatively high growth rates. If those relationships do not hold, the model's results should be viewed with some caution.

I also recognize that, whereas the Constant Growth DCF model assumes existing capital market conditions will remain constant, Risk Premium-based methods (discussed later in this Appendix) directly reflect the changing capital market environment (*see* Section VI). Because it is important to reflect the results of different models, and the mean low Constant Growth DCF results are

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108 Source: Regulatory Research Associates. Eight of those eleven were the outcome of Illinois formula rate plans. Excluding Illinois formula rate plans, since 2015, only two electric utility rate cases included an authorized ROE below 9.00 percent, and only one of those two was for a vertically integrated electric utility.

far-removed from recently authorized returns, I concluded that they should be given less weight than other methods in determining the Company's ROE.

B. CAPM Analyses

Q. PLEASE BRIEFLY DESCRIBE THE GENERAL FORM OF THE CAPM.

A. The CAPM is a risk premium method that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [6], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [6]$$

where:

K_e = the required market ROE for a security;

β = Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market, as a whole.

In Equation [6], the term (r_m – r_f) represents the Market Risk Premium.[109] According to the theory underlying the CAPM, because unsystematic risk can be diversified away by adding securities to investment portfolios, investors should be concerned only with systematic or non-

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109 The Market Risk Premium is defined as the incremental return of the market portfolio over the risk-free rate.

diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} x \, \rho_{j,m} \quad [7]$$

where:

σ_j = the standard deviation of returns for company "j,"

σ_m = the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and

$\rho_{j,m}$ = the correlation of returns in between company j and the broad market.

The Beta coefficient therefore represents both relative volatility (*i.e.*, the standard deviation) of returns and the correlation in returns between the subject company and the overall market. Intuitively, Beta coefficients approaching unity indicate the subject company's returns have moved in tandem with the overall market.

Q. WHAT ASSUMPTIONS DID YOU INCLUDE IN YOUR CAPM ANALYSIS?

A. Because utility equity is a long duration investment, I used two different measures of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 2.63 percent);[110] and (2) the near-term projected 30-year

[110] Bloomberg Professional.

Treasury yield (*i.e.*, 2.70 percent).[111]

Q. WHY HAVE YOU RELIED ON THE 30-YEAR TREASURY YIELD FOR YOUR CAPM ANALYSIS?

A. In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. As noted above, electric utilities typically are long-duration investments and, as such, the 30-year Treasury yield is more suitable for the purpose of calculating the Cost of Equity.

Q. PLEASE DESCRIBE YOUR *EX-ANTE* APPROACH TO ESTIMATING THE MARKET RISK PREMIUM.

A. The approach is based on the market-required return, less the current 30-year Treasury yield. To estimate the market required return, I calculated the market capitalization weighted average ROE based on the Constant Growth DCF model. To do so, I relied on data from two sources: (1) Bloomberg; and (2) Value Line.[112] With respect to Bloomberg-derived growth estimates, I calculated the expected dividend yield (using the same one-half growth rate assumption described earlier), and combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the companies for which

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[111] Blue Chip Financial Forecasts, Vol. 38, No. 7, July 1, 2019, at 2. Consensus projections of the 30-year Treasury yield for the six quarters ending December 2020.

[112] Exhibit RBH-2.

Bloomberg provided both dividend yields and consensus growth rates. I then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived *ex-ante* market risk premium estimate. In the case of Value Line, I performed the same calculation, again using all companies for which five-year earnings growth rates were available. The results of those calculations are provided in Exhibit DWD-2.

Q. HOW DID YOU APPLY YOUR EXPECTED MARKET RISK PREMIUM AND RISK-FREE RATE ESTIMATES?

A. I relied on the *ex-ante* Market Risk Premia discussed above, together with the current and near-term projected 30-year Treasury yields as inputs to my CAPM analysis.

Q. HOW DID YOU APPLY YOUR EXPECTED MARKET RISK PREMIUM AND RISK-FREE RATE ESTIMATES?

A. As shown in Exhibit DWD-3, I considered the Beta coefficients reported by Value Line and Bloomberg, both of which adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00. A notable difference between the two is that Value Line calculates the Beta coefficient over a five-year period, whereas Bloomberg's calculation is based on two years of data.

Q. HOW DID YOU APPLY YOUR EXPECTED MARKET RISK PREMIUM AND RISK-FREE RATE ESTIMATES?

A. As shown in Table 7 (below) the CAPM analyses suggest an ROE range of 8.68 percent to 9.81 percent (*see also* Exhibit DWD-4).

Table 7: Summary of CAPM Results[113]

	Bloomberg Derived Market Risk Premium	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	8.73%	8.68%
Near-Term Projected 30-Year Treasury (2.70%)	8.80%	8.75%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	9.74%	9.69%
Near-Term Projected 30-Year Treasury (2.70%)	9.81%	9.75%

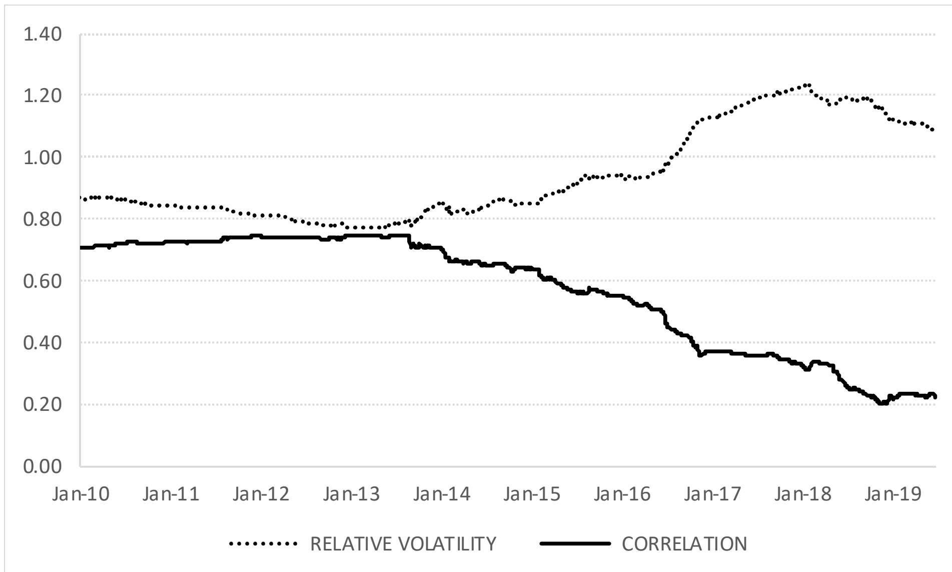
Q. DOES THE RECENT DECLINE IN THE PROXY GROUP AVERAGE BETA COEFFICIENT IMPLY A DECREASE IN RISK RELATIVE TO THE MARKET?

A. Not necessarily. Although the proxy group average Beta coefficient reported by Bloomberg has fallen from approximately 0.76 in 2014 to 0.50 in June 2019, as Chart 15 below demonstrates, when the Beta coefficient is deconstructed into its components shown in Equation [7] above, we see that the correlation between the proxy group companies and the S&P 500 has declined, while the relative risk has increased. Given that the correlation between the proxy group

[113] Exhibit RBH-4.

companies and the S&P 500 has declined since 2014, while the relative risk has increased, the CAPM in the form presented here may not adequately reflect the expected systematic risk, and therefore, the returns required by investors in low-Beta coefficient companies such as utilities.

Chart 15: Components of Beta Coefficients Over Time[114]



Q. DID YOU CONSIDER ANOTHER FORM OF THE CAPM IN YOUR ANALYSIS?

A. Yes. I also included the ECAPM approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium, and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient.[115] The results of the two calculations are summed, along with the risk-free rate, to

[114] Source: S&P Global Market Intelligence. Calculated as an index.
[115] *See e.g.*, Roger A. Morin, *New Regulatory Finance* 189-90 (2006).

produce the ECAPM result, as noted in Equation [8] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [8]$$

where:

k_e = the required market ROE.

β = Adjusted Beta coefficient of an individual security.

r_f = the risk-free rate of return.

r_m = the required return on the market as a whole.

Q. WHAT IS THE BENEFIT OF THE ECAPM APPROACH?

A. The ECAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients. As discussed below, the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.[116]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the

[116] *Ibid.*, at 191 ("The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks.").

predicted SML.[117] Fama and French state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[118] Similarly, Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. . . .
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x(R_M - R_F) + (1\text{-}x)\ \beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [119]

Some analysts claim that using adjusted Beta coefficients addresses the empirical issues with the CAPM by increasing the expected returns for low Beta coefficient stocks and decreasing the returns for high Beta coefficient stocks, concluding that there is no need for the ECAPM approach. I disagree with that conclusion. Beta coefficients are adjusted because of their general regression

117 *Ibid*. at 175. The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

118 Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

119 Roger A. Morin, *New Regulatory Finance* 175, 190 (2006).

tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the SML described by the CAPM formula is not as steeply sloped as the predicted SML. To that point, Morin states:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. [120]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM. As with the CAPM, my application of the ECAPM uses the Market DCF-derived *ex-ante* Market Risk Premium estimate, the current yield on 30-year Treasury securities as the risk-free rate, and two estimates of the Beta coefficient. The results of my ECAPM analyses are shown

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[120] *Ibid.*, at 191.

in Exhibit DWD-4 and summarized in Table 8 below.

Table 8: Summary of ECAPM Results[121]

	Bloomberg Derived Market Risk Premium	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.63%)	10.27%	10.21%
Near-Term Projected 30-Year Treasury (2.70%)	10.34%	10.28%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.63%)	11.03%	10.96%
Near-Term Projected 30-Year Treasury (2.70%)	11.10%	11.03%

C. Bond Yield Plus Risk Premium Analysis

Q. PLEASE DESCRIBE THE BOND YIELD PLUS RISK PREMIUM APPROACH.

A. This approach is based on the basic financial tenet that equity investors bear the residual risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have more risk than returns to bondholders, equity investors must be compensated for bearing that additional risk. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a given class of bonds. Since the Equity Risk Premium is not directly observable, it typically is estimated using a variety of approaches, some

121 Exhibit RBH-4.

of which incorporate *ex-ante*, or forward-looking estimates of the Cost of Equity, and others that consider historical, or *ex-post*, estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the Equity Risk Premium.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. As suggested above, I first defined the Equity Risk Premium as the difference between the authorized ROE and the then-prevailing level of the long-term (*i.e.*, 30-year) Treasury yield. I therefore gathered data for the ROE authorized in 1,593 electric utility rate proceedings between January 1980 and June 28, 2019. In addition to the authorized ROE, I also calculated the average period between the filing of the case and the date of the final order (the "lag period"). To reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average lag period (approximately 200 days).[122]

Because the data covers multiple economic cycles,[123] the analysis also may be used to assess the stability of the Equity Risk Premium. For example, prior research has shown that the Equity Risk Premium is inversely related to

[122] Regulatory proceedings frequently retroactively apply the newly authorized ROE to a period preceding the decision date.

[123] *See,* National Bureau of Economic Research, *U.S. Business Cycle Expansions and Contractions*.

the level of interest rates.[124] That analysis is particularly relevant given the relatively low level of current Treasury yields.

Q. HOW DID YOU ANALYZE THE RELATIONSHIP BETWEEN INTEREST RATES AND THE EQUITY RISK PREMIUM?

A. The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Relative to the long-term historical average, the analytical period includes interest rates and authorized ROEs that are quite high during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the post-Lehman bankruptcy period). To account for that variability, I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$\text{RP} = \alpha + \beta(LN(T_{30})) \quad [9]$$

As shown on Chart 16 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

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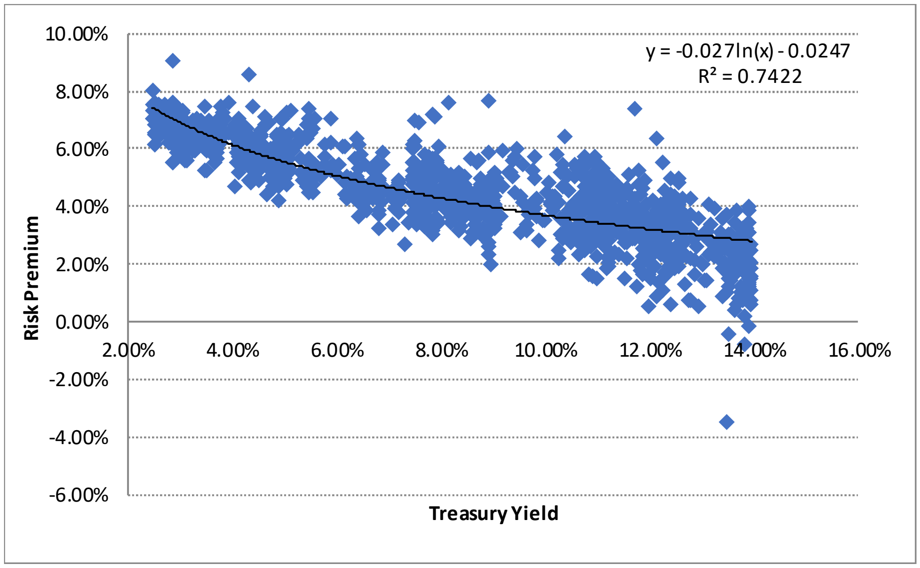
[124] *See, for example*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, (Spring 1985), at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, (Autumn 1995), at 89-95.

Chart 16: Equity Risk Premium[125]



As Chart 16 illustrates, over time there has been a statistically significant, negative (*i.e.*, inverse) relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.68 percent would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in Chart 16, however, the implied ROE is between 9.90 percent and 10.06 percent (*see* Table 9 and Exhibit DWD-5).

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125 Exhibit RBH-5.

Table 9: Summary of Bond Yield Plus Risk Premium Results

	Return on Equity
Current 30-Year Treasury (2.63%)	9.90%
Near-Term Projected 30-Year Treasury (2.70%)	9.90%
Long-Term Projected 30-Year Treasury (3.70%)	10.06%

D. Expected Earnings

Q. PLEASE DESCRIBE THE EXPECTED EARNINGS ANALYSIS.

A. The Expected Earnings analysis is based on the principle of opportunity costs. Because investors may invest in and earn returns on alternative investments of similar risk, those rates of return can provide a useful benchmark in determining the appropriate rate of return for a firm. Further, because those results are based solely on the returns expected by investors, exclusive of market-data or models, the Expected Earnings approach provides a direct comparison.

Q. PLEASE EXPLAIN HOW THE EXPECTED EARNINGS ANALYSIS IS CONDUCTED.

A. The Expected Earnings analysis typically takes the actual earnings on book value of investment for each of the members of the proxy group and compares those values to the rate of return in question. Although the traditional approach uses data based on historical accounting records, it is common to use forecasted data in conducting the analysis. Projected returns on book investment are provided by various industry publications (*e.g.*, Value Line), which I have used in my analysis.

I relied on Value Line's projected Return on Common Equity for the period 2022-2024, and adjusted those projected returns to account for the fact that they reflect common shares outstanding at the end of the period, rather than the average shares outstanding over the course of the year.[126] The Expected Earnings analysis results in an average value of 10.44 percent and a median value of 10.54 percent (*see* Exhibit DWD-6).

[126] The rationale for that adjustment is straightforward: Earnings are achieved over the course of a year, and should be related to the equity that was, on average, in place during that year. *See,* Leopold A. Bernstein, Financial Statement Analysis: Theory, Application, and Interpretation, Irwin, 4th Ed., 1988, at 630.

Resume of:

Dylan W. D'Ascendis, CRRA, CVA
Director

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). He has served as a consultant for investor-owned and municipal utilities and authorities for 11 years. Dylan has extensive experience in rate of return analyses, class cost of service, rate design, and valuation for regulated public utilities. He has testified as an expert witness in the subjects of rate of return, cost of service, rate design, and valuation before 19 regulatory commissions in the U.S., one Canadian province, and an American Arbitration Association panel.

He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured.

Areas of Specialization

- Regulation and Rates
- Utilities
- Mutual Fund Benchmarking
- Capital Market Risk
- Financial Modeling
- Valuation
- Regulatory Strategy
- Rate Case Support
- Rate of Return
- Cost of Service
- Rate Design

Recent Expert Testimony Submission/Appearances

Jurisdiction	***Topic***
Massachusetts Department of Public Utilities	Rate of Return
New Jersey Board of Public Utilities	Rate of Return
Hawaii Public Utilities Commission	Cost of Service, Rate Design
South Carolina Public Service Commission	Return on Common Equity
American Arbitration Association	Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Publications and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020.
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319.
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA.
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013.
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN.

Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W01445A-18-0164	Rate of Return
Colorado Public Utilities Commission				
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Return on Equity
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Return on Equity
Delaware Public Service Commission				
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Hawaii Public Utilities Commission				
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	8/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy	07/19	Atmos Energy	19-ATMG-525-RTS	Rate of Return
Louisiana Public Service Commission				
Atmos Energy	04/2020	Atmos Energy	Docket No. U-35535	Rate of Return

Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maryland Public Service Commission				
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	Docket No. 15-75	Rate of Return
Mississippi Public Service Commission				
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Docket No. SR-2016-0202	Rate of Return
New Jersey Board of Public Utilities				
FirstEnergy	02/2020	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
North Carolina Utilities Commission				
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Docket No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return

Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
Virginia State Corporation Commission				
WGL Holdings, Inc.	7/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	5/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	7/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this rebuttal testimony ("Rebuttal Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Company, doing business in North Carolina as Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the direct testimony of the following Intervenor witnesses with respect to the Return on Equity ("ROE"):

- Dr. J. Randall Woolridge, who testifies on behalf of Public Staff ("Staff");
- Mr. Richard A. Baudino, who testifies on behalf of the North Carolina Attorney General's Office ("AG");
- Mr. Kevin W. O'Donnell, who testifies on behalf of the Carolina Utility Customers Association ("CUCA");
- Mr. Steve W. Chriss, who testifies on behalf of the Commercial Group ("Commercial Group");
- Mr. Nicholas Phillips, Jr., who testifies on behalf of Carolina Industrial Group for Fair Utility Rates ("CIGFUR");
- Mr. Kurt G. Strunk, who testifies on behalf of Apple, Inc., Facebook, Inc., and Google LLC (the "Tech Customers"); and
- Mr. Rory McIlmoil, who testifies on behalf of the Center for Biological Diversity and Appalachian Voices ("CBDAV").

I refer to these witnesses collectively as the "Opposing Witnesses" as their testimony relates to the Company's ROE and capital structure. My Rebuttal Testimony also updates many of the analyses contained in my Direct Testimony, and provides several additional analyses developed in response to the Opposing Witnesses.

II. SUMMARY AND CONCLUSIONS

Q. WHAT ARE YOUR SPECIFIC OBSERVATIONS REGARDING THE OPPOSING WITNESSES' RETURN ON EQUITY AND CAPITAL STRUCTURE RECOMMENDATIONS?

A. Quite simply, the Opposing Witnesses' recommendations are below any reasonable measure of the Company's Cost of Equity. As discussed throughout my Rebuttal Testimony, those recommendations are (1) far below those authorized for other utilities nationally and in North Carolina, (2) do not recognize the risks faced by DE Carolinas, and (3) do not appropriately reflect the evolving capital market environment.

Based on the analyses discussed in my Direct and Rebuttal Testimony, I continue to believe the Company faces risks that fully support my ROE recommendation. Looking to all model results, and considering the quantitative and qualitative data presented throughout my Rebuttal Testimony, I continue to recommend an ROE in the range of 10.00 percent to 11.00 percent, with a point estimate of 10.50 percent.

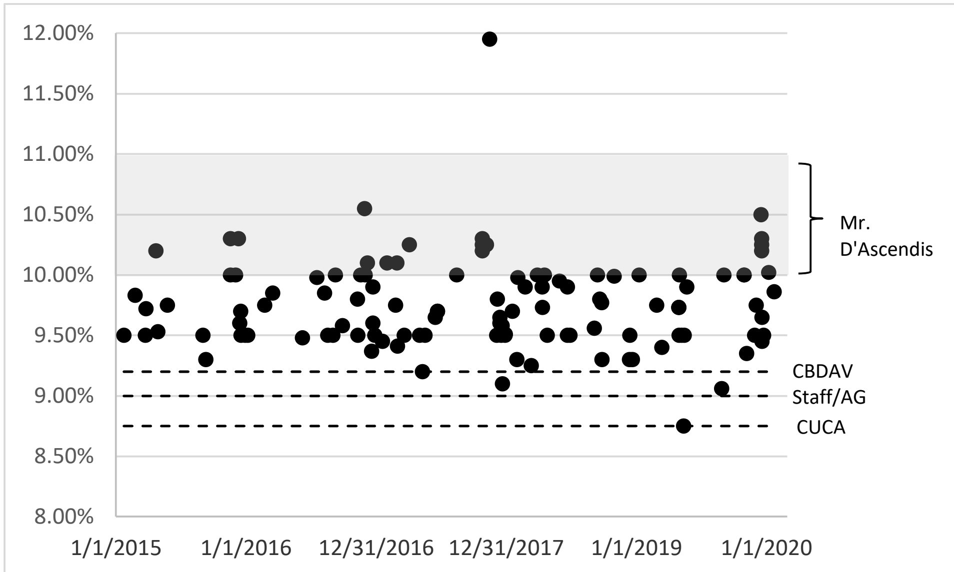
As to the Company's proposed capital structure, none of the Opposing Witnesses have explained why their proposals properly address the many and complicated financing objectives and constraints that operating utilities must manage. Rather, they inappropriately point to capital structures at the consolidated parent, without acknowledging the importance of matching the nature of utility assets and operations with the components of capital used to fund those assets. Further, although certain of the Opposing Witnesses suggest the Company should take on more financial risk to take advantage of debt costs that are lower than the Cost of Equity, they fail to acknowledge the costs and risks brought about by that increased financial risk. On balance, I believe the Opposing Witnesses' recommendations are overly simplistic, their analyses are partial, and their proposals should be rejected.

Q. PLEASE NOW PROVIDE AN OVERVIEW OF YOUR RESPONSE TO THE ROE RECOMMENDATIONS MADE BY THE OPPOSING WITNESSES.

A. Although the Opposing Witnesses believe their recommendations are reasonable and support the Company's financial integrity, nearly all authorized ROEs for vertically integrated electric utilities over the last five years have been above their recommendations (*see* Chart 1, below). Whereas the Opposing Witnesses' recommendations are far below those available to other utilities, my recommended range (10.00 percent to 11.00 percent), is within that range.[1]

[1] There have been 22 vertically integrated electric rate cases since January 1, 2017 in which the authorized ROE was 10.00 percent or greater. Of those, ten were authorized in 2019-2020. *See*, Rebuttal Exhibit DWD-8.

Chart 1: Vertically Integrated Electric Utility Authorized ROEs (2015 – 2020) and Witness Recommendations[2]



That significant departure from the returns available to other utilities raises two concerns. First, DE Carolinas must compete with other companies, including utilities, for the long-term capital needed to provide safe and reliable utility service. Given the choice between two similarly situated utilities, one with a return that falls far below industry averages and another with a return that more closely aligns with returns available to other utilities, investors will choose the latter. That is a particular concern for the Company, given its risk profile, its need to access external capital, and the implication of Staff's overall recommendation. If the Commission were to approve an ROE in the range recommended by the Opposing Witnesses, investors would receive a lower

[2] Source: Regulatory Research Associates ("RRA"). Authorized ROEs for vertically integrated electric utilities from January 1, 2015 through January 31, 2020. ROEs authorized for limited issue rate rider proceedings are excluded.

return with greater risk than would be available from other utilities. A likely outcome would be increasing reluctance on the part of investors to provide capital at reasonable costs and terms.

Second, although no regulatory commission sets returns solely by reference to those authorized elsewhere, authorized returns do provide observable and measurable benchmarks against which return recommendations may be assessed. In my experience, regulatory commissions generally consider the same types of market, methodological, and risk factors at issue in this proceeding. They recognize that financial models are important tools in determining returns and appreciate that because all models are subject to assumptions, no one method is most reliable at all times, and under all conditions.

As discussed throughout my Rebuttal Testimony, that holds true in this case. Even if we focus on a single method, it remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results. Just as investors consider company-specific and general market factors in developing their return requirements, we should do the same. Those considerations, and that judgment, lead to the conclusion that the Opposing Witnesses' ROE recommendations are unduly low.

Q. HAS THE COMMISSION NOTED THE RISKS SURROUNDING SETTING AN ROE THAT MAY BE TOO LOW?

A. Yes, it has. In its Order in Docket No. E-7, Sub 1026, the Commission clearly stated that it is well aware of the danger and repercussions of an ROE that is set unduly low. Citing to its Order in Docket No. E-2, Sub 1023, the Commission noted that:

> Moreover, the Commission in establishing a rate of return on equity and other cost of service determinations is mindful that should it set the rate of return on equity too low, the impact on long term rates may be harmful to ratepayers. The utilities the Commission regulates compete in a market to raise capital. Financial analysts, rating agencies, and investors themselves scrutinize with great care the regulatory environment and decisions in which these utilities operate. The regulatory environment includes the utilities commissions, consumer advocates, the state legislature, the executive branch and the appellate courts. When regulatory risk is high, the cost of capital goes up. Should regulatory ratemaking decisions swing too far toward low consumer rates in a given case, the long term result may likely be higher rates in the future, irrespective of the now unknown economic conditions that will exist at such future time.[3]

I appreciate that the Commission has the difficult obligation of balancing the interests of investors and customers, such that rates are fair and reasonable, and the Company is allowed the opportunity to receive a reasonable return. As the Commission found, that balance is necessary for the Company to be "financially sound and capable of providing its customers with safe and

[3] North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Issued September 24, 2013, at 39 – 40.

reliable service".[4] I also appreciate the Commission's finding that the lowest rate of return does not necessarily achieve that balance; as the Commission observed, a return too low in the near-term may produce higher customer rates in the future. In that important respect, I believe the Opposing Witnesses' recommendations do not strike the balance the Commission seeks to achieve.

Q. IS THERE REASON TO BE CONCERNED THAT THE FINANCIAL COMMUNITY WOULD REACT ADVERSELY IF AN ROE IN THE RANGE OF THE OPPOSING WITNESSES' RECOMMENDATIONS WAS TO BE ADOPTED?

A. Yes, I believe so. Investors are aware of, and are concerned with, regulatory decisions that depart from regulatory practice. Here, the Opposing Witnesses' recommendations are far removed from recent regulatory decisions. In my view, that departure presents a risk that would cause investors to increase the return they would require to invest in the Company. If that were to occur, and its equity were to be further devalued, the Company's ability to compete for the capital needed to fund its utility investments would be further diminished.

Q. ARE YOU AWARE OF A RECENT RATE DECISION IN WHICH THE FINANCIAL COMMUNITY RESPONDED NEGATIVELY TO AN ADVERSE REGULATORY OUTCOME?

A. Yes, I am. As discussed below, CenterPoint Energy Houston Electric ("CEHE")

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[4] North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, Issued October 23, 2013, at 42.

recently was authorized an ROE of 9.40 percent, together with an equity ratio of 42.50 percent. Throughout the Public Utility Commission of Texas's ("PUCT") deliberations in that proceeding, the financial community monitored the PUCT's deliberations, which initially called for an ROE of 9.25 percent and an equity ratio of 40.00 percent. The real-time effect of those deliberations has been clear: the stock of the Company's parent, CenterPoint Energy, Inc. ("CNP"),[5] significantly underperformed the utility sector, and its credit rating from Fitch has been downgraded by one credit "notch." The equally clear result is that CEHE's cost of capital has increased, to the detriment of its customers.

Q. PLEASE DESCRIBE THE FINANCIAL COMMUNITY'S REACTION TO THE PUCT'S DELIBERATIONS REGARDING CEHE'S RECENT RATE PROCEEDING.

A. By way of background, in April 2019, CEHE filed a rate case including a proposed ROE of 10.40 percent, and an equity ratio of 50.00 percent.[6] In their September 16, 2019 Proposal For Decision ("PFD"), the Administrative Law Judges ("ALJs") recommended an ROE of 9.42 percent (including a three basis point penalty for service complaints), and a capital structure including 45.00 percent equity (55.00 percent long-term debt).[7]

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5 As of December 2018, CEHE represented about 75.00 percent of CNP's combined pre-tax operating profit.

6 Source: PUCT Docket No. 49421, Item Number: 1.

7 As a point of reference, in December 2018 the PUCT approved a settlement for Texas-New Mexico Power, also a distribution electric utility operating in the ERCOT region of Texas, including a 9.65 percent ROE, and a 45.00 percent equity ratio.

In its November 14, 2019 open meeting deliberations, the PUCT discussed authorizing an ROE of 9.25 percent, and a hypothetical equity ratio of 40.00 percent, both downward revisions to the PFD, and to the PUCT's previously authorized ROE of 10.00 percent and hypothetical equity ratio of 45.00 percent. The PUCT also discussed ordering a series of "ring-fencing" provisions, similar to those approved for Oncor Electric Delivery Company LLC ("Oncor") in connection with Oncor's acquisition by Sempra Energy, recommended in the PFD. The ring-fencing provisions included in the PFD were beyond those already (voluntarily) put in place by CEHE. Although the PUCT indicated it had reached its decision regarding CEHE's ROE, capital structure, and ring-fencing provisions, it directed PUCT Staff to quantify the revenue requirement effect of certain revenue requirement determinations, and allowed parties to the proceeding to file briefs regarding the ring-fencing issue.[8] With that information, the PUCT was expected to issue its final decision at its December 13, 2019 open meeting.[9]

On November 15, 2019, CNP's stock was downgraded by analysts at

[8] As CEHE explained in its November 25, 2019 brief, one of the ring-fencing provisions proposed by PUCT Staff was to limit dividends from CEHE to CNP to CEHE's net income. At the same time, reducing the equity ratio to 40.00 percent would require CEHE to dividend about $800 million to CNP, violating the ring-fencing provision. Together, the capital structure and ring-fencing provisions would put CEHE in the difficult position of choosing between violating the ring-fencing provisions, or maintaining considerably more equity in its actual capital structure than provided in its authorized capital structure. That equity would be "trapped" at the CEHE level, with no ability to earn the authorized return. Source: S&P Global Market Intelligence, *Texas PUC puts off ruling on CenterPoint rate case to allow settlement talks*, December 13, 2019.

[9] Source: S&P Global Market Intelligence, *Texas Regulators signal lower ROE, more ring-fencing for CenterPoint Houston*, November 15, 2019.

BofA Merrill Lynch, Credit Suisse, Guggenheim, and SunTrust RH.[10] At the same time, Evercore, Mizuho, Wolfe, and Wells Fargo lowered their price targets for the stock.[11] For the day, CNP lost nearly 5.00 percent of its value, making it the worst performing stock in the S&P 500.[12] On Monday November 18, 2019, analysts at Morgan Stanley reduced their price target for CNP, and financial market reporting services noted an increase in options activity for CNP stock.[13] By closing that day, CNP had lost about 10.50 percent of its value since November 13, only three trading days, representing a loss in market capitalization of about $1.5 billion. By December 3, 2019, CNP's stock price had lost nearly 14.00 percent of its value, reflecting a decline in market capitalization of about $1.85 billion.[14]

On December 12, 2019, CEHE notified the PUCT that several parties to the proceeding were engaged in discussions regarding a possible stipulation, and requested additional time to continue those discussions.[15] At its December 13, 2019 open meeting, the PUCT agreed to give the parties additional time to discuss the potential stipulation, and postponed its final deliberations. On

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10 Source: Seeking Alpha, *CenterPoint Energy slammed with downgrades at four Wall Street firms*, November 15, 2019. Each of those four companies also lower their price targets for CNP.

11 Source: Bloomberg Professional, Mizuho Securities USA LLC, CenterPoint Energy, Inc., *Phi Slama Jammed*, November 15, 2019; Wolfe Research, CenterPoint Energy, *Tex-Mess*, November 14, 2019; Wells Fargo Securities, CenterPoint Energy, Inc., CNP: *The Hits Keep Coming – Lowering Estimates And Price Targe*t, November 14, 2019.

12 Source: Seeking Alpha, *CenterPoint Energy slammed with downgrades at four Wall Street firms*, November 15, 2019.

13 Source: Bloomberg Professional.

14 Source: S&P Capital IQ.

15 Source: PUCT Docket No. 49421, Item Number: 777.

January 23, 2020, CEHE filed a Stipulation and Settlement Agreement among CEHE and intervening parties, including PUCT Staff. The stipulation included an ROE of 9.40 percent, an equity ratio of 42.50 percent, and various ring-fencing measures.[16] During its February 14, 2020 open meeting, the PUCT approved the stipulation.[17]

On February 19, 2020, Fitch downgraded CEHE from A- to BBB+, with a Negative outlook. In summarizing its decision to downgrade CEHE (while affirming CNP's existing rating), Fitch explained it "believes that the unfavorable outcome signals a more challenging regulatory environment in Texas for CEHE." Fitch went on to note that "[l]ower authorized returns and equity capitalization, combined with tax-reform related refund will pressure CEHE's and CNP's credit metrics in the next few years", and explained further negative rating action is possible if the Company's credit metrics, deteriorate.[18]

Fitch's concern with the potential deterioration in credit metrics, and in the regulatory environment, is similar to earlier concerns expressed earlier by equity analysts regarding the PUCT's deliberations. Wells Fargo, for example, noted:

> While it is difficult to know how much of the outcome was company-specific, this is a distinctly negative data point on the TX regulatory landscape. In addition to the below average

16 Source: PUCT Docket No. 49421, Item Number: 785.

17 S&P Global Market Intelligence, *Texas PUC OKs CenterPoint rate case settlement, adds no dividend restrictions*, February 14, 2020.

18 Fitch Ratings, *Fitch Downgrades CenterPoint Energy Houston Electric to 'BBB+'; Affirms CNP; Outlooks Negative*, February 19, 2020.

> ROE of 9.25%, the PUCT actually lowered Houston Electric's equity ratio at a time when most states are moving in the other direction.[19]

In a similar fashion, Guggenheim stated:

> While we were supporters of CNP in improving transparency and resetting the regulated business for growth (we've been the low estimate on the street for '20), we now believe that the deterioration of the PUCT relationship will make it difficult to invest in Texas (a core part of our prior thesis). We hope the PUCT aims to rethink the direction of where the regulatory construct is heading as we expect additional capital to be directed out of the state… the PFD updates represent a sharp turn in PUCT positioning, which makes us question CNP investability and the near-term future of the regulatory construct.

Guggenheim then expressed its concern with other utilities operating in Texas, noting that their costs of capital likely had increased:

> With other rate filings happening or expected to be filed in TX with our other coverage names including AEP, ETR, SRE (Oncor), investors will now likely place a higher risk premium on shares, thereby driving the cost of capital to business in the Lonestar State higher – we hope this latest process with CNP is anomalistic and not a read with other peers.[20]

To summarize, debt and equity analysts became concerned not only with the financial implication of the PUCT's decision, they became quite concerned with what appeared to be a deterioration in the regulatory environment. As Fitch's downgrade and Guggenheim's comments suggest, those concerns likely reflect higher costs of capital for CEHE.

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19 Wells Fargo Securities, CenterPoint Energy, Inc., CNP: *The Hits Keep Coming – Lowering Estimates And Price Targe*t, November 14, 2019

20 Guggenheim Securities, LLC, *CNP – Houston, We Have a Problem – PUCT Environment Deteriorates, CNP Un-Investable in the NT*; Downgrade to Neutral, November 14, 2019.

Q. HAVE YOU ANALYZED THE MARKET REACTIONS TO THE REGULATORY ACTIVITY ASSOCIATED WITH CEHE'S RATE CASE?

A. Although it is difficult to disentangle the effect of the PUCT's deliberations relating to ROE, capital structure, and ring-fencing, it is clear investors found the combined effect of those factors on CEHE's financial and risk profile to be troubling. One perspective on the extent of that concern is to view CNP's daily returns relative to the daily returns on indices of utility stocks. As noted above, there had been certain events that affected investors' perceptions of CEHE's risk and, therefore, CNP's stock price. To assess the effect of those events, we can view CNP's daily return on a cumulative basis, relative to the cumulative daily returns of utility stock indices.

As Chart 2 (below) suggests, coincident with the PUCT's November 14, 2019 open meeting, CNP began to meaningfully underperform[21] the utility sector. That underperformance continued into December, reaching its lowest point on December 3, 2019. CNP's stock price began to recover around December 13, 2019, when CNP notified the PUCT that settlement discussions were continuing. The price recovered somewhat more through December 20, 2019, shortly after CEHE's update to the PUCT regarding the status of settlement discussions. Since then, it has traded in a relatively narrow range.

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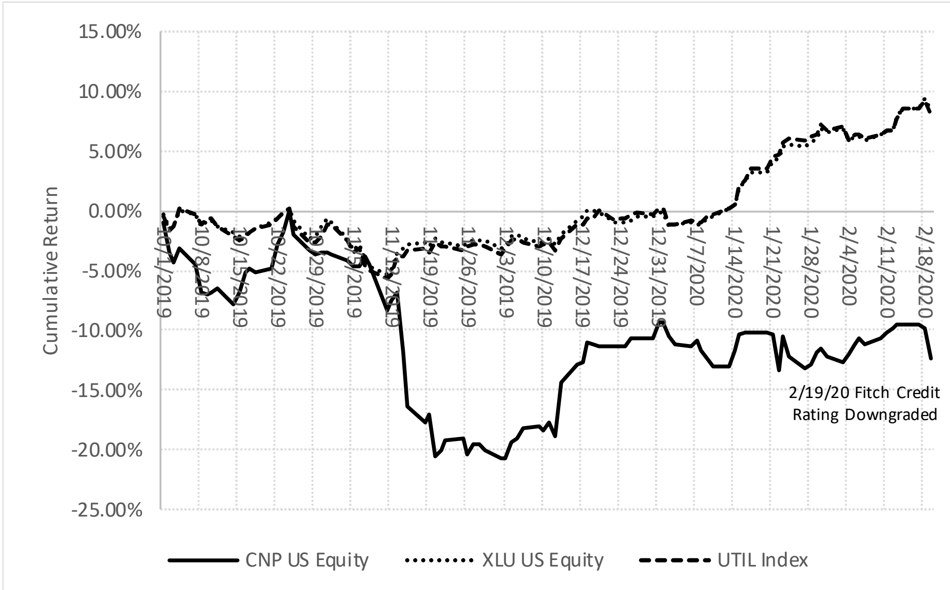
21 As explained in Appendix A, that underperformance was statistically meaningful.

1 **Chart 2: Cumulative Returns (10/1/2019-2/19/2020)[22]**



22 Source: Bloomberg Professional.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THAT INFORMATION?

A. It is apparent that analysts and investors found the PUCT's deliberations troubling. Although we cannot attribute specific portions of CNP's stock price underperformance to the PUCT's deliberations regarding each of the ROE, capital structure, and ring-fencing issues, we can say that in aggregate, the market saw them as value-reducing.

III. SUMMARY OF UPDATED ANALYSES

Q. PLEASE SUMMARIZE THE ANALYSES CONTAINED IN YOUR REBUTTAL TESTIMONY.

A. I have updated many of the analyses contained in my Direct Testimony, including the Constant Growth Discounted Cash Flow ("DCF") analyses, the Capital Asset Pricing Model ("CAPM"), the Empirical CAPM ("ECAPM"), the Bond Yield Plus Risk Premium approach, and the Expected Earnings approach. I also have updated my proxy group based on recent data. Lastly, I have provided additional analyses in response to the Opposing Witnesses.

Q. PLEASE DESCRIBE YOUR UPDATED PROXY GROUP.

A. I have included Avista Corporation ("Avista"), which had been party to a proposed acquisition by Hydro One Limited; that transaction was terminated on

January 23, 2019.[23] Because Avista meets all my screening criteria and enough time has passed that the model inputs no longer are affected by the proposed transaction, I included Avista in my proxy group. I refer to the resulting group as the "Updated Proxy Group" and is provided in Table 1, below.

Table 1: Updated Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company	AEP
Avangrid, Inc.	AGR
Avista Corporation	AVA
CMS Energy Corporation	CMS
DTE Energy Company	DTE
Evergy, Inc.	EVRG
Hawaiian Electric Industries, Inc.	HE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

[23] *See, Hydro One and Avista Mutually Agree to Terminate Merger Agreement*, Press Release, January 23, 2019.

My updated analytical results based on the Updated Proxy Group are provided in Section XI, Table 13.

IV. RESPONSE TO STAFF WITNESS DR. WOOLRIDGE

PLEASE BRIEFLY SUMMARIZE DR. WOOLDRIDGE'S ROE ANALYSES AND RECOMMENDATIONS.

A. Although Dr. Woolridge asserts "an appropriate ROE for the Company is in the range of 6.90% to 8.40%", his "primary" recommendation is an ROE of 9.00 percent, assuming his 50.00 percent proposed common equity ratio.[24] He provides an "alternative" recommendation of 8.40 percent, based on the Company's recommended equity ratio of 53.00 percent.[25] In each case, Dr. Woolridge's recommendation is based primarily on his Constant Growth Discounted Cash Flow ("DCF") analysis.[26]

Q. WHAT ARE THE SPECIFIC AREAS IN WHICH YOU DISAGREE WITH DR. WOOLRIDGE'S ANALYSES AND CONCLUSIONS?

A. There are several areas in which I disagree with Dr. Woolridge, including: (1) the overall reasonableness of his ROE recommendation; (2) the interpretation of current capital market conditions; (3) the selection of the proxy companies; (4) Dr. Woolridge's application of the Constant Growth DCF model; (5) Dr. Woolridge's application of the CAPM; (6) the applicability of

24 Testimony of J. Randall Woolridge, at 7.
25 Testimony of J. Randall Woolridge, at 7-8.
26 Testimony of J. Randall Woolridge, at 46-47, 79-80.

the ECAPM; (7) the reasonableness of the Bond Yield Plus Risk Premium method; (8) Dr. Woolridge's position that the Expected Earnings approach is not an accurate measure of investor expectations; 9) the relevance of Market-to-Book ("M/B") ratios in determining the ROE; (10) Dr. Woolridge's position that the Company is less risky than its peers; (11) the implications of economic conditions in North Carolina for the Company's Cost of Equity; and (12) the reasonableness of his capital structure proposal.

A. Recommended ROE

Q. ARE DR. WOOLRIDGE'S 8.40 PERCENT OR 9.00 PERCENT ROE RECOMMENDATIONS CONSISTENT WITH RETURNS RECENTLY AUTHORIZED IN NORTH CAROLINA?

A. No, they are not. On February 25, 2020, in Docket No. E-22, Sub 562, the Commission authorized an ROE of 9.75 percent for Dominion Energy North Carolina. Prior to that, the Commission authorized an ROE of 9.90 percent for the Company, Duke Energy Progress, and Piedmont Natural Gas.[27] That is, the Commission's most recent authorized return is 75 to 135 basis points above Dr. Woolridge's recommendations, and 285 basis points above the low end of his range. Dr. Woolridge has provided no evidence to support the conclusion the Company has become so less risky than its peers that investors would require a return so far below those recently authorized by this Commission.

[27] *See,* NCUC Docket Nos. E-7 Sub 1146; E-2, Sub 1142; and G-9 Sub 743.

Q. ARE DR. WOOLRIDGE'S ROE RECOMMENDATIONS CONSISTENT WITH RETURNS RECENTLY AUTHORIZED IN OTHER JURISDICTIONS CONSIDERED TO HAVE CONSTRUCTIVE REGULATORY ENVIRONMENTS?

A. No. As discussed in my response to Mr. Chriss, Regulatory Research Associates ("RRA") currently ranks North Carolina in the top third of all jurisdictions from investors' perspectives. Since 2016, the average and median authorized ROE in jurisdictions similar to North Carolina was 9.93 percent and 9.98 percent, respectively (within a range of 9.37 percent to 10.55 percent).[28] Dr. Woolridge's recommendations are well below even the low end of that range. If adopted, Dr. Woolridge's 9.00 percent ROE recommendation would be only 25 basis points above the lowest authorized return for a vertically integrated electric utility since at least 1980.[29]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT AUTHORIZED RETURNS FOR ELECTRIC AND NATURAL GAS UTILITIES HAVE DECLINED OVER THE PAST FIVE YEARS?[30]

A. No, I do not. In fact, Dr. Woolridge's own data contradicts that position. As shown in Table 2 below, according to Dr. Woolridge's data,[31] the average annual

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28 *See*, Rebuttal Exhibit DWD-23 and Table 11.
29 Source: Regulatory Research Associates. As discussed in my response to Mr. O'Donnell, the market response after the South Dakota PUC's 8.75 percent ROE decision for Otter Tail Power was immediate and negative.
30 Testimony of J. Randall Woolridge, at 23.
31 Dr. Woolridge's source is Regulatory Research Associates.

authorized ROE for electric utilities has been relatively stable over the past five years. If anything, Dr. Woolridge's data shows the average authorized ROE has increased slightly over the past five years.

Table 2: Dr. Woolridge's Reported Average Authorized ROE for Electric Utilities[32]

Year	Average
2015	9.58%
2016	9.60%
2017	9.68%
2018	9.56%
2019	9.64%

Moreover, Dr. Woolridge's data includes ROEs authorized for distribution-only electric utilities, in addition to vertically integrated electric utilities. Looking to the average and median ROE authorized for only vertically integrated electric utilities, the trend over the past five years also has been relatively stable (*see* Table 3, below). In either case, Tables 2 and 3 demonstrate that Dr. Woolridge's position that there has been a downward trend in authorized ROEs is incorrect.

Table 3: Average and Median Authorized ROE for Vertically Integrated Electric Utilities[33]

Year	Average	Median
2015	9.75%	9.70%
2016	9.77%	9.78%
2017	9.80%	9.65%
2018	9.68%	9.73%
2019	9.73%	9.73%

32 Testimony of J. Randall Woolridge, at 23.
33 Source: Regulatory Research Associates. Excludes Limited Issue Rate Rider proceedings.

Lastly, although Dr. Woolridge asserts his 9.00 percent recommendation "gives weight to the higher authorized ROEs"[34] for electric utilities, Tables 2 and 3 demonstrate the unreasonableness of Dr. Woolridge's recommendations.

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S REFERENCE TO A MARCH 2015 REPORT BY MOODY'S REGARDING THE EFFECT OF ROES ON UTILITIES' NEAR-TERM CREDIT PROFILES.

A. Dr. Woolridge points to the March 2015 Moody's report and concludes lower authorized ROEs are not impairing utilities' credit profiles and are not "deterring them from raising record amounts of capital."[35] He argues the Moody's article "supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital."[36]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S ASSESSMENT OF THAT ARTICLE?

A. No, I do not. The March 2015 Moody's article makes clear utilities' cash flow had benefited from increased deferred taxes, which themselves were due to bonus depreciation. In that report, Moody's noted the rise in deferred taxes eventually would reverse.[37] In January 2018, Moody's spoke to the effect of

34 Testimony of J. Randall Woolridge, at 80.
35 Testimony of J. Randall Woolridge, at 83.
36 Testimony of J. Randall Woolridge, at 84.
37 Moody's Investors Service, *Lower Authorized Returns Will Not Hurt Near-Term Credit Profiles*, March 10, 2015, at 4.

that reversal on utility credit profiles in the context of tax reform:

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.[38]

In June 2018, Moody's changed its outlook on the U.S. regulated sector to "negative" from "stable". Moody's explained that its change in outlook "…primarily reflects a degradation in key financial credit ratios, specifically the ratio of cash flow from operations to debt, funds from operations ("FFO") to debt and retained cash flow to debt, as well as certain book leverage ratios."[39] The sector's outlook could remain "negative" if cash flow-based metrics continue to decline, or if there emerge signs of a more "contentious" regulatory environment (which, Moody's notes, is not fully reflected in lower authorized returns). Dr. Woolridge's reference to a 2015 article does not consider Moody's more recent position.

[38] Moody's Investors' Service, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform*, January 19, 2018.

[39] Moody's Investors Service, *Announcement: Moody's changes the US regulated utility sector outlook to negative from stable,* June 18, 2018.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S PRIMARY RELIANCE ON A SINGLE MODEL (*I.E.*, THE CONSTANT GROWTH DCF MODEL) IN DEVELOPING HIS RECOMMENDED ROE?

A. No, I do not. First, the relevant issue is whether investors use multiple methods in evaluating investment opportunities and making investment decisions. Nowhere has Dr. Woolridge demonstrated investors are inclined to disregard other methods in favor of the Constant Growth DCF approach. Because no individual model is more reliable than all others at all times and under all conditions, it is important to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. To that point, in its June 2018 *Order Accepting Stipulation* authorizing the 9.90 percent ROE for the Company, the Commission noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged from 8.45 percent to 8.80 percent) and found "all of these DCF analyses in the current market produce unrealistically low results."[40] As noted in my Direct Testimony, other regulatory commissions have come to similar conclusions.[41]

As to its use among investors, an article published in Financial Analysts Journal surveyed financial analysts to determine the analytical techniques that

[40] North Carolina Utilities Commission, Docket No. E-7, Sub 1146, *In the Matter of 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, July 25, 2017, at 62.

[41] Direct Testimony of Dylan W. D'Ascendis, at, 6-7, 16-17.

are used in practice, which included the CAPM.[42] That survey clearly indicated that the CAPM is used by practitioners. Similarly, a 2001 article by Professors Graham and Harvey demonstrated that industry practitioners are far more likely to use the CAPM than the DCF model.[43]

Q. IS THERE PUBLISHED SUPPORT FOR THE USE OF MULTIPLE METHODS IN ESTIMATING THE COST OF EQUITY?

A. Yes, there is. For example, Dr. Morin notes:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.
>
> No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. *Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data*.[44]

In a similar fashion, Professor Eugene Brigham, a widely respected scholar and

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42 *See,* Stanley B. Block, *A Study of Financial Analysts: Practice and Theory,* Financial Analysts Journal, July/August, 1999.

43 *See,* John R. Graham, Campbell R. Harvey, *The Theory and Practice of Corporate Finance: Evidence from the Field*, Journal of Financial Economics, 2001. *See*, Robert S. Harris, Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts,* Journal of Applied Finance, 2001.

44 Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 428. [*Emphasis added*]

finance academician, recommends the CAPM, DCF, and Bond Yield Plus Risk Premium approaches:

> Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach. These methods are not mutually exclusive – no method dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, *we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand*.[45]

Similarly, Dr. Morin (quoting, in part, Professor Stewart Myers), stated:

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. *That means you should not use any one model or measure mechanically and exclusively*. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.

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> While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM

[45] *Ibid*., at 430-431, citing Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341. [*Emphasis added*]

methodologies.[46]

As those authors make clear, we should not mechanically apply models. Rather, as Brigham noted, we should choose among them based on our confidence in the data at hand. That is what I have done.

Lastly, we know investors consider multiple metrics – including Price/Earnings ("P/E"), M/B, and Enterprise Value/EBITDA[47] multiples – in their buying and selling decisions. They do so because no single financial model produces the most accurate and reliable measure of value at all times and under all conditions.

Q. ARE THERE STRUCTURAL REASONS WHY THE CONSTANT GROWTH DCF MODEL MAY NOT ALWAYS PROVIDE RELIABLE ROE ESTIMATES?

A. Yes, there are. As explained in my Direct Testimony, the DCF model noted by the equation $k = \frac{D(1+g)}{P_0} + g$ is derived from the longer-form present value formula:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Using the DCF model as the principal method[48] to estimate the Cost of Equity fundamentally assumes investors use the present value structure alone to find

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46 Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 430-431. [*Emphasis added*]

47 Earnings Before Interest, Taxes, Depreciation, and Amortization.

48 At page 46 of his testimony, Dr. Woolridge refers to the DCF method as providing "the best measure of equity cost rates for public utilities."

the intrinsic value of common stock, and intrinsic value always equals market value.[49] The model therefore will not produce accurate estimates of the market-required ROE if the market price diverges from the present value-based estimate of intrinsic value. That concern is not academic; differences between market prices and intrinsic valuations may arise when investors take short-term trading positions to hedge risk (*e.g.*, a "flight to safety"), to speculate (*e.g.*, momentum trades), or as temporary position to increase current income (*i.e.*, a "reach for yield"), much like the current market environment.[50]

The implications of market prices diverging from DCF-based estimates of intrinsic value was studied in an article published in the Journal of Applied Finance. That article, which focused on back-tests of the Constant Growth DCF model, found that even under "ideal" circumstances:

> … it is difficult to obtain good intrinsic value estimates in models stretching over lengthy periods of time. Shorter horizon models based on five or fewer years show more promise. Any model based on dividend streams of ten years or more, whether as a teaching tool or in practice, should be used with caution since they are likely to produce low-quality estimates.[51]

In short, because the DCF model is derived from a valuation model that assumes constancy in perpetuity, it is likely to produce less reliable ROE estimates when

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49 *See*, Direct Testimony of Dylan W. D'Ascendis, at 10.

50 Some investors may select relatively high dividend yield companies as a "reach for yield" in response to the shortage of investment alternatives that provide adequate yield in today's capital market, rather than investing in stocks based on their long-term return potential.

51 P. McLemore, G. Woodward, and T. Zwirlein, *Back-tests of the Dividend Discount Model using Time-varying Cost of Equity*, Journal of Applied Finance, No. 2, 2015, at 19.

market conditions are non-constant, and when investor practice is to consider multiple valuation methods.

Q. IS IT YOUR VIEW THAT THE DCF MODEL SHOULD BE GIVEN NO WEIGHT IN DETERMINING THE COMPANY'S COST OF EQUITY?

A. No, it is not. It is my view, however, that we should carefully consider the range of results the model produces, and doing so fully supports my ROE range and recommendation and is consistent with the Commission's prior orders. More importantly, it is necessary to consider the result of multiple methods, because no single method is appropriate in all market conditions.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S PROPOSED REDUCTION TO HIS ROE RECOMMENDATION TO 8.40 PERCENT IF THE COMMISSION ACCEPTS THE COMPANY'S PROPOSED CAPITAL STRUCTURE?[52]

A. No, I do not. Dr. Woolridge's recommendation is based on his view that holding company capital structures are the proper benchmark.[53] Because they can be directly observed and reflect the common practice of matching permanent assets with permanent capital, operating company capital structures should be used as the measure of industry practice. Dr. Woolridge fails to perform such an analysis. Consequently, there is no basis for a 60-basis point adjustment to the Company's ROE in connection with the Company's capital structure.

52 Testimony of J. Randall Woolridge, at 8, 37.
53 Testimony of J. Randall Woolridge, at 29.

Q. WHAT ARE YOUR CONCLUSIONS RELATED TO DR. WOOLRIDGE'S ROE RECOMMENDATION?

A. Dr. Woolridge's 8.40 percent and 9.00 percent recommendations are unduly low and inconsistent with authorized returns by this Commission and in other constructive jurisdictions. In large measure, Dr. Woolridge's recommendations are driven by his focus on the Constant Growth Discounted Cash Flow method. Even under more stable conditions, relying principally on a single method may lead to unreliable ROE estimates. Market prices are set by the buying and selling behavior of individual investors, whose motivations are driven by any number of factors.

There is little question investors' motivations change during volatile markets; capital preservation becomes a principal objective. The Discounted Cash Flow model, which requires us to assume constancy in perpetuity, is particularly susceptible to estimation error during those periods. It requires us to assume the motivations underlying investor decisions in that environment, including capital preservation, are the same motivations that will persist, every day, forever. Because that assumption is not likely to hold, we should be very cautious about giving the Constant Growth DCF method undue weight.

Q. IS THERE "A DISCONNECT" BETWEEN YOUR RECOMMENDED ROE OF 10.50 PERCENT AND YOUR ROE STUDIES?[54]

A. No, there is not. Dr. Woolridge states "the vast majority of [my] equity cost rate results point to a lower ROE" and the "the only results that point to an ROE as high as 10.50% are some of [my] CAPM/ECAPM results".[55] As discussed in my Direct Testimony, practitioners and academics recognize that financial models are simply tools to be used in the ROE estimation process, and that strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions.[56] My ROE recommendation considers all my analyses, not a single method.

Further, Dr. Woolridge is incorrect in stating that only my CAPM results point to an ROE as high as 10.50 percent. For example, in Exhibit DWD-1 in my Direct Testimony, my DCF method produces a range of ROE results from a low of 6.23 percent to a high of 13.71 percent. My recommended ROE of 10.50 percent fits squarely within this range. Exhibit DWD-6 in my Direct Testimony also corroborates my recommended ROE. The Expected Earnings approach in Exhibit DWD-6 in my Direct Testimony produces a range of results from a low of 6.00 percent to a high of 14.06 percent. Again, my recommended ROE of 10.50 percent fits squarely within this range.

54 Testimony of J. Randall Woolridge, at 10 and 87.
55 Testimony of J. Randall Woolridge, at 87. [clarification added]
56 Direct Testimony of Dylan W. D'Ascendis, at 16.

B. Capital Market Conditions

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S TESTIMONY AS IT RELATES TO CURRENT CAPITAL MARKET CONDITIONS.

A. Dr. Woolridge argues that my "analyses, ROE results, and recommendations reflect an assumption of higher interest rates and capital costs".[57] He goes on to state that "despite the Federal Reserve's moves to increase the federal funds rate over the 2015-18 time period, interest rates and capital costs remained at low levels";[58] and observes that "[i]n 2019, interest rates fell dramatically with moderate economic growth and low inflation."[59] On that basis, Dr. Woolridge suggests the Commission "set an equity cost rate based on current indicators of market-cost rates rather than speculating on the future direction of interest rates"[60] based on his conclusion that "it is practically impossible to accurately forecast interest rates and prices of investments that are determined in financial markets".[61]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S CONCLUSION THAT THE CAPITAL MARKET ENVIRONMENT SUGGESTS A LOWER COST OF EQUITY FOR THE COMPANY?

A. No, I do not. In 2019, the 30-year Treasury yield fell by 119 basis points, a

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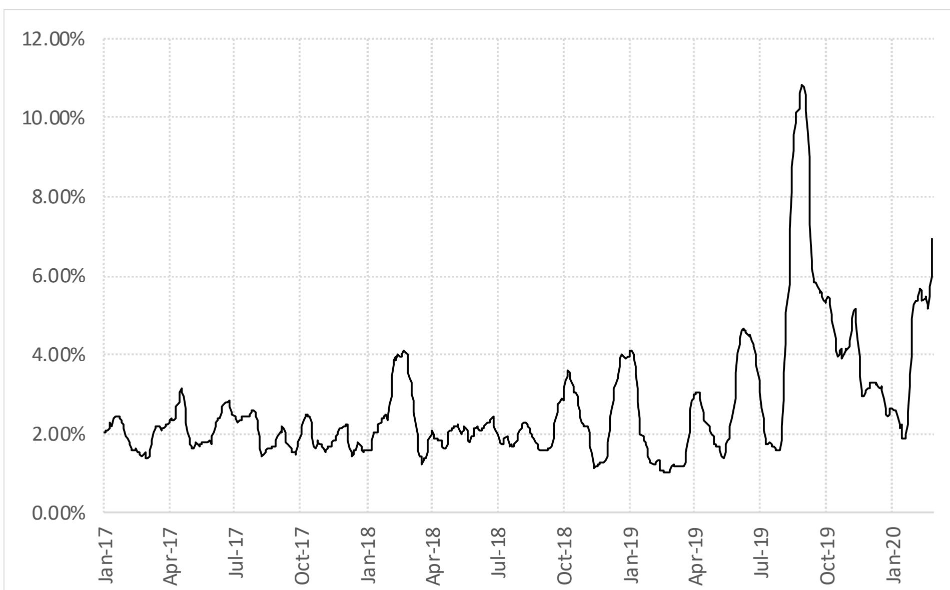
57 Testimony of J. Randall Woolridge, at 9.
58 Testimony of J. Randall Woolridge, at 9.
59 Testimony of J. Randall Woolridge, at 9.
60 Testimony of J. Randall Woolridge, at 19.
61 Testimony of J. Randall Woolridge, at 22.

decline of about 38.00 percent, in 126 trading days. Looking back to 2001, only 124 of 4,806 observations saw greater declines (only thirteen saw greater percentage declines). On an absolute basis, 161 observations experienced greater basis point changes, and only 63 saw greater percentage changes.

One means of viewing the increasing volatility of Treasury yields is to view the Coefficient of Variation ("CoV") over time. The CoV is the ratio of the standard deviation to the average; it is a means of standardizing variability. As Chart 3 (below) demonstrates, by that measure long-term Treasury yields became increasingly variable in 2019 through February 2020, relative to 2017.

Chart 3: 30-Year Treasury Yields Coefficient of Variation[62]



At issue is the extent to which that volatility should be considered in assessing the relationship between Treasury yields and the Cost of Equity. If

62 Source: S&P Global Market Intelligence.

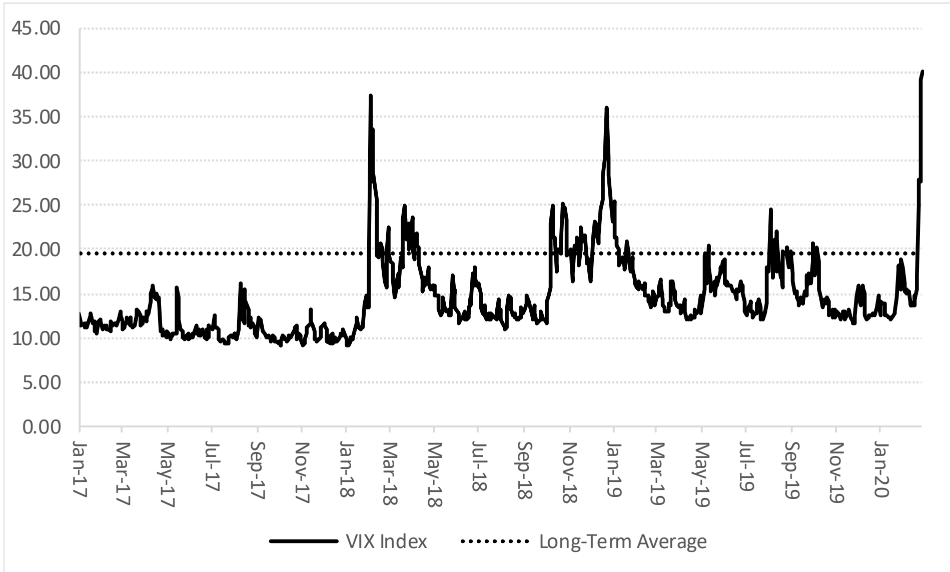
the variability in yields relates to something other than long-term fundamental market factors, we should question the extent to which changes in bond yields reflect changes in investor return requirements.

As noted in my Direct Testimony, over time, significant and abrupt declines in Treasury yields have been associated with increases in equity market volatility.[63] That relationship makes intuitive sense; as investors see increasing risk their objectives may shift to capital preservation (that is, avoiding a capital loss), rather than capital appreciation. Consistent with that objective, investors may allocate capital to the relative safety of Treasury yields, in a "flight to safety." Because bond yields are inversely related to bond prices, as investors bid up the prices of bonds, they bid down the yields. That pattern is seen in Chart 10 in my Direct Testimony, in which decreases in the 30-year Treasury yield coincided with increases in the VIX. In those instances, the fall in yields does not reflect a reduction in required returns, it reflects an increase in risk aversion and, therefore, an increase in investor-required returns.

As also shown in my Direct Testimony, the Cboe Options Exchange Volatility Index ("VIX") increased since 2017.[64] Looking to more recent data (*see* Chart 4, below), the VIX continues to remain elevated relative to 2017. In addition, although the VIX traded in a relatively narrow range in 2017, it experienced greater variability in 2018 and 2019.

[63] Direct Testimony of Dylan W. D'Ascendis at 65.
[64] Direct Testimony of Dylan W. D'Ascendis at 64-65.

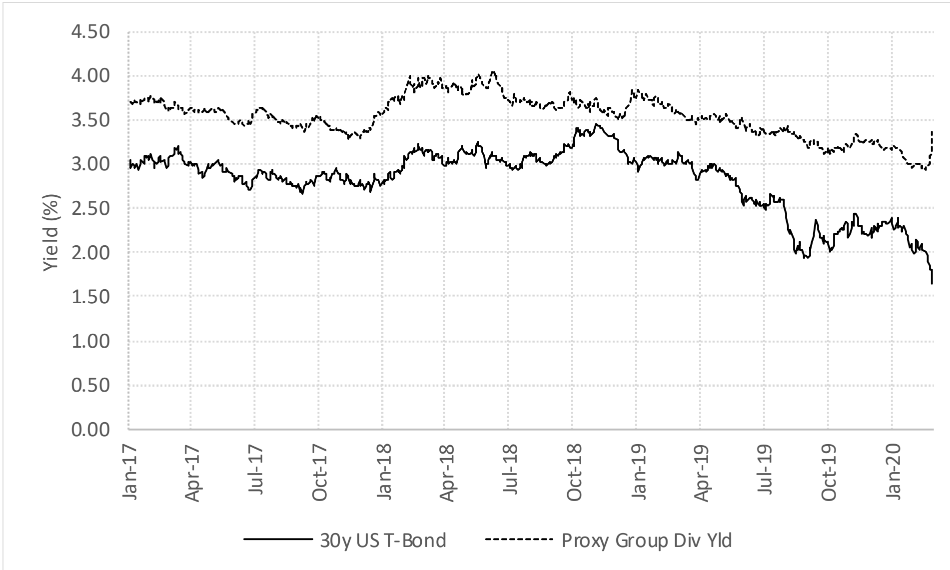
Chart 4: VIX January 2017 – February 2020[65]



As discussed in my Direct Testimony, since the 2008/2009 financial crisis, Treasury yields have generally remained below utility dividend yields.[66] As shown in Chart 5, below, as Treasury yields fell in 2019, the dividend yields for Dr. Woolridge's proxy group did not fall to the same degree.

65 Source: Bloomberg Professional, as of January 31, 2020.
66 *See*, Direct Testimony of Dylan W. D'Ascendis at 69.

Chart 5: Dr. Woolridge's Proxy Group Utility Dividend Yields and 30-Year Treasury Yields[67]



Between July 1, 2019 and February 28, 2020, the 30-year Treasury yield fell by approximately 35.00 percent, whereas the dividend yield for Dr. Woolridge's proxy group fell by approximately 0.88 percent. Therefore, dividend yields did not move to the same extent as Treasury yields when Treasury yields significantly and abruptly fell. We can conclude the reason is investors likely saw the drop in yields more likely as transitory rather than a long-term, fundamental change. As such, I do not agree that current market conditions imply a lower ROE.

[67] Source: S&P Global Market Intelligence.

C. Proxy Group Selection

Q. PLEASE DESCRIBE THE SCREENING CRITERIA BY WHICH DR. WOOLRIDGE DEVELOPED HIS PROXY GROUP.

A. Dr. Woolridge relied on six screening criteria to develop his proxy group of 30 companies:

1. Received at least 50.00 percent of revenues from regulated electric operations as reported in SEC Form 10-K report;
2. Is listed as a U.S.-based Electric Utility by *Value Line Investment Survey*;
3. Has an investment-grade corporate credit and bond rating;
4. Has paid a cash dividend for the past six months with no cuts or omissions;
5. Is not involved in an acquisition of another utility, or be the target of an acquisition; and
6. Has analysts' long-term EPS growth forecasts available from Yahoo or Zacks.[68]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S SCREENING CRITERIA?

A. Not entirely. Although we do have certain criteria in common (for example, we both exclude companies that are party to a significant corporate transaction or that do not consistently pay dividends), as explained below, Dr. Woolridge's screens do not render a group of companies that is sufficiently comparable to the Company.

68 Testimony of J. Randall Woolridge, at 24-25.

Q. WHAT IS YOUR CONCERN WITH DR. WOOLRIDGE'S USE OF REVENUE, RATHER THAN INCOME, AS A SCREENING CRITERION?

A. Measures of income are far more likely to be considered by the financial community in making credit assessments and investment decisions than are measures of revenue. From the perspective of credit markets, measures of financial strength and liquidity are focused on cash from operations, which is directly derivative of earnings, as opposed to revenue. As part of its rating methodology, for example, Moody's assigns a 40.00 percent weight to measures of financial strength and liquidity, of which 22.50 percent specifically relates to the ability to cover debt obligations with cash from operations.[69]

Just as rating agencies focus on measures of cash from operations, equity analysts rely on measures of income in assessing equity valuation levels; common measures of relative value include the P/E ratio, and the ratio of Enterprise Value to EBITDA. Revenue, however, may be several steps removed from the earnings and cash flows that form the basis of equity valuations. Focusing on revenue may mislead the analyst into assuming a given operating unit is the primary driver of expected growth, when the majority of earnings and cash flows are derived from other business segments. Here, we are considering whether the underlying utility is the principal source of long-

[69] *See,* Moody's Investors Service, Rating Methodology, *Regulated Electric and Gas Utilities,* June 23, 2017, at 4.

term growth, and as such, focusing on revenue may obscure important elements of the analysis.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S CONSIDERATION OF DUKE ENERGY CORPORATION, DE CAROLINAS' PARENT, IN HIS PROXY GROUP?

A. No, I do not. As noted in my Direct Testimony, it is my practice to exclude parent companies from the proxy groups of subsidiary utilities, as the inclusion of a parent involves circular logic.[70]

D. Constant Growth DCF Model

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE CONSTANT GROWTH DCF MODEL AND DR. WOOLRIDGE'S APPLICATION OF THE MODEL.

A. There are several practical concerns with Dr. Woolridge's application of the model, and his interpretation of its results. For example, Dr. Woolridge's approach includes a degree of subjectivity that prevents us from replicating the fundamental inputs that drive his results. Moreover, Dr. Woolridge's judgment is to give "primary weight"[71] to growth rate projections produced by equity analysts, despite his assertion that those analysts knowingly and persistently produce biased growth rate forecasts.

[70] Direct Testimony of Dylan W. D'Ascendis, at 24.
[71] Testimony of J. Randall Woolridge, at 61-62.

Q. WHAT GROWTH RATES DID DR. WOOLRIDGE REVIEW IN HIS CONSTANT GROWTH DCF ANALYSIS?

A. Dr. Woolridge reviewed a number of growth rates, including historical and projected Dividend Per Share ("DPS"), Book Value Per Share ("BVPS"), and Earnings Per Share ("EPS") growth rates as reported by Value Line; analysts' consensus EPS growth rate projections from Yahoo!, Reuters, and Zacks; and an estimate of sustainable growth derived from data provided by Value Line.[72] Dr. Woolridge states that in arriving at his growth rate projections for the proxy group he gave "primary weight" to projected EPS growth rates.[73]

Table 4: Summary of Dr. Woolridge's Growth Rate Estimates[74]

	Dr. Woolridge's Proxy Group	**D'Ascendis Proxy Group**
Value Line Historical Growth Rates (DPS, BVPS, EPS)	4.30%	4.80%
Value Line Projected Growth Rates (DPS, BVPS, EPS)	5.10%	5.10%
Sustainable Growth	3.60%	3.40%
Analyst Projected EPS Growth Rates (Yahoo! And Zacks) – Mean/Median	4.90% / 4.70%	5.40% / 5.40%
Dr. Woolridge's Assumed DCF Growth Rate	5.00%	5.40%

72 Exhibit JRW-7.
73 Testimony of J. Randall Woolridge, at 61-62.
74 Testimony of J. Randall Woolridge, at 61-62; Exhibit JRW-7, at 1, 6.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT ANALYSTS' EARNINGS GROWTH PROJECTIONS ARE CONSISTENTLY BIASED?

A. No, I do not. Dr. Woolridge argues analysts' earnings growth estimates are "overly optimistic and upwardly biased",[75] and believes relying on such estimates is a methodological error. He further argues that, due to that bias, "the DCF growth rate must be adjusted downward from the projected EPS growth rate".[76] Dr. Woolridge's position, however, is based on observations of the broad market; he has provided no evidence that any of the growth rates used in my (or his) DCF analyses are the result of a consistent and pervasive bias on the part of the analysts providing those projections. Notably, despite his view that they are biased, it was by "[g]iving primary weight to the projected EPS growth rate of Wall Street analysts" that Dr. Woolridge arrived at his assumed growth rates.[77]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THAT POINT?

A. There is no reason to believe the analyst growth rates used in my DCF analyses are biased. As a practical matter, the October 2003 Global Research Analyst Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required

75 Testimony of J. Randall Woolridge, at 57.
76 Testimony of J. Randall Woolridge, at 59.
77 Testimony of J. Randall Woolridge, at 61-62.

the settling financial institutions to fund independent third-party research.[78] I have reviewed the Letters of Acceptance, Waiver and Consent signed by financial institutions that were party to the Global Settlement, and found no reference to misconduct by analysts following the utility sector.

Moreover, pursuant to Regulation AC, which became effective in April 2003, analysts must certify that "…the views expressed in the report accurately reflect his or her personal views, and disclose whether or not the analyst received compensation or other payments in connection with his or her specific recommendations or views."[79] I further understand industry practice is to avoid conflicts of interest by ensuring that compensation is not directly or indirectly linked to the opinions contained in those reports. Dr. Woolridge has not explained why any of the analysts covering our respective proxy companies would bias their projections despite those certification requirements.

Lastly, Dr. Woolridge argues utilities generally are in the "mature" stage of their industry life cycle.[80] Key characteristics of a mature industry include predictable cash flows and earnings, both of which would enable more stable, less "biased" earnings estimates. Dr. Woolridge has not reconciled those two largely competing points.

[78] The 2002 Global Financial Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts.

[79] Securities and Exchange Commission, 17 CFR PART 242 [Release Nos. 33-8193; 34-47384; File No. S7-30-02], RIN 3235-AI60 Regulation Analyst Certification.

[80] Testimony of J. Randall Woolridge, at 50.

Q. IS THE USE OF ANALYSTS' EARNINGS GROWTH PROJECTIONS IN THE DCF MODEL SUPPORTED BY FINANCIAL LITERATURE?

A. Yes, it is. Several published articles support the use of analysts' earnings growth projections in the DCF model. Dr. Robert Harris, for example, found financial analysts' earnings forecasts (referred to in the article as "FAF") to be appropriate in calculating the expected Market Risk Premium:[81]

> ... a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average of forecasts by individual analysts.[82]

Dr. Harris further noted that:

> Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements.[83]

Similarly, in *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts*, Harris and Marston presented "estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts."[84] As Harris and Marston reported:

> ... in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in

[81] *See*, Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, 1986, at 66.

[82] *Ibid*., at 59. As noted in my Direct Testimony, Zacks and First Call, the sources of earnings growth projections that Dr. Woolridge uses in addition to Value Line, are consensus forecasts.

[83] *Ibid*., at 60.

[84] Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 63.

> estimating return requirements provides reasonable empirical results that can be useful in practical applications.[85]

Here again, the finding was clear: Analysts' earnings forecasts are highly related to stock price valuations and are appropriate inputs to stock valuation and ROE estimation models.[86]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT "THE DCF GROWTH RATE MUST BE ADJUSTED DOWNWARD FROM THE PROJECTED EPS GROWTH RATE TO REFLECT THIS UPWARD BIAS"?[87]

A. No, I do not. If current stock prices (and therefore the dividend yield) already reflect analysts' bias,[88] it is unclear why it is necessary to adjust the growth rate. And as noted earlier, although Dr. Woolridge asserts "…long-term EPS growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased"[89], he has not demonstrated that to be true for the electric companies in the proxy group. To that point, I reviewed quarterly earnings presentations of companies in the proxy group and found analysts' growth rate projections to be within the long-term growth rate ranges provided by the companies' management teams (*see* Table 5, below). I therefore do not believe

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85 *Ibid*.

86 In *the Risk Premium Approach to Measuring a Utility's Cost of Equity*, published in Financial Management, Spring 1985, Brigham, Shome and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data; and (ii) investors do rely on analysts' forecasts."

87 Testimony of J. Randall Woolridge, at 59.

88 Testimony of J. Randall Woolridge, at 58.

89 Testimony of J. Randall Woolridge, at 57.

the earnings projections included in our respective analyses are likely to be systemically biased.

Table 5: Analysts' Earnings Growth Projections Relative to Management Presentations[90]

Company	Ticker	Zacks Earnings Growth	First Call Earnings Growth	Investor Presentation Earnings Growth Range
ALLETE, Inc.	ALE	NA	7.00%	5.00% - 7.00%
American Electric Power	AEP	5.60%	6.05%	5.00% - 7.00%
CMS Energy Corp.	CMS	6.10%	7.50%	6.00% - 8.00%
DTE Energy Company	DTE	6.00%	6.00%	5.00% - 7.00%
Evergy, Inc.	EVRG	6.50%	6.50%	5.00% - 7.00%
NextEra Energy, Inc.	NEE	7.80%	7.74%	6.00% - 8.00%
WEC Energy Group	WEC	6.20%	6.08%	5.00% - 7.00%
Xcel Energy Inc.	XEL	5.70%	6.10%	5.00% - 7.00%

Q. DO YOU AGREE WITH DR. WOOLRIDGE THAT HISTORICAL GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?[91]

A. No, I do not. As Dr. Woolridge acknowledges, the growth component of the Constant Growth DCF model is a forward-looking measure of investors' expectations.[92] To the extent historical growth influences expectations of future growth, it already will be reflected in analysts' consensus earnings growth

90 Source: Zacks, Yahoo! Finance (*see*, Rebuttal Exhibit DWD-1), and individual company fourth quarter 2019 or first quarter 2020 investor presentations.

91 Testimony of J. Randall Woolridge, at 54.

92 Testimony of J. Randall Woolridge, at 51, 54.

estimates. Carlton and Vander Weide found "overwhelming evidence that consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price."93 Consequently, I do not believe historical growth rates are appropriate for the Constant Growth DCF model.

Q. WHY DO YOU DISAGREE WITH DR. WOOLRIDGE'S POSITION THAT DIVIDEND AND BOOK VALUE GROWTH RATES ARE APPROPRIATE INPUTS TO THE CONSTANT GROWTH DCF MODEL?[94]

A. First, earnings growth enables both dividend and book value growth. Under the strict assumptions of the Constant Growth DCF model, earnings, dividends, book value, and stock prices all grow at the same, constant rate in perpetuity. As Rebuttal Exhibit DWD-9 demonstrates, under those assumptions the assumed growth rate equals the rate of capital appreciation (*i.e.*, the stock price growth rate).

Simply, earnings are the fundamental driver of both book value and dividend growth. As noted earlier, book value increases with the amount of earnings not distributed as dividends (that is, retained earnings), and the price at which new equity is issued is a function of the EPS and the then-current P/E

93 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs History*, The Journal of Portfolio Management (Spring 1988).

94 Testimony of J. Randall Woolridge, at 53.

ratio. Similarly, the ability to pay dividends depends fundamentally on expected earnings.[95] Because dividend policy contemplates additional factors, including the disproportionately negative effect on prices resulting from dividend cuts, as opposed to dividend increases, in the short-run dividend growth may be disconnected from earnings growth.[96] In the long run, however, dividends cannot be increased without earnings growth.

Because investors often assess stock values on the basis of P/E ratios, it is important to consider whether the growth rates used in the DCF model are related to those valuations.

Q. HAVE YOU UNDERTAKEN ANY ANALYSES TO DETERMINE WHICH MEASURES OF GROWTH ARE STATISTICALLY RELATED TO THE PROXY COMPANIES' STOCK VALUATION LEVELS?

A. Yes, I have. My analysis is based on the methodological approach used by Professors Carleton and Vander Weide, who compared the predictive capability of historical growth estimates and analysts' forecasts on the valuation levels of sixty-five utility companies.[97] I structured the analysis to understand whether projected and historical earnings, dividend, book value, or retention growth rates best explain utility stock valuations. In particular, my analysis examined

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95 *See,* Jing Liu, Doron Nissim, and Jacob Thomas, *Is Cash Flow King in Valuations?*, Financial Analysts Journal, Volume 63, Number 2, 2007.

96 *See,* Servaes and Tufano, *Corporate Dividend Policy: The Theory and Practice of Corporate Dividend and Share Repurchase Policy*, Deutsche Bank, February 2006.

97 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs History*, The Journal of Portfolio Management (Spring 1988).

the statistical relationship between the P/E ratios of the natural gas and electric utilities as classified by Value Line, and the projected EPS, DPS, BVPS, and the "BxR" retention growth[98] rates as reported by Value Line, as well as the historical EPS, DPS, and BVPS as reported by Value Line. To determine which, if any, of those growth rates are statistically related to utility stock valuations, I performed a series of regression analyses in which the projected growth rates were explanatory variables and the P/E ratio was the dependent variable. The results of those analyses are presented in Rebuttal Exhibit DWD-10.

In that analysis, I performed ten separate regressions with the P/E as the dependent variable, and historical EPS, DPS, and BVPS; projected EPS, DPS and BVPS; and the sustainable growth rate, respectively, as the independent variable. I also performed a separate regression with all ten growth rates as independent variables. I then reviewed the T- and F-Statistics to determine whether the variables and equations were statistically significant.[99]

Q. WHAT DID THOSE ANALYSES REVEAL?

A. As shown in Rebuttal Exhibit DWD-10, the only growth rate that was statistically significant and positively related to the P/E ratio was projected Earnings Per Share. Because EPS growth is the only growth rate that is both

98 As discussed below, Dr. Woolridge reviews the more limiting "BxR" form of the retention growth rate.

99 In general, a T-Statistic of 2.00 or greater indicates that the variable is likely to be different than zero, or "statistically significant." The F-Statistic is used to determine whether the model as a whole has statistically significant predictive capability.

statistically and positively related to utility valuation, earnings is the proper measure of growth in the Constant Growth DCF Model.

Q. DO YOU HAVE ANY CONCERNS WITH DR. WOOLRIDGE'S SPECIFICATION OF THE RETENTION GROWTH RATE?

A. Yes, I do. The full form of the model assumes growth is a function of its expected earnings, and the extent to which it retains earnings to invest in the enterprise. The form of the model on which Dr. Woolridge relies is its simplest form, which defines growth solely as a function of internally generated funds. Although I do not believe it is appropriate to use the Retention Growth rate to estimate the Cost of Equity in this proceeding, if Dr. Woolridge is going to consider a form of Retention Growth, he should use the "BR + SV" form of the model, which reflects growth both from internally generated funds *(i.e.*, the "BR" term) and from issuances of equity (*i.e.*, the "SV" term). As noted above, the first term is the product of the retention ratio (*i.e.*, "B", or the portion of net income not paid in dividends) and the expected ROE (*i.e.*, "R"), which represents the portion of net income that is "plowed back" into the company as a means of funding growth. The "SV" term is represented as:

$$\left(\frac{m}{b} - 1\right) x\ Common\ shares\ growth\ rate \quad [2]$$

where:

$$\left(\frac{m}{b}\right) = \text{ the Market} - \text{to} - \text{Book ratio.}$$

In that form, the "SV" term reflects an element of growth as the product of (1) the growth in shares outstanding, and (2) that portion of the M/B ratio that exceeds unity.

E. Capital Asset Pricing Model

Q. PLEASE BRIEFLY DESCRIBE DR. WOOLRIDGE'S CAPM ANALYSIS AND RESULTS.

A. Dr. Woolridge's CAPM analysis produces an estimated Cost of Equity of 6.90 percent for both his and my proxy group.[100] I strongly disagree estimates that low are a reasonable measure of the Company's Cost of Equity. As discussed below, Dr. Woolridge's unduly low CAPM estimate principally falls from his estimated Market Risk Premium.

Dr. Woolridge combines a risk-free rate of 3.75 percent and a Market Risk Premium ("MRP") of 5.75 percent to the average Beta coefficient of his and my proxy groups (0.55). In estimating his MRP, Dr. Woolridge reviews a series of studies that calculate the MRP using different methodologies; he also considers the results of his "Building Blocks" approach. Based on that review, Dr. Woolridge argues the MRP ranges from 4.00 percent to 6.00 percent and, within that range, 5.75 percent is "conservatively high".[101]

100 Testimony of J. Randall Woolridge, at 79, Exhibit JRW-8.
101 Testimony of J. Randall Woolridge, at 78.

Q. DOES DR. WOOLRIDGE EXPRESS ANY CONCERNS REGARDING YOUR CAPM ANALYSIS?

A. Dr. Woolridge's principal disagreements with my CAPM analysis include: (1) the Market Risk Premium component of the model; and (2) the applicability of the Empirical form of the CAPM.[102]

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S CONCERNS REGARDING YOUR USE OF EXPECTED MARKET RETURNS.

A. Regarding the use of expected market returns, Dr. Woolridge states that the result is "excessive."[103] Dr. Woolridge also points to the long-term EPS growth rates for the S&P 500 based on the data from Bloomberg and Value Line, respectively, and notes that they "are inconsistent with both historic and projected economic and earnings growth in the U.S".[104] He also points to MRPs provided in academic studies, assumed by investment banks and management consulting firms, and found in surveys of financial professionals as support for his position that the MRP is in the range of 4.00 percent to 6.00 percent.[105]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THOSE POINTS?

A. Dr. Woolridge refers to two surveys of financial professionals in support of his MRP: the Duke Chief Financial Officer ("Duke CFO") survey and the

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102 Testimony of J. Randall Woolridge, at 98.
103 Testimony of J. Randall Woolridge, at 102, 115.
104 Testimony of J. Randall Woolridge, at 102-103.
105 Testimony of J. Randall Woolridge, at 99-100.

Philadelphia Federal Reserve Survey of Professional Forecasters.[106] Looking to the Federal Bank of Philadelphia's First Quarter 2020 survey, only 17 of 37 participants responded to the question regarding the expected return for the S&P 500 over the next ten years, and 23 of 37 responded to the question regarding expected return on ten-year Treasury bonds.[107]

Even if all 37 economists provided expected market returns and Treasury yields, Dr. Woolridge gives economists' interest rate projections little weight, going so far as to note that in a 2014 Bloomberg survey, "100% of the economists were wrong".[108] Despite that conviction, Dr. Woolridge gives economists' forecasts of market returns and GDP considerable weight in supporting his ROE recommendation. It is unclear why Dr. Woolridge finds economists' estimates appropriate for his analyses, but improper for mine.

As for the Duke CFO survey, Dr. Woolridge's 8.40 percent and 9.00 percent ROE recommendations, which apply to a company that is less risky than the overall market,[109] are 159 to 219 basis points above the expected market return suggested by the survey results. If the survey was a reasonable method of determining the expected market return, Dr. Woolridge's ROE

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106 Testimony of J. Randall Woolridge, at 70.

107 *See*, Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter of 2020 at 19.

108 Testimony of J. Randall Woolridge, at 20.

109 Dr. Woolridge agrees that Beta coefficients for our proxy companies are less than 1.0.

recommendation would be no higher than 6.81 percent.[110] Lastly, over time the survey results have rather significantly underestimated actual market performance (*see* Table 6, below).

Table 6: S&P 500 Market Return: Accuracy of Survey Estimates[111]

	Actual	Survey Estimate
2018	-4.38%	6.57%
2017	21.83%	5.00%
2016	11.96%	4.32%
2015	1.38%	6.07%
2014	13.69%	5.00%
2013	32.39%	3.40%
2012	16.00%	4.00%
2011	2.11%	5.30%
2010	15.06%	6.28%
Average	12.23%	5.10%

The Duke CFO Survey authors also have noted a distinction between the expected market return on one hand, and the "hurdle rate" on the other. In the Third Quarter 2017 survey, the authors reported an average hurdle rate, which is the return required for capital investments, of 13.50 percent. The authors further reported the average Weighted Average Cost of Capital, which includes the cost of debt, was 9.20 percent even though the expected market return was 6.50 percent.[112] In my view, Dr. Woolridge's reference to a 4.99 percent[113]

[110] 6.81 percent equals the expected annual average market return over the next 10 years suggested by the Duke CFO survey. Duke/CFO Magazine Global Business Outlook survey – U.S., Fourth Quarter 2019, at 38. *See also*, Testimony of J. Randall Woolridge, at 74.

[111] Source: Duff & Phelps, 2019 SBBI Yearbook Appendix A-1; http://www.cfosurvey.org (One-year return estimates as of fourth quarter of the previous year).

[112] Duke/CFO Magazine Global Business Outlook survey – U.S., Third Quarter 2017.

[113] Testimony of J. Randall Woolridge, at 74.

expected MRP estimate based on the Duke CFO Survey should be given little weight.

Q. AT PAGE 77 OF HIS TESTIMONY, DR. WOOLRIDGE REFERS TO THE WEBSITE MARKET-RISK-PREMIA.COM, WHICH SUGGESTS A RISK-FREE RATE OF 1.78 PERCENT, AND AN MRP OF 4.00 PERCENT. DO YOU HAVE ANY OBSERVATIONS REGARDING THOSE DATA POINTS?

A. Yes, I do. First, as Dr. Woolridge points out, those estimates combine to suggest an expected market return of 5.78 percent. Because that estimate falls 112 basis points below the low end of his recommended range (6.90 percent),[114] it is unclear what, if any, weight Dr. Woolridge gives that data. Second, I reviewed the website, and it is unclear how the service calculates the expected market return, or the Market Risk Premium.[115] In any case, if Dr. Woolridge believed the website's 5.78 percent expected market return was proper, his CAPM estimate would be 4.87 percent,[116] only 36 basis points above the Company's embedded cost of debt.

[114] Testimony of J. Randall Woolridge, at 80.
[115] http://www.market-risk-premia.com/theoretical-background.html
[116] 4.87% = 3.75% + (0.55 x (5.78% - 3.75%)).

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S REFERENCE TO STUDIES THAT REPORT MRP ESTIMATES BASED ON EXPECTED GEOMETRIC RETURNS?

A. No, I do not. The MRP should reflect the expected arithmetic average return. The important distinction between the arithmetic and geometric averages is that the arithmetic mean assumes that each periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. The geometric mean, on the other hand, is a backward-looking calculation that equates a beginning value to an ending value. Although geometric averages provide a standardized basis of review of historical performance across investments or investment managers, they do not reflect forward-looking uncertainty. That is why investors and researchers commonly use the arithmetic mean when estimating the risk premium over historical periods to estimate the Cost of Equity. As Morningstar notes:

> The arithmetic average equity risk premium can be demonstrated to be the most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of the stock market returns and riskless rates is the relevant number.[117]

Lastly, investment risk, or volatility, typically is measured based on the standard deviation. The standard deviation, in turn, is a function of the arithmetic mean,

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[117] Morningstar, Inc., 2013 Ibbotson SBBI Valuation Yearbook, at 56.

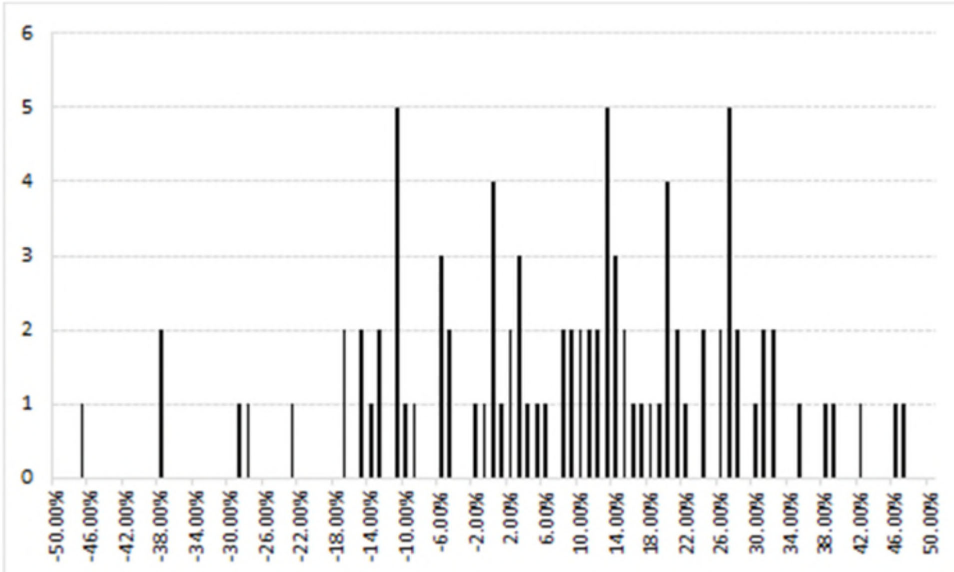
not the geometric mean. In that regard, the Beta coefficients applied in CAPM analyses are a function of the standard deviation of returns.[118]

Q. TURNING TO DR. WOOLRIDGE'S POSITION THAT THE EPS GROWTH RATES USED TO DEVELOP YOUR ESTIMATED MARKET RETURN ARE TOO HIGH,[119] DID YOU CONSIDER WHERE YOUR ESTIMATE FALLS WITHIN THE RANGE OF HISTORICAL OBSERVATIONS?

A. Yes. I gathered the annual capital appreciation[120] return on Large Company Stocks reported by Morningstar for the years 1926 through 2018, produced a histogram of those observations (*see* Chart 6, below), and calculated the probability that a given capital appreciation return estimate would be observed. The results of that analysis demonstrate that capital appreciation rates of 12.68 percent to 12.70 percent (as Dr. Woolridge calculates) and higher actually occurred quite often, representing approximately the 57th percentile.

118 Direct Testimony of Dylan W. D'Ascendis, at 84.
119 Testimony of J. Randall Woolridge, at 100-101.
120 Under the Constant Growth DCF model's assumptions, the growth rate equals the rate of capital appreciation.

Chart 6: Frequency Distribution of Capital Appreciation Returns, 1926-2018[121]

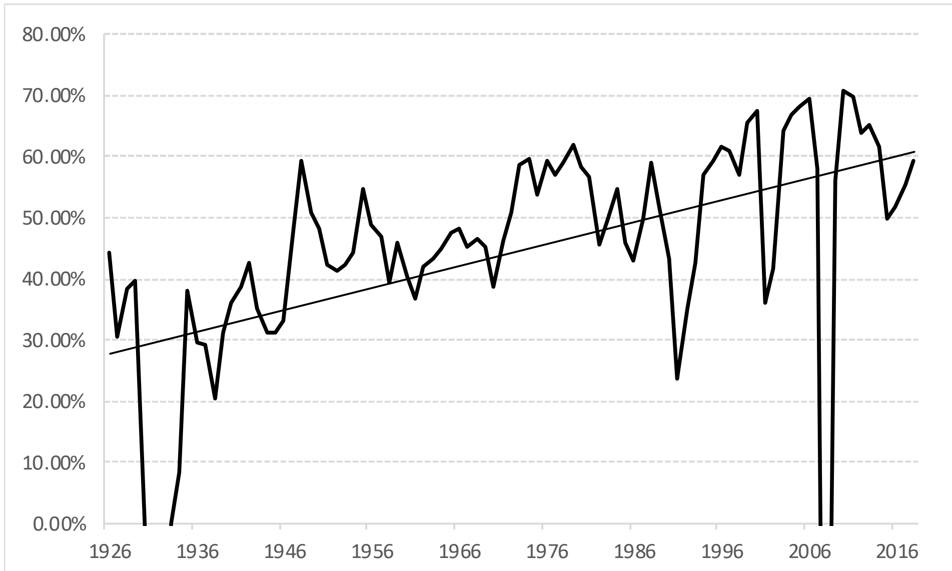


As to Dr. Woolridge's analysis of the S&P 500 EPS and GDP growth rates (in his Table 8), his conclusion that net income of the S&P 500 would grow to represent approximately 81.70 of GDP[122] is substantially driven by his unduly low GDP growth rate. Under the Sustainable Growth model, if the retention ratio is higher now than it historically has been, there would be reason to believe that expected growth rates would be higher than historical growth rates. To determine whether that has been the case, I calculated the annual retention ratio from 1926 to 2018 using earnings and dividends data published by Dr. Robert J. Shiller. As shown in Chart 7 (below), that data indicates the S&P 500 earnings retention has trended upward over time and is currently well above its

121 Duff & Phelps, 2019 SBBI Yearbook, at A-3.
122 Testimony of J. Randall Woolridge, at 112-113.

historical average. Consequently, the Sustainable Growth model included in Dr. Woolridge's DCF analysis suggests that the future growth of the S&P 500 could outpace its historical growth.

Chart 7: S&P 500 Annual Earnings Retention Ratio, 1926 – 2018[123]



Q. HAVE ANY REGULATORY COMMISSIONS CONSIDERED THE SUSTAINABILITY OF GROWTH RATES IN THE MARKET RISK PREMIUM?

A. The Federal Energy Regulatory Commission ("FERC") has found the DCF-based growth rates used to calculate the Market Risk Premium in the CAPM need not meet a sustainability threshold because, although an individual company may not be expected to sustain high short-term growth rates in

[123] Source: http://www.econ.yale.edu/~shiller/data.htm.

perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization. As the FERC stated in Opinion 531-B (March 3, 2015):

> The rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. That is because the S&P 500 is regularly updated to include only companies with high market capitalization. While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.[124]

As such, Dr. Woolridge's concern regarding sustainability of growth rates in the S&P 500 is misplaced.

Q. WHAT IS THE BASIS OF DR. WOOLRIDGE'S CONCERN WITH YOUR MRP AS IT RELATES TO HISTORICAL NOMINAL GDP GROWTH RATES?

A. Dr. Woolridge argues "nominal GDP growth in recent decades has slowed and that a figure in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy."[125] To support his position, Dr. Woolridge reviews average nominal GDP growth over periods of ten to 50 years. As shown on Chart 8 (below),

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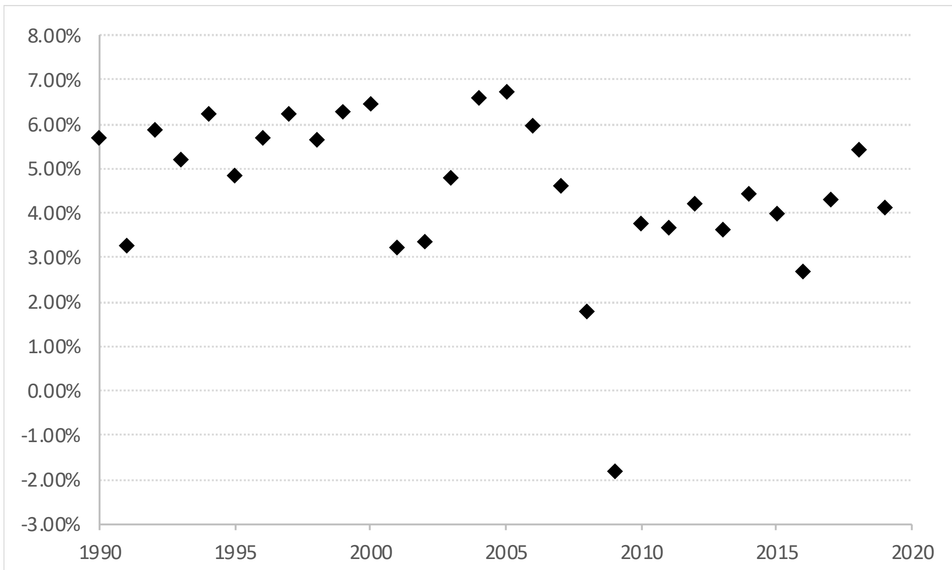
[124] Docket No. EL11-66-002, *Opinion 531-B Order on Rehearing*, 150 FERC ¶ 61,165 (March 3, 2015), at Para. 113.

[125] Testimony of J. Randall Woolridge, at 106.

however, since 1990 (*i.e.*, in "recent decades") the annual nominal growth rate in GDP has remained relatively stable, but for the period 2008 to 2012, which includes the recent recession. Over that time, annual nominal GDP growth rates greater than 5.00 percent (the high end of Dr. Woolridge's suggested range) occurred in 13 of 30 years.

Chart 8: Annual Nominal GDP Growth Rates[126]



126 Source: Bureau of Economic Analysis, January 30, 2020 update.

Q. AT PAGES 107 TO 108 OF HIS TESTIMONY, DR. WOOLRIDGE REFERS TO A 2015 STUDY BY MCKINSEY & CO. ("MCKINSEY") AND ARGUES THAT REAL GDP GROWTH MAY FALL BY 40.00 PERCENT. DO YOU AGREE WITH DR. WOOLRIDGE'S CONCLUSION?

A. No, I do not. Dr. Woolridge argues that future real global economic growth will fall to 2.10 percent, principally due to slow growth in the working age population. He argues that is the case "even if productivity remains at the rapid rate of the past 50 years of 1.8%".[127] McKinsey, however, also points to five "sector case studies", that find "more than enough productivity-acceleration scope to counter slower labor growth."[128] Based on those studies, McKinsey finds sufficient potential for productivity growth to reach 4.00 percent. Of note, about three-quarters of that global potential "would come from the broader adoption of existing best practices", which the firm would characterize as "catch-up" productivity improvements."[129] As to the remainder, McKinsey states:

> The remaining one-quarter, or about one percentage point a year, could come from technological, operational, or business innovations that go beyond today's best practices and that "push the frontier" of the world's GDP potential. In contrast to some

[127] Testimony of J. Randall Woolridge, at 108.
[128] McKinsey Global Institute, *Global Growth: Can Productivity Save the Day In An Aging World?*, January 2015, at PDF 9.
[129] *Ibid.*, at 53 (PDF 63).

> observers, we do not find that a drying up of technological or business innovations will act as a constraint to growth. On the contrary, we see a strong innovation pipeline in both developed and developing economies in the sectors we studied. Our estimate of the potential here is based only on the innovations that we can foresee. It is quite possible that waves of innovation may, in reality, push the frontier far further than we can ascertain based on the current evidence.[130]

In short, the McKinsey study does not conclude the declining workforce necessarily means lower real global GDP growth. Rather, the potential for meaningful productivity increases may provide greater avenues for global real economic growth well greater than Dr. Woolridge assumes.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S REFERENCE TO GDP FORECASTS PROVIDED BY THE *SURVEY OF PROFESSIONAL FORECASTERS*, THE ENERGY INFORMATION ADMINISTRATION ("EIA"), AND THE CONGRESSIONAL BUDGET OFFICE ("CBO")?[131]

A. First, Dr. Woolridge has not demonstrated investors rely on the surveys cited in his testimony. Second, as Dr. Woolridge points out, the *Survey of Professional Forecasters* relates to the years 2019 to 2029; given Dr. Woolridge's concern with my growth rates over the coming period of three-to-five years, his use of the *Survey of Professional Forecasters* does not address that issue. As to the CBO and EIA forecast, those forecasts cover only fifteen to 25 years of a

130 *Ibid*.
131 Testimony of J. Randall Woolridge, at 106-107.

perpetual period and are not consensus forecasts. Lastly, because the EIA's GDP growth forecast is an input to its annual energy projections, the assumptions and methods underlying its GDP forecast are for that specific purpose.

The CBO provides updates regarding its forecasting record. In that context, the CBO has noted that comparisons to other forecasts are not always appropriate, at least in part because forecasts may be based on different assumptions and used for different purposes.[132] The CBO also observes it is required to assume future fiscal policy generally will reflect current law, so that it may provide a benchmark against which proposed changes in law may be assessed.[133] The CBO goes on to explain that "[d]ifferent assumptions about monetary policy can also make it difficult to compare CBO's forecasts with other forecasts. CBO's forecasts incorporate the assumption that monetary policy will reflect the economic conditions that the agency expects to prevail under the fiscal policy specified in current law."[134] The CBO also notes that among its two-year forecasts (since the early 1980s), the forecast error for "growth of real output" and inflation (measured by the Consumer Price Index)

132 *See, CBO's Economic Forecasting Record: 2019 Update*, October 2019, at 8.

133 *Ibid*. "CBO is required by statute to assume that future fiscal policy will generally reflect the provisions in current law, an approach that derives from the agency's responsibility to provide a benchmark for lawmakers as they consider proposed legislative changes. When the Administration prepares its forecasts, however, it assumes that the fiscal policy in the President's proposed budget will be adopted…Forecast errors may be affected by those different fiscal policy assumptions, especially when forecasts are made while policymakers are considering major legislative changes."

134 *Ibid*.

has been 1.30 percentage points and 0.90 percentage points, respectively.[135]

As to the accuracy of the EIA's GDP forecast, the agency reviews its projections in its *Annual Energy Outlook ("AEO") Retrospective Review*. There, the EIA has noted "[t]he projections in the AEO are not statements of what will happen but of what may happen given assumptions in the underlying National Energy Modeling System (NEMS)."[136]

As EIA makes clear, the Reference case projections assume current laws and regulations remain unchanged throughout the projection period.[137] The agency's projections, therefore, are based on the economic environment at the time of the forecast. As shown in Table 3 of the *AEO Retrospective Review*, the EIA compares its past real GDP growth projections to actual real GDP growth. In its 1994 forecast of GDP growth – a time during which the U.S. was coming out of a recession – the agency generally underestimated GDP growth. During the stronger economic times of the 2000s, the agency generally overestimated GDP growth into the future.[138] The agency's 2020 to 2050 reference case is based on the current economic environment of below average GDP growth,

135 *Ibid.*, at 2. Root mean square error.
136 U.S. Energy Information Administration, *Annual Energy Outlook Retrospective Review: Evaluation of AEO2018 and Prior Reference Case Projections,* December 2018, at 1. Clarification added.
137 U.S. Energy Information Administration, Annual Energy Outlook 2020 with Projections to 2050, January 2020, at 4.
138 U.S. Energy Information Administration, *Annual Energy Outlook Retrospective Review: Evaluation of AEO2018 and Prior Reference Case Projections,* December 2018, Table 3.

inflation, and interest rates.[139]

Q. PLEASE DESCRIBE DR. WOOLRIDGE'S CONCERNS WITH THE EMPIRICAL CAPITAL ASSET PRICING MODEL.

A. Dr. Woolridge believes the ECAPM is an "ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals."[140] That point aside, he does not agree with the use of adjusted Beta coefficients in the ECAPM.[141] For the reasons discussed below, I disagree with Dr. Woolridge's concerns.

Q. WHY DID YOU INCLUDE THE ECAPM IN YOUR ANALYSES?

A. As discussed in my Direct Testimony, numerous tests have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. Empirical studies have found that returns on low-Beta securities are higher than the CAPM would predict and lower than the CAPM would predict for high-Beta securities.[142] Simply, the ECAPM method addresses the tendency of the CAPM to underestimate the Cost of Equity for low-Beta coefficient companies such as regulated utilities. In its text on cost of capital analysis for regulated industries, for example, the Brattle Group summarizes a number of

[139] U.S. Energy Information Administration, Annual Energy Outlook 2020 with Projections to 2050, January 2020, at Table 20.
[140] Testimony of J. Randall Woolridge, at 116.
[141] Testimony of J. Randall Woolridge, at 117.
[142] Direct Testimony of Dylan W. D'Ascendis, at 89-90.

studies estimating the alpha component of the ECAPM.[143]

Q. HAS THE ECAPM METHOD BEEN RECOGNIZED IN OTHER REGULATORY JURISDICTIONS?

A. Yes. It has been accepted in Minnesota, Mississippi, and New York.[144] Additionally, the Commission recently found the ECAPM to be "credible, probative, and entitled to substantial weight."[145]

Q. HAVE YOU UNDERTAKEN ANY INDEPENDENT ANALYSES TO DETERMINE WHETHER THERE IS A RELATIONSHIP BETWEEN BETA COEFFICIENTS AND EXCESS RETURNS PRODUCED BY THE CAPM AND ECAPM?

A. Yes. I performed an analysis of excess returns produced by the CAPM, by Beta coefficient decile, over the eleven years ended 2019. The analysis compared the observed returns of the companies in the S&P 500 Index to expected returns

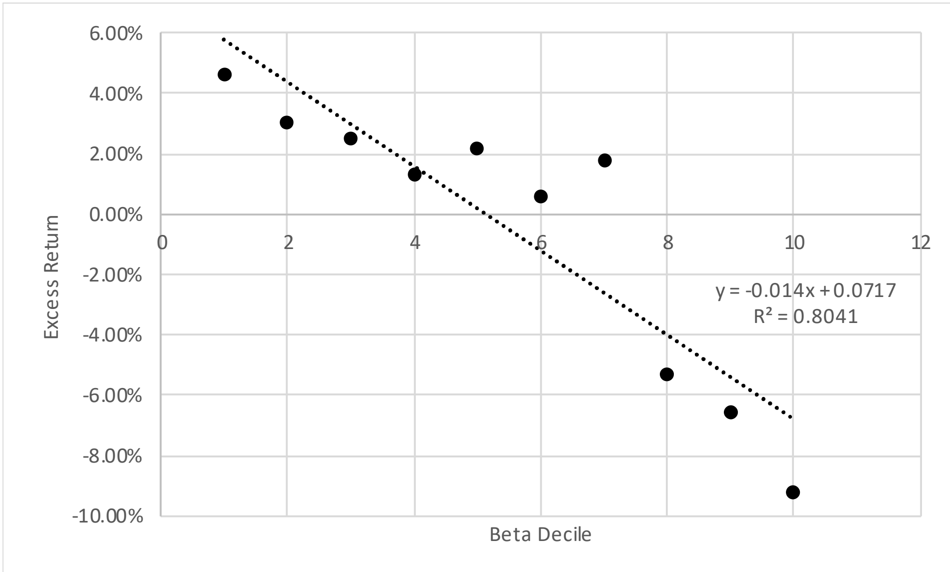
143 Villadsen, Vilbert, Harris, and Kolbe, Risk and Return for Regulated Industries, 2017, Table 4.1 at 83. Alpha is an adjustment to the security market line that increases the intercept and lowers the slope of the line.

144 Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Findings of Fact, Conclusions of Law, and Recommendation*, August 19, 2016, at 29; Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001, at 19; New York Public Service Commission, Case 16-G-0058, P*roceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32.

145 *In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 25, 2020, at 40.

based on the CAPM. Observed returns were calculated as the total return for each company from the first day of a given year to the end of that year. The expected return for each company was calculated using the CAPM as applied to the following annual data: (1) a risk-free rate equal to the average 30-year Treasury yield for that year; (2) an adjusted Beta coefficient as of the beginning of the year using Bloomberg's standard calculation method (two years of weekly return data, using the S&P 500 Index as the comparison benchmark); and (3) a market return equal to the S&P 500 Index total return for that year. The companies were grouped into deciles each year based on their Beta coefficients, and the median excess return (or return deficiency) was calculated for each decile group. Excess returns were calculated as the observed return less the return implied by the CAPM. Chart 9 (below) summarizes those results.

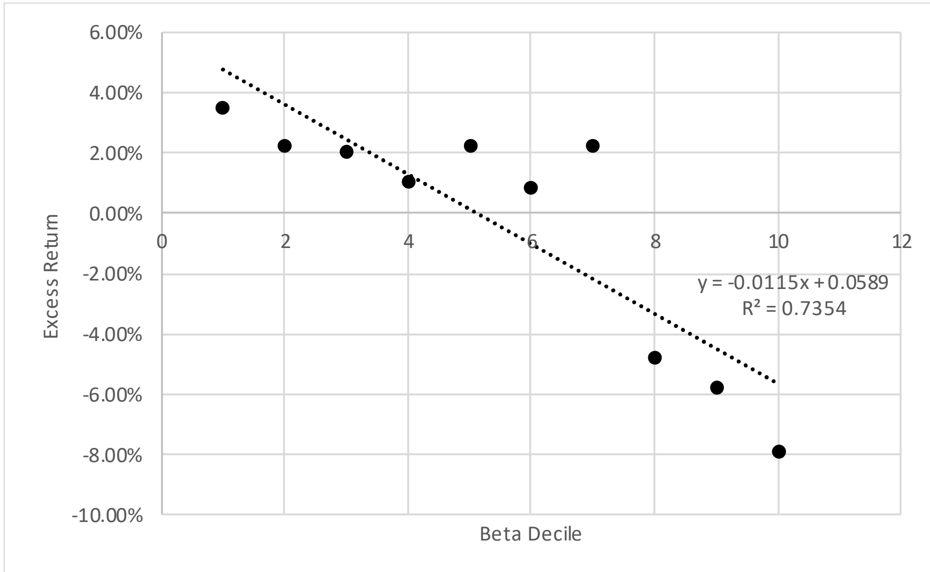
Chart 9: Excess Returns Under CAPM[146]



As Chart 9 demonstrates, the relationship between Excess Return and Beta coefficient deciles is strong, with deciles explaining approximately 80.00 percent of the Excess Return. Using the same data and calculating the Excess Return by reference to the ECAPM, produces the same downward sloping relationship, but not to the same degree (*see* Chart 10, below).

146 Source: Bloomberg Professional Services.

Chart 10: Excess Returns Under ECAPM[147]



There are two principal observations to be drawn from the data presented in Charts 9 and 10. First, under the ECAPM the slope coefficient is somewhat less negative (relative to the CAPM), suggesting a flatter relationship between Beta coefficient deciles and the excess return. The flatter slope moves closer to the point at which the excess return is zero across all deciles. Second, the excess return values are somewhat moderated under the ECAPM; the high excess returns are lower than under the CAPM, and the low excess returns are higher. Again, that finding suggests the ECAPM mitigates, but does not solve the issue of the CAPM underestimating returns for low-Beta coefficient firms.

In summary, Charts 9 and 10 support the position that the CAPM tends to underestimate returns for low-Beta coefficient firms, and the ECAPM

[147] Source: Bloomberg Professional Services.

moderates that effect to some extent, but it does not appear to eliminate it. Because the ECAPM mitigates the drift in Beta coefficients, I believe it is a reasonable method.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S CONCERN WITH THE USE OF ADJUSTED BETA COEFFICIENTS IN THE ECAPM APPROACH?

A. As discussed in my Direct Testimony, the use of adjusted Beta coefficients is not equivalent to the use of the ECAPM.[148] Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. Numerous studies have determined that at any given point in time the Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[149] As noted by Dr. Morin, "[t]he ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence."[150]

[148] Direct Testimony of Dylan W. D'Ascendis, at 90-91.
[149] Direct Testimony of Dylan W. D'Ascendis, at 89-90.
[150] Roger A. Morin, *New Regulatory Finance*, at 191 (2006).

F. Bond Yield Plus Risk Premium Analysis

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S RESPONSE TO YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. Dr. Woolridge argues the Risk Premium derived from the analysis is "inflated" and "is a gauge of *commission* behavior and not *investor* behavior."[151] Dr. Woolridge further notes that the Risk Premium approach results reflect "other utility- and rate case-specific information in setting ROEs"[152] and points to what he views as a potential discrepancy between settled and litigated cases.[153] Dr. Woolridge also suggests the analysis overstates the actual ROE because the estimated risk premium is based on historical Treasury yields, whereas the model is applied to current and expected yields.[154]

Q. WHAT IS DR. WOOLRIDGE'S POSITION REGARDING THE RISK-FREE RATES APPLIED IN YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Dr. Woolridge finds the Treasury bond yields used in my Bond Yield Plus Risk Premium analysis "excessive", and argues they must not be accurate because if they were, investors would not be buying Treasury bonds at their current yield"[155], then about 2.30 percent.

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151 Testimony of J. Randall Woolridge, at 119. [*Emphasis included in original*]
152 Testimony of J. Randall Woolridge, at 119.
153 Testimony of J. Randall Woolridge, at 119-120.
154 Testimony of J. Randall Woolridge, at 119.
155 Testimony of J. Randall Woolridge, at 118.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THAT POINT?

A. Dr. Woolridge's argument is misplaced. In his CAPM analysis, Dr. Woolridge relies on a 3.75 percent risk-free rate,[156] which is higher than the three risk-free rates presented in my Bond Yield Plus Risk Premium analysis and 150 basis points above the current 30-day average risk-free rate.[157] Still, Dr. Woolridge argues investors give such projections no weight in their decision to purchase bonds at current yields. I disagree. The Cost of Equity is fundamentally forward-looking, and the use of expected Treasury yields (such as the 3.75 percent Dr. Woolridge uses) is consistent with that principle.

Lastly, Dr. Woolridge's argument that investors would not acquire Treasury securities if they felt interest rates were to increase (because the price would decrease) appears to assume investors take short-term trading positions. Although that may be the case for some, I do not believe it is for all Treasury bond investors. In my experience, Treasury securities often are "immunized", by matching their duration to the duration of a corresponding liability (for example, in a benefit plan). In that case, reductions in the price brought about by higher interest rates are offset by the higher interest income associated with those rates. Because many investors in Treasury securities are institutions, whose objectives and strategies may go beyond short-term trading positions, we cannot say there is no implied risk of future rate increases.

156 Testimony of J. Randall Woolridge, at 65; Exhibit JRW-8.
157 *See*, Rebuttal Exhibit DWD-5.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT THE RISK PREMIUM ANALYSIS IS A STUDY OF UTILITY COMMISSION BEHAVIOR RATHER THAN INVESTOR BEHAVIOR?

A. Those cases, and their associated decisions, reflect the same type of market-based analyses at issue in this proceeding. Because authorized returns are publicly available (the proxy companies disclose authorized returns, by jurisdiction, in their 2018 SEC Forms 10-K),[158] it therefore is reasonable to conclude that data is reflected, at least to some degree, in investors' return expectations and requirements. From that perspective, ROE recommendations that are far removed from prevailing levels, such as Dr. Woolridge's, should be reconciled by reference to differences in risk. I do not believe Dr. Woolridge's recommendation reasonably does so.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT YOUR ANALYSIS APPLIES AN HISTORICAL RISK PREMIUM TO PROJECTED RATES AND, AS SUCH, OVERSTATES THE COST OF EQUITY?[159]

A. I applied both historical and projected interest rates to the regression coefficients developed in the Risk Premium analysis, not to an average

[158] *See, for example*, American Electric Power Company, Inc., SEC Form 10-K for the year ended December 31, 2018, at 4; ALLETE Inc., SEC Form 10-K for the year ended December 31, 2018, at 15-16; Duke Energy Corporation, SEC Form 10-K for the year ended December 31, 2018, at 16; WEC Energy Group, Inc., SEC Form 10-K for the year ended December 31, 2018, at 134–136.

[159] Testimony of J. Randall Woolridge, at 119.

historical risk premium. As discussed in my Direct Testimony, the regression coefficients specifically recognize that as interest rates decrease, the Equity Risk Premium increases.[160] A consequence of that relationship is that interest rates and the Cost of Equity generally move in the same direction, although not on a one-to-one basis. As projected interest rates increase, the Cost of Equity also increases, but not to the same degree. Dr. Woolridge's concern that I applied projected interest rates to an historical risk premium is misplaced, in that (1) the analysis does not rely on an historical risk premium; and (2) because the estimated risk premium does not increase in lock step with interest rates, the resulting ROE estimate does not overstate the Cost of Equity.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT YOUR RISK PREMIUM ANALYSIS MUST TAKE INTO CONSIDERATION THE SPECIFIC ASPECTS OF THIS PROCEEDING RELATIVE TO ALL OTHERS?[161]

A. There is no disagreement that every case has its unique set of issues and circumstances. Reviewing over 1,600 cases over many economic cycles and using that data to develop the relationship between the Equity Risk Premium and interest rates mitigates that concern.

[160] Direct Testimony of Dylan W. D'Ascendis, at 93-94, 95.
[161] Testimony of J. Randall Woolridge, at 119-120.

Q. IS IT A CONCERN, AS DR. WOOLRIDGE ARGUES, TO INCLUDE BOTH FULLY LITIGATED AND SETTLED RATE CASES IN YOUR RISK PREMIUM ANALYSIS?[162]

A. No, it is not. Of the 1,600 rate cases in my updated Risk Premium analysis (*see* Rebuttal Exhibit DWD-5), 1,158 were fully litigated and 459 were settled. More recently (from January 2015 through January 31, 2020), 76 cases were fully litigated and 98 were settled. Over the same period, the difference in average authorized returns between the two, however, was approximately 12 basis points. Further, the same inverse relationship between interest rates and the Equity Risk Premium is present, whether the analysis includes fully litigated rate cases, settled rate cases, or both.[163] I therefore disagree with Dr. Woolridge's concern.

G. Expected Earnings Analysis

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S CONCERNS WITH YOUR EXPECTED EARNINGS ANALYSIS.

A. Dr. Woolridge argues the Expected Earnings approach is inappropriate because: (1) it is accounting based and does not measure market-based investor return requirements; (2) book equity does not change with investor return requirements as do market prices; (3) the approach is circular; and (4) the data

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162 Testimony of J. Randall Woolridge, at 119-120.

163 Rebuttal Exhibit DWD-11.

partially reflect earnings of non-regulated operations.[164]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE?

A. Although I agree economic and financial factors and the market-based models that depend on them are important, those factors do not invalidate the Expected Earnings approach. As discussed in my Direct Testimony, no single method best captures investor expectations at all times and under all conditions.[165] Market-based models necessarily require us to draw inferences from market data based on the assumptions and construction of methods such as the DCF and CAPM approaches. The simplicity of the Expected Earnings approach is a benefit, not a detriment.

Although many factors affect stock returns and M/B ratios, the accounting-based ROE is one of them and cannot be ignored.[166] As a practical matter, the Economic Value Added consulting practices[167] and related value-based-management systems[168] encourage financial managers to focus on elements of the Return on Net Assets, and Return on Invested Capital.

In addition, the standard revenue requirements formula applied by the Commission explicitly recognizes the validity of the book value of equity by choosing to measure capital structures based on book values, rather than market

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164 Testimony of J. Randall Woolridge, at 121-123.

165 Direct Testimony of Dylan W. D'Ascendis, at 5.

166 I am not suggesting the M/B ratio necessarily will equal 1.00 when the accounting-based ROE equals the Cost of Equity.

167 *See*, G. Bennett Stewart, The Quest for Value, HarperCollins Publishers, Inc., 1990.

168 *See,* Institute of Management Accountants, *Measuring and Managing Shareholder Value Creation*, 1997.

value. The Expected Earnings approach provides a direct measure of the book-based return comparable-risk utilities are expected to earn. In that sense, it is a direct measure of the expected opportunity cost on the book value of equity. Equally important, because it looks to the earnings expected of comparable-risk companies, the approach is consistent with the *Hope* and *Bluefield* "comparable return" standard. As Dr. Morin notes, the method "is easily understood, and is firmly anchored in regulatory tradition," concluding that "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with [Expected] Earnings, is highly meaningful."[169]

Lastly, among the growth rates Dr. Woolridge considers in his DCF analyses is the "sustainable growth" method. Under that method, expected growth depends on the expected return on the book value of common equity, and the extent to which that return is retained (that is, not paid in dividends). Although he does not adjust them to reflect average book value balances, Dr. Woolridge reports mean and median expected returns of 10.40 percent and 10.30 percent, respectively.[170]

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169 Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006 at 395. [clarification added].

170 *See*, Exhibit JRW-7, page 4. Mean and median of Dr. Woolridge's proxy group.

Q. HAS THE COMMISSION ACCEPTED THE EXPECTED EARNINGS ANALYSIS IN PAST CASES?

A. Yes. In the Company's prior rate case (Docket No. E-7, Sub 1146), the Commission found the Comparable Earnings analysis, which is similar to my Expected Earnings Analysis, to be "credible".[171] The Commission also has noted the reasonableness of the Comparable Earnings analysis in prior orders, stating that it is "credible, probative and entitled to substantial weight."[172]

H. Market-To-Book Ratios and the Cost of Equity

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S POSITION REGARDING THE RELATIONSHIP BETWEEN M/B RATIOS AND THE COST OF EQUITY.

A. Dr. Woolridge suggests M/B ratios greater than one[173] indicate the subject company's earned Return on Equity exceeds its Cost of Equity.[174] In Dr. Woolridge's view, the relationship between M/B ratios and the Cost of Equity is "relatively straightforward":

> A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book

171 North Carolina Utilities Commission, Docket No. E-7, Sub 1146, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, at 49.

172 North Carolina Utilities Commission, Docket No. E-2, Sub 1131, Docket No. E-2, Sub 1142, Docket No. E-2, Sub 1103, Docket No. E-2, Sub 1153, Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, at 82.

173 M/B ratios in excess of unity simply means that the firm is worth more as a going concern than the book value of its assets.

174 Testimony of J. Randall Woolridge, at 39-42.

value.[175]

In discussing normative economic models of firms, which he notes are "developed under very restrictive assumptions",[176] Dr. Woolridge explains that in a perfectly competitive market, firms will produce to the point that price equals marginal cost:

> Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.[177]

Dr. Woolridge suggests the same relationship holds in the utility sector, arguing "[g]iven that the market-to-book ratios have been above 1.0 for a number of years, this also demonstrates that utilities have been earnings ROEs above the cost of equity capital for many years."[178] In short, Dr. Woolridge's position is clear: If a utility's M/B ratio is greater than one, its earned return is greater than its investor-required return.

Q. HAS DR. WOOLRIDGE UNDERTAKEN HIS OWN ANALYSES OF THE RELATIONSHIP BETWEEN M/B RATIOS AND EARNED RETURNS?

A. Yes. Dr. Woolridge performs a regression analysis to examine the relationship

175 Testimony of J. Randall Woolridge, at 41.
176 Testimony of J. Randall Woolridge, at 39.
177 Testimony of J. Randall Woolridge, at 39.
178 Testimony of J. Randall Woolridge, at 42.

between the earned Return on Equity and M/B ratios for all electric and gas utilities covered by Value Line.[179] Based on his analysis, Dr. Woolridge argues there is a strong relationship between the two variables. In fact, because he reports an R-Squared of 50.00 percent (in the first analysis), Dr. Woolridge concludes there is a "statistically significant positive relationship between ROEs and market-to-book ratios for electric utilities and gas companies."[180]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THOSE POINTS?

A. Although expected earned returns are a factor that weigh in M/B ratios, they are not the only factor. Dr. Woolridge's linear regression says as much; other variables account for 50.00 percent of the variation in M/B ratios. Based on Dr. Woolridge's regression analysis, we cannot conclude earned returns are greater than required returns whenever M/B ratios are greater than one.

Looking beyond Dr. Woolridge's analysis, there are fundamental reasons we should not rely on M/B ratios as the measure of excess returns. By way of background, the M/B ratio equals the market value (or stock price) per share, divided by the total common equity (or the book value) per share. Book value per share is an accounting construct that reflects historical costs. In contrast, market value per share (*i.e.,* the stock price) is forward-looking, and a function of many variables, including, but not limited to, expected earnings and

179 Testimony of J. Randall Woolridge, at 42, Exhibit JRW-4.
180 Testimony of J. Randall Woolridge, at 42 and Exhibit JRW-4.

cash flow growth, expected payout ratios, measures of "earnings quality," the regulatory climate, the equity ratio, expected capital expenditures, and the earned return on common equity.[181] As Dr. Morin states, it is rarely the case in cost of service-based regulation that M/B ratios equal 1.00:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the market-to-book (M/B) ratio of a given stock exceeds unity. This was particularly relevant in the capital market environment of the 1990s and 2000s whose utility stocks are trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.[182]

Here, Dr. Woolridge argues that whenever the earned ROE is greater than the Cost of Equity ("*k*"), the M/B ratio will exceed one.[183] Under certain restrictive assumptions, the DCF model can be rewritten to express the M/B ratio[184] as follows:

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181 *See*, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 366. Please note, Dr. Morin cites several academic articles that address the various factors that affect the M/B ratio for utilities.

182 *Ibid*., at 434.

183 Testimony of J. Randall Woolridge, at 41.

184 B. Branch, A. Sharma, C. Chawla, and F. Tu, *An Updated Model of Price-to-Book*, Journal of Applied Finance, No. 1 (2014).

$$\frac{\mathrm{M}}{\mathrm{B}} = \frac{\mathrm{ROE} - g}{k - g} \qquad [3]$$

where ROE is the return on book equity, k is the Cost of Equity, and g is the long-term growth rate. Rearranging Equation [3] produces the familiar Gordon Growth model:

$$\mathrm{P} = \frac{\mathrm{D}}{k - g} \qquad [4]$$

and the Constant Growth DCF model:

$$\mathrm{P} = \frac{\mathrm{D}}{\mathrm{P}} + g \qquad [5]$$

Dr. Woolridge's assumed relationship between the accounting Return on Equity and the Cost of Equity therefore directly relies the Constant Growth DCF model; one cannot be assumed without the other. Any inferences drawn from relationships among M/B, ROE, and k from Equation [3] therefore rely on the explicit acceptance of all assumptions underlying the Constant Growth DCF model. That is, Equation [3] only can be drawn from the Constant Growth DCF model if we assume: (1) a constant dividend payout ratio in perpetuity; (2) no stock issuances or repurchases; (3) the P/E ratio, and the M/B ratio will remain constant in perpetuity; and (4) the Cost of Equity estimated today will never change. Taken together, those assumptions are quite restrictive, especially in the currently unstable capital market. Consequently, I do not believe we can assume the definitive and permanent relationship among M/B, ROE, and k that Dr. Woolridge's position assumes.

Q. WHAT WOULD BE THE RESULT IF REGULATORY COMMISSIONS DID FORCE M/B RATIOS TOWARD UNITY?

A. Looking to Dr. Woolridge's Electric Proxy Group, the average capital loss for equity investors would be about 50.00 percent.[185] That loss would not just affect investors, it also would substantially diminish the ability of utilities to attract external capital. To summarize, if regulatory commissions were to set rates with an eye toward moving the M/B ratio toward unity, that practice may well impede the ability to attract the capital required to support its operations, especially in markets during which the M/B ratio for the overall market is significantly greater than 100.00 percent.

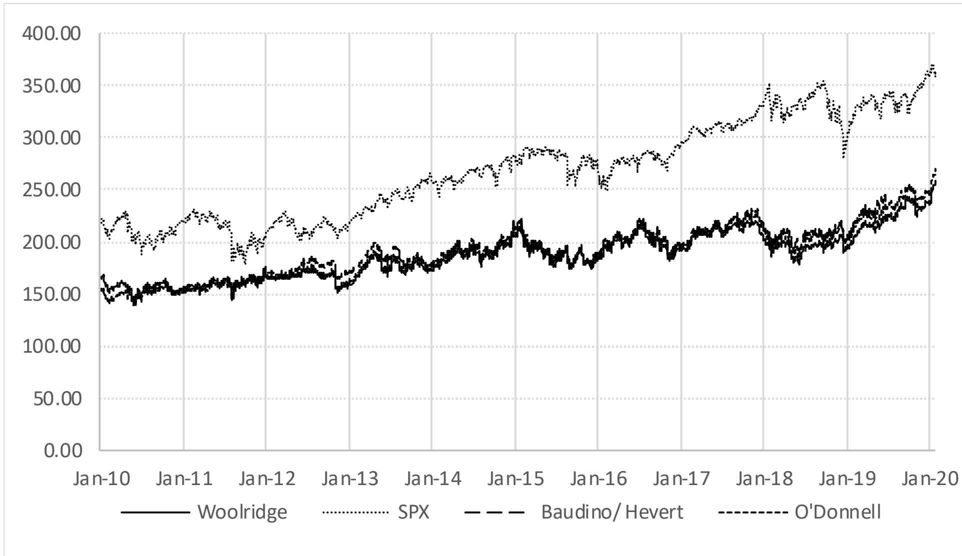
Q. HAVE UTILITY M/B RATIOS GENERALLY EXCEEDED 1.00?

A. Yes, they have. Chart 11 (below) demonstrates that since 2010, the Opposing Witnesses' proxy group M/B ratios have exceeded 1.00, and generally have moved with the S&P 500 Index M/B ratio. If Dr. Woolridge is of the view that M/B ratios greater than 1.00 reflect earned returns greater than the Cost of Equity, it follows that utility commissions have long been incorrect in their ROE determinations. If, over many years and across many companies, investors felt the returns they expected had so significantly exceeded the returns they required, they would adjust their requirements. In Dr. Woolridge's construct, the difference between expected and required returns would dissipate, and take

185 Based on Dr. Woolridge's proxy group average M/B ratio of 200.00. (200.00 -100.00)/ 200.00 = 50.00 percent. Exhibit JRW-2, page 1.

with it the difference between market and book values. That has not occurred.

Chart 11: Comparison Groups, S&P 500 Market/Book Ratios (2010 – 2020)[186]



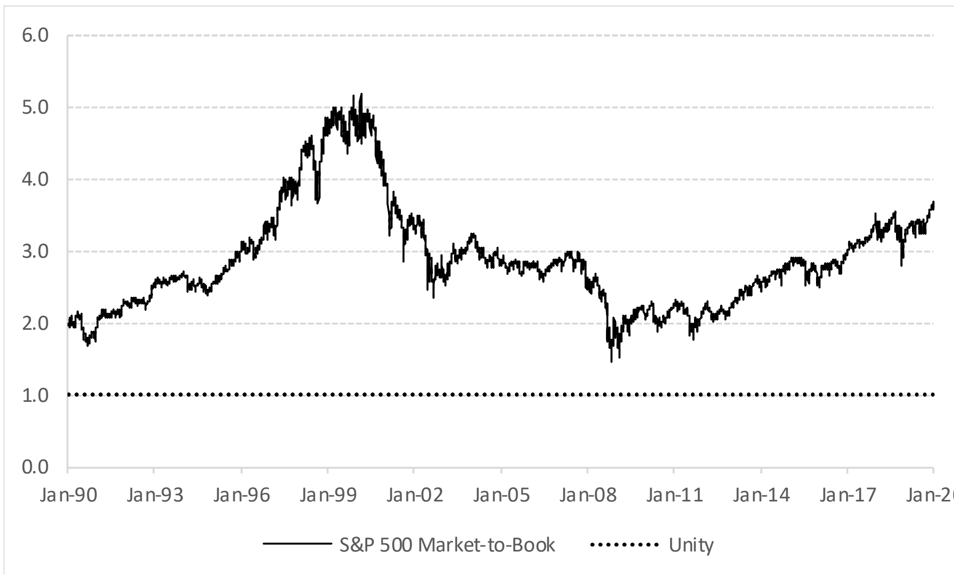
Lastly, although the broad market represents a cross section of market sectors, of which the utility sector is just one, the observed variation in market-level M/B ratios speaks to the time-varying influence of general macroeconomic factors, not to any failure of regulation. The relationship between the Opposing Witnesses' proxy group M/B ratios and the S&P 500 M/B ratio is positive and statistically significant. That is the case even when we control for serial correlation.[187] We therefore reasonably can conclude that broad macroeconomic and capital market factors affect both utilities and non-regulated entities.

186 Source: S&P Global Market Intelligence, Bloomberg Professional.
187 Using the Prais-Winsten routine.

Q. HAVE M/B VALUES GENERALLY EXCEEDED 1.00 FOR THE BROAD EQUITY MARKET?

A. Yes, they have. As Chart 12 (below) demonstrates, since 1990 the average M/B ratio for the S&P 500 Index has been 2.89; it has never reached unity.

Chart 12: S&P 500 M/B Ratio Over Time[188]



188 Source: Bloomberg Professional Services.

Q. ARE YOU AWARE OF LITERATURE THAT HAS FOCUSED ON THE M/B RATIOS OF REGULATED UTILITIES?

A. Yes. Literature focusing on utilities has long concluded that regulation may not necessarily result in M/B ratios approaching unity. As noted by Phillips in 1993:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.'[189]

In 1988 Bonbright stated:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. In short, market prices are beyond the control, though not beyond the influence, of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels.[190]

And in 1972 Stewart Myers came to the following conclusion:

> In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that

189 Charles F. Phillips, The Regulation of Public Utilities – Theory and Practice (Public Utility Reports, Inc., 1993) at 395.

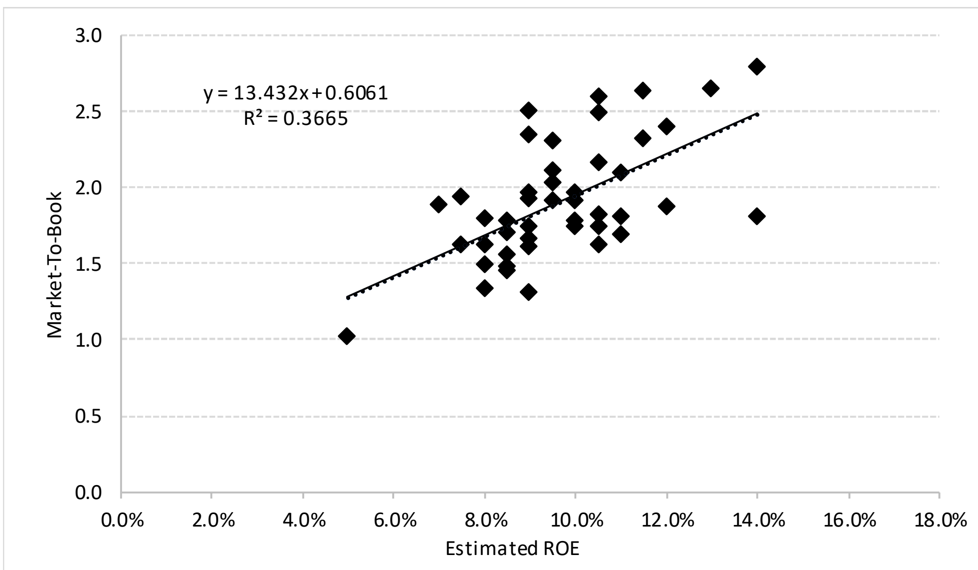
190 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates (Public Utilities Reports, Inc., 1988), at 334.

> the market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book.[191]

Q. HAVE YOU REVIEWED THE ROE AND M/B RATIO DATA PROVIDED IN EXHIBIT JRW-4?

A. Yes, I have updated the chart contained in Exhibit JRW-4, including the regression coefficients, based on the method described by Dr. Woolridge[192] (*see* Chart 13, below).

Chart 13: Update of Exhibit JRW-4, With Regression Coefficients[193]



Based Dr. Woolridge's approach, an M/B ratio of 1.00 is associated with an

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191 Stewart C. Myers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 3, No. 1 (Spring 1972), at 58-97.

192 Testimony of J. Randall Woolridge, at 42; Exhibit JRW-4.

193 Source: Value Line, accessed February 19, 2020.

ROE of 2.93 percent,[194] a highly improbable condition. Even the one observation for which the M/B ratio is about 1.00 suggests an ROE of approximately 5.00 percent. Dr. Woolridge's data, therefore, do not support the theory that ROEs greater than 1.00 demonstrate earned returns exceed investors' required returns.

Q. HAVE YOU ANALYZED WHETHER THE ACTUAL EARNED RETURN ON EQUITY EXPLAINS THE M/B RATIOS FOR DR. WOOLRIDGE'S PROXY GROUP?

A. Yes, I have. Using data provided by S&P Global Market Intelligence, I performed a regression analysis in which the M/B ratio was the dependent variable, and the Return on Average Common Equity ("ROACE") for 2018 was the explanatory variable. As shown in Rebuttal Exhibit DWD-12, the R-squared was approximately 32.00 percent. An R-squared of 32.00 percent means that factors other than ROACE explain up to 68.00 percent of M/B ratios in the proxy group.[195] Those results support the position that although the earned Return on Equity is a factor that explains M/B ratios, it is not the only factor. In any case, the regression equation indicates that an M/B ratio of 1.00 (that is, 100.00 percent) is associated with a Return on Common Equity of approximately -8.68 percent; an M/B ratio of 1.10 relates to an ROACE of approximately -6.82 percent. Because those estimates are nonsensical, I do not

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194 1.00 = 0.606 + (13.432 x 2.93%).

195 0.68 = (1 – 0.32).

agree that M/B ratios greater than 1.00 demonstrate earnings in excess of investors' requirements.

I. Relative Risk

Q. ON PAGE 27 OF HIS DIRECT TESTIMONY, DR. WOOLRIDGE ARGUES THAT THE COMPANY IS "LESS RISKY" THAN THE PROXY COMPANIES, BECAUSE ITS CREDIT RATING IS HIGHER THAN THE PROXY GROUP AVERAGE. DO YOU BELIEVE CREDIT RATINGS ARE A FULL MEASURE OF THE COMPANY'S EQUITY RISK ITS PEERS?

A. No, I do not. Although over the long term credit ratings (and therefore credit spreads) may be directionally related to the Cost of Equity over the long-term, a change in one is not a direct measure of a change in the other. Debt and equity are entirely different securities with different risk/return characteristics, different lives, and different investors. Debt investors have a contractual, senior claim on cash flows not available to equity investors and as such, equity investors bear the residual risk of ownership. Moreover, debt investors' exposure to business and financial risk is finite (due to the finite life of debt) whereas equity investors are exposed to residual risk in perpetuity. Consequently, any inferences drawn from differences in credit ratings regarding the Company's Cost of Equity should be drawn with caution.

A visible measure of the distinction of the risks to which debt and equity investors are exposed is the difference in their respective Beta coefficients. Although I disagree with his conclusions, Dr. Woolridge recommends an average Beta coefficient of 0.55 for his proxy group.[196] Duff & Phelps notes that as of June 2019, Beta coefficients for A-rated debt was 0.09,[197] far below the equity Beta coefficient assumed by Dr. Woolridge. In fact, a debt Beta coefficient of 0.71 is associated with Caa rated debt, which is considered below investment grade.[198] Those differences are a clear indication that the risks assumed by debt investors are far different than those assumed by equity investors.

Q. DOES THE DATA PROVIDED BY DR. WOOLRIDGE INDICATE A RELATIONSHIP BETWEEN COST OF EQUITY ESTIMATES AND CREDIT RATINGS?

A. No, they do not. Using the growth rates and dividend yields reported by Dr. Woolridge, I produced Constant Growth DCF results for each of the comparison companies.[199] Those results do not support Dr. Woolridge's conclusion. For example, Southern Company is rated A-, and Hawaiian Electric Industries, Inc. is rated BBB-, three credit "notches" apart. Yet, based on Dr. Woolridge's data, their DCF results are 7.08 percent and 6.67 percent, respectively, only 41 basis points apart. On the other hand, Consolidated Edison, Inc. and Evergy Inc. are

[196] Exhibit JRW-8, page 1.
[197] Source: Duff & Phelps Cost of Capital Navigator.
[198] *Ibid*.
[199] Rebuttal Exhibit DWD-13.

both are rated A-, but their DCF results differ by 435 basis points.[200] We cannot say, based on Dr. Woolridge's primary method, that there is a definitive relationship between credit rating notches and Cost of Equity estimates.

Q. DID YOU PERFORM ANY ANALYSES TO DETERMINE WHETHER DR. WOOLRIDGE'S DATA SUPPORTS THE ASSUMPTION THAT THERE IS A QUANTIFIABLE DIFFERENCE IN THE COST OF EQUITY FOR COMPANIES WITH DIFFERENT BOND CREDIT RATINGS?

A. Yes. Using the same Constant Growth DCF results for each of Dr. Woolridge's comparison companies discussed above, I applied "credit scores" to Dr. Woolridge's comparison companies by converting the S&P bond ratings reported in his Direct Testimony to a numerical value. If there is a quantifiable relationship between the proxy companies' credit ratings and Cost of Equity, there should be a positive, statistically significant relationship between the credit score and the DCF results. That is, as credit quality deteriorates (resulting in a higher score), the Cost of Equity should increase. Therefore, I performed a regression analysis in which the dependent variable was the DCF result and the explanatory variable was the credit score. As shown in Rebuttal Exhibit DWD-13, the regression analysis showed no significant statistical relationship between the two, and the relationship was negative. In fact, the highest R-

[200] 30-day average dividend yields.

squared of the regressions was only 0.0045, which indicates that credit ratings accounted for, at most, 0.45 percent of the change in the DCF-estimated Cost of Equity.[201]

Q. DO YOU HAVE ANY OTHER CONCERNS WITH DR. WOOLRIDGE'S REVIEW OF CREDIT RATINGS?

A. Yes, I do. My concern with Dr. Woolridge's comparison of DE Carolinas to the credit ratings of the proxy companies is that Moody's ratings methodology specifically considers the relationship between parent and operating companies, and typically rates parent companies lower the operating company subsidiaries. As Moody's explains:

> Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and nonutility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors.[202]

Moody's further explains its assessment of structural subordination considers a variety of factors, such that "a formulaic approach is not practical".[203] Based

201 The rank correlation coefficient between DCF results and credit ratings was approximately negative 0.035, which is statistically insignificant at the 95.00 percent level.
202 Moody's Investors Service, *Rating Methodology, Regulated Electric and Gas Utilities*, June 23, 2017, at 22.
203 *Ibid*. at 23.

on its review, Moody's may reduce the parent company rating up to three notches relative to the operating companies.

That relationship holds among the companies in Dr. Woolridge's proxy group. For example, Southern Company's Issuer Credit Rating from Moody's is Baa2, whereas Alabama Power's rating is A1. Similarly, whereas WEC Energy Group's rating is Baa1, Wisconsin Electric Power's rating is A2. A similar relationship applies to Duke Energy Corporation and DE Carolinas; the parent rating is Baa1, and DE Carolinas' rating is A1.[204] Rebuttal Exhibit DWD-14 provides the parent and operating subsidiary credit ratings for the 30 companies in Dr. Woolridge's proxy group. As that exhibit demonstrates, in each case the parent company credit rating is generally one to two notches below the utility operating company ratings.

Because Dr. Woolridge's comparison of DE Carolinas to parent companies does not reflect Moody's focus on structural subordination, it incorrectly suggests the Company is less risky than its peers. When we apply the proper comparison, operating companies to operating companies, we see that is not the case.

[204] Source: S&P Global Market Intelligence.

Q. DID DR. WOOLRIDGE STATE THE COMPANY'S OTHER UNIQUE RISK FACTORS CAN BE ATTRIBUTED TO THE COMPANY'S CREDIT RATING?

A. Yes. Dr. Woolridge believes the credit rating process reflects the unique risk factors I described in my Direct Testimony, including the Company's relatively high level of capital investment, its generation portfolio, and environmental regulations.[205] I do not disagree with Dr. Woolridge that rating agencies may analyze those specific factors in their review. As explained above, however, I do not believe credit ratings are a full measure of equity risk.

J. Flotation Costs

Q. DID DR. WOOLRIDGE ADDRESS THE ISSUE OF FLOTATION COSTS IN HIS DIRECT TESTIMONY?

A. Yes. Dr. Woolridge devotes several pages of his testimony discussing various reasons why he believes such an adjustment is not necessary.[206] Dr. Woolridge does not account for flotation costs, reasoning that flotation costs for stock issuances are not out-of-pocket costs and, even if they were, current market conditions suggest that a *reduction* to the Cost of Equity is required to account for flotation costs.[207] Additionally, Dr. Woolridge asserts I did not identify any flotation costs for DEC and that North Carolina legal precedent precludes the

[205] Testimony of J. Randall Woolridge, at 123-124.
[206] Testimony of J. Randall Woolridge, at 124-128.
[207] Testimony of J. Randall Woolridge, at 125-126, 127-128.

Company from recovering flotation costs when it does not expect to issue stock in the near future.[208]

Q. PLEASE RESPOND TO DR. WOOLRIDGE IN THAT REGARD.

A. I disagree with Dr. Woolridge's position that flotation costs for stock issuances are different than issuance costs associated with long-term debt. Companies pay the same types of fees (both direct and indirect) regardless of whether they are issuing equity or debt. As to Dr. Woolridge's observation that underwriter fees are not "out-of-pocket" expenses,[209] I view that to be a distinction without a meaningful difference. Whether paid directly or via an underwriting discount, the cost results in net proceeds that are less than the gross proceeds. I also disagree with Dr. Woolridge's position that flotation costs could represent a *reduction* in Cost of Equity. Flotation costs are true and necessary costs to the issuer, and represent funds that otherwise would be invested in long-lived assets. As explained in my Direct Testimony, to the extent flotation costs are not recovered, the issuing company is denied a portion of the opportunity to earn its expected (or required) return;[210] that point is further demonstrated in Rebuttal Exhibit DWD-15.

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208 Testimony of J. Randall Woolridge, at 124-125.
209 Testimony of J. Randall Woolridge, at 126.
210 Direct Testimony of Dylan W. D'Ascendis at 35.

Q. HAS DUKE ENERGY CORPORATION RECENTLY ISSUED COMMON STOCK?

A. Yes, it has. Duke Energy Corporation issued 28.75 million shares of common stock on November 18, 2019, after the Company filed its rate case. As explained in my Direct Testimony, although the Company is a wholly owned subsidiary of Duke Energy, it is appropriate to consider flotation costs because wholly owned subsidiaries receive equity capital from their parents and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based on the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately would penalize the investors that fund the utility operations and would inhibit the utility's ability to obtain new equity capital at a reasonable cost.[211] Consequently, Dr. Woolridge's position that the Company had no plans to issue stock is incorrect.

K. North Carolina Economic Conditions

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S RESPONSE TO YOUR ASSESSMENT OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. In my Direct Testimony I reviewed several measures of economic conditions, including the rate of unemployment, real Gross Domestic Product growth,

[211] Direct Testimony of Dylan W. D'Ascendis, at 35.

median household income, residential electricity rates, and broad measures of income and consumption.[212] Based on that review, I found economic conditions in North Carolina have improved since the Company's last rate case; Dr. Woolridge generally agrees with that conclusion.[213] Dr. Woolridge argues, however, that although economic conditions generally have improved, certain measures do not support the Company's proposed Rate of Return, including my recommended ROE.[214]

Q. WHAT ARE YOUR CONCLUSIONS REGARDING ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. For the reasons discussed in my response to Mr. Baudino, I disagree with Dr. Woolridge's position regarding my review of the economic conditions in North Carolina. As discussed in my Direct Testimony, the unemployment rate has fallen consistently over the past decade in both North Carolina and the Company's service territory. In addition, the growth in the State's GDP has been relatively consistent the national GDP, while the overall cost of living in North Carolina is below the national average. Residential electricity rates in North Carolina have grown at a slower pace than the national average and remain below the national average.[215]

I appreciate there seems to be no fundamental disagreement that

212 *See,* Direct Testimony of Dylan W. D'Ascendis, at 53-63.
213 Testimony of J. Randall Woolridge, at 129.
214 Testimony of J. Randall Woolridge, at 129-130.
215 Direct Testimony of Dylan W. D'Ascendis, at 61-62.

conditions have improved since the Company's last rate case. I also appreciate that the Commission has the difficult task of considering those conditions as it balances the interests of investors and consumers. In my view, Dr. Woolridge's recommendation is unduly low and is not supported by the improving economic conditions in North Carolina and the Company's service territory.

Q. IN YOUR OPINION, IS THE PROPOSED ROE FAIR AND REASONABLE TO DE CAROLINAS, ITS SHAREHOLDERS, AND ITS CUSTOMERS, AND NOT UNDULY BURDENSOME TO THE COMPANY'S CUSTOMERS CONSIDERING THE EFFECT OF THESE CHANGING ECONOMIC CONDITIONS?

A. Yes. Based on the factors discussed above, I believe that an ROE of 10.50 percent is fair and reasonable to DE Carolinas, its shareholders, and its customers in light of the effect of the improving economic conditions.

L. Capital Structure

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE.

A. Dr. Woolridge suggests that because Duke Energy's equity ratio is lower than the DE Carolinas', the Company is engaging in double leverage.[216] On that basis, Dr. Woolridge's primary recommendation is a hypothetical capital

[216] Testimony of J. Randall Woolridge, at 30-35.

structure consisting of 50.00 percent long-term debt and 50.00 percent common equity.[217] To support his recommendation, Dr. Woolridge compares the Company's capital structure to electric utility capital structures at the holding company level. That review suggests the Company's peers finance their utility assets with as little as 28.90 percent common equity.[218]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S APPROACH AND CONCLUSIONS?

A. No, I do not. As explained below, companies (including subsidiary companies) are financed in light of the specific risks and funding requirements associated with their individual operations. As such, the proper point of comparison is the mix of long-term capital (common equity, preferred stock, and long-term term debt) in place at utility operating companies, not utility holding companies. The nature of utility operations, and the corresponding nature of the assets providing utility service, create common financing objectives and constraints addressed by financing practices at the operating company level. Instead, Dr. Woolridge's recommendation to increase the Company's financial leverage by reference to holding company capital structures would increase its financial risk and, therefore, its cost of capital.

217 Testimony of J. Randall Woolridge, at 35-36.
218 *See*, Exhibit JRW-2, page 1.

Q. WHAT FACTORS DO UTILITIES GENERALLY CONSIDER IN DEVELOPING THEIR TARGET CAPITAL STRUCTURES?

A. Capital structure management is dynamic and complex, looking to satisfy multiple objectives subject to multiple constraints. Utilities must focus on the nature of the assets providing utility service, and recognize the constraints brought about by the obligation to serve. It therefore is important to understand utility financing practice, including the principles and constraints that drive financing decisions, and how that practice is reflected in the cost of capital.

In many ways, the nature of regulation determines the nature of utility assets, and how they are financed. In exchange for the obligation to serve, equity investors expect utilities to have the opportunity to earn a fair return on prudent investments. As the regulated rate of return granted to utilities is below that expected from unregulated enterprises, the nature of regulation is such that the variation in returns (that is, the expected risk) for utilities is expected to be less than those of unregulated companies. It is the nature of regulation that enables utilities to finance large, essentially irreversible, investments that are recovered over decades. Financing practice therefore must address the nature of investments made under the regulatory compact.

It also is important to keep in mind that capital structures, and the financial strength they support, are set not only to ensure capital access during normal markets, but to enable access when markets are constrained. The reason is straightforward: The obligation to serve is not contingent on capital market conditions. When markets are constrained, only those utilities with sufficient financial strength are able to attract capital at reasonable terms. That ability provides those utilities with critically important financing flexibility.

The requirement to access the capital markets in all market conditions can be contrasted with the financial needs of other entities without the legal obligation to serve. Because of that obligation, the financial flexibility brought about by the access to both long-term capital and short-term liquidity is critical for utilities' financial integrity, and their ability to continually attract capital. Unregulated firms have options to choose whether, where, and when to make investments; what services or products will be offered; whether to invest in expansions; and whether to cease operations in a given location. That is, unregulated companies may adjust the timing and amount of their major capital expenditures to align with economic cycles, and to defer decisions and investments to better match market conditions. Regulated companies have limited options to do so. Ensuring the financial strength to access capital because of the reduced spending flexibility therefore is critically important to utilities, their investors, and their customers.

As noted above, an appropriate capital structure is important not only to ensure long-term financial integrity, it also is critical to enabling access to capital during constrained markets, or when near-term liquidity is needed to fund extraordinary requirements. In that important respect, the capital structure, and the financial strength it engenders, must support both normal circumstances and periods of market uncertainty. Optimizing the capital structure therefore is a very complex process, which balances the need to maintain an appropriate financial profile while ensuring reasonable capital cost rates.

Q. IS THERE A GENERAL FINANCING PRACTICE TYPICALLY USED BY UTILITIES?

A. Yes, there is. Although capital structure optimization is complex, there are certain principles that commonly apply among utilities. In my experience, the financing practice sometimes referred to as "maturity matching" is chief among those principles. That practice aligns the average life of the securities in the capital structure with the average lives of the assets being financed.[219] As noted by Brigham and Houston, "[t]his strategy minimizes the risk that the firm will be unable to pay off its maturing obligations."[220]

The perpetual nature of common equity makes it an important component of the capital structure. Because long-term debt generally has a duration shorter than the average life of the rate base, common equity is needed to extend the capital structure's duration to more closely match that of the rate

219 This is not to say that an individual dollar may be traced from its source to its use.

220 Brigham, Eugene F. and Joel F. Houston, Fundamentals of Financial Management, Concise 4th Ed., Thomson South-Western, 2004, at 574.

base. That is, owing to its perpetual life, common equity extends the weighted average life of the capital structure, and mitigates financing risk. Conversely, relying more heavily on debt increases the risk of refinancing maturing obligations during less accommodating market environments.

Q. IF COMPANIES MATCH THE LIVES OF THEIR ASSETS WITH THE TERM OF THE SECURITIES FINANCING THEM, CAN INDIVIDUAL SOURCES OF FINANCING BE TRACKED TO SPECIFIC ASSETS?

A. No. Because cash is fungible, it is not feasible to track a given dollar from its source to its use. Rather, companies tend to apply the more general maturity matching strategy under which short-term debt is borrowed to satisfy the overall, day-to-day, fluctuating, and somewhat unpredictable, cash needs, not to finance an individual utility function.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S CONCLUSION THAT THE COMPANY'S CAPITAL STRUCTURE "CONSISTS OF MORE COMMON EQUITY AND LESS FINANCIAL RISK"[221] THAN THE OTHER COMPANIES IN THE PROXY GROUP?

A. No, I do not. Dr. Woolridge's assessment focuses on the proxy group average, without considering differences within the group. As with all statistical analyses, a single metric – in this case a simple average – may not be meaningful

[221] Testimony of J. Randall Woolridge, at 35.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S CONCLUSION THAT THE COMPANY'S CAPITAL STRUCTURE "CONSISTS OF MORE COMMON EQUITY AND LESS FINANCIAL RISK"[222] THAN THE OTHER COMPANIES IN THE PROXY GROUP?

A. No, I do not. Dr. Woolridge's assessment focuses on the proxy group average, without considering differences within the group. As with all statistical analyses, a single metric – in this case a simple average – may not be meaningful in isolation. For example, the common equity ratio for the Updated Proxy Group ranges from 45.65 percent to 61.20 percent (*see* Rebuttal Exhibit DWD-7). The Company's proposed equity ratio of 53.00 percent is 8.20 percentage points below the high end of the range. Eleven of the 20 proxy companies have average common equity ratios above the Company's proposed equity ratio. Based on the Updated Proxy Group as a whole, it is apparent that a capital structure of 53.00 percent common equity and 47.00 percent long-term debt is consistent with industry practice.

Q. HAS THE COMMISSION RECENTLY AUTHORIZED COMMON EQUITY RATIOS IN LINE WITH THE COMPANY'S PROPOSED RATEMAKING CAPITAL STRUCTURE?

A. Yes, it has. In recent cases, the Commission has authorized common equity ratios of 52.00 percent for Dominion Energy North Carolina, the Company,

222 Testimony of J. Randall Woolridge, at 35.

Duke Energy Progress, and Piedmont Natural Gas.[223]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT IT IS APPROPRIATE TO LOOK TO THE PROXY GROUP CAPITAL STRUCTURE AT THE HOLDING COMPANY LEVEL?[224]

A. No, I do not. Dr. Woolridge's position is based on the fact that the operating subsidiaries are not publicly traded. Although there may not be market data at the operating subsidiary level on which to perform cost of capital analyses, Dr. Woolridge fails to acknowledge the proxy companies generally report capital structure data for its regulated operating subsidiaries.

Quite simply, when assessing the appropriate capital structure for ratemaking purposes for a regulated operating company, the relevant point of comparison is to the capital structure of the proxy group companies' *regulated* operations, *i.e.*, at the regulated operating company level. Because capital at the parent holding company level capital may finance non-regulated operations, comparisons to the parent company capital structure may lead to flawed and misleading conclusions.

[223] *See,* NCUC Docket Nos. E-22, Sub 562; E-7 Sub 1146; E-2, Sub 1142; and G-9, Sub 743.
[224] Testimony of J. Randall Woolridge, at 29.

Q. ARE THERE COMPANIES WITHIN DR. WOOLRIDGE'S PROXY GROUP THAT DEMONSTRATE WHY IT IS INAPPROPRIATE TO USE HOLDING COMPANIES TO SET OPERATING UTILITY CAPITAL STRUCTURES?

A. Yes, there are. As explained in my response to Mr. O'Donnell, NextEra Energy's capital structure, which includes debt not associated with utility operations, is an example of how comparisons to holding company capital structures can be misplaced. Another example is, Hawaiian Electric Industries ("HE"). In 2018, HE had approximately $13.10 billion of consolidated assets, of which $6.90 billion was associated with its commercial banking operations.[225] Only a small portion (8.86 percent) of the banking segment's assets were financed with equity;[226] the vast majority was supported by customer deposits.[227] Although it is common in the commercial banking industry to fund assets with customer deposits, that is not the case in the electric utility industry. The important point is that by looking to the operating utility capital structure, we can avoid those types of distortions.

[225] Hawaiian Electric Industries, Inc., SEC Form 10-K For the fiscal year ended December 31, 2018, at 55, 78.
[226] *Ibid.*, at 55.
[227] *Ibid.*, at 55.

Q. HAVE YOU REVIEWED THE OPERATING COMPANY CAPITAL STRUCTURES FOR DR. WOOLRIDGE'S PROXY GROUP?

A. Yes, I have. Rebuttal Exhibit DWD-16 which provides that data, shows quite clearly that over time and across companies, operating utility equity ratios tend to be higher than the parent company ratio. That finding makes sense, given the utility financing practices discussed above.

As Rebuttal Exhibit DWD-16 also makes clear, the Company's proposed equity ratio is highly consistent with those in place at the operating utilities held within his proxy group. In fact, the average equity ratio for Dr. Woolridge's proxy group is approximately 54.00 percent, 100 basis points above the Company's proposed equity ratio. Among the operating utilities in my Updated Proxy Group, the average has been 53.69 percent,[228] again, quite consistent with the Company's proposal.

[228] Rebuttal Exhibit DWD-7.

Q. DR. WOOLRIDGE OBSERVES THAT THE COMPANY'S PROPOSED CAPITAL STRUCTURE IS "MUCH HIGHER"[229] THAN THE COMMON EQUITY RATIO OF ITS PARENT, DUKE ENERGY CORPORATION, AND FURTHER DISCUSSES THE "ISSUE OF PUBLIC UTILITY HOLDING COMPANIES SUCH AS DUKE ENERGY USING DEBT TO FINANCE THE EQUITY IN SUBSIDIARIES SUCH AS THE COMPANY."[230] WHAT IS YOUR RESPONSE?

A. Dr. Woolridge's position appears to suggest the Company is engaging in double leverage, to the detriment of customers.[231] I have several concerns with that position. First, as discussed above, in my experience utilities typically apply the prudent financing principle of maturity, or duration matching. Under that principle, long-lived assets are financed with correspondingly long-lived securities. As discussed earlier, due to its perpetual life common equity has a long duration. Adding equity to the capital structure therefore extends the capital structure's weighted average duration, more closely aligning it with the assets that form the rate base.

Dr. Woolridge's position also runs counter to the to the widely accepted "stand-alone" regulatory principle, which treats each utility subsidiary as its own company. Under the stand-alone approach, the cost of capital is

229 Testimony of J. Randall Woolridge, at 30-31.
230 Testimony of J. Randall Woolridge, at 31-32.
231 Testimony of J. Randall Woolridge, at 31-33.

determined using the subsidiary's capital structure and cost of debt and equity; the Cost of Equity is generally estimated by reference to a proxy group of firms of comparable risk.

Consistent with the stand-alone principle, the ownership structure does not affect the operating utility's capital structure or cost of capital. Parent entities, like other investors, have capital constraints and must consider the attractiveness of the expected risk-adjusted return of each investment alternative as part of their capital budgeting process. This opportunity cost concept applies regardless of the source of the funding. When funding is provided by a parent entity, the return on that financing must still be sufficient to provide an incentive to the parent entity to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with its affiliates and with other, similarly situated utility companies.

From an external investor's perspective, the combined company must provide a return reflecting the risks of the company's constituent parts. Investors therefore value combined entities on a sum-of-the-parts basis, expecting each operating segment to provide its appropriate risk-adjusted return. That practical financial principle is consistent with the regulatory principle of treating utilities as stand-alone entities. From both perspectives, it is the utility's operating risk that defines the capital structure and cost of capital, not investors' sources of funds.

Contrary to those basic principles, Dr. Woolridge's double leverage argument assumes the required return depends on the source of financing, not on the risks of the underlying utility operations. The position that a company would have a different cost rates depending on how its investors fund their equity investments violates the widely acknowledged economic "law of one price", which states that in an efficient market, identical assets would have the same value. In other words, two utilities, identical in all respects but for their form of ownership, should have the same common equity cost rates.

Moreover, if the common equity of a subsidiary were held by both the parent and an external investor, the equity held by the parent would have one required return, and the equity held by outside investors would have another. To the extent the required returns differ, so would the value of the equity. But in an efficient market, identical assets must have the same price (value). If not, the difference quickly would be arbitraged away. As Dr. Roger Morin noted in New Regulatory Finance:

> Carrying the double leverage standard to its logical conclusion leads to even more unreasonable prescriptions. If the common shares of a subsidiary were held by both the parent and by individual investors, the equity contributed by the parent would have one cost under the double leverage computation while the equity contributed by the public would have another.[232]

[232] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 523.

The double leverage argument also requires every affiliate within the corporate family to have the same cost of capital, regardless of differences in risk. Duke Energy Corporation reports four operating segments: electric utilities and infrastructure, gas utilities and infrastructure, commercial renewables, and other operations.[233] Because they are separately reported, we reasonably can assume those segments face different risks. And because they face different risks, we reasonably may assume they require different returns. Dr. Morin further noted:

> Just as individual investors require different returns from different assets in managing their personal affairs, why should regulation cause parent companies making investment decisions on behalf of their shareholders to act any differently? A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between the subsidiaries. Yet, the double leverage calculation would assign the same return to each activity, based on the parent's cost of capital. Investors recognize that different subsidiaries are exposed to different risks, as evidenced by the different bond ratings and cost rates of operating subsidiaries. The same argument carries over to common equity. If the cost rate for debt is different because the risk is different, the cost rate for common equity is also different, and the double leverage adjustment shouldn't obscure this fact.[234]

Longstanding academic literature has thoroughly discussed the flaws associated with the double leverage approach. For example:

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[233] *See*, Duke Energy Corporation, SEC Form 10-K for the year ended December 31, 2018, at 9.
[234] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 524-525.

1. Pettway and Jordan (1983), and Beranek and Miles (1988) point out the flaws in the double leverage argument, particularly the excess return argument, and also demonstrate that the "stand-alone" method is the superior approach.[235]
2. Rozeff (1983) discusses the ratepayer cross-subsidies of one subsidiary by another when employing double leverage.[236]
3. Lerner (1973) concludes that the returns granted to equity investors must be based on the risks to which the investors' capital is exposed and not the investors' source of funds.[237]

Basic finance texts reach the same conclusions. In Principles of Corporate Finance, 8th edition, Brealey, Myers, and Allen state:

> In principle, each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put. If we wish to estimate the cost of capital for a particular project, it is project risk that counts.[238]

Likewise, in Modern Corporate Finance, 1st edition, Shapiro states:

> Each project has its own required return, reflecting three basic elements: (1) the real or inflation-adjusted risk-free interest rate; (2) an inflation premium approximately equal to the amount of expected inflation; and (3) a premium for risk. The first two cost

235 Richard H. Pettway and Bradford D. Jordan, *Diversification, Double Leverage, and the Cost of Capital*, The Journal of Financial Research, Vol. VI, No. 4, Winter 1983; William Beranek and James A. Miles, *The Excess Return Argument and Double Leverage,* The Financial Review, Vo. 23, No. 2, May 1988.

236 Michael S. Rozeff, "Modified Double Leverage – A New Approach," Public Utilities Fortnightly, March 31, 1983.

237 Eugene M. Lerner, "What are the Real Double Leverage Problems?" Public Utilities Fortnightly, June 7, 1973.

238 Richard A. Brealey, Steward C. Meyers, Franklin Allen, Principles of Corporate Finance, McGraw-Hill Irwin, 8th Ed., 2006, at 234.

> elements are shared by all projects and reflect the time value of money, whereas the third component varies according to the risks borne by investors in the different projects. For a project to be acceptable to the firm's shareholders, its return must be sufficient to compensate them for all three cost components. This minimum or required return is the project's cost of capital and is sometimes referred to as a hurdle rate.
>
> The preceding paragraph bears a crucial message: The cost of capital for a project depends on the riskiness of the assets being financed, not on the identity of the firm undertaking the project.[239]

Simply, the notion of double leverage runs counter to both financial and regulatory principles.

Lastly, double leverage arguments have been rejected by several regulatory commissions, including the Maryland Public Service Commission:

> We reject People's Counsel's proposed capital structure [reflecting a double leverage adjustment] because it suffers from numerous flaws. First, it assumes that the rate of return depends on the source of capital rather than the risks faced by the capital.[240]

In 2016, the FERC reiterated its previous position on "double leveraging,"[241] stating that "the motivations of a parent company are irrelevant"[242] so long as the operating company passes the FERC's three-part

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[239] Alan C. Shapiro, Modern Corporate Finance, Wiley, 1st Ed., 1990, at 276.

[240] Maryland Public Service Commission, Order No. 81517, Case No. 9092, *In the Matter of the Application of Potomac Electric Power Company for Authority to Revise its Rate and Charges for Electric Service and for Certain Rate Design Changes*, July 19, 2007, at 73. [Clarification added]

[241] *See*, *Transcontinental Gas Pipe Line Corp.*, 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

[242] *See*, 154 FERC ¶ 61,004, Docket No. ER15-945-001, at 15.

test: (i) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by the commission.[243] Under FERC guidance, the capital structure of Duke Energy Corporation is not applicable to DE Carolinas.

The Washington Utilities and Transportation Commission ("WUTC") has cited to FERC's position on the use of double leverage in support of its decision in Docket No. UE 050684:

> The FERC does not embrace the concept of double leverage. For purposes of calculating rate of return for wholly owned subsidiaries, FERC uses the stand-alone capital structure and return on equity of the subsidiary so long as the subsidiary issues its own debt, maintains its own credit ratings and meets other standards related to equity ratio. The courts have upheld this policy. *See Missouri Pub. Serv. Comm'n v. Federal Energy Reg Comm'n, 215 F.3d 1, 342 U. S. App. DC. 1* (D.C. Cir. June 27, 2000).[244]

In that same Order, the WUTC considered the effects of ring fencing in protecting ratepayers against financial leverage at the parent level:

> The ring fencing provisions required by our final order in Docket UE-051090 insulate PacifiCorp and its customers from risks and financial distress at the MEHC level. Nonetheless, after having insulated PacifiCorp and its customers from the risks of leveraged financing at the parent, Staff and Public Counsel seek to secure for customers the cost and tax benefits of that financing. The Company's expert witness argues this may violate the familiar principle in utility law that financial benefits should follow burden of risks. We agree. If the risks and costs

[243] *Ibid*. *See also*, *Transcontinental Gas Pipe Line Corp.*, 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

[244] Washington Utilities and Transportation Commission, Docket No. UE 050684, Order No. 4, at 117.

> of activities at the parent-level are born exclusively by shareholders—because customers are insulated from them by the ring fence—then it is fair and appropriate for the shareholders, and not the customers, to receive the benefits that result from those activities.[245]

Q. HAS THE COMMISSION NOTED THE REASONABLENESS OF THE DIFFERENCES BETWEEN THE CAPITAL STRUCTURES OF OPERATING COMPANIES AND PARENT COMPANIES?

A. Yes, it has. In Docket No. G-5, Sub 565, the Commission gave "significant weight" to [Mr. Robert B. Hevert's] testimony regarding the differences in the financing needs of holding companies and operating companies, and concluded "[t]hus, the appropriate mix of debt and equity for a public utility operating company can be significantly different form that of its holding company."[246] In that case, the Commission approved a stipulated equity ratio of 52.00 percent,[247] similar to the equity ratio requested by the Company.

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATE CAPITAL STRUCTURE FOR THE COMPANY?

A. As shown in Rebuttal Exhibit DWD-7 the Company's proposed capital structure is in line with the capital structure in place at the proxy group companies and is consistent with the Commission's past decisions.

245 *Ibid.*, at 54.

246 North Carolina Utilities Commission Docket No. G-5, Sub 565, *Order Approving Rate Increase and Integrity Management Tracker*, October 28, 2016, at 24.

247 As noted earlier, the Commission similarly authorized a 52.00 percent equity ratio for the Company in its last rate case, as well as for Duke Energy Progress and Dominion Energy North Carolina.

Consequently, I disagree that Dr. Woolridge's recommended hypothetical capital structure of 50.00 percent long-term debt, and 50.00 percent common equity is appropriate for DE Carolinas. For the reasons noted earlier, I further disagree that the Company's ROE should be reduced if its proposed capital structure is adopted.

V. RESPONSE TO AG WITNESS MR. BAUDINO

Q. PLEASE SUMMARIZE MR. BAUDINO'S ROE ANALYSES AND RECOMMENDATION IN THIS PROCEEDING.

A. Mr. Baudino recommends an ROE of 9.00 percent, which is based primarily on the results of his Constant Growth DCF analyses applied to the proxy group of 19 companies used in my Direct Testimony.[248] Mr. Baudino also performs two CAPM analyses, which he uses in support of his DCF results and his recommended ROE.[249]

Q. WHAT ARE THE PRINCIPAL AREAS IN WHICH YOU DISAGREE WITH MR. BAUDINO'S ROE ANALYSES?

A. The principal areas in which I disagree with Mr. Baudino include: (1) the growth rates applied in the Constant Growth DCF model; (2) his reliance on the Constant Growth DCF model to determine the Company's Cost of Equity; (3) the Market Risk Premium used in the CAPM; (4) the relevance of the ECAPM

248 Direct Testimony of Richard A. Baudino, at 2-3.
249 Direct Testimony of Richard A. Baudino, at 3, 29-30.

analysis; (5) whether the Bond Yield Plus Risk Premium analysis provides reasonable estimates of the Company's Cost of Equity; (6) the reasonableness of the Expected Earnings analysis; (7) the relevance of flotation costs, (8) our respective assessments of the Company's level of business and financial risk; (9) our interpretations of current capital market conditions and their effect on the Company's Cost of Equity; (10) our interpretations of North Carolina's current economic conditions; and (11) Mr. Baudino's proposed capital structure.

Q. AS A PRELIMINARY MATTER, DO YOU AGREE WITH MR. BAUDINO'S POSITION THAT HIS 9.00 PERCENT RECOMMENDATION "IS REASONABLY CLOSE TO RECENTLY ALLOWED ROES"[250]?

A. No, I do not. As shown in Rebuttal Exhibit DWD-8, the average and median authorized ROE for vertically integrated electric utilities since 2015 is 9.75 percent and 9.72 percent, respectively. On February 24, 2020 in Docket No. E-22, Sub 562 the Commission authorized Dominion Energy North Carolina an ROE of 9.75 percent. Since January 2019, there have been ten cases in which a regulatory commission authorized an ROE within my range of 10.00 percent to 11.00 percent. During that same time period, only two were "reasonably close" [251] to Mr. Baudino's recommendation of 9.00 percent (s*ee also* Chart 18

[250] Direct Testimony of Richard A. Baudino, at 36.

[251] That is, within 25 basis points of Mr. Baudino's 9.00 percent ROE recommendation. The South Dakota PUC authorized an ROE of 8.75 percent for Otter Tail Power and the Vermont

presented in my response to Mr. Phillips).

Q. MR. BAUDINO ASSERTS YOUR ROE RECOMMENDATION IGNORES YOUR DCF RESULTS.[252] WHAT IS YOUR RESPONSE?

A. As noted in my Direct Testimony and throughout my Rebuttal Testimony, all models are subject to limiting assumptions and no single model is more reliable than all others under all market conditions.[253] As also noted in my Direct Testimony, it is my view that the Constant Growth DCF model is subject to several assumptions that likely are not consistent with current market conditions, and therefore should be given less weight in the current capital market. To that point, authorized returns consistently have exceeded Constant Growth DCF estimates.[254] Further, as discussed in my Direct Testimony, other regulatory commissions have found it appropriate to place less weight on the DCF model results.[255] As to Mr. Baudino's argument that I reject the results of my DCF analysis, he rejects two out of his three approaches, relying exclusively on his Constant Growth DCF model results. Lastly, although Mr. Baudino argues that relying on the high DCF results is inappropriate, his 9.00 percent recommendation is based on his high DCF result.[256]

PUC authorized a 9.06 percent ROE for Green Mountain Power. I address the Otter Tail Power decision in my response to Mr. O'Donnell.

[252] Direct Testimony of Richard A. Baudino, at 4, 46.

[253] Direct Testimony of Dylan W. D'Ascendis, at 5, 25.

[254] *See*, Direct Testimony of Dylan W. D'Ascendis, at 6.

[255] Direct Testimony of Dylan W. D'Ascendis, at 6-9, 16-17.

[256] Direct Testimony of Richard A. Baudino, at 36; Exhibit RAB-3, page 2.

Q. AT PAGE 60 OF HIS TESTIMONY, MR. BAUDINO POINTS TO FERC OPINION NO. 569 REGARDING THE ORDER DIRECTING BRIEFS YOU REFER TO IN YOUR DIRECT TESTIMONY. WHAT IS YOUR RESPONSE?

A. If Mr. Baudino's point is FERC's Opinion No. 569 implies the Risk Premium and Expected Earnings approaches should be disregarded, I disagree. In my view, Opinion No. 569 should not be seen as invalidating those methods in this case. The revised approach under Opinion No. 569 is not settled policy. As FERC has acknowledged, there are multiple requests for rehearing of Opinion No. 569 currently pending.[257] Further, FERC recently has established a paper hearing to address the methods proposed in its prior Coakley Briefing Order, and MISO Briefing Order, the same Briefing Orders that proposed the DCF, CAPM, Risk Premium, and Expected Earnings approaches.[258] That process is ongoing, with no current resolution. Consequently, as a general proposition I do not agree Opinion No. 569 "invalidates" my use of the Expected Earnings, and Risk Premium approaches.

[257] *See*, Potomac-Appalachian Transmission Highline, LLC, Opinion No. 554-A, 170 FERC ¶ 61,050 (2020), Order on Rehearing, Directing Briefs, and Accepting in Part and Rejecting in Part Compliance Filings, at para. 5.

[258] *Ibid*. *See also*, Direct Testimony of Dylan W. D'Ascendis, at 7-8.

A. Application of the Constant Growth DCF Model

Q. PLEASE BRIEFLY DESCRIBE MR. BAUDINO'S CONSTANT GROWTH DCF ANALYSIS AND RESULTS.

A. Mr. Baudino calculates an average dividend yield of 2.88 percent by dividing each proxy company's annualized dividend by its monthly stock price for the six-month period ending January 2020,[259] noting that the average dividend yield for the proxy group ranged from 2.82 percent to 2.94 percent during the six-month period.[260] For the expected growth rate, Mr. Baudino relies on Earnings Per Share growth rate projections from Value Line, Zacks, and First Call, as well as Dividend Per Share growth rate projections from Value Line.[261] Mr. Baudino then calculates his DCF results based on the mean and median growth rate of the four sources noted above, producing eight ROE estimates, which range from 8.21 percent to 9.02 percent.[262]

Mr. Baudino refers to the DCF results produced using mean growth rates as "Method 1", and DCF results produced using median growth rates as "Method 2". The mean DCF results of his Methods 1 and 2 were 8.54 percent and 8.67 percent, respectively.[263]

259 Direct Testimony of Richard A. Baudino, at 22-23.
260 Exhibit RAB-2.
261 Direct Testimony of Richard A. Baudino, at 24-25, Exhibit RAB-3.
262 Direct Testimony of Richard A. Baudino. at 25-26; Exhibit RAB-3, page 2.
263 Direct Testimony of Richard A. Baudino, at 26; Exhibit RAB-3, page 2.

Q. DO YOU AGREE WITH MR. BAUDINO THAT DIVIDEND GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?

A. No, I do not. As discussed in my Direct Testimony, academic literature supports the use of earnings growth rates in the DCF model.[264] Earnings growth is the fundamental driver of the ability to pay dividends. Further, as noted in my Direct Testimony, to reduce growth to a single measure we assume a fixed payout ratio, and a constant growth rate for Earnings Per Share, Dividend Per Share, and Book Value Per Share.[265] Because earnings are the fundamental driver of dividends, and knowing investors tend to value common equity on the basis of P/E ratios, the Cost of Equity is a function of the expected growth in earnings, not dividends. As discussed in my response to Dr. Woolridge, earnings growth rate projections are the only growth rates that are statistically and positively related to the P/E ratio. Lastly, as discussed in my response to Mr. O'Donnell, Value Line is the only service that reports dividend growth projections. The fact that services such as Zacks and First Call provide earnings, but not dividend growth estimates indicates that they see little investor demand for such data.

[264] Direct Testimony of Dylan W. D'Ascendis, at 77-78.
[265] Direct Testimony of Dylan W. D'Ascendis., at 76. *See also*, Rebuttal Exhibit DWD-9.

B. DCF Model Assumptions

Q. PLEASE BRIEFLY DESCRIBE MR. BAUDINO'S CONCERNS WITH YOUR ARGUMENTS REGARDING THE ASSUMPTIONS OF THE DCF MODEL.

A. Mr. Baudino argues the industry's current P/E ratio's departure from its long-term average is not a valid concern.[266]

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S CONCERN WITH YOUR ASSUMPTION REGARDING P/E RATIOS?

A. Mr. Baudino asserts that current stock prices reflect investors' required ROE.[267] As explained in my response to Dr. Woolridge, the DCF model will not produce accurate estimates of the market-required ROE if the market price diverges from intrinsic value as defined by the present value formula.

As also discussed in my response to Dr. Woolridge, recently elevated utility valuations likely arose from the "reach for yield" that sometimes occurs during periods of low Treasury yields. As Mr. Baudino acknowledges,[268] during those periods, some investors would turn to dividend-paying sectors, such as utilities, as an alternative source of income (that is, for the dividend yield).[269] Then, when interest rates increased, investors rotated out of the utility sector,

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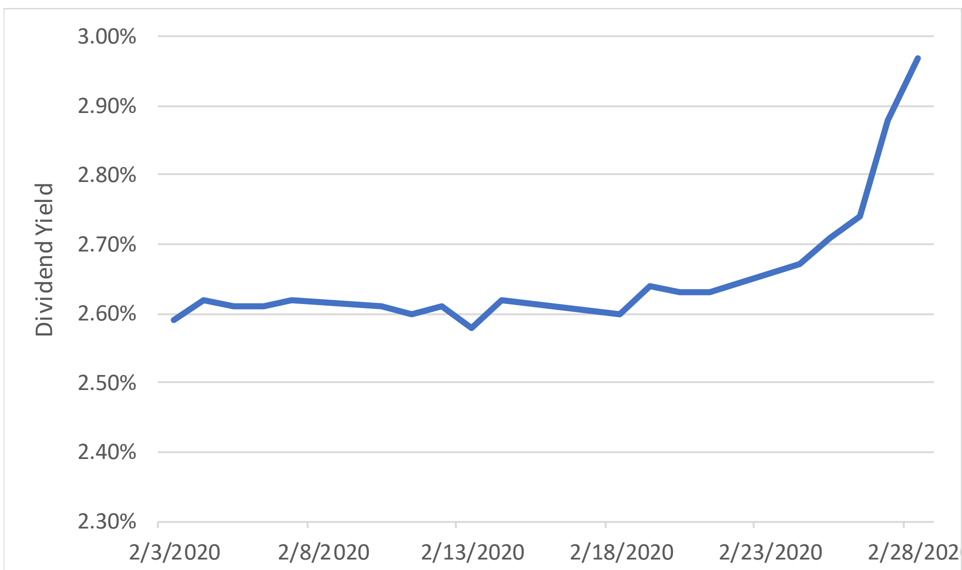
266 Direct Testimony of Richard A. Baudino, at 49.
267 Direct Testimony of Richard A. Baudino, at 49.
268 Direct Testimony of Richard A. Baudino, at 36.
269 The relationship between utility prices and utility dividend yields is given in Equation [5], page 74 of my Direct Testimony.

causing prices to fall.

The Constant Growth DCF model also assumes the dividend yield will remain constant, as stock prices and dividends grow that the same, constant rate. As the recent drop in the stock market demonstrates, the assumption of a constant dividend yield is limiting. For example, during the month of February 2020, the dividend yield for Mr. Baudino's proxy group increased approximately 15.00 percent from 2.59 percent to 2.97 percent (*see* Chart 14 below).

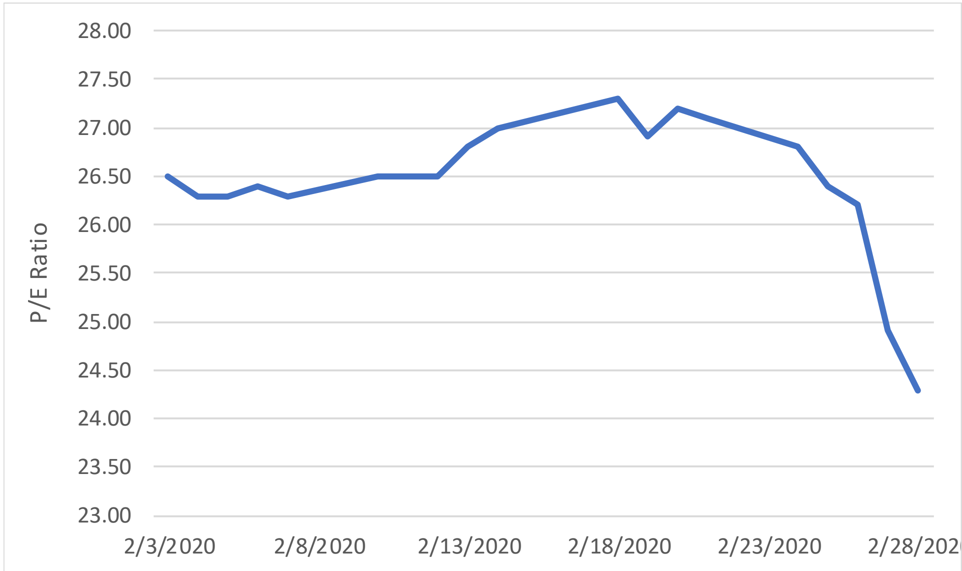
Chart 14: Mr. Baudino's Proxy Group Dividend Yield in February 2020[270]



Over the same time period, the P/E ratio of Mr. Baudino's proxy group fell significantly (*see* Chart 15 below).

[270] Source: S&P Global Market Intelligence. Mr. Baudino's proxy group calculated as an index.

Chart 15: Mr. Baudino's Proxy Group P/E Ratio in February 2020[271]



Because the Constant Growth DCF model assumes a constant P/E ratio in perpetuity, during in periods of elevated P/E ratios, it will underestimate the required return. I do not believe we should place significant weight on the Constant Growth DCF model's results when the assumptions underlying that model are plainly inconsistent with market expectations.

Q. HAVE THERE BEEN RECENT PERIODS WHEN UTILITY VALUATION LEVELS WERE HIGH RELATIVE TO BOTH THEIR LONG-TERM AVERAGE AND THE MARKET?

A. Yes. For example, between July and December 2016, the S&P Electric Utility Index lost approximately 9.00 percent of its value. At the same time, the S&P 500 increased by approximately 7.00 percent, indicating that the utility sector

[271] Source: S&P Global Market Intelligence. Mr. Baudino's proxy group calculated as an index.

under-performed the market by about 16.00 percent. Also during that time, the 30-year Treasury yield increased by as much as approximately 95 basis points (an increase of approximately 44.00 percent). More recently, between January and March 2018, the S&P Electric Utility Index lost approximately 7.00 percent of its value while the S&P 500 increased by approximately 2.00 percent, an under-performance of about 9.00 percent as the 30-year Treasury yield increased by nearly 40 basis points. The point simply is that as interest rates increased, utility valuations fell.

C. Capital Asset Pricing Model

Q. PLEASE SUMMARIZE MR. BAUDINO'S CAPM ANALYSES.

A. Mr. Baudino's CAPM analyses include two Market Risk Premium measures. His first set relies on the forecasted total market return as determined using Value Line projections, and the six-month average 30-year Treasury yield and Duff & Phelps' normalized risk-free rate (*i.e.*, 2.21 percent and 3.00 percent, respectively).[272] He assumes an expected growth rate for the market of 9.50 percent, using the average of the book value and earnings growth forecasts (8.00 percent and 11.00 percent, respectively) for all companies covered by Value Line. Mr. Baudino combines that average growth rate with Value Line's average expected dividend yield of 1.06 percent for the same group of companies, producing an estimated market return of 10.61 percent. Mr.

[272] Exhibit RAB-4.

Baudino averages that estimate with Value Line's projected annual total return of 11.61 percent[273] to arrive at his final expected market return of 11.11 percent.[274]

Mr. Baudino's two forward-looking Market Risk Premium measures represent the difference between (1) his calculated expected market total return, and (2) the average yield over the past six months on 30-year Treasury securities (2.21 percent) and Duff & Phelps' normalized risk-free rate (3.00 percent). Mr. Baudino arrives at his CAPM results using the average Value Line Beta coefficient of 0.56 for his proxy companies.[275]

Mr. Baudino's second set of CAPM analyses calculate the arithmetic mean long-term annual returns on stocks, and long-term annual income returns on long-term government bonds, producing an historical measures of the Market Risk Premium.[276] He also considers an adjusted historical Market Risk Premium calculated by Dr. Roger Ibbotson and Dr. Peng Chen, and reported by Duff & Phelps.[277] Mr. Baudino uses those two Market Risk Premium measures in combination with the six month average 30-year Treasury bond yield, Duff and Phelps' normalized risk-free rate, and the average Value Line Beta coefficient to calculate four additional CAPM results. Although Mr. Baudino

[273] The average of Value Line's median and average projected annual total return of 11.00 percent and 12.21 percent, respectively.

[274] Direct Testimony of Richard A. Baudino, at 30. Exhibit RAB-4.

[275] Exhibit RAB-4.

[276] Direct Testimony of Richard A. Baudino, at 31-32. Exhibit RAB-5.

[277] Direct Testimony of Richard A. Baudino, at 32. Exhibit RAB-5.

advises the Commission to consider only his DCF results in establishing the Company's ROE, he reports CAPM results ranging from 7.20 percent to 7.55 percent for his forward-looking return analysis and 5.66 percent to 6.87 percent for his historical returns analysis.[278]

Q. DO YOU AGREE WITH MR. BAUDINO'S APPLICATION OF THE CAPM AND HIS INTERPRETATION OF ITS RESULTS?

A. No. My primary area of disagreement with Mr. Baudino's CAPM approach is his calculation of the Market Risk Premium.

Q. WHAT CONCERNS DO YOU HAVE WITH MR. BAUDINO'S *EX-ANTE* MARKET RISK PREMIUM CALCULATIONS?

A. Mr. Baudino calculates the expected market return using an average of earnings growth projections (11.00 percent) and book value growth projections (8.00 percent). As noted above, academic research indicates investors rely on estimates of earnings growth in arriving at their investment decisions. In that regard, Mr. Baudino did not include book value growth projections in his proxy group DCF analysis, nor has he explained why it is reasonable to include those growth rates in his Market Risk Premium analysis but not his proxy company DCF analyses. Excluding book value growth estimates from Mr. Baudino's market return calculation would increase his Market Risk Premium estimate by

[278] Direct Testimony of Richard A. Baudino, at 33.

approximately 75 basis points.[279]

Q. DO YOU AGREE WITH MR. BAUDINO'S USE OF HISTORICAL ESTIMATES OF THE MARKET RISK PREMIUM?

A. No, I do not. For the reasons discussed in my response to Dr. Woolridge, the Market Risk Premium is meant to be a forward-looking parameter. A Market Risk Premium calculated using historical market returns does not necessarily reflect investors' expectations or, for that matter, the relationship between market risk and returns. The relevant analytical issue in applying the CAPM is to ensure that all three components of the model (*i.e.*, the risk-free rate, Beta, and the Market Risk Premium) are consistent with market conditions and investor expectations. Therefore, *ex-ante* CAPM analyses are the more appropriate method to estimate DE Carolinas' Cost of Equity.

Q. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S COMMENTS REGARDING YOUR *EX-ANTE* CAPM ANALYSES.

A. Mr. Baudino disagrees with my *ex-ante* Market Risk Premium, arguing that the market return estimates "are extraordinarily high."[280] He further disagrees with the use of forecasted Treasury bond yields applied in my CAPM analyses, but notes his and my risk-free rates "do not differ significantly in this proceeding."[281]

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279 [(1.06% x (1+(0.5*11.00%)) + 11.00%)+11.61%] / 2 = 11.86%. ((11.86% - 2.21%) – (11.11% - 2.21%)) = 0.75%

280 Direct Testimony of Richard A. Baudino, at 54.

281 Direct Testimony of Richard A. Baudino, at 54.

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S POSITION THAT YOUR MARKET RISK PREMIA ARE "EXTRAORDINARILY HIGH"[282]?

A. The market return estimates presented in my Direct Testimony represent approximately the 52nd percentile of actual returns observed from 1926 to 2018.[283] Moreover, because market returns historically have been volatile, my market return estimates are statistically indistinguishable from the long-term arithmetic average market data on which Mr. Baudino relies.[284] Regarding the use of projected interest rates, it is important to remember that, as Mr. Baudino states, the "[r]eturn on equity analysis is a forward-looking process."[285] In that regard, I have considered forward-looking estimates of the risk-free rate. Because my analyses are predicated on market expectations, the expected increase in Treasury yields (as reflected in consensus projections) is a measurable and relevant data point.

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282 Direct Testimony of Richard A. Baudino, at 54.

283 *See*, Rebuttal Exhibit DWD-17.

284 Source: Duff & Phelps, 2098 SBBI Yearbook Appendix A-1. Even if we were to look at the standard error, my estimates are within two standard errors of the long-term average.

285 Direct Testimony of Richard A. Baudino, at 24.

D. Empirical Capital Asset Pricing Model

Q. PLEASE SUMMARIZE MR. BAUDINO'S POSITION REGARDING THE EMPIRICAL CAPITAL ASSET PRICING MODEL.

A. Mr. Baudino argues the ECAPM suggests Beta coefficients published by Value Line and Bloomberg are "incorrect and that investors should not rely on them".[286]

Q. IS MR. BAUDINO CORRECT?

A. No. The ECAPM reflects published research finding companies with lower Beta coefficients tend to have higher returns than those predicted by the CAPM, and those with higher Beta coefficients tend to have lower returns than expected.[287] Beta coefficient adjustments such as those used by Value Line on the other hand, address the tendency of "raw" Beta coefficients to regress toward the market mean of 1.00 over time. The two are different issues and are addressed with different methods.

Fama and French succinctly describe the empirical issue addressed by the ECAPM when they note that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[288] Similarly, Dr. Roger Morin observes that "[w]ith few exceptions, the empirical studies

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[286] Direct Testimony of Richard A. Baudino, at 56.

[287] Direct Testimony of Dylan W. D'Ascendis, at 89. *See also*, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 175-176.

[288] Eugene F. Fama and Kenneth R. French, The Capital Asset Pricing Model: Theory and Evidence, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted."[289] As Dr. Morin also explains, the ECAPM "makes use" of those findings, and estimates the Cost of Equity based on the following equation:[290]

$$k_e = R_f + \alpha + \beta(\text{MRP} - \alpha) \qquad [6]$$

where α, or "alpha," is an adjustment to the risk/return line, and "MRP" is the Market Risk Premium (defined above). Summarizing empirical evidence regarding the range of estimates for alpha, Dr. Morin explains that the model "reduces to the following more pragmatic form"[291] used in my Direct Testimony:

$$k_e = R_f + 0.25(R_m - R_f) + 0.75\beta(R_m - R_f) \qquad [7]$$

where:

k_e = the investor-required ROE;

R_f = the risk-free rate of return;

β = Adjusted Beta coefficient of an individual security; and

R_m = the required return on the market.

The relationship between expected returns from the CAPM and ECAPM can be seen in Chart 16, below. That chart, which reflects Mr.

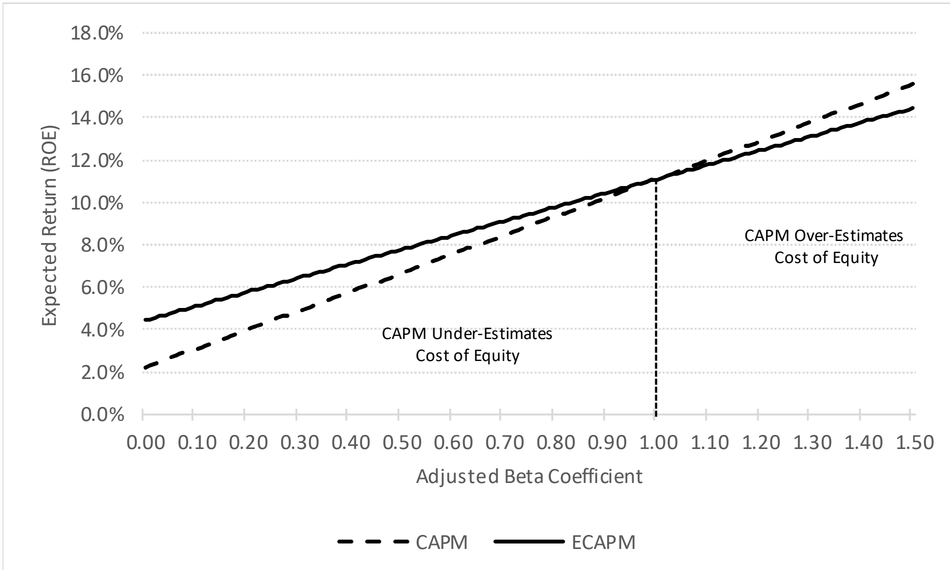
289 Roger A. Morin, <u>New Regulatory Finance</u>, Public Utility Reports, Inc., 2006, at 175.

290 *Ibid.*, at 189.

291 *Ibid.*, at 190. Equations [6] and [7] tend to produce similar results when "alpha" is in the range of 1.00 percent to 2.00 percent. *See*, Rebuttal Exhibit DWD-18. As Dr. Morin explains, alpha coefficients in that range are highly consistent with those identified in prior published research.

Baudino's risk-free rate and MRP, illustrates the extent to which the CAPM under-states the expected return relative to the ECAPM when Beta coefficients, whether adjusted or unadjusted, are less than 1.00.

Chart 16: CAPM and ECAPM Expected Returns[292]



The ECAPM is an adjustment to the risk/return line which, as noted in Chart 16 above, is flatter than the CAPM assumes. That adjustment is required even with the use of adjusted Beta coefficients, such as those provide by Value Line. As Dr. Morin observes:

> Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence.

292 *See,* Rebuttal Exhibit DWD-18. The finding that the ECAPM is not an adjustment to the Beta coefficient also is clear in Equation [6] ($k_e = R_f + \alpha + \beta(MRP - \alpha)$), in which the alpha coefficient increases the intercept (the expected return when the Beta coefficient equals zero), and reduces the Market Risk Premium.

> *The ECAPM and the use of adjusted betas comprised two separate features of asset pricing…Both adjustments are necessary.*[293]

Q. PLEASE EXPLAIN WHY VALUE LINE ADJUSTS ITS BETA COEFFICIENTS.

A. Value Line's adjustment is based on the research of Marshall Blume, who found that "[n]o economic variable including the beta coefficient is constant over time."[294] Consistent with that finding, Blume observed a tendency of raw Beta coefficients to change gradually over time:

> …there is obviously some tendency for the estimated values of the risk parameter [beta] to change gradually over time. This tendency is most pronounced in the lowest risk portfolios, for which the estimated risk in the second period is invariably higher than that estimated in the first period. There is some tendency for the high risk portfolios to have lower estimated risk coefficients in the second period than in those estimated in the first. Therefore, the estimated values of the risk coefficients in one period are biased assessments of the future values, and furthermore the values of the risk coefficients as measured by the estimates of β_1 tend to regress towards the means with this tendency stronger for the lower risk portfolios than the higher risk portfolios. (emphasis added)

Blume proposed a correction for that "regression bias" to provide more accurate assessments of risk and, therefore, the Cost of Equity:

> For individual securities as well as portfolios of two or more securities, the assessments adjusted for the historical rate of regression are more accurate than the unadjusted or naïve

293 Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 191 [*emphasis added*].

294 Marshall E. Blume, *On the Assessment of Risk*, The Journal of Finance, Vol. XXVI, No. 1, March 1971.

> assessments. Thus, an improvement in the accuracy of one's assessments of risk can be obtained by adjusting for the historical rate of regression even though the rate of regression over time is not strictly stationary.[295]

Based on Blume's results, Value Line adjusts its "raw" Beta coefficients according to the following formula:

$$\beta_{adjusted} = 0.35 + \left(0.67 \text{ x } \beta_{raw}\right) \quad [8]$$

Lastly, as discussed in my response to Dr. Woolridge, the ECAPM mitigates the CAPM's tendency to underestimate returns for relatively low Beta coefficient stocks, but does not eliminate that effect. That is the case assuming adjusted Beta coefficients.

E. Bond Yield Plus Risk Premium Approach

Q. WHAT CONCERNS DOES MR. BAUDINO EXPRESS REGARDING YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Mr. Baudino suggests the Bond Yield Plus Risk Premium method is "imprecise and can only provide very general guidance," and notes that "[r]isk premiums can change substantially over time."[296] He likens the approach to a "blunt instrument".[297] Regarding its application, Mr. Baudino disagrees with the use of projected Treasury yields.

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S OBSERVATIONS?

A. Turning first to Mr. Baudino's point that the Risk Premium can change over

295 *Ibid*.
296 Direct Testimony of Richard A. Baudino, at 57.
297 Direct Testimony of Richard A. Baudino, at 57.

time, I agree. As noted in my Direct Testimony, there is a statistically significant negative relationship between long-term Treasury yields and the Equity Risk Premium.[298] Given Mr. Baudino's observation that interest rates have declined since 2008,[299] the Bond Yield Plus Risk Premium analysis provides an empirically and theoretically sound method of quantifying the relationship between the Cost of Equity and interest rates. That is, it provides a method to quantify the change Mr. Baudino has observed.

As to Mr. Baudino's notion that the approach is a "blunt instrument," I disagree. As shown in Chart 16 in my Direct Testimony, the R-squared of the Bond Yield Plus Risk Premium regression analysis is approximately 0.74, indicating a rather high degree of explanatory value. More importantly, the relationship is highly statistically significant. Consequently, the Bond Yield Plus Risk Premium approach provides empirically and theoretically sound results that can be used, at a minimum, to assess the wide range of ROE results produced by Mr. Baudino's analyses in general, and his 9.00 percent recommendation in particular.

[298] Direct Testimony of Dylan W. D'Ascendis, at 95.
[299] Direct Testimony of Richard A. Baudino, at 6.

Q. DO YOU AGREE WITH MR. BAUDINO'S POSITION THAT YOUR BOND YIELD PLUS RISK PREMIUM RESULTS DO NOT ACCURATELY TRACK RECENTLY ALLOWED ROES"?[300]

A. No, I do not. Although Mr. Baudino points to a 36-basis point difference between the model's result and the actual authorized ROE for one specific year (*i.e.*, 2018), as shown in Chart 17 below,[301] since 2000, the model has been quite accurate on average, underestimating the authorized ROE by about ten basis points, well within one standard deviation of the average error. Further, as discussed below, my approach has been considerably more accurate than using a constant historical average risk premium.

Q. HAVE YOU PERFORMED AN ANALYSIS TO DEMONSTRATE THE RELATIVE ACCURACY OF A RISK PREMIUM THAT REFLECTS THE INVERSE RELATIONSHIP BETWEEN BOND YIELDS AND THE EQUITY RISK PREMIUM COMPARED TO AN AVERAGE EQUITY RISK PREMIUM?

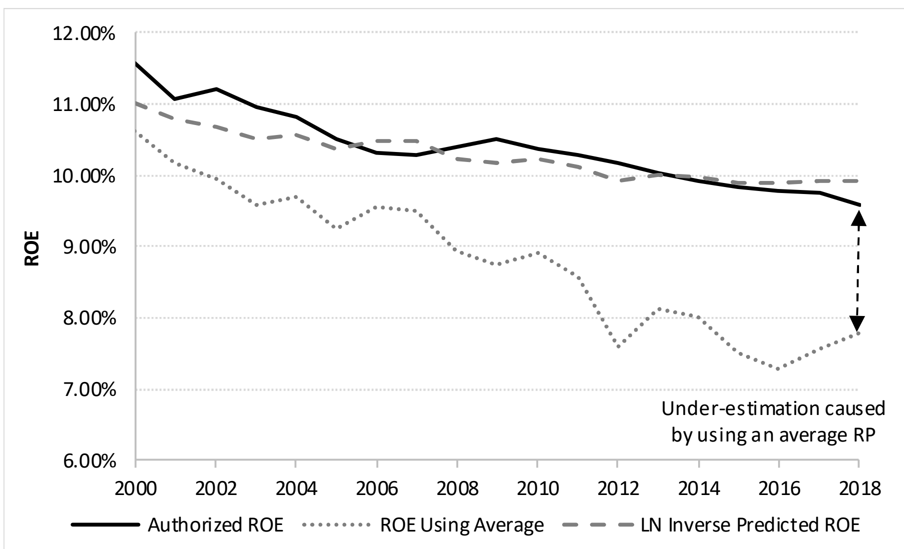
A. Yes, I have. I first calculated the ROE that an average 4.68 percent[302] "static" risk premium would predict using 2000-2019 annual average 30-year Treasury yields, and the error between the predicted ROE and the actual observed average ROE. I then calculated the ROE predicted in each year using my

300 Direct Testimony of Richard A. Baudino, at 58.
301 *See also*, Rebuttal Exhibit DWD-19.
302 The average Equity Risk Premium over the 1980 – 2019 time period calculated in Exhibit DWD-5.

methodology, which accounts for the log normal[303] relationship discussed in my Direct Testimony, and the error between the actual and predicted observations.

As shown in Rebuttal Exhibit DWD-19, using an average Equity Risk Premium, produces estimates that are as much as 258 basis points removed from the actual observed ROE. Using a Risk Premium approach to reflect the inverse relationship between bond yields and the Equity Risk Premium, however, reduces the largest prediction error to 55 basis points. Chart 17 (*see also* Rebuttal Exhibit DWD-19) demonstrates that, contrary to Mr. Baudino's position, my approach produces generally accurate estimates of observed average authorized ROEs.

Chart 17: Accuracy of Risk Premium ROE Estimates



[303] Direct Testimony of Dylan W. D'Ascendis, at 94.

Q. DO YOU AGREE WITH MR. BAUDINO'S CLAIM THAT INCLUDING RATE CASE RESULTS SINCE 1980 IS "AN IRRELEVANT EXERCISE"?[304]

A. No, I do not. Simply, the model focuses on the relationship between interest rates and the Equity Risk Premium; it does not view the two in isolation. There is no evidence that excluding data from my analysis would improve the model's ability to estimate expected returns.

In any event, an authorized ROE of 9.00 percent and lower for a vertically integrated electric utility has occurred very infrequently, even in the current lower interest rate environment. In fact, it has only occurred twice: in 2013 for Maui Electric Company in Hawaii[305] and in 2019 for Otter Tail Power in South Dakota.[306] From that perspective, Mr. Baudino's recommendation is far below returns authorized for other vertically integrated electric utilities.

F. Expected Earnings Analysis

Q. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S POSITION REGARDING THE EXPECTED EARNINGS ANALYSIS.

A. Mr. Baudino asserts that the "flaw" in the Expected Earnings approach is that "it measures accounting returns on book value, not investor required returns in

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304 Direct Testimony of Richard A. Baudino, at 51.

305 The 2013 order for Maui Electric included a 50 basis point reduction for "system inefficiencies". Hawaii PUC Docket No. 2011-0092, Decision and Order No. 31288, May 2013, at 107.

306 I discuss the Otter Tail Power order in my response to Mr. O'Donnell.

the marketplace."[307]

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO ON THAT POINT?

A. Although I agree economic and financial factors, and the market-based models that depend on them are important, I do not agree those factors invalidate the Expected Earnings approach. As discussed in my response to Dr. Woolridge, no single method best captures investor expectations at all times and under all conditions. The simplicity of the Expected Earnings approach is a benefit, not a detriment. Lastly, utility rates are set based on the book value of equity and the Expected Earnings approach provides a direct measure of the book-based return comparable-risk utilities are expected to earn.

G. Flotation Costs

Q. MR. BAUDINO ARGUES THAT FLOTATION COSTS SHOULD NOT BE CONSIDERED BECAUSE, IN HIS OPINION, "IT IS LIKELY THAT FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES".[308] WHAT IS YOUR RESPONSE TO MR. BAUDINO ON THAT POINT?

A. I disagree. The models used to estimate the appropriate ROE assume no "friction" or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the CAPM and the Bond Yield Plus Risk Premium model). Mr. Baudino provides no support

[307] Direct Testimony of Richard A. Baudino, at 60.
[308] Direct Testimony of Richard A. Baudino, at 61.

for his opinion that current stock prices account for flotation costs, and his position should be disregarded.

H. Relative Risk

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S POSITION REGARDING THE COMPANY'S BUSINESS RISKS?

A. Mr. Baudino asserts my review of the Company's business risks is "one-sided"[309] and that its risks are accounted for in its credit rating. As explained in my response to Dr. Woolridge, although I do not disagree that rating agencies may analyze company-specific factors in their review, I do not believe credit ratings are a full measure of equity risk.

As to his position that my assessment is "one-sided", I disagree. As shown in Rebuttal Exhibit DWD-23, and discussed in my response to Mr. Chriss, my recommended range is consistent with the returns authorized in more constructive jurisdictions such as North Carolina. That is, my recommendation accounts for North Carolina's "credit supportive regulatory environment".[310]

[309] Direct Testimony of Richard A. Baudino, at 62.
[310] Direct Testimony of Richard A. Baudino, at 18.

I. Capital Market Environment

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO'S POSITION THAT "SECURITIES MARKETS ARE EFFICIENT AND MOST LIKELY REFLECT INVESTORS' EXPECTATIONS ABOUT FUTURE INTEREST RATES"?[311]

A. Mr. Baudino makes that argument in the context of "market efficiency", suggesting that if markets are efficient, expectations regarding the direction and level of interest rates already are embedded in stock prices and Treasury yields. Mr. Baudino points to Dr. Morin's 2006 reference to the forecast accuracy of naïve extrapolations and "no-change" methods of projecting interest rates in support of his position that there is no need to consider projected interest rates in setting the current ROE.[312] I have several responses to Mr. Baudino on those points.

Regarding the suggestion that the "no-change" method of projecting interest rates is appropriate in the current market, I do not believe that to be the case. As Mr. Baudino acknowledges,[313] the Federal Reserve's Quantitative Easing program, which was initiated after 2006 (that is, after Dr. Morin's book was published), was designed to put downward pressure on long-term interest rates. Consequently, the observed Treasury yield in a given month likely would

311 Direct Testimony of Richard A. Baudino, at 12.
312 Direct Testimony of Richard A. Baudino, at 12.
313 Direct Testimony of Richard A. Baudino, at 6, 11.

over-forecast the observed Treasury yield twelve months in the future. Conversely, when the Federal Reserve completed its Quantitative Easing program, it would be reasonable to assume the observed Treasury yield would under-forecast the yield twelve months in the future (as yields increase).

Mr. Baudino's data support that position. As shown in Table 7, from February 2007 through the end of Quantitative Easing (October 2015),[314] the 30-year Treasury yield over-forecast the twelve-month forward yield 71.00 percent of the time. After October 2015, current yields over-forecast future yields only 45.00 percent of the time; from 2017 through January 2020, in only 15 of 37 months (about 41.00 percent of the time). That is, from 2017 through the January 2020, the "no-change" approach under-forecast Treasury yields in 22 of 37 months.

Table 7: "No-Change" Forecast Error Observations[315]

	Feb. 2007 – Oct. 2015	**Nov. 2015 – January 2020**	**Jan. 2017 – January 2020**
Number of Observations			
Over-Forecast	75	23	15
Under-Forecast	30	28	22
Total	105	51	37
% Over-Forecast	71.00%	45.00%	41.00%
% Under-Forecast	29.00%	55.00%	59.00%

If Mr. Baudino wishes to consider current Treasury yields as measures

314 Because the Treasury Department discontinued issuances of 30-year Treasury bonds from March 2002 to January 2006, February 2007 was the first month for which the forecast yield was available.

315 Source: Mr. Baudino's workpapers; Federal Reserve Board Schedule H.15.

of future rates, we can view the market's expectations based on the current yield curve. Those expected rates, often referred to as "forward yields" are derived from the "Expectations" theory, which states that (for example) the current 30-year Treasury yield equals the combination of the current five-year Treasury yield, and the 25-year Treasury yield expected in five years. That is, an investor would be indifferent to (1) holding a 30-year Treasury bond to maturity, or (2) holding a five-year Treasury note to maturity, then a 25-year Treasury bond, also to maturity.[316] Here, we can apply compare historical Treasury yield data to calculate the forward and current (interpolated) 25-year Treasury yield. If the forward 25-year Treasury yield exceeds the current 25-year yield, that relationship indicates expectations of future rate increases.

Based on the data from the Federal Reserve, forward yields consistently exceeded current spot yields over the previous six months (*see* Table 8, below). That is, just as economists' projections (such as *Blue Chip*) called for increased

[316] In addition to Expectations theory, there are other theories regarding the term structure of interest rates including: Liquidity Premium Theory, which asserts that investors require a premium for holding long term bonds; Market Segmentation Theory, which states that securities of different terms are not substitutable and, as such, the supply of and demand for short-term and long-term instruments is developed independently; and Preferred Habitat Theory, which states that in addition to interest rate expectations, certain investors have distinct investment horizons and will require a return premium for bonds with maturities outside of that preference.

interest rates, so have forward Treasury yields.

Table 8: Forward vs. Interpolated 25-Year Treasury Yields[317]

	30-Year Treasury Yield	5-Year Treasury Yield	Forward 25-Year Treasury Yield	Interpolated 25-Year Treasury Yield
August 2019	2.12%	1.49%	2.25%	1.99%
September 2019	2.16%	1.57%	2.28%	2.04%
October 2019	2.19%	1.53%	2.32%	2.06%
November 2019	2.28%	1.64%	2.41%	2.15%
December 2019	2.30%	1.68%	2.42%	2.18%
January 2020	2.22%	1.56%	2.35%	2.09%
Average	2.21%	1.58%	2.34%	2.09%

Importantly, forward yields assume the current slope of the yield curve will remain constant going forward. They therefore assume the conditions supporting the current slope also will remain constant. Consequently, the current yield curve may not fully reflect market expectations. Nonetheless, implied forward yields certainly are known and considered by the professionals that contribute to the consensus long-term bond yield projections published by sources such as *Blue Chip Financial Forecasts*. In that case, forward yields would be reflected in economists' projections.

J. North Carolina Economic Conditions

Q. PLEASE PROVIDE A SUMMARY OF MR. BAUDINO'S REVIEW OF YOUR NORTH CAROLINA ECONOMIC CONDITIONS.

A. Mr. Baudino observes that the unemployment rate in North Carolina and the

[317] Source: Federal Reserve Board of Governors Schedule H.15.

Company's service territory are currently higher than the national average, and (2) the median income in North Carolina and in the Company's service territory are lower than the national average. He concludes that the Company's lower than average residential rates and the lower than average cost of living in North Carolina do not justify the Company's requested ROE.[318]

Q. WHAT IS YOUR RESPONSE TO MR. BAUDINO?

A. First, Mr. Baudino acknowledges that the difference in the unemployment rate between North Carolina and the U.S. overall has narrowed since I filed my Direct Testimony.[319] In fact, the unemployment rate in North Carolina has declined by 0.50 percentage points since June 2019, whereas the U.S. unemployment rate has declined by 0.20 percentage points.[320] Second, with respect to the median income, as noted in my Direct Testimony, since 2009, median household income in North Carolina has grown at a slightly faster compound annual rate (2.72 percent) than it has in the U.S. (2.68 percent compound annual rate).[321] Consequently, I continue to believe my recommended ROE is fair and reasonable in light of the North Carolina's current economic conditions.

318 Direct Testimony of Richard A. Baudino, at 40.
319 Direct Testimony of Richard A. Baudino, at 41.
320 Direct Testimony of Richard A. Baudino, at 41 and his Table 5.
321 Direct Testimony of Dylan W. D'Ascendis, at 57.

K. Capital Structure

Q. WHAT CAPITAL STRUCTURE DOES MR. BAUDINO RECOMMEND IN THIS PROCEEDING?

A. Mr. Baudino recommends a capital structure including 51.50 percent common equity and 48.50 percent long-term debt, consistent with the Company's actual common equity at the end of the test year.[322] In Mr. Baudino's view, the Company's proposed 53.00 percent equity ratio is high relative to the actual equity ratios in 2018 at the consolidated parent company level among the proxy groups.[323]

Q. DO YOU AGREE WITH MR. BAUDINO'S CAPITAL STRUCTURE RECOMMENDATION?

A. No, I do not. As discussed throughout my Rebuttal Testimony, the Company's proposal is consistent with the capital structures in place at the proxy companies and with those recently approved by the Commission. Further, any comparison to the capital structures at the consolidated parent company level is inappropriate and should be disregarded.

[322] Direct Testimony of Richard A. Baudino, at 3, 39.
[323] Direct Testimony of Richard A. Baudino, at 37-38.

VI. RESPONSE TO CUCA WITNESS MR. O'DONNELL

Q. PLEASE PROVIDE A SUMMARY OF MR. O'DONNELL'S TESTIMONY AND RECOMMENDATION.

A. Mr. O'Donnell recommends an ROE of 8.75 percent,[324] based on his application of the Constant Growth DCF method.[325] As to the Company's capital structure, he recommends an capital structure consisting of 50.00 percent common equity and 50.00 percent long-term debt.[326] In performing his analyses, Mr. O'Donnell reviews data for his and my proxy groups. Regarding his assumed growth rates, Mr. O'Donnell reviews a variety of historical and prospective growth rates for each of his proxy companies. His DCF-based recommendation, which ranges from 7.00 percent to 9.00 percent, are based on his conclusion that a "proper" range of growth rates is from 4.00 percent to 6.00 percent.[327]

In his Comparable Earnings approach, Mr. O'Donnell reviews the actual and expected returns on equity for his and my proxy groups from 2017 to 2024, and finds ranges of 9.80 percent to 10.70 percent, and 9.60 percent to 10.20 percent to be reasonable for his and my proxy group, respectively.[328] He then concludes the proper range for his Comparable Earnings approach is 9.25 percent to 10.25 percent, based on the trend of recent authorized ROEs and the

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324 Direct Testimony of Kevin W. O'Donnell, CFA, at 6.
325 Direct Testimony of Kevin W. O'Donnell, CFA, at 114.
326 Direct Testimony of Kevin W. O'Donnell, CFA, at 6.
327 *See*, Direct Testimony of Kevin W. O'Donnell, CFA, at 98, 101.
328 *See*, Direct Testimony of Kevin W. O'Donnell, CFA, at 111-112, Exhibit KWO-4, Exhibit KWO-8.

forecasted earned returns of his proxy group.[329]

In developing his CAPM analyses, Mr. O'Donnell uses the current 30-year Treasury bond, together with Value Line Beta coefficients and MRP estimates of 4.00 percent and 6.00 percent, producing ROE estimates ranging from 4.30 percent to 6.70 percent for his proxy group and 4.30 percent to 6.60 percent for my proxy group.[330]

Q. WHAT ARE THE PRINCIPAL AREAS IN WHICH YOU DISAGREE WITH MR. O'DONNELL'S ROE ANALYSES, METHODOLOGIES, AND CONCLUSIONS?

A. My principal areas of disagreement include: (1) the inclusion of Duke Energy Corporation in Mr. O'Donnell's proxy group; (2) certain aspects of Mr. O'Donnell's Constant Growth DCF analyses, particularly the growth rate component; (3) the application of the Comparable Earnings approach; (4) the application of the CAPM; (5) Mr. O'Donnell's criticisms of my Bond Yield Plus Risk Premium approach; (6) Mr. O'Donnell's concerns regarding the weight given certain model results; (7) Mr. O'Donnell's review of select orders from other regulatory commissions; and (8) his proposed capital structure consisting of 50.00 percent common equity and 50.00 percent long-term debt.

329 Direct Testimony of Kevin W. O'Donnell, CFA, at 113.
330 Direct Testimony of Kevin W. O'Donnell, CFA, at 109, and Exhibit KWO-3, Exhibit KWO-7.

Q. ON PAGE 67 OF HIS TESTIMONY, MR. O'DONNELL ASSERTS THAT THE NATURE OF REGULATION DOES NOT POSE ANY RISK TO A UTILITY. DO YOU AGREE WITH HIS POSITION?

A. No, I do not. Although I agree the nature of regulation may provide "risk-reducing components"[331] relative to non-regulated businesses, I disagree with Mr. O'Donnell's position that the nature of regulation poses no risk at all (*i.e.*, that regulatory risk is non-existent). If that were the case, there would be no need for credit rating agencies to consider the regulatory environment in their rating assessments. To that point, the fact that utilities disclose regulatory risks in their SEC Form 10-Ks demonstrates such risks are present.

As Mr. O'Donnell acknowledges, the regulatory compact provides that a utility should be afforded a reasonable opportunity to recover its return of, and return on, its prudently-incurred investments.[332] It does not guarantee that return. Statutes and commission precedents change.[333] As noted earlier in my Rebuttal Testimony, the risk of adverse regulatory outcomes is valid, and the financial community carefully monitors the regulatory environment. Consequently, Mr. O'Donnell's position that regulation does not pose any risk is misplaced.

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[331] Direct Testimony of Kevin W. O'Donnell, CFA, at 67-68.

[332] Direct Testimony of Kevin W. O'Donnell, CFA, at 69.

[333] For example, South Carolina recently repealed legislation that supported the construction and cost recovery of new nuclear generating plants. After the repeal, the regulatory environment in South Carolina deteriorated from the top third of regulatory environments to the bottom third, as evaluated by Regulatory Research Associates.

A. Proxy Group Selection

Q. PLEASE DESCRIBE THE SCREENING CRITERIA BY WHICH MR. O'DONNELL DEVELOPED HIS PROXY GROUP.

A. Mr. O'Donnell relied on six screening criteria to develop his proxy group of 29 companies:

1. Followed by *Value Line Investment Survey* as an electric utility;
2. Derived at least 50.00 percent of 2018 revenues from regulated operations;
3. Has an investment-grade corporate credit and bond rating;
4. Is not in the midst of merger or acquisition discussions
5. Have at least five years of historical data; and
6. Must have paid a dividend each quarter in the past year.[334]

Q. DO YOU AGREE WITH MR. O'DONNELL'S SCREENING CRITERIA?

A. Not entirely. As discussed in my response to Dr. Woolridge, I disagree with the use of revenue, rather than income as a screening criterion. Additionally, Mr. O'Donnell included El Paso Electric Company, even though it is currently involved in an acquisition by JP Morgan Investment Management.[335]

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334 Direct Testimony of Kevin W. O'Donnell, CFA, at 80.

335 Press Release, *El Paso Electric Enters into Agreement to Be Purchased by the Infrastructure Investments Fund, an Investment Vehicle Advised by J.P. Morgan Investment Management Inc.*, June 3, 2019.

Q. DO YOU AGREE WITH MR. O'DONNELL'S INCLUSION OF DUKE ENERGY CORPORATION, DE CAROLINAS' PARENT, IN HIS PROXY GROUP?

A. No, I do not. As noted earlier in my response to Dr. Woolridge, the inclusion of a parent company involves circular logic.[336]

B. Constant Growth Discounted Cash Flow Model

Q. WHAT GROWTH RATES DID MR. O'DONNELL CONSIDER IN HIS CONSTANT GROWTH DCF ANALYSIS?

A. Mr. O'Donnell reviews a variety of growth rates, including: (1) the historical and projected "plowback ratio" (also referred to as "sustainable growth" rates or "Retention Growth" rates) as reported by Value Line; (2) the historical ten-year and five-year compound annual growth rates in EPS, BVPS, and DPS as reported by Value Line; (3) the Value Line projected EPS, BVPS, and DPS growth rates; and (4) consensus projected EPS growth rates, as reported by CFRA and Charles Schwab & Co.[337]

[336] Direct Testimony of Dylan W. D'Ascendis, at 24.
[337] Direct Testimony of Kevin W. O'Donnell, CFA, at 93-96; Exhibit KWO-1, Exhibit KWO-2, Exhibit KWO-5; Exhibit KWO-6.

Q. DO YOU AGREE WITH MR. O'DONNELL THAT HISTORICAL GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?

A. No. For the reasons discussed in my response to Dr. Woolridge and Mr. Baudino, I do not believe historical growth rates are appropriate for the Constant Growth DCF model.

Q. WHY DO YOU DISAGREE WITH MR. O'DONNELL'S POSITION THAT DIVIDEND OR BOOK VALUE GROWTH RATES ARE APPROPRIATE INPUTS TO THE CONSTANT GROWTH DCF MODEL?

A. As explained earlier in my response to Dr. Woolridge, earnings growth enables both dividend and book value growth. Under the strict assumptions of the Constant Growth DCF model, earnings, dividends, book value, and stock prices all grow at the same, constant rate.[338]

In addition, Value Line is the only service relied on by Mr. O'Donnell that provides either DPS or BVPS growth projections. The fact that services such as Zacks and First Call provide earnings, but not dividend or book value growth estimates indicates that they see little investor demand for such data. As Dr. Roger Morin notes:

> Casual inspection of the Zacks Investment Research, First Call Thompson, and Multex Web sites reveals that earnings per share

[338] Direct Testimony of Dylan W. D'Ascendis, at 74.

> forecasts dominate the information provided. There are few, if any, dividend growth forecasts. Only Value Line provides comprehensive long-term dividend growth forecasts. The wide availability of earnings forecast is not surprising. There is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividend indicates that the investment community regards earnings growth as a superior indicator of future long term growth.[339]

Moreover, Value Line estimates are available only via a subscription service and are attributable to a single analyst. Services such as Zacks and First Call, on the other hand, provide consensus growth estimates of multiple analysts and as such, are less likely to be skewed in one direction or another by an individual analyst.

Q. DO YOU AGREE WITH MR. O'DONNELL'S POSITION THAT ANALYSTS' EARNINGS GROWTH FORECASTS ARE "UNREALISTICALLY HIGH"[340] AND INACCURATE[341]?

A. No, I do not. Mr. O'Donnell cites several studies to support his position regarding the "accuracy" of analysts' earnings forecasts.[342] His position, however, is based on observations of the broad market; Mr. O'Donnell has provided no evidence that any of the growth rates used in my DCF analyses are

339 Roger A. Morin, PhD, New Regulatory Finance, (Public Utilities Reports, Inc., 2006), at 302-303.
340 Direct Testimony of Kevin W. O'Donnell, CFA, at 101.
341 Direct Testimony of Kevin W. O'Donnell, CFA, at 100.
342 Direct Testimony of Kevin W. O'Donnell, CFA, at 99-100.

the result of a consistent and pervasive bias on the part of the analysts providing those projections. More importantly, the salient issue is the growth that investors *expect*, not what actually happens.

Further, as discussed in my response to Dr. Woolridge, regulations implemented in 2003 insulated financial institutions' investment banking functions from its analysis functions. In reviewing the Letters of Acceptance, Waiver and Consent signed by financial institutions that were party to the Global Settlement, I found no reference to misconduct by analysts following the utility sector.

Q. IS THE USE OF ANALYSTS' EARNINGS GROWTH PROJECTIONS IN THE DCF MODEL SUPPORTED BY FINANCIAL LITERATURE?

A. Yes, it is. As noted in my Direct Testimony[343] and discussed in my response to Dr. Woolridge, peer-reviewed, published articles support the use of analysts' earnings growth projections in the DCF model. Again, earnings growth, not dividend growth, is the appropriate estimate in the Constant Growth DCF model. Further, as discussed in my response to Dr. Woolridge and shown in Rebuttal Exhibit DWD-10, the only growth rate that is statistically significant and positively related to the P/E ratio is projected Earnings Per Share. Because EPS growth is the only growth rate that is both statistically and positively related to utility valuation, earnings growth is the proper measure of growth in

[343] Direct Testimony of Dylan W. D'Ascendis, at 77-78.

the Constant Growth DCF Model.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH MR. O'DONNELL'S USE OF THE RETENTION GROWTH MODEL.

A. I have several concerns with Mr. O'Donnell's use of the Retention Growth model. First, as discussed below, the model's underlying premise is that future earnings will increase as the retention ratio increases. That is, if future growth is modeled as "B x R" (where B is the retention ratio, and R is the earned return on book equity), growth will increase as B increases. There are several reasons, however, why that may not be the case. Management decisions to conserve cash for capital investments, to manage the dividend payout to minimize future dividend reductions, or to signal future earnings prospects can and do influence dividend payout (and therefore earnings retention) decisions in the near-term. Consequently, it is appropriate to determine whether the data relied on by Mr. O'Donnell supports the assumption that higher earnings retention ratios necessarily are associated with higher future earnings growth rates.

Q. DID YOU PERFORM ANY ANALYSES TO TEST THE RELATIONSHIP BETWEEN RETENTION RATIOS AND FUTURE GROWTH RATES?

A. Yes, I did. Using EPS and DPS data from Value Line (the source of the data Mr. O'Donnell used to calculate his earnings Retention Growth estimate), I calculated the historical dividend payout ratio, retention ratio, and subsequent five-year average earnings growth rate for each of his proxy companies with a consistent history of dividend payments. I then performed a regression analysis in which the dependent variable was the five-year earnings growth rate, and the explanatory variable was the earnings retention ratio. The purpose of that analysis was to determine whether Mr. O'Donnell's data empirically supports the assumption that higher retention ratios necessarily produce higher earnings growth rates.

Q. WHAT DID THAT ANALYSIS REVEAL?

A. As shown in Table 9 below (*see also* Rebuttal Exhibit DWD-20), there was a statistically significant negative relationship between the five-year average earnings growth rate and the earnings retention ratio. That is, based on Mr. O'Donnell's own data source, earnings growth actually *decreased* as the retention ratio increased. Those findings clearly call into question Mr. O'Donnell's reliance on his "Retention Growth" estimate.

Table 9: Regression Results - Retention Ratio / Earnings Growth[344]

	Coefficient	**Standard Error**	**t-Statistic**
Intercept	0.109	0.011	9.648
Retention Ratio	-0.168	0.023	-7.440

[344] Rebuttal Exhibit DWD-20.

Q. ARE YOU AWARE OF INDEPENDENT RESEARCH THAT SUPPORTS YOUR FINDINGS?

A. Yes, I am. In 2006, for example, two articles in Financial Analysts Journal addressed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[345] Both articles cite a 2003 study by Arnott and Asness,[346] who found that over the course of 130 years of data, future earnings growth is associated with high, rather than low, payout ratios.[347] In essence, the findings of all three studies are consistent with my findings regarding the relationship between retention ratios and future earnings growth for Mr. O'Donnell's proxy companies: there is a negative, not a positive relationship between the two. In light of those articles, it appears my findings are reasonable. Given the strong statistical results of my analyses, and the corroborating research discussed above, I continue to believe Mr. O'Donnell's substantial reliance on the "B x R" approach is inappropriate.

345 *See,* Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth,* Financial Analysts Journal, Vol. 62, No. 3, 2006. *See also,* Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns,* Financial Analysts Journal, Vol. 62, No. 7, 2006.

346 *See,* Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth,* Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

347 Because the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

Q. ARE VALUE LINE'S PROJECTIONS FOR THE PROXY COMPANIES' GROWTH IN EARNINGS PER SHARE CONSISTENT WITH THE RETENTION GROWTH ESTIMATE?

A. No, they are not. As shown in Rebuttal Exhibit DWD-21, I calculated the Retention Growth rate using Value Line's projected financial metrics for each company in our combined proxy group for the year 2019, and their respective three-to-five year projections. I then compared those estimates to Value Line's expected earnings growth for each company. As shown in Rebuttal Exhibit DWD-21, Value Line frequently expects actual earnings growth to exceed the growth rate indicated by the Retention Growth formula.[348] Consequently, the assumption that the Retention Growth estimate accurately reflects future growth may be too limiting.

Q. ASIDE FROM THOSE CONCERNS, DO YOU AGREE WITH MR. O'DONNELL'S SPECIFICATION OF THE RETENTION GROWTH RATE?

A. No, I do not. As discussed in my response to Dr. Woolridge, if Mr. O'Donnell is going to consider a form of Retention Growth, he should use the "BR + SV" form of the model, which reflects growth both from internally generated funds (*i.e.*, the "BR" term) and from issuances of equity (*i.e.*, the "SV" term).

[348] To be conservative, I calculated the Retention Growth rate using the "BR + SV" approach described below; however, if I had used the "BxR" approach Mr. O'Donnell uses, there would have been more observations in which the Retention Growth rate underestimated the expected earnings growth rate. *See,* Rebuttal Exhibit DWD-21.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S USE OF NEGATIVE GROWTH RATES IN HIS DCF ANALYSIS?[349]

A. Consideration of negative growth rates as Mr. O'Donnell has applied them is intuitively incorrect.[350] No rational investor would invest in an individual stock that is expected to decrease its earnings in perpetuity. Recall that under the Constant Growth DCF model's assumptions, the assumed growth rate equals the assumed rate of capital appreciation. By including negative growth rates, Mr. O'Donnell assumes investors knowingly and willingly would invest in a company that they expect to lose value every year, in perpetuity.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE GROWTH RATE FOR THE CONSTANT GROWTH DCF MODEL?

A. Based on the analyses and research noted above, I conclude projected EPS growth rates represent the appropriate measure of growth in the Constant Growth DCF model.

349 Mr. O'Donnell includes negative growth rates in his review of historical EPS, BVPS, and DPS growth. *See*, Exhibit KWO-1.

350 Applying negative growth rates to establish the expected market return is a different matter. There, investors understand that over time, the market will include companies that grow quickly, and others that recede.

C. Comparable Earnings Method

Q. HOW DID MR. O'DONNELL DERIVE HIS 9.25 PERCENT TO 10.25 PERCENT ROE RANGE BASED ON THE COMPARABLE EARNINGS METHOD?

A. As Mr. O'Donnell states at pages 113-114 of his direct testimony, the low end of his comparable earnings method range of results (*i.e.*, 9.25 percent) recognizes "the unmistakable downward trend of the average ROE allowed by state regulators for electric utilities dating back to 2005" and the high end (*i.e.*, 10.25 percent) "recognizes high forecasted earned returns on equity for the O'Donnell and D'Ascendis comparable groups".

Q. BEFORE DISCUSSING YOUR CONCERNS WITH MR. O'DONNELL'S COMPARABLE EARNINGS METHOD, PLEASE COMMENT ON MR. O'DONNELL'S DETERMINATION OF THE LOW-END OF HIS RANGE BASED ON THAT APPROACH.

A. As shown in Exhibits KWO-4 and KWO-8, Mr. O'Donnell's Comparable Earnings results range from 9.60 percent to 10.70 percent. The low end of his Comparable Earnings-based range, therefore, is 45 basis points below the low end of the range of his model results. As discussed in response to Dr. Woolridge, authorized ROEs have been in a relatively narrow range since 2015; time explains less than 0.01 percent of the variation in returns.[351] As such, Mr.

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[351] Excludes limited issue rate proceedings. Source: Regulatory Research Associates.

O'Donnell's premise that recent years reflect lower authorized returns and capital costs is incorrect. Mr. O'Donnell argues the average authorized ROE for all electric utilities in 2019 was 9.64 percent.[352] As such, the 9.25 percent low end of his Comparable Earnings recommended range is unsupported.

Q. PLEASE ADDRESS YOUR CONCERNS REGARDING THE USE OF HISTORICAL EARNED RATES OF RETURN IN THE COMPARABLE EARNINGS ANALYSIS.

A. Because the Cost of Equity is inherently forward-looking,[353] the only relevant earnings figures provided on Exhibit KWO-4 and Exhibit KWO-8 are the 2019 and 2022/2024 expected returns. Notably, the proxy groups' average expected return for 2019 and 2022/2024 range from 9.80 percent to 10.60 percent, 105 to 185 basis points above Mr. O'Donnell's estimate of the market required ROE, the average of which falls within my recommended range. Again, that inconsistency calls into question the relevance of Mr. O'Donnell's 8.75 percent estimate of the market required ROE and recommendation.

352 Direct Testimony of Kevin W. O'Donnell, CFA, at 112. The average for vertically integrated electric utilities in 2019 was 9.73%

353 Direct Testimony of Dylan W. D'Ascendis, at 34.

Q. MR. O'DONNELL IMPLIES THAT THE COMPARABLE EARNINGS ANALYSIS PRODUCES ESTIMATES HIGHER THAN INVESTORS ARE EXPECTING IN TODAY'S MARKETPLACE.[354] IS HE CORRECT?

A. No, he is not. Mr. O'Donnell's position is that because market values exceed book values, any analyses based on book value will overstate the market return investors require. He appears to largely dismiss the Comparable Earnings method on that basis, looking instead to a 15-year trend in authorized ROEs.[355]

I appreciate there is a difference between market and book value. That does not mean, however, that book-based earnings are of no consequence to investors. Rather, accounting-based performance measures are related to market-based performance measures, such as market returns, and market to book ratios. Lehn and Makhija document a positive correlation between ROE and stock returns, significant at the 0.01 percent level.[356] In regressing market to book on factors including the excess of ROE over Cost of Equity (the "equity spread"), Varaiya, Kerin and Weeks find a positive and significant coefficient on the equity spread.[357] Nichols and Wahlen document a significant positive

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354 Direct Testimony of Kevin W. O'Donnell, CFA, at 110.

355 Direct Testimony of Kevin W. O'Donnell, CFA, at 112.

356 Kenneth Lehn, Anil Makhija, *EVA, Accounting Profits, and CEO Turnover: An Empirical Examination, 1985-1994*, Journal of Applied Corporate Finance, Vol 10.2, Summer 1997, at 90.

357 Nikhil Varaiya, Roger Kerin, David Weeks, *The Relationship Between Growth, Profitability, and Firm Value*, Strategic Management Journal, Vol. 8 No. 5, September-October 1987, at 487.

relationship between stock returns and earnings relative to assets measured at book value.[358] Taken together, these results suggest that although many factors may affect stock returns and market to book ratios, the accounting-based ROE is one of them, and should not be ignored.[359]

Alongside these peer-reviewed empirical investigations is a parallel body of literature based on the importance of managing ROE and other accounting-based metrics. Arzac proposes a value-creation model for managers based on the equity spread.[360] As discussed in my response to Dr. Woolridge, the Economic Value Added consulting practices and related value-based-management systems encourage managers to focus on elements of return on net assets and return on invested capital.

Lastly, I have not suggested using the Expected Earnings approach as the sole measure of the appropriate ROE. Rather, I have used that method to corroborate the DCF, CAPM, ECAPM, and Risk Premium methods.

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358 D. Craig Nichols, James M. Wahlen, *How Do Earnings Numbers Relate to Stock Returns? A Review of Classic Accounting Research with Updated Evidence*, Accounting Horizons, Vol 18, No. 4, December, 2004, at 272 – 274, 285.

359 I am not suggesting the M/B ratio necessarily will equal 1.00 when the accounting-based ROE equals the Cost of Equity.

360 *See*, Enrique R. Arzac, *Do Your Business Units Create Shareholder Value?*, Harvard Business Review, January – February 1986, at 122.

Q. ARE THE RESULTS OF MR. O'DONNELL'S COMPARABLE EARNINGS APPROACH SIMILAR TO THE RESULTS OF YOUR EXPECTED EARNINGS ANALYSIS?

A. Yes, they are. Mr. O'Donnell's projected earned returns produce ROE estimates of 9.80 percent and 10.60 percent for his proxy group, and 9.80 percent to 10.20 percent for my proxy group. Those results are within the range of results in my updated Expected Earnings analysis (*see* Rebuttal Exhibit DWD-6) and overlap with my recommended range and point estimate.

D. Capital Asset Pricing Model

Q. PLEASE SUMMARIZE MR. O'DONNELL'S CAPM ANALYSIS.

A. Mr. O'Donnell uses the range of the 30-year Treasury yield over the last year, Value Line Beta coefficients, and MRPs of 4.00 percent and 6.00 percent based on historical and investment professionals' forecasts to derive CAPM estimates of 4.30 percent to 6.70 percent for his proxy group and 4.30 percent to 6.60 percent for my proxy group.[361] In Mr. O'Donnell's view, the Constant Growth "DCF model is superior to other approaches"[362] because the DCF incorporates "daily and ongoing market prices."[363]

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361 Direct Testimony of Kevin W. O'Donnell, CFA, at 109. Mr. O'Donnell concludes that the "proper" ROE range based on his CAPM results is 5.00 percent to 7.00 percent.
362 Direct Testimony of Kevin W. O'Donnell, CFA, at 87.
363 Direct Testimony of Kevin W. O'Donnell, CFA, at 87.

Q. DO YOU AGREE WITH MR. O'DONNELL'S ASSESSMENT OF THE CAPM AND OTHER METHODS?

A. No, I do not. First, Mr. O'Donnell has provided no evidence that the DCF model is "superior" to other methods, or that investors prefer the DCF approach. The relevant issue is whether investors use multiple methods, including risk premium-based approaches, in evaluating investment opportunities and making investment decisions. Nowhere has Mr. O'Donnell demonstrated investors would disregard those methods in favor of the Constant Growth DCF approach. To that point, an article published in Financial Analysts Journal surveyed financial analysts to determine the analytical techniques that are used in practice, and this included the CAPM.[364] That survey, which was conducted by Stanley Block, clearly indicated that the CAPM is used by practitioners. Similarly, a 2001 article by Professors Graham and Harvey demonstrated that industry practitioners are far more likely to use the CAPM than the DCF model.[365] As such, I strongly disagree with Mr. O'Donnell's assertion that the DCF approach is "superior" to other approaches such as the CAPM.

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364 *See*, Stanley B. Block, *A Study of Financial Analysts: Practice and Theory*, Financial Analysts Journal, July/August, 1999.

365 *See*, John R. Graham, Campbell R. Harvey, *The Theory and Practice of Corporate Finance: Evidence from the Field*, Journal of Financial Economics, 2001. *See*, Robert S. Harris, Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts,* Journal of Applied Finance, 2001.

Q. ARE THERE OTHER REASONS YOU BELIEVE THE CAPM IS APPLICABLE IN THE CONTEXT OF SETTING THE ROE IN REGULATORY PROCEEDINGS?

A. Yes. As discussed in my Direct Testimony at page 19, the Commission applies the standards established under *Hope* and *Bluefield,* which includes the "comparability" standard. Although I am not an attorney, I understand that standard to recognize the authorized ROE should reflect the return investors require in light of the subject company's risks, and the returns available to investments of comparable risk. My Direct Testimony also noted that under the CAPM, the Beta coefficient reflects "systematic" risk, or the portion of market risk that cannot be diversified away.[366] That is, the Beta coefficient is a measure of relative risk. Because Beta coefficients provide a direct measure of relative risk, they address the "comparable risk" standard in a way that DCF-based methods do not. Putting aside the finding that the CAPM is regularly used in practice, its ability to address the "comparable risk" standard fully supports its use in regulatory proceedings.

Q. WHAT CONCERNS HAS MR. O'DONNELL EXPRESSED REGARDING YOUR CAPM ANALYSES?

A. Mr. O'Donnell's concern is the market return estimates used in my *ex-ante* MRP calculation are higher than what is forecasted by some market participants.[367]

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366 Direct Testimony of Dylan W. D'Ascendis, at 83-84.
367 Direct Testimony of Kevin W. O'Donnell, CFA, at 61, 106-108.

Q. PLEASE DESCRIBE HOW YOU DERIVED YOUR MARKET RISK PREMIUM ESTIMATE IN THIS PROCEEDING.

A. The Market Risk Premium represents the incremental return (over the risk-free rate) investors currently require for assuming the risk of equity ownership, as measured by the market as a whole. In my Direct Testimony, I calculated the expected market return using consensus analysts' projected growth rates and current expected dividend yields on a market capitalization-weighted basis for the S&P 500 Index.[368] That calculation was performed using earnings growth rate projections from two sources, Bloomberg and Value Line. From those estimates of the required market return, I calculated the MRP by subtracting the current 30-day average yield on 30-year Treasury securities.[369]

Q. IS THE MRP CONSTANT OVER TIME?

A. No, it is not. Mr. O'Donnell fails to recognize the MRP can be influenced by factors such as investors' changing levels of risk aversion, or changes in interest rates. Regarding the relationship between interest rates and the MRP, academic studies found an inverse relationship between the two. Discussing that relationship, Dr. Morin notes:

> … [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates - rising

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368 Direct Testimony of Dylan W. D'Ascendis, at 85-86.
369 Direct Testimony of Dylan W. D'Ascendis, at 86; Exhibit DWD-2, Rebuttal Exhibit DWD-2.

when rates fell and declining when interest rates rose.[370]

As such, increases in the MRP coincident with declining interest rates is consistent with financial theory.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S REFERENCE TO PROFESSIONAL INVESTOR FORECASTS AND MARKET SURVEYS THAT INDICATE EXPECTED MARKET RETURNS RANGE FROM NEGATIVE 4.40 PERCENT (REAL) TO 6.10 PERCENT (NOMINAL)?[371]

A. I have several concerns with his reference. First, Mr. O'Donnell's 8.75 percent ROE estimate is entirely at odds with the data he presents. In this instance, Mr. O'Donnell refers to the market forecasts summarized in Table 10, below.

Table 10: Summary of Mr. O'Donnell's Market Return Forecast References[372]

INSTITUTION	MARKET RETURN FORECAST
BlackRock Investment Institute	6.1% nominal (not inflation adjusted) return for US large caps over the next decade
Grantham, Mayo, & van Otterloo ("GMO")	-4.4% real (inflation adjusted) returns for US large caps over the next 7 years
JP Morgan Asset Management	5.6% nominal return for US equities over a 10-15 year horizon
Morningstar Investment Management	1.7% 10-year nominal returns for US stocks
Research Affiliates	0.3% real (inflation adjusted) returns for US large caps furring [*sic*] the next 10 years
Vanguard	Nominal equity market returns of 3.5% to 5.5% during the next decade

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370 Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 128 [clarification added].

371 Direct Testimony of Kevin W. O'Donnell, CFA, at 106-107.

372 Direct Testimony of Kevin W. O'Donnell, CFA, at 106-107.

As Table 10 indicates, the expected market returns (on a nominal basis) range from 1.70 percent to 6.10 percent for U.S. equities. Mr. O'Donnell, however, estimates an ROE of 8.75 percent for a utility that, we agree, is less risky than the overall market. If Mr. O'Donnell believed these expected returns were meaningful measures of investor-required returns, which is the subject of his testimony, his recommendation would be no higher than 6.10 percent.[373]

Lastly, Mr. O'Donnell does not consider the limiting language often contained in documents providing expected market returns. For example, JP Morgan Asset Management's *2019 Long-Term Capital Market Assumptions* (the source document for the 5.60 percent expected market return noted in Table 10, above) states:

> Please note that all information shown is based on qualitative analysis. Exclusive reliance on the above is not advised. This information is not intended as a recommendation to invest in any particular asset class or strategy or as a promise of future performance. Note that these asset class and strategy assumptions are passive only – they do not consider the impact of active management. References to future returns are not promises or even estimates of actual returns a client portfolio may achieve. Assumptions, opinions and estimates are provided for illustrative purposes only.[374]

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[373] Mr. O'Donnell also points to the results of the Duke University CFO Survey ("Duke University CFO Survey"), which, as discussed in my response to Dr. Woolridge, has consistently underestimated market returns.

[374] JP Morgan Asset Management, *2019 Long-Term Capital Market Assumptions*, at PDF 112.

Q. DO YOU AGREE WITH MR. O'DONNELL'S USE OF THE TOTAL RETURN ON LONG-TERM GOVERNMENT BONDS IN HIS CALCULATION OF THE HISTORICAL MRP?

A. No, I do not. The MRP should reflect the difference between the arithmetic average return on large company stocks and the income-only return on long-term government bonds as reported by Duff & Phelps (producing an estimated risk premium in 2018 of 6.90 percent).[375] Mr. O'Donnell, however, calculates the risk premium as the difference between the total return on those two asset classes, implying a risk premium of 4.10 percent to 5.60 percent in 2018.[376]

As Morningstar points out, the total return on a security is composed of three components: (1) the income return; (2) capital gains (or capital losses, if the value of the security falls); and (3) reinvestment return.[377] The income return is generally defined as the coupon, or interest rate on the security, which does not change over the life of the security. In contrast, the value of the security rises or falls as interest rates change, resulting in uncertain capital gains. As such, the income return is the only "riskless" component of the total return. Consequently, it is the income-only portion of the return, as opposed to the total return, that should be used in calculating the MRP.

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375 Duff & Phelps, 2019 SBBI Yearbook, at 6-17.
376 *See,* Direct Testimony of Kevin W. O'Donnell, CFA, at 106.
377 *See,* Duff & Phelps 2017 Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook, at 10-22.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S CONCERN THAT YOU USED AN EXPECTED MARKET RATE OF RETURN HIGHER THAN THE 12.00 PERCENT AVERAGE MARKET RETURN AS REPORTED BY DUFF & PHELPS (WHICH NOW PUBLISHES THE MORNINGSTAR DATA MR. O'DONNELL REFERS TO)?[378]

A. Although Mr. O'Donnell notes the average arithmetic average approximately 11.90 percent,[379] the standard deviation was approximately 19.80 percent.[380] One standard deviation around the long-term average through 2018 suggests a range of -7.90 percent to 31.70 percent.[381] As Rebuttal Exhibit DWD-17 demonstrates and as noted in my response to Mr. Baudino, the expected returns included in my Direct Testimony are well within the range of historical results, especially when we consider the historical standard deviation.

Q. AT PAGES 61-62 OF HIS TESTIMONY, MR. O'DONNELL COMPARES THE MARKET RISK PREMIA APPLIED IN YOUR CAPM ANALYSES TO THE EQUITY RISK PREMIA APPLIED IN YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS. IS HIS COMPARISON APT?

A. No, it is not. Mr. O'Donnell appears to conflate the Market Risk Premium applied in the CAPM (calculated as the difference between the total expected return on the market and the current 30-year Treasury yield) with the Equity

378 Direct Testimony of Kevin W. O'Donnell, CFA, at 62.
379 Direct Testimony of Kevin W. O'Donnell, CFA, at 106.
380 Duff & Phelps, 2019 SBBI Yearbook, at 6-17.
381 11.90% - 19.80% = -7.90%; 11.90% + 19.80% = 31.70%.

Risk Premium applied in the Bond Yield Plus Risk Premium analysis (calculated as the difference between the authorized ROE and the lagged 30-year Treasury yield). The two are different concepts and, therefore, are not comparable.

E. Bond Yield Plus Risk Premium Method

Q. DOES MR. O'DONNELL COMMENT ON YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Other than his position that the "flaws" he asserts appear in my CAPM analysis "flow through" to my Bond Yield Plus Risk Premium analysis,[382] Mr. O'Donnell does not comment on my approach. Further, Mr. O'Donnell provides no explanation to support his view that my Bond Yield Plus Risk Premium analysis is "flawed".

F. Weighting of Model Results

Q. MR. O'DONNELL ACCUSES YOU OF "DISAVOWING"[383] THE CONSTANT GROWTH DCF MODEL, IN PART BECAUSE YOU QUESTION WHETHER THE CONSTANT GROWTH DCF MODEL'S ASSUMPTIONS ARE CONSISTENT WITH THE CURRENT MARKET. IS HIS POSITION CORRECT?

A. No, it is not. My concern is not with the model itself. As discussed earlier, my concern is whether the model's fundamental assumptions reasonably hold in the

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382 Direct Testimony of Kevin W. O'Donnell, CFA, at 63, 64.

383 Direct Testimony of Kevin W. O'Donnell, CFA, at 57.

current market. Given the model's restrictive assumptions, it not only is reasonable to consider and give weight to alternative methods, it is prudent to do so.

G. Orders from Other Regulatory Commissions Cited by Mr. O'Donnell

Q. AT PAGES 63-64 OF HIS DIRECT TESTIMONY, MR. O'DONNELL REFERS TO AN ORDER FROM THE VIRGINIA CORPORATION COMMISSION REGARDING A DOCKET IN WHICH YOU PROVIDED TESTIMONY. WHAT IS YOUR RESPONSE TO MR. O'DONNELL ON THAT POINT?

A. Mr. O'Donnell fails to note orders that were supportive of my analyses and conclusions. For example, Mr. O'Donnell refers to orders in May 2019 by the South Carolina Public Service Commission ("SCPSC"), and the South Dakota Public Service Commission ("SDPUC"), pointing to the authorized return in those cases relative to my recommendations.[384] However, Mr. O'Donnell neglects to point out that in February 2019, the SCPSC reviewed [Mr. Robert B. Hevert's] testimony and found "there is ample evidence and reason to conclude that the analyses conducted by Mr. Hevert are accurate and reliable estimates of SCE&G's cost of equity."[385]

Regarding the SDPUC's order relating to Otter Tail Power, there are

384 Direct Testimony of Kevin W. O'Donnell, CFA, at 64-65.

385 Public Service Commission of South Carolina, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, Order No. 2019-122, dated February 12, 2019, at 26.

several points to keep in mind. First, South Dakota represents less than 9.00 percent of Otter Tail Corporation's ("OTTR") retail electric revenues.[386] Yet, from May 6 to May 31, 2019, OTTR lost about 5.20 percent of its market value, even though the Dow Jones Utility Average gained about 1.00 percent.[387] I recognize that is a limited observation; however, it appears OTTR meaningfully underperformed the utility sector around the time the SDPUC issued its order.

My view that the SDPUC's order was anomalously low relative to returns authorized in other jurisdictions is consistent with OTTR's price behavior. It also is supported by the financial community's reaction to the CEHE order, discussed in Section II.

H. Capital Structure

Q. WHAT CAPITAL STRUCTURE DOES MR. O'DONNELL RECOMMEND IN THIS PROCEEDING?

A. Mr. O'Donnell recommends a hypothetical capital structure including 50.00 percent common equity, and 50.00 percent long-term debt.[388] In Mr. O'Donnell's view, the Company's proposed 53.00 percent equity ratio is high relative to authorized equity ratios, the equity ratios at the consolidated parent company level among the proxy groups, and Duke Energy Corporation's consolidated equity ratio as of December 2018.[389]

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386 Otter Tail Corporation, SEC Form 10-K for the fiscal year ended December 31, 2018, at 5.
387 Source: Yahoo! Finance.
388 Direct Testimony of Kevin W. O'Donnell, CFA, at 129.
389 Direct Testimony of Kevin W. O'Donnell, CFA, at 128-129.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S COMPARISON TO THE PROXY GROUP EQUITY RATIO AT THE HOLDING COMPANY LEVEL?

A. First, by relying on the parent capital structure, Mr. O'Donnell assumes all subsidiaries can and should be financed in the same proportions as the parent. That clearly is not the case – companies (including subsidiary companies) are financed in light of the specific risks and funding requirements associated with their individual operations.

The use of the operating subsidiary's actual capital structure – the capital funding the utility plant and equipment that enables utility service – also is consistent with FERC's precedent, under which the commission prefers to use the applicant's capital structure, where possible.[390] As noted earlier, FERC will use the utility operating company's capital structure if it meets three criteria: (1) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by the Commission.[391] FERC noted that if those conditions are not met, it may apply the consolidated capital structure. [392]

FERC also noted that it does not apply a specific cap to the equity ratio. Rather, the commission stated:

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390 *See, Transcontinental Gas Pipe Line Corp,* 80 FERC ¶ 61,157, 61,657 (1997) ("Opinion No. 414").

391 148 FERC ¶ 61,049 Docket No. EL14-12-000, at P 190.

392 *Ibid.*, at P 191.

> [we] recognize that a utility may consider a range of factors beyond simple capital cost minimization in developing their capital structures. Such considerations include, but are not limited to, managing risk and cash flow.[393]

FERC therefore has recognized that the capital structure is tied to the assets being financed, and to the nature of utility operations.

Because vertically integrated electric utilities must finance similar types of assets (electric generation, transmission, and distribution infrastructure), it would be reasonable to expect those companies to have comparable capital structures. Although I do not agree with Mr. O'Donnell's view that the parent is the appropriate point of comparison for operating company capital structures, I note the Company's proposed common equity ratio of 53.00 percent is well within the range of results presented in his Tables 9 and 10. In fact, the Company's proposed equity ratio is within approximately one standard deviation of the average.

Q. IS IT APPROPRIATE TO ASSUME THE PROXY GROUP AVERAGE CAPITAL STRUCTURE APPLIES TO DE CAROLINAS?

A. No, it is not. Although utilities have certain factors in common, each has its own risk profile, which influences its target capital structure. In my view, although it is proper to review the range of operating utility equity ratios in assessing the Company's proposed capital structure, there is no reason to

[393] *Ibid.*, at P 197.

assume we should default to the average. Nonetheless, as noted above, the Company's proposal is within approximately one standard deviation from the proxy group average, as provided by Mr. O'Donnell's data.

Q. AT PAGES 123-124 OF HIS TESTIMONY, MR. O'DONNELL REVIEWS THE CONSOLIDATED PARENT CAPITAL STRUCTURES FOR THE COMPANIES IN HIS PROXY GROUP. DO YOU HAVE ANY OBSERVATION REGARDING MR. O'DONNELL'S REVIEW?

A. Yes, I do. As discussed in my response to Dr. Woolridge, if we are going to review capital structures in place at other utilities, the appropriate reference is to operating companies, not consolidated parent companies. The reason is quite straightforward: Parent company capital structures may reflect operations other than the rate base at issue in this proceeding. It therefore would not be surprising to see operating utility equity ratios that differ from the consolidated parent company equity ratio.

Q. HAVE YOU REVIEWED THE OPERATING COMPANY CAPITAL STRUCTURES FOR MR. O'DONNELL'S PROXY GROUP?

A. Yes, I have. Rebuttal Exhibit DWD-22 which provides that data, shows quite clearly that over time and across companies, operating utility equity ratios tend to be higher than the parent company ratio. That finding makes sense, given the utility financing practices discussed earlier in my Rebuttal Testimony. As Rebuttal Exhibit DWD-22 demonstrates, the average equity ratio for Mr.

O'Donnell's proxy group is 53.62 percent, 62 basis points above the Company's proposed equity ratio, quite consistent with the Company's proposal.

Q. LOOKING TO MR. O'DONNELL'S PROXY GROUP, ARE THERE EXAMPLES OF WHY THE PARENT COMPANY CAPITAL STRUCTURE DOES NOT APPLY TO UTILITY OPERATING COMPANIES?

A. Yes, there are. For example, in addition to Florida Power & Light ("FPL"), NextEra Energy, Inc. ("NEE") holds NextEra Energy Resources, LLC, ("NEER") which develops, owns, and operates electric generating facilities in wholesale energy markets.[394] Among the vehicles used by NEER to fund those facilities are project-specific, limited, or non-recourse financing structures.[395] Because they are not used to fund rate base assets, the debt associated with those financing structures should not be considered in assessing the Company's capital structure. In any event, whereas NEE's equity ratio has historically been approximately 45.00 percent on average,[396] FPL's equity ratio has been considerably higher, in the range of 62.00 percent.[397]

Again, the ratemaking capital structure should relate to utility operations, and the permanent assets that support those operations. Because, as in the case of NEE, parent company capital structures may contain debt not

394 NextEra Energy, Inc., SEC Form 10-K For the fiscal year ended December 31, 2018, at 11.
395 NextEra Energy, Inc., SEC Form 10-K For the fiscal year ended December 31, 2018, at 30.
396 Source: *Value Line Investment Survey*, November 15, 2019 for the years 2009 - 2018.
397 Rebuttal Exhibit DWD-7.

associated with utility operations, the parent company capital structure should not be used to assess the Company's proposed equity ratio.

Q. WHY IS THE CAPITAL STRUCTURE IMPORTANT TO UTILITIES' FINANCIAL INTEGRITY?

A. As explained earlier in my response to Dr. Woolridge, utility capital structures, and the financial strength they support, are set not only to ensure capital access during normal markets, but to enable access when markets are constrained. The reason is straightforward: A utility's obligation to serve is not contingent on capital market conditions. When markets are constrained, only those utilities with sufficient financial strength are able to attract capital at reasonable terms. That ability provides those utilities with critically important financing flexibility.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S REVIEW OF AUTHORIZED EQUITY RATIOS?

A. First, I note that Mr. O'Donnell's reported 49.90 percent average equity ratio includes distribution-only electric utilities. The more appropriate comparison is to vertically integrated electric utilities, for which the average and median authorized equity ratio in 2019 was 50.20 percent and 52.00 percent, respectively, within a range of 33.71 percent to 57.02 percent. Again, the Company's proposed 53.00 percent equity ratio is well within that range (and less than one standard deviation from the mean).

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS REGARDING MR. O'DONNELL'S REFERENCE TO AUTHORIZED EQUITY RATIOS?

A. Yes, I do. Mr. O'Donnell's review includes equity ratios authorized in jurisdictions that include non-investor supplied capital in the capital structure (*i.e.*, Arkansas, Florida, Indiana, and Michigan). If those jurisdictions are excluded, the average and median authorized equity ratio in 2019 was 51.93 percent and 52.00 percent for vertically integrated utilities. Again, that review suggests the Company's proposed 53.00 percent equity ratio is consistent with authorized equity ratios.

VII. RESPONSE TO COMMERCIAL GROUP WITNESS MR. CHRISS

Q. PLEASE SUMMARIZE MR. CHRISS' TESTIMONY REGARDING THE COMPANY'S ROE.

A. Mr. Chriss opposes the Company's proposed ROE based on his review of authorized ROEs since 2016 nationwide and within North Carolina.[398] He recommends the Commission "closely examine" the Company's proposed ROE:

> [I]n light of: (1) The customer impact of the resulting revenue requirement increase as discussed above; (2) recent rate case ROEs approved by the Commission; and (3) recent rate case ROEs approved by commissions nationwide.[399]

[398] Direct Testimony of Steve W. Chriss, at 8-11.
[399] Direct Testimony of Steve W. Chriss, at 4, 12.

However, Mr. Chriss did not undertake an independent, market-based analysis of the Company's Cost of Equity.

Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?

A. Yes, there are. The regulatory environment is one of the most important factors debt and equity investors factor in their assessment of risk. Further, utility credit ratings and outlooks depend substantially on the extent to which rating agencies view the regulatory environment as credit supportive, or not. For example, Moody's finds the regulatory environment to be so important that 50.00 percent of the factors that weigh in its ratings determination are determined by the nature of regulation.[400] Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, I believe it is important to consider the extent to which the jurisdictions that recently have authorized ROEs for electric utilities are viewed as having constructive regulatory environments.

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400 *See,* Moody's Investors Service Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

Q. HAVE YOU REVIEWED AND UPDATED THE INFORMATION CONTAINED IN MR. CHRISS' EXHIBIT 3?

A. Yes. As shown in Table 11 (below; *see also* Rebuttal Exhibit DWD-23), I analyzed the authorized ROE for electric utilities based on the jurisdiction's ranking by RRA. RRA, which is the source of Mr. Chriss' data, provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.[401]

The Commission currently is ranked "Average/1", which falls in the top-third of the 53 jurisdictions ranked by RRA.

Across the 98 vertically integrated rate cases for which RRA reports an authorized ROE since 2016, there was a 30-basis point difference between the median return for jurisdictions ranked in the top third of all jurisdictions and jurisdictions ranked in the bottom third of all jurisdictions (the higher-ranked

[401] Source: Regulatory Research Associates, accessed February 28, 2020.

jurisdictions providing the higher authorized returns, *see* Table 11, below). As Table 11 indicates, authorized ROEs for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions, including North Carolina, range from 9.37 percent to 10.55 percent, with an average of 9.93 percent, and a median of 9.98 percent.

Table 11: Vertically Integrated Authorized ROE by RRA Ranking[402]

Authorized ROE (%) Vertically Integrated Electric Utilities			
RRA Ranking	**Top Third**	**Middle Third**	**Bottom Third**
Mean	9.93%	9.52%	9.63%
Median	9.98%	9.50%	9.50%
Maximum	10.55%	10.30%	11.95%
Minimum	9.37%	8.75%	9.06%

My recommended range, 10.00 percent to 11.00 percent, is consistent with the returns authorized in more constructive jurisdictions.

Q. DO YOU AGREE WITH MR. CHRISS' CALCULATION OF THE AVERAGE AUTHORIZED ROE FOR ALL UTILITIES?[403]

A. No, I do not. Mr. Chriss's average authorized ROE reported in his Chriss Exhibit 3 for the 2016 to 2020 period for all utilities and for distribution only utilities includes ROEs authorized as part of the Illinois Formula Rate Plan

402 Source: Regulatory Research Associates. "Top Third" includes Above Average/1,2,3 and Average/1; "Middle Third" includes Average/2; "Bottom Third" includes Average/3 and Below Average/1,2,3. The "Top Third" and "Bottom Third" groups each include 19 (of the 53 total) jurisdictions. The "Middle Third" group includes 15 jurisdictions. *See also*, Rebuttal Exhibit DWD-23. Excludes limited issue riders and Illinois formula rate proceedings.

403 Chriss Exhibit 3.

("FRP") proceedings,[404] which has resulted in the lowest ROEs in at least 30 years and biases his calculated average downward. Table 12 below illustrates the effect of removing the Illinois Formula Rate Plans from his average ROE calculations.[405]

Table 12: Average Authorized ROE Presented in Chriss Exhibit 3 Excluding Illinois Formula Rate Plan Proceedings

	All Electric Utility Rate Cases	
	Average Including Illinois FRPs	Average Excluding Illinois FRPs
Entire Period (2016-2020)	9.61%	9.66%
2016	9.60%	9.66%
2017	9.68%	9.74%
2018	9.54%	9.57%
2019	9.64%	9.69%

Q. HAS MR. CHRISS CONSIDERED THE EFFECT OF HIS RECOMMENDATION ON THE COMPANY'S FINANCIAL PROFILE?

A. No, he has not. The financial community carefully monitors utility companies' financial conditions, both current and expected, as well as the regulatory environment in which those companies operate. Here, Mr. Chriss suggests the

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[404] In Illinois, statutes require the ROEs for Commonwealth Edison and Ameren Illinois to be re-set annually, under a formula rate plan ratemaking paradigm where the allowed ROE is set by application of a 580 basis-point premium to the 12-month average 30-year Treasury Bond yield. In the historically low interest rate environment, this framework has resulted in the lowest ROEs in at least 30 years. Source: Regulatory Research Associates.

[405] Source: Regulatory Research Associates. The average authorized ROE period for distribution-only electric utilities excluding Illinois FRPs over the 2016-2020 period is 9.48 percent

Commission should reduce the Company's ROE by some unspecified amount without the benefit of market-based, comparative analyses to support that recommendation. The consequence of doing so would indicate an increased degree of regulatory risk.

VIII. RESPONSE TO CIGFUR WITNESS MR. PHILLIPS

Q. PLEASE SUMMARIZE MR. PHILLIPS TESTIMONY REGARDING THE COMPANY'S ROE.

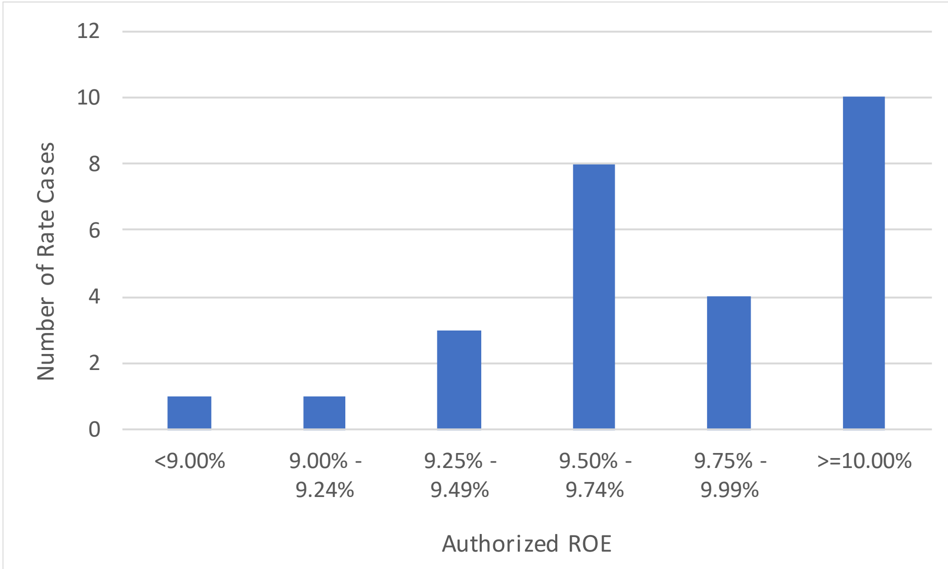
A. Mr. Phillips opposes the Company's proposed ROE based on his review of authorized ROEs during 2019, as reported by RRA.[406] Mr. Phillips reasons that because RRA reports the average authorized ROE for vertically integrated electric utilities to be 9.73 percent, that the Commission should not authorize an ROE above that level for the Company.[407]

Q. HAVE YOU REVIEWED THE 9.73 PERCENT RETURN MR. PHILLIPS DISCUSSED IN HIS TESTIMONY?

A. Yes, I have. To gain another perspective regarding the returns authorized in 2019, I prepared a histogram of the returns authorized for vertically integrated electric utilities. As shown in Chart 18 below, more than one-third (*i.e.*, ten of 27) of the rate cases in 2019 through January 2020 awarded an ROE of 10.00 percent and higher, within my recommended range.

406 Direct Testimony of Nicholas Phillips, Jr., at 27.
407 Direct Testimony of Nicholas Phillips, Jr., at 27, 29.

Chart 18: Frequency of Vertically Integrated Electric Utility Authorized ROEs in 2019-2020[408]



As discussed in my response to Mr. Chriss, and as shown in Table 11 (above; *see also* Rebuttal Exhibit DWD-23), I analyzed the authorized ROE for vertically integrated electric utilities based on each jurisdiction's ranking by RRA. As discussed in my response to Mr. Chriss, authorized ROEs for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions range from 9.37 percent to 10.55 percent, with an average of 9.93 percent, and a median of 9.98 percent (*see* Table 11 above).

Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?

A. Yes, there are. Utility credit ratings and outlooks depend substantially on the

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408 Source: Regulatory Research Associates. *See*, Rebuttal Exhibit DWD-8.

extent to which rating agencies view the regulatory environment as credit supportive, or not. As noted in my response to Mr. Chriss, Moody's finds the regulatory environment to be so important that 50.00 percent of the factors that weigh in its ratings determination are determined by the nature of regulation. Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, it is important to consider the extent to which the jurisdictions that recently have authorized ROEs are viewed as having constructive regulatory environments.

IX. RESPONSE TO TECH CUSTOMERS WITNESS MR. STRUNK

Q. PLEASE SUMMARIZE MR. STRUNK'S TESTIMONY REGARDING THE COMPANY'S ROE.

A. Mr. Strunk argues the Company's requested Return on Equity is "excessive, internally inconsistent, and should be rejected".[409] To support his claim, Mr. Strunk suggests DE Carolinas is less risky than the proxy group.[410] He concludes my recommended ROE of 10.50 percent should be rejected.[411] Lastly, Mr. Strunk asserts that the Company's proposed equity ratio of 53.00 percent is "among the highest allowed", which indicates low financial risk.[412]

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[409] *See*, Direct Testimony of Kurt G. Strunk, at 31.
[410] Direct Testimony of Kurt G. Strunk, at 37-39.
[411] Direct Testimony of Kurt G. Strunk, at 39.
[412] Direct Testimony of Kurt G. Strunk, at 39.

Q. DID MR. STRUNK PERFORM AN INDEPENDENT, MARKET-BASED ASSESSMENT OF THE COMPANY'S COST OF EQUITY?

A. No, he did not.

Q. WHAT IS YOUR RESPONSE TO MR. STRUNK'S POSITION THAT THE COMPANY IS LESS RISKY THAN THE PROXY GROUP COMPANIES?

A. Mr. Strunk asserts the Company has a higher Business Risk and Financial Risk assessment from S&P relative to the proxy group. However, his analysis compares the Company, which is an operating subsidiary of Duke Energy Corporation, to the proxy companies at the consolidated parent level. Additionally, there are more proxy companies with the same "Excellent" Business Risk rating as the Company, than there with the lower "Strong" Business Risk rating.[413] Those points aside, for the reasons discussed in response to Dr. Woolridge, I do not believe credit ratings are a full measure of equity risk.

Q. PLEASE SUMMARIZE MR. STRUNK'S CRITICISMS OF THE COMPANY'S PROPOSED CAPITAL STRUCTURE.

A. Mr. Strunk compared the Company's proposed equity ratio to those approved for other vertically integrated electric utilities in 2019 and 2020. Based on that review, Mr. Strunk concludes the Company's proposed 53.00 percent equity

[413] Direct Testimony of Kurt G. Strunk, at Figure 3.

ratio is "among the highest in the proxy group" and, therefore, indicative of low financial risk.[414]

Q. WHAT IS YOUR RESPONSE TO MR. STRUNK ON THOSE POINTS?

A. I disagree with his analysis and conclusions. Whereas Mr. Strunk has limited his analysis to capital structures approved in 2019-2020, I have compared the Company's proposed capital structure to the actual capital structures for the proxy group operating companies over the last eight fiscal quarters. As shown in Rebuttal Exhibit DWD-7, the average equity ratio for my Updated Proxy Group is 53.69 percent, within a range of 45.65 percent to 61.20 percent. For the individual operating companies, the average equity ratios range from 45.46 percent to 76.41 percent. Therefore, the Company's proposed equity ratio of 53.00 percent is well within the range of actual equity ratios in place at the proxy companies. Further, Mr. Strunk's review considers the equity ratios from jurisdictions in which non-investor supplied capital is included in the capital structure, thus biasing his review of the Company's proposed equity ratio relative to equity ratios authorized for other electric utilities.

Although Mr. Strunk has not recommended a specific equity ratio, I note that more than half (*i.e.*, 16 of 28) of the companies included in his Figure 2 have been authorized equity ratios above the 50.00 percent equity ratio recommended by Dr. Woolridge and Mr. O'Donnell. As such, I do not believe

[414] Direct Testimony of Kurt G. Strunk, at 35-36.

that the Company's proposed equity ratio is inconsistent with those in place at the proxy companies, or that it indicates a lower financial risk.

Q. WHAT IS YOUR RESPONSE TO MR. STRUNK'S CLAIM THAT THE COMPANY HAS NOT DEMONSTRATED ITS PROPOSAL "OPTIMIZES" THE CAPITAL STRUCTURE AND "RESULTS IN THE LOWEST COST OF CAPITAL FOR CUSTOMERS?"[415]

A. Mr. Strunk appears to assume a capital structure that "minimizes" the calculated overall Rate of Return is the "optimal" capital structure. I disagree with that premise. If the capital structure and the costs of debt and equity were independent of each other, the cost of capital could be mathematically "minimized", with a capital structure of 100.00 percent debt and 0.00 percent equity. In reality, however, those variables are interrelated: As financial leverage increases, so do the costs of debt and equity.

Further, because they have taken on the obligation to serve, utilities do not have the option to defer large, irreversible capital investments, or to delay accessing capital, even when capital markets are constrained. Because they cannot defer acquiring or investing capital on behalf of their customers, utilities must have the financial wherewithal to access capital, regardless of market conditions.

Capital structure optimization addresses numerous constraints

415 Direct Testimony of Kurt G. Strunk, at 5.

associated with financing decisions, and understands that financing costs go beyond coupon rates. As explained in my responses to Dr. Woolridge, financing constraints are dynamic in nature – they continually change in response to market conditions. A noted example is the reaction of utilities to the credit constraints experienced during the 2008 market downturn. The U.S. capital markets experienced significant turmoil in 2008 and 2009, and those companies without preexisting and/or contractually obligated sources of liquidity faced either onerous financing terms, or the potential of not being able to access funds at all. In summary, the definition and realization of an "optimal" capital structure is far more complex than Mr. Strunk's position assumes.

Q. DO YOU BELIEVE CREDIT RATINGS DIRECTLY MEASURE DE CAROLINAS' EQUITY RISK RELATIVE TO THE PROXY GROUP?

A. No, I do not. As discussed in my response to Dr. Woolridge, debt and equity are entirely different securities with different risk/return characteristics, different lives, and different investors. As such, any inferences drawn from differences in credit ratings regarding the Company's Cost of Equity should be drawn with caution.

X. RESPONSE TO CBDAV WITNESS MR. MCILMOIL

Q. PLEASE SUMMARIZE MR. MCILMOIL'S TESTIMONY AS IT RELATES TO THE RETURN ON EQUITY.

A. Mr. McIlmoil recommends the Commission approve an ROE of "no greater than 9.2 percent" and "maintain DEC's current capital structure of 52 percent equity and 48 percent debt."[416]

Q. DID MR. MCILMOIL PERFORM AN INDEPENDENT, MARKET-BASED ASSESSMENT OF THE COMPANY'S RETURN ON EQUITY?

A. No, he did not. Mr. McIlmoil's recommendation of an ROE of "no greater than 9.2 percent" is based entirely on the ROE approved for Dominion Energy Virginia (*i.e.*, Virginia Electric Power Company or "VEPCO"), by the Virginia State Corporation Commission in November 2019.[417] Mr. McIlmoil provides no support for the position that an ROE authorized for one specific electric utility in Virginia is more relevant as the basis for the Company's ROE than other cases.

Further, Mr. McIlmoil fails to acknowledge that the nature of the VEPCO proceeding was to determine the fair rate of return on common equity to be applied to its Rate Adjustment Clauses ("RAC") and to measure earnings in the first triennial review proceeding in 2021 pursuant to Code § 56-585.1:1 A. The proceeding was not a general rate case. The current authorized ROE

[416] Direct Testimony of Rory McIlmoil, at 6.
[417] Direct Testimony of Rory McIlmoil, at 6, 69.

for Dominion Energy Virginia's general rate base assets is 10.00 percent.[418] Further, the framework in Virginia includes an earnings sharing mechanism of a 70 basis point deadband around the 9.20 percent ROE. Lastly, as noted earlier, the Commission recently authorized a 9.75 percent ROE for VEPCO's North Carolina operations.

XI. CONCLUSION

Q. PLEASE SUMMARIZE THE ANALYSES AND CONCLUSIONS CONTAINED IN YOUR REBUTTAL TESTIMONY.

A. My updated analytical results applied to my Updated Proxy Group described above are provided in Table 13 below. Based on the analyses discussed throughout my Rebuttal Testimony, and the results summarized in Table 13, I continue to believe the reasonable range of ROE estimates is from 10.00 percent to 11.00 percent and within that range, 10.50 percent is a reasonable and

418 Virginia Corporation Commission, Case No. PUE-2013-00020, Final Order (Nov. 26, 2013), at 14.

appropriate estimate of the Company's Cost of Equity.

Table 13: Summary of Updated Analytical Results

Discounted Cash Flow	***Mean Low***	***Mean***	***Mean High***
30-Day Constant Growth DCF	7.71%	8.48%	9.24%
90-Day Constant Growth DCF	7.77%	8.54%	9.30%
180-Day Constant Growth DCF	7.82%	8.59%	9.35%
CAPM Results		***Bloomberg Derived Market Risk Premium***	***Value Line Derived Market Risk Premium***
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (2.25%)		7.99%	8.54%
Near-Term Projected 30-Year Treasury (2.42%)		8.15%	8.70%
Long-Term Projected 30-Year Treasury (3.45%)		9.18%	9.73%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (2.25%)		8.52%	9.12%
Near-Term Projected 30-Year Treasury (2.42%)		8.69%	9.29%
Long-Term Projected 30-Year Treasury (3.45%)		9.72%	10.32%
ECAPM Results		***Bloomberg Derived Market Risk Premium***	***Value Line Derived Market Risk Premium***
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (2.25%)		9.35%	10.03%
Near-Term Projected 30-Year Treasury (2.42%)		9.51%	10.19%
Long-Term Projected 30-Year Treasury (3.45%)		10.55%	11.22%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (2.25%)		9.75%	10.47%
Near-Term Projected 30-Year Treasury (2.42%)		9.91%	10.63%
Long-Term Projected 30-Year Treasury (3.45%)		10.95%	11.67%
Bond Yield Risk Premium			
	Low	***Mid***	***High***
Bond Yield Risk Premium	9.92%	9.90%	9.98%
		Median	**Average**
Expected Earnings		10.06%	10.09%

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

APPENDIX A

Q. HAVE YOU TESTED WHETHER CNP'S CUMULATIVE UNDERPERFORMANCE IS STATISTICALLY MEANINGFUL?

A. Yes, I have. A method frequently used to determine whether a given event likely had a significant effect on stock returns is an "event study", sometimes referred to as a "cumulative abnormal return" analysis. To understand whether a specific event affected stock prices and returns, it is important to look at factors beyond the event under consideration. The portion of the stock's return that is not attributable to those other factors is considered the "abnormal" or "excess" return; the sum of those excess returns is the "cumulative" abnormal return.

To apply that approach, I defined the abnormal return on a given day as:

$$A_t = R_{i,t} - R_{m,t} \qquad [A1]$$

where A_t is the Abnormal Return on day t, $R_{i,t}$ is the actual return for CNP[419] on day t, and $R_{m,t}$ is the expected return for CNP. The expected return is defined in Equation [A2] below.

$$R_{m,t} = \alpha_t + \beta_{m,t} \qquad [A2]$$

The expected return, $R_{m,t}$, is based on a regression equation in which CNP's daily returns are the dependent variable, and the utility sector's daily return (measured by XLU) is the explanatory variable. Because it relies on market-adjusted returns, the approach controls for factors that affect companies across

[419] Calculated as an index. Source: S&P Global Market Intelligence.

the utility sector. I applied the regression (*i.e.*, Equation [A2]) over the period January 1, 2019 to February 19, 2020, using daily returns.[420] The equation and slope coefficient both were statistically significant (*see* Table A1, below).

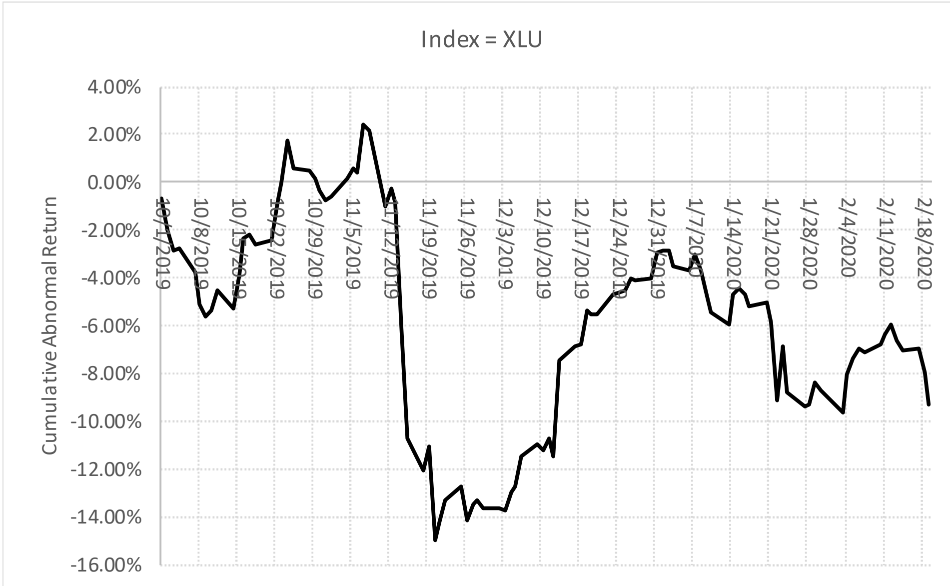
Table A1: Regression Statistics (XLU as Index)

	Slope	Intercept
Coefficient	0.8323	-0.0010
Std. Err.	0.0847	0.0006
R-Square	0.2472	
F-Statistic	96.5161	
T-Statistic	9.8243	-1.6376

To determine whether the PUCT's deliberations likely affected CNP's stock price and return, I considered the "event date" to be October 1, 2019. Because it pre-dates the deliberations and post-dates the PFD, the event date provides for the possibility that equity investors were aware of the regulatory process, and began to consider how the PUCT's decision might affect CNP's risk profile. I then calculated the cumulative abnormal return for each day from October 1, 2019 to February 19, 2020. Chart A1 (below) provides the cumulative abnormal return during that period. Not surprisingly, the cumulative abnormal return reached its lowest point around December 3, 2019, reversing itself around December 13, 2019 (when PUCT deferred its final decision pending ongoing settlement discussions), then falling coincident with the Stipulation and Settlement, and the Fitch downgrade.

[420] I did not use a longer historical period to avoid any possible effect of CNP's acquisition of Vectren, which closed on February 1, 2019.

Chart A1: Cumulative Abnormal Return (XLU as Index)



Q. WHAT CONCLUSIONS DO YOU DRAW FROM THAT ANALYSIS?

A. Controlling for sector-wide events, the PUCT's deliberations had a significant effect on CNP's price performance. That is true even if we measure the cumulative abnormal return through February 19, 2020.[421] If that level of underperformance were to continue, CNP would be substantially disadvantaged in its ability to compete for capital, to the detriment of ratepayers and investors. Further, the CEHE case illustrates the importance the financial community places on the regulatory environment.

[421] Based on a t-test. Please note that the same findings hold when the Dow Jones Utility Average is used as the sector index.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this supplemental rebuttal testimony ("Supplemental Rebuttal Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Progress, LLC ("DE Progress") and Duke Energy Carolinas, LLC ("DE Carolinas") (collectively, "the Companies").

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS THAT SUBMITTED DIRECT AND REBUTTAL TESTIMONIES IN THESE PROCEEDINGS?

A. Yes, I am.

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

A. The purpose of my Supplemental Rebuttal Testimony is two-fold. First, I update my cost of common equity ("ROE") models and second, I respond to the Supplemental Direct Testimony of Mr. Richard A. Baudino, witness for the North Carolina Attorney General's Office ("AG").

II. UPDATED ROE ANALYSES

Q. PLEASE SUMMARIZE YOUR UPDATED ROE ANALYSES.

A. My updated analytical results are provided in Table 1. The results are based on market data as of June 30, 2020.

Table 1: Summary of Updated Analytical Results[1]

Discounted Cash Flow	**Mean Low**	**Mean**	**Mean High**
30-Day Constant Growth DCF	8.14%	8.92%	9.67%
90-Day Constant Growth DCF	8.04%	8.82%	9.57%
180-Day Constant Growth DCF	7.76%	8.54%	9.29%
CAPM Results		**Bloomberg Derived MRP**	**Value Line Derived MRP**
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (1.47%)		13.21%	13.78%
Near-Term Projected 30-Year Treasury (1.72%)		13.45%	14.02%
Long-Term Projected 30-Year Treasury (3.40%)		15.14%	15.70%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (1.47%)		10.19%	10.60%
Near-Term Projected 30-Year Treasury (1.72%)		10.43%	10.85%
Long-Term Projected 30-Year Treasury (3.40%)		12.11%	12.53%
ECAPM Results		**Bloomberg Derived MRP**	**Value Line Derived MRP**
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (1.47%)		13.21%	13.77%
Near-Term Projected 30-Year Treasury (1.72%)		13.45%	14.02%
Long-Term Projected 30-Year Treasury (3.40%)		15.14%	15.70%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (1.47%)		10.94%	11.40%
Near-Term Projected 30-Year Treasury (1.72%)		11.18%	11.64%
Long-Term Projected 30-Year Treasury (3.40%)		12.87%	13.32%
Bond Yield Risk Premium			
	Current T-Bond	**Near-Term Proj.**	**Long-Term Proj.**
Bond Yield Risk Premium	10.25%	10.08%	9.96%
		Median	**Average**

[1] Updated model results are contained in Supplemental Rebuttal Exhibits DWD-1 through DWD-6.

Expected Earnings	10.55%	10.18%

Q. WHAT ARE YOUR SPECIFIC OBSERVATIONS REGARDING THE COST OF CAPITAL MODEL RESULTS SINCE YOUR REBUTTAL TESTIMONY IN THE DE PROGRESS PROCEEDING (SPOT DATE AS OF APRIL 17, 2020)?

A. Aside from the updated Beta coefficients provided by Value Line Investment Survey ("Value Line"), which increased from 0.548[2] to 0.743, there has been little movement in the other inputs to my models. This leads me to conclude that market conditions are generally unchanged from my analysis of market conditions in my most recent Rebuttal Testimony;[3] however, the substantial increase in Beta coefficients demonstrates greater risk for utility equities (and therefore a higher ROE) relative to the market. On balance, I maintain my recommended range of ROEs from 10.00 percent to 11.00 percent and a point estimate of 10.50 percent. In my opinion, an authorized ROE of 10.50 percent is a reasonable, but conservative measure of the Companies' required return, especially in view of the highly volatile current market conditions.

Q. HAVE YOU UPDATED YOUR PROXY GROUP IN YOUR ANALYSIS?

A. No, I have not. My Proxy Group is unchanged from my Proxy Group used in

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2 Docket No. E-2, Sub 1219, Rebuttal Exhibit DWD-3.
3 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 11-30.

my Rebuttal Testimony.[4]

Q. HAVE YOU APPLIED YOUR COST OF COMMON EQUITY MODELS IN THE SAME MANNER YOU APPLIED THEM IN YOUR DIRECT AND REBUTTAL TESTIMONIES?

A. Yes, I have.

III. <u>RESPONSE TO AG WITNESS MR. BAUDINO</u>

Q. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S POSITIONS AND CONCLUSIONS REGARDING THE RECENT CAPITAL MARKET DISLOCATION, AND ITS IMPLICATIONS FOR THE COMPANIES' COST OF COMMON EQUITY.

A. Mr. Baudino's Supplemental Direct Testimony provides an update of the interest rate and market data since the beginning of March 2020, "when concerns about the Covid-19 pandemic began to roil financial markets with extreme volatility".[5]

Mr. Baudino then describes the volatility surrounding 30-year Treasury bond yields, public utility bond yields, the stock market as a whole, and the utility industry for the period between March and June 30, 2020.[6] Additionally, Mr. Baudino summarizes the Federal Reserve Board's (the "Fed") actions to

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[4] *Ibid.*, at 30-31. Mr. Baudino uses this same proxy group filed for his updated analyses. Supplemental Direct Testimony of Richard A. Baudino, at 8.

[5] Supplemental Direct Testimony of Richard A. Baudino, at 2.

[6] *Ibid.*, at 3-4.

attempt to stabilize markets through providing liquidity to individuals and companies throughout that same period.[7]

From these observations, Mr. Baudino draws the following conclusions:

- That the decreases in Treasury and utility bond yields do not support higher ROEs for the Companies;[8]
- That regulated electric utilities like the Companies "continue to be safe, conservative, and relatively stable investments even in present market conditions";[9]
- That the increase in Beta coefficients could be a short-term phenomenon;[10]
- That the increase in Beta coefficients are not consistent with the decrease in bond yields;[11] and
- That the stability of the Companies' credit ratings do not suggest that their required ROE has increased.[12]

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7 *Ibid.*, at 4-7.
8 *Ibid.*, at 10.
9 *Ibid.*, at 7.
10 *Ibid.*, at 11.
11 *Ibid.*
12 *Ibid.*, at 10.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING MR. BAUDINO'S DISCUSSION ABOUT CAPITAL MARKETS AND THE CONCLUSIONS HE REACHES?

A. I do. While the facts he presents (*i.e.*, the levels of interest rates, market indices, and Fed actions) echo my observations about current market conditions presented in my Rebuttal Testimony,[13] his conclusions from those facts are contradictory. At several points in his Supplemental Direct Testimony, Mr. Baudino discusses the shocks,[14] extreme volatility,[15] unprecedented economic contraction,[16] skyrocketing unemployment,[17] and continuing effect on economic activity[18] brought upon by the COVID-19 pandemic, and yet he continues to support a 9.00 percent ROE, which is below any reasonable measure of the Companies' required return as shown on Chart 1, below:[19]

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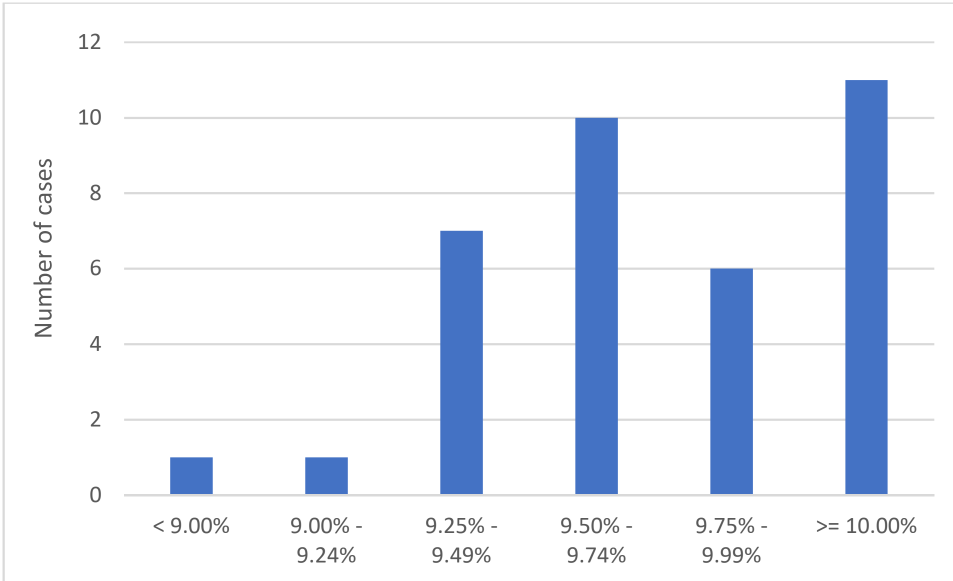
13 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 11-30.
14 Supplemental Direct Testimony of Richard A. Baudino, at 2.
15 *Ibid.*, at, 2, 7, 11.
16 *Ibid.*, at 13.
17 *Ibid.*
18 *Ibid.*, at 14.
19 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 4.

Chart 1: Frequency of Vertically Integrated Electric Utility Authorized ROEs in 2019-2020[20]



It must be noted that the rate cases in Chart 1 do not reflect current market conditions. As will be discussed in detail below, current market conditions are indicating a higher risk environment than those at the beginning of the year.

Q. WHY DO YOU DISAGREE WITH MR. BAUDINO REGARDING THE RELATIONSHIP BETWEEN CURRENT INTEREST RATES AND THE COST OF CAPITAL?

A. As discussed in my Rebuttal Testimony,[21] despite the Fed's actions, the 30-year Treasury bond yield has become highly volatile, as seen in its Coefficient of

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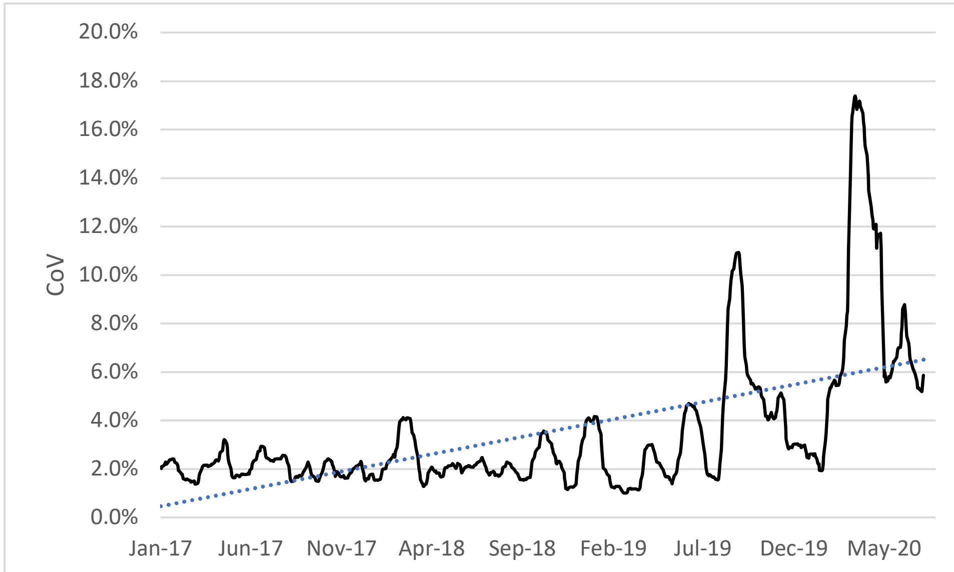
[20] Source: Regulatory Research Associates.
[21] *Ibid.*, at 17-18.

Variation ("CoV"):[22]

Chart 2: Coefficient of Variation in 30-Year Treasury Yields[23]



In response to Mr. Baudino's observations regarding public utility bonds,[24] I recreated the same analysis for A-rated utility bond yields:

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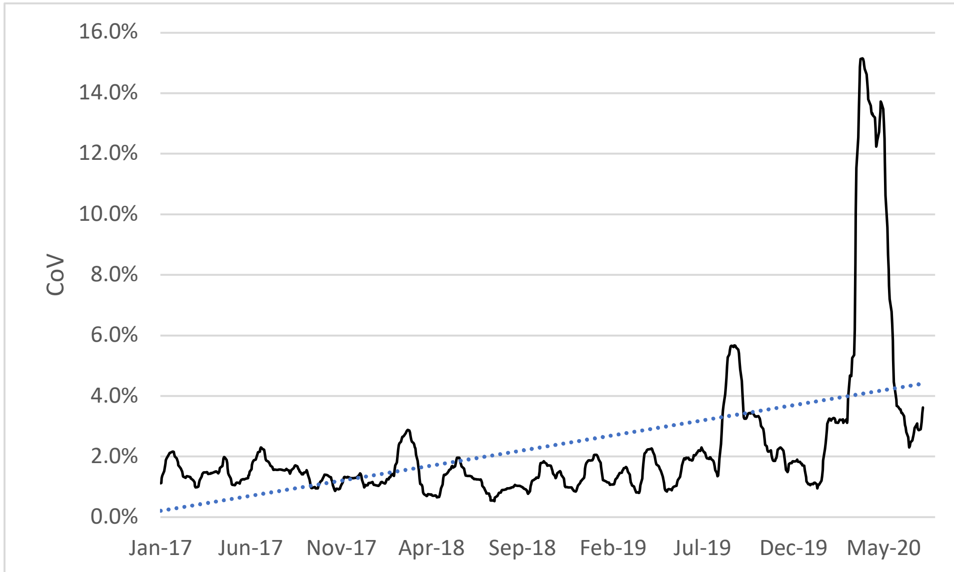
[22] The coefficient of variation is used by investors and economists to determine volatility.

[23] Source: S&P Global Market Intelligence. Data through July 10, 2020.

[24] Supplemental Direct Testimony of Richard A. Baudino, at 3.

Chart 3: Coefficient of Variation in A-Rated Public Utility Bonds[25]



As discussed in my Direct Testimony,[26] significant and abrupt increases in volatility tend to be associated with declines in Treasury yields, as investors seek to preserve their capital in "safe haven" investments. Even though it is Mr. Baudino's opinion that electric utility stocks are "safe haven" investments in this period of extreme market volatility, they are not.

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[25] *Ibid.*

[26] Docket No. E-2, Sub 1219, Direct Testimony of Dylan W. D'Ascendis, at 67. *see also*, Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 35.

Q. WHY ARE ELECTRIC UTILITY STOCKS NOT "SAFE HAVEN" INVESTMENTS IN THE CURRENT MARKET?

A. I have studied the relative performance and annualized volatilities[27] of my Proxy Group and the S&P 500 to gauge whether the Proxy Group has weathered the COVID-19 pandemic to date better than the overall market. As shown on Supplemental Rebuttal Exhibit DWD-7, from January 31, 2020[28] to July 10, 2020, returns for the Proxy Group companies ranged from negative 3.21 percent to negative 32.48 percent, averaging negative 20.64 percent while the S&P 500 return over the same period was negative 1.25 percent. The annualized volatility of the Proxy Group companies ranged from 53.44 percent to 80.88 percent, averaging 64.20 percent while the S&P 500's annualized volatility over the same period was 48.84 percent. This study shows that the Proxy Group performed worse than the overall market and has been more volatile (*i.e.*, riskier) than the market as well.

Q. HAVE YOU CONDUCTED ADDITIONAL ANALYSES TO SHOW THAT UTILITY STOCKS SHOULD NOT BE CONSIDERED SAFE OR

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27 The annualized volatility of a stock is measured by taking the standard deviation of the price changes within the sample and multiplying by the square root of 252 (the assumed number of trading days in a year)

28 I chose January 31, 2020 because on June 8, 2020, the National Bureau of Economic Research determined that a peak in monthly economic activity occurred in the U.S. economy in February 2020. The peak marks the end of the expansion that began in June 2009 and the beginning of a recession. https://www.nber.org/cycles/june2020.html

CONSERVATIVE INVESTMENTS IN THE CURRENT ECONOMIC ENVIRONMENT?

A. Yes. In my Rebuttal Testimony in the DE Progress proceeding, I explained that during volatile markets, "correlations go to 1" and utility stocks lose their defensive quality.[29] As such, I calculated the correlation coefficients of the price changes of several groups of utilities relative to the S&P 500 and the Dow Jones Industrial Index ("DJIA") from February 1, 2020 to July 10, 2020. Specifically, I calculated correlation coefficients for the following relationships:

- The price changes of the S&P 500 relative to the price changes of the Proxy Group;
- The price changes of the S&P 500 relative to the price changes of the S&P Utilities Index;
- The price changes of the S&P 500 relative to the price changes of the S&P Electric Index;
- The price changes of the S&P 500 relative to the price changes of the Dow Jones Utility Index ("DJU");
- The price changes of the DJIA relative to the price changes of the Proxy Group;
- The price changes of the DJIA relative to the price changes of the S&P

[29] Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 20.

Utilities Index;

- The price changes of the DJIA relative to the price changes of the S&P Electric Index; and
- The price changes of the DJIA relative to the price changes of the DJU.

Table 2 provides the results of the calculations:

Table 2: Calculation of Correlation Coefficients for Utility Groups Relative to Market Indices from February 2020 to July 2020[30]

Group	S&P 500	DJIA
Proxy Group	83.62%	82.23%
S&P Utility Index	85.98%	84.67%
S&P Electric Index	85.95%	84.77%
DJU	85.46%	84.49%

As shown on Table 2, utility stocks have been trading in tandem with market indices during the current market dislocation. The behavior of utility stocks to move in tandem with the market during market distress is not limited to the current period. During the Great Recession (December 2007 to June 2009), correlations between these same groups were similar, as shown on Table 3, below:

Table 3: Calculation of Correlation Coefficients for Utility Groups Relative to Market Indices from December 2007 to June 2009[31]

Group	S&P 500	DJIA
Proxy Group	78.71%	80.11%
S&P Utility Index	81.73%	82.27%
S&P Electric Index	79.16%	79.99%
DJU	81.57%	82.13%

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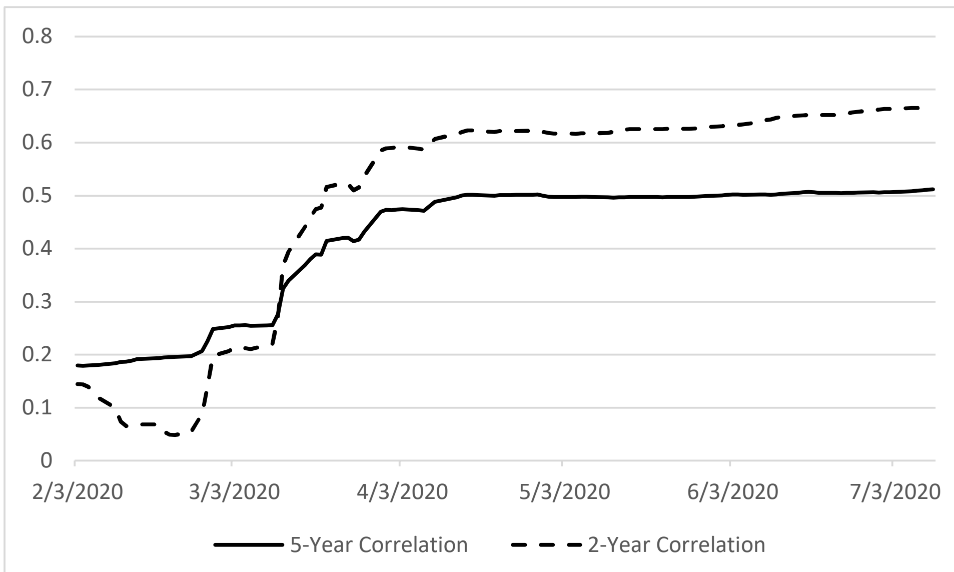
30 Source: Bloomberg Professional Services.
31 *Ibid*.

To further the point, I have calculated two-year[32] and five-year[33] correlation coefficients between the price changes in the S&P 500 and price changes in the Proxy Group from February 2020 to July 2020. As shown on Chart 4, as the COVID-19 pandemic became apparent, the correlation coefficients increased from approximately 0.15 to approximately 0.70 (two-year horizon) and from approximately 0.20 to approximately 0.50 (five-year horizon).

Chart 4: Two-Year and Five-Year Correlation Coefficients for the Proxy Group Relative to the S&P 500[34]



The increase in volatility (*i.e.*, risk), as explained above in combination

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[32] Consistent with the calculation horizon of Bloomberg's Beta coefficients.
[33] Consistent with the calculation horizon of Value Line's Beta coefficients.
[34] Source: S&P Global Market Intelligence.

with the increased correlation between the Proxy Group and market indices ultimately leads to higher Beta coefficients, as evidenced in their increase during the course of these proceedings:

Table 4: Evolution of Beta Coefficients Throughout the Proceedings[35]

Source	Direct (DEC) 6/28/19	Direct (DEP) 8/16/19	Rebuttal (DEC) 1/31/20	Rebuttal (DEP) 4/17/20	Supplemental Rebuttal 6/30/20
Bloomberg	0.498	0.499	0.513	0.995	1.000
Value Line	0.580	0.572	0.561	0.548	0.743

In view of all of the above, it is apparent that electric utilities, as represented by the Proxy Group, are essentially just as risky as the market at this time. Mr. Baudino's conclusion that electric utilities "continue to be safe, conservative, and relatively stable investments even in present market conditions" is not justified by his own analysis. That analysis confirms the highly volatile nature of current market conditions, even as to regulated electric utilities, and these highly volatile conditions are even in his own estimation indicators of increased risk.[36] The upward trend in Beta coefficients depicted in Table 4 shows this, and nothing in Mr. Baudino's Supplemental Direct Testimony refutes it.

35 Supplemental Rebuttal Exhibit DWD-8.
36 Supplemental Direct Testimony of Richard A. Baudino, at 10-11.

Q. MR. BAUDINO CLAIMS THAT THE INCREASED BETA COEFFICIENTS ARE A SHORT-TERM PHENOMENON.[37] DO YOU AGREE WITH HIS ASSESSMENT?

A. No. As I discussed previously, Bloomberg and Value Line Beta coefficients are calculated over time horizons of two- and five-years, respectively. That means the effect of the COVID-19 pandemic on markets reflected in the Beta coefficient calculation would last until at least February 2022 (Bloomberg) and February 2025 (Value Line).[38] Additionally, as discussed in my Rebuttal Testimony,[39] the potential range of economic financial outcomes due to COVID-19 is wide, and there is no way anyone, including Mr. Baudino, can know how it will shake out. This is corroborated by the Fed's press release on June 10, 2020, which was cited by Mr. Baudino:

> The ongoing health crisis will weigh heavily on economic activity, employment, and inflation in the near term and poses considerable risks to the economic outlook in the medium term.[40]

Because the public health crisis has not yet abated, its total impact on markets cannot be measured.

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37 Supplemental Direct Testimony of Richard A. Baudino, at 11.

38 *Also see*, Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 234-235. As noted there, Value Line data is not as current as Bloomberg data regarding Beta coefficients. Further, as Value Line data is updated on a rolling regional basis and updates reflecting COVID-19 effects for the West region have not as yet been provided, at this time Value Line's Beta coefficients lag Bloomberg's.

39 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 28.

40 Federal Reserve Board, Press Release, June 10, 2020.

Q. MR. BAUDINO REFERENCES THE DECLINE OF THE CHICAGO BOARD OPTIONS EXCHANGE ("CBOE") VOLATILITY INDEX ("VIX") FROM ITS MARCH 16, 2020 PEAK OF 82.69 TO 30.43 CURRENTLY AS A REASON WHY "IT IS HIGHLY UNLIKELY THAT A 32% INCREASE IN EXPECTED BETAS FOR ELECTRIC UTILITIES SINCE EARLIER IN THE YEAR IS ACCURATE AND RELIABLE."[41] PLEASE RESPOND.

A. While Mr. Baudino is correct that the VIX has declined to approximately 30.00 from its peak of 82.69, a VIX of 30.00 is still 50 percent higher than its historical average level of approximately 20.00.[42] As I discussed in my Direct Testimony,[43] one means of assessing market expectations regarding the future level of volatility is to review CBOE's "Term Structure of Volatility", which is described by CBOE as:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[44]

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41 Supplemental Direct Testimony of Richard A. Baudino, at 12.
42 *See*, Docket No. E-7, Sub 1214, Direct Testimony of Dylan W. D'Ascendis, at 39, Chart 4.
43 Docket No. E-2, Sub 1219, Direct Testimony of Dylan W. D'Ascendis, at 66.
44 Source: www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

As shown in Table 5, the implied volatility is expected to remain approximately 50 percent above historical volatility until at least December 2021.

Table 5: CBOE Term Structure of Volatility[45]

Date	Projected VIX
August 2020	28.05
September 2020	29.93
October 2020	31.18
November 2020	32.47
December 2020	33.19
January 2021	31.45
March 2021	30.70
June 2021	29.54
September 2021	28.52
December 2021	29.87

The current and expected increased volatility in the market, in addition to the time horizon used to calculate Beta coefficients, and the uncertainty surrounding the length and total impact of the COVID-19 pandemic would lead to the conclusion that the increase in Beta coefficients will not be short-term in nature.

Q. DO YOU AGREE WITH MR. BAUDINO'S POSITION THAT THE INCREASE IN BETA COEFFICIENTS ARE INCONSISTENT WITH THE ABRUPT FALL IN INTEREST RATES?

A. No, I do not. As discussed in detail previously, event-driven increases in

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45 Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, accessed July 10, 2020.

volatility lowers bond yields as investors seek to preserve capital. As the volatility of the market and utility stocks increase, so did the correlation of their price changes, leading to increasing Beta coefficients.

Q. ONE OF MR. BAUDINO'S REASONS FOR NOT ADJUSTING HIS RECOMMENDED ROE IS BECAUSE THE COMPANIES' CREDIT RATINGS WERE NOT AFFECTED DURING THE PANDEMIC. IS THAT VALID REASONING?

A. No. As discussed in my Rebuttal Testimony,[46] I do not think that credit ratings are a full measure of any company's relative equity risk. That being said, and as I also discussed in my Rebuttal Testimony,[47] S&P downgraded its outlook on the utility sector from "Stable" to "Negative" on April 4, 2020. Regarding liquidity and capital access, S&P observes that "the industry continues to exhibit adequate liquidity and access to the debt markets, despite uneven performance of the commercial paper market for tier 2 issuers", but availability to equity markets "remains extraordinarily challenging."[48] S&P expects the negative discretionary cash flow associated with high capital investment commitments and the "lack of access to the equity markets" to "lead to a weakening of credit measures."[49]

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[46] Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 113-116.
[47] *Ibid.*, at 24-25.
[48] *Ibid.*
[49] *Ibid.*

Moody's Investor Services ("Moody's") similarly observed that "[i]n a prolonged economic downturn, boards of directors are likely to review dividend plans as an option to conserve cash."[50] Moody's expects companies with higher payout ratios as more likely to reduce dividends, and sees the potential for average dividend payout ratios to increase to about 80.00 percent from a median of 63.00 percent in 2019.[51] In Moody's view, the ability to reduce dividends provides utilities "with a significant source of internal cash that could help them offset the impact of a potentially prolonged coronavirus-related economic downturn."[52]

Because utilities require adequate access to capital to provide safe and reliable service,[53] in times of market distress, the ability to access capital is even more critical. Utilities with strong financial profiles will have access to capital at more favorable terms and can pass those lower costs to customers.

Q. HAVE ANY UTILITY COMPANIES RECENTLY CUT THEIR DIVIDEND?

A. Yes. On April 1, 2020, CenterPoint Energy announced that it was reducing its dividend from $0.29 per share to $0.15 per share, in part citing the negative

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50 Moody's Investors Service, *Dividends a major source of cash if coronavirus downturn is prolonged*, April 6, 2020, at 1.

51 *Ibid.*, at 2-3.

52 *Ibid.*, at 1.

53 Docket No. E-2, Sub 1219, Rebuttal Testimony of Dylan W. D'Ascendis, at 130-131.

effect of the COVID-19 pandemic on the energy market and economy.[54] On July 5, 2020, Dominion Energy, following an asset sale, rebased (*i.e.*, cut) its dividend payment reflecting the sale of the assets and its payout ratio targets.[55] In short, even though the Companies' credit ratings were unchanged (so far) during the current public health crisis, the credit rating agencies recognize the risks presented by COVID-19, and some utilities are already reacting to those risks.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING CURRENT CAPITAL MARKET CONDITIONS?

A. Based on all of the analyses provided previously in this Supplemental Rebuttal Testimony, it has been shown that the volatility of both utility stocks and the market as a whole have increased and that the correlations of the price changes between utility stocks and market indices have likewise increased. Looking toward expected market volatility, it has been shown that the current level of market volatility, which is 50 percent higher than normal levels, is expected to persist until at least the end of 2021. Finally, credit rating agencies and individual utilities have recognized the risk presented by COVID-19 and have begun to act on responding to those risks. On balance, risk is higher now than

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54 Tomi Kilgore, "CenterPoint Energy cuts dividend nearly in half and lowers capex; CFO leaving company," MarketWatch, April 2, 2020.

55 Dominion Energy, Press Release, July 5, 2020.

it was at the beginning of the year and must be reflected in the investor-required return.

Q. PLEASE BRIEFLY SUMMARIZE MR. BAUDINO'S OBSERVATIONS AND CONCLUSIONS REGARDING NORTH CAROLINA-SPECIFIC ECONOMIC CONDITIONS.

A. Mr. Baudino states that the COVID-19 pandemic caused an unprecedented economic contraction and skyrocketing unemployment in North Carolina.[56] He reviews unemployment rates of both North Carolina and the U.S., which have risen from 3.60 percent and 3.50 percent in February 2020 to 12.90 percent and 13.30 percent in May 2020, respectively, and reviews the national Gross Domestic Product ("GDP") growth of negative 5.00 percent for the first quarter 2020.[57] Mr. Baudino then concludes that it is more important than ever for the Commission to consider the impacts of the Companies' requested ROE on their customers.[58]

Q. DO YOU HAVE COMMENTS ON MR. BAUDINO'S OBSERVATIONS AND CONCLUSIONS REGARDING NORTH CAROLINA ECONOMIC CONDITIONS?

A. Yes. While I agree that COVID-19 has affected the North Carolina economy,

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56 Supplemental Direct Testimony of Richard A. Baudino, at 13.
57 *Ibid.*, at 13-14.
58 *Ibid.*, at 14.

it has equally affected the entire U.S. economy. As discussed in my Direct Testimony,[59] in its Order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the ROE. Even though the North Carolina and the U.S. economy has contracted, those relationships still hold.

Regarding GDP, the U.S. contracted 5.00 percent (annualized) in the first quarter 2020, while North Carolina's GDP contracted at a similar 5.10 percent in the first quarter 2020. The correlations between U.S. and North Carolina GDP growth for the period 2005 – first quarter 2020, and for the four quarters ended first quarter 2020, are 0.9769 and 0.9993, respectively.

Regarding unemployment rates, as of May 2020 (the most recent data for North Carolina-specific unemployment rates), the unemployment rate[60] for the U.S., North Carolina, the counties served by DE Progress, and the counties served by DE Carolinas were 13.00 percent, 12.70 percent, 11.89 percent, and 12.97 percent, respectively.[61] While all the unemployment rates are extraordinarily high, it could be argued that North Carolina customers, and customers within the Companies' service area have been relatively better off

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59 Docket No. E-2, Sub 1219, Direct Testimony of Dylan W. D'Ascendis, at 57-58.

60 Not seasonally adjusted.

61 Source: U.S. Bureau of Labor Statistics. Unemployment rate for the counties served by DE Progress and DE Carolinas is the average of the respective counties.

than the rest of the country. The correlations between the U.S. unemployment rate with the North Carolina unemployment rate, the counties served by DE Progress unemployment rate, and the counties served by DE Carolinas are shown in Table 6, below:

Table 6: Correlations of Unemployment Rates of U.S., North Carolina, and Territories Served by the Companies February 2020 – May 2020

	U.S. Unemployment Rate
North Carolina Unemployment Rate	99.29%
DE Progress Unemployment Rate	98.84%
DE Carolinas Unemployment Rate	99.41%

On balance, the values and the correlations between national and state-wide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain in place, and, as such, continue to be reflected in the models and data used to estimate the ROE.

IV. CONCLUSION

Q. DO YOU MAINTAIN YOUR 10.50 PERCENT RECOMMENDED ROE FOR THE COMPANIES GIVEN CURRENT MARKET CONDITIONS?

A. Yes, I do.

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO AUTHORIZE THE COMPANIES THEIR FULL REQUIRED ROE IN THESE PROCEEDINGS?

A. Utilities, like the Companies, are the engine for economic growth for the communities they serve, and as such need to be able to access capital at reasonable costs to provide safe and reliable service. To allow the Companies an opportunity to earn an ROE below investors' required return not only disadvantages the Companies, but also the businesses and individuals the Companies serve.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Yes, it does.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. I am a Director at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, New Jersey 08054.

Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS WHO SUBMITTED DIRECT, REBUTTAL, AND SUPPLEMENTAL REBUTTAL TESTIMONIES IN THIS PROCEEDING?

A. Yes, I filed direct testimony ("Direct Testimony"), rebuttal testimony ("Rebuttal Testimony"), and supplemental rebuttal testimony ("Supplemental Rebuttal Testimony") on behalf of Duke Energy Carolinas ("DE Carolinas" or the "Company"). In my Direct, Rebuttal, and Supplemental Rebuttal Testimonies I recommended a Return on Equity ("ROE") of 10.50 percent, within a range of 10.00 percent to 11.00 percent.

Q. WHAT IS THE PURPOSE OF YOUR SETTLEMENT SUPPORT TESTIMONY?

A. The purpose of my testimony is to explain my support for the Second Agreement and Stipulation of Partial Settlement dated July 31, 2020 (the "Second Partial Settlement") among the Company and the Public Staff (collectively, the "Settling

Parties"). In particular, my testimony addresses the agreed-upon ROE, capital structure, and overall Rate of Return contained in the Second Partial Settlement.[1]

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONJUNCTION WITH YOUR TESTIMONY?

A. Yes. Settlement Exhibit No. DWD-1 has been prepared by me, or under my direct supervision.

II. STIPULATED ROE, EQUITY RATIO, AND OVERALL RATE OF RETURN

Q. ARE YOU FAMILIAR WITH THE TERMS OF THE SECOND PARTIAL SETTLEMENT AS IT RELATES TO THE COMPANY'S OVERALL RATE OF RETURN?

A. Yes. I understand the Settling Parties have agreed to an ROE of 9.60 percent, and a capital structure including 52.00 percent common equity and 48.00 percent long-term debt for the Company. I further understand the overall Rate of Return contained in the Second Partial Settlement concerning DE Carolinas is 7.04 percent.[2]

Q. IN GENERAL, DO YOU SUPPORT THE COMPANY'S DECISION TO AGREE TO THE STIPULATED ROE?

A. Yes, I do. Although the Stipulated ROE is somewhat below the lower bound of my recommended range (*i.e.*, 10.00 percent), I recognize the Second Partial Settlement

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1 *See,* Second Agreement and Stipulation of Partial Settlement, July 31, 2020, at 10. I refer to the 9.60 percent ROE as the "Stipulated ROE", the 52.00 percent equity ratio as the "Stipulated Equity Ratio", and the 7.04 percent overall Rate of Return as the "Stipulated Rate of Return".

2 *Ibid*.

represents negotiations among the Settling Parties regarding several otherwise-contested issues. I understand the Company has determined that the terms of the Second Partial Settlement, in particular the Stipulated ROE and Equity Ratio, would be viewed by the rating agencies as constructive and equitable. I understand and respect that determination.

Q. PLEASE NOW SUMMARIZE YOUR POSITION REGARDING THE STIPULATED ROE.

A. Although the Stipulated ROE falls below my recommended range (the low end of which is 10.00 percent), it is within the range of the analytical results presented in my Direct, Rebuttal, and Supplemental Rebuttal Testimonies. As discussed throughout my Rebuttal and Supplemental Rebuttal Testimonies, capital market conditions became quite volatile as a result of the COVID-19 pandemic. Consequently, the models used to estimate the Cost of Equity produce a wide range of estimates. Those market conditions, in particular the increasing correlation between the utility sector and the broad market, support investors' increased capital cost requirements. It therefore remains my position that in a fully litigated proceeding, a range of common equity cost rates between 10.00 percent and 11.00 percent is reasonable, if not conservative. Nonetheless, I recognize the benefits associated with the decision to enter into the Second Partial Settlement and as such, it is my view that the 9.60 percent Stipulated ROE is a reasonable resolution of an otherwise contentious issue.

Q. HAVE YOU ALSO CONSIDERED THE STIPULATED ROE IN THE CONTEXT OF AUTHORIZED RETURNS FOR OTHER VERTICALLY INTEGRATED ELECTRIC UTILITIES?

A. Yes, I have. From January 2016 through June 2020, the average authorized ROE for vertically integrated electric utilities was 9.74 percent, 14 basis points above the Stipulated ROE. Of the 107 cases decided during that period, 64 (*i.e.*, nearly 60.00 percent) included authorized returns of 9.60 percent or higher.[3]

Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?

A. Yes. As noted in my Rebuttal Testimony, the Company's credit rating and outlook depend substantially on the extent to which rating agencies view the regulatory environment as credit supportive, or not.[4] I noted, for example, that Moody's finds the regulatory environment to be so important that 50.00 percent of the factors that weigh in its ratings determination are determined by the nature of regulation.[5]

Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, I believe it is important to consider the extent to which the jurisdictions that recently have authorized ROEs for electric utilities are viewed as having constructive regulatory environments.

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3 *See* Settlement Exhibit DWD-1.

4 Rebuttal Testimony of Dylan W. D'Ascendis, at 222.

5 *Ibid.*

Q. IS NORTH CAROLINA GENERALLY CONSIDERED TO HAVE A CONSTRUCTIVE REGULATORY ENVIRONMENT?

A. Yes, it is. As discussed in my Rebuttal Testimony, Regulatory Research Associates ("RRA"), which is a widely referenced source of rate case data, provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not.[6] As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.[7]

Within RRA's ranking system, North Carolina is rated "Average/1", which falls in the top one-third of the 53 regulatory commissions ranked by RRA.[8]

Q. DID YOU CONSIDER THOSE DISTINCTIONS IN YOUR REVIEW OF AUTHORIZED RETURNS RELATIVE TO THE STIPULATED ROE?

A. Yes. Across the 107 cases noted above, there was a 40-basis point difference between the median return for the Top Third and Bottom Third of jurisdictions (the higher-ranked jurisdictions providing the higher authorized returns, see Table 1,

[6] Rebuttal Testimony of Dylan W. D'Ascendis, 223.

[7] Source: Regulatory Research Associates, accessed July 28, 2020. *See*, also, Rebuttal Testimony of Dylan W. D'Ascendis, at 223.

[8] Source: Regulatory Research Associates, accessed July 28, 2020.

below). As Table 1 indicates, authorized ROEs for vertically integrated electric utilities in jurisdictions that, like North Carolina, are rated at least Average/1 range from 9.25 percent to 10.55 percent, with a median of 9.90 percent.

Table 1: Average Authorized ROE by RRA Ranking[9]

	Authorized ROE Vertically Integrated Electric Utilities		
RRA Ranking	Top Third	Middle Third	Bottom Third
Average	9.91%	9.53%	9.62%
Median	9.90%	9.50%	9.50%
Maximum	10.55%	10.30%	11.95%
Minimum	9.25%	8.75%	9.06%

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THAT DATA?

A. The Stipulated ROE falls 30 to 31 basis points below the median and mean authorized ROE, respectively, for jurisdictions that are comparable to North Carolina's constructive regulatory environment, and 10 basis points above the median return authorized in less supportive jurisdictions. Taken from that perspective, the Stipulation ROE is a reasonable, if not somewhat conservative measure of the Company's Cost of Equity.

Q. DO YOU BELIEVE THE STIPULATED CAPITAL STRUCTURE ALSO IS REASONABLE?

A. Yes, I do. As demonstrated in Table 2 (below) the Stipulated Equity Ratio is equal to the median authorized equity ratio in supportive regulatory jurisdictions (*i.e.*,

[9] Source: Regulatory Research Associates. "Top Third" includes Above Average/1,2,3 and Average/1; "Average" includes Average/2 and Average/3; "Bottom Third" includes Below Average/1,2,3. The "Top Third" group includes 18 of 53 jurisdictions, or about one-third of the total. *See* Settlement Exhibit DWD-1

52.00 percent), and is well within the range of equity ratios authorized in those jurisdictions (40.25 percent to 57.16 percent).

Table 2: Average Authorized Equity Ratio by RRA Ranking[10]

	Authorized Equity Ratio Vertically Integrated Electric Utilities		
RRA Ranking	Top Third	Middle Third	Bottom Third
Average	51.29%	51.58%	50.69%
Median	52.00%	51.48%	49.46%
Maximum	57.16%	57.10%	58.18%
Minimum	40.25%	44.00%	48.35%

As discussed in my Rebuttal Testimony, because no two companies are identical, we should not view the average (or median) equity ratio (whether authorized or observed) as a strict measure of industry practice.[11] Nonetheless, the Stipulated Equity Ratio falls well within the range of authorized equity ratios, and is equal to the median for constructive regulatory jurisdictions. In my view, that finding provides additional support for its acceptance.

Q. HOW DOES THE 7.04 PERCENT OVERALL RATE OF RETURN CONTAINED IN THE SECOND PARTIAL SETTLEMENT COMPARE TO RECENTLY AUTHORIZED RETURNS?

A. It is quite low. Since January 2016, there have been 105 cases reported by RRA (for vertically integrated electric utilities) in which an overall Rate of Return was specified. Over those 105 cases, the median Rate of Return was 7.20 percent, 16 basis points above the 7.04 percent Rate of Return for the Company as contained

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10 Source: Regulatory Research Associates. Excludes capital structure decisions from Arkansas, Florida, Indiana, and Michigan, all of which include some form of non-investor supplied capital in the ratemaking capital structure.

11 Rebuttal Testimony of Dylan W. D'Ascendis, at 58.

in the Second Partial Settlement. From a slightly different perspective, 66 of the 105 cases had overall Rates of Return greater than 7.04 percent. In fact, the Second Partial Settlement's overall Rate of Return falls in the bottom 38th percentile of the 105 cases decided since 2016.

The low overall Rate of Return contained in the Second Partial Settlement are brought about by the Company's rather low cost of debt. That low cost of debt is supported by reasonable regulatory outcomes, including constructive decisions regarding the Return on Equity, and capital structure. In my view, the Second Partial Settlement continues that support, and produces the low overall Rate of Return on which customer rates would be set. From that important perspective, the Stipulated ROE and capital structure strike the necessary balance between customer and investor interests.

Q. HAS YOUR TESTIMONY CONSIDERED ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. Yes, it has. I understand and appreciate the Commission's need to balance the interests of investors and ratepayers, and to consider economic conditions in the State, as it sets rates. As explained in my Supplemental Rebuttal Testimony, I recognize that economic conditions have deteriorated in North Carolina in the first half of 2020, as have the economic conditions in across the U.S.[12] Because North Carolina's economic conditions remain highly correlated to the overall conditions in the U.S., my review of North Carolina's economic conditions do not alter my

[12] Supplemental Rebuttal Testimony of Dylan W. D'Ascendis, at 21-23.

conclusion that the Stipulated ROE, Equity Ratio, and Rate of Return are reasonable resolutions to otherwise contentious issues.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes, it does.

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Karl W. Newlin. My business address is 400 South Tryon Street, Charlotte, North Carolina, 28202. I am employed by Duke Energy Business Services, LLC ("DEBS") as Senior Vice President, Corporate Development and Treasurer. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC, ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Southern Methodist University with a Bachelor of Business Administration degree in 1991. I subsequently received a Master in Business Administration degree from UCLA's Anderson School of Management in 1998. I am also a Chartered Financial Analyst.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. In November 2018, I assumed the role of Senior Vice President, Corporate Development and Treasurer for Duke Energy. Previously, I served as Senior Vice President and Chief Commercial Officer for Duke Energy's natural gas business. In this role, I was responsible for gas commercial operations, which included supply, wholesale marketing, transportation and pipeline services, field customer service, sales and delivery, and business development. I was named to this position following Duke Energy's acquisition of Piedmont Natural Gas ("Piedmont") in October 2016.

I joined Piedmont in 2010 to manage Piedmont's strategic planning functions, new business development activities and joint venture investments. In November 2011, I was appointed to the position of Chief Financial Officer, assuming responsibility for Piedmont's accounting, controller, finance, treasurer, investor relations, insurance, credit policy, risk management and state regulatory affairs areas. Prior to joining Piedmont, I served as Managing Director of Investment Banking for Merrill Lynch & Co. in its New York and Los Angeles offices.

Q. PLEASE DESCRIBE YOUR DUTIES AS SENIOR VICE PRESIDENT, CORPORATE DEVELOPMENT AND TREASURER.

A. In my role as Treasurer, I am responsible for treasury-related services to Duke Energy and its subsidiaries, including DE Carolinas. I monitor trends in the investment markets and maintain key relationships with debt investors, analysts, and financial institutions. Under my supervision, the Treasury Department arranges and executes all capital raising and liquidity transactions, including credit facilities and commercial paper, debt securities, preferred and hybrid securities, and common stock, as well as daily cash management for Duke Energy and its subsidiaries. My responsibilities include managing Duke Energy and its subsidiaries' credit ratings and interactions with the major credit rating agencies, commercial banks, and the capital markets. I am also responsible for liability management and long-term investments. As head of corporate development, I am responsible for the Company's corporate development activities, as well as mergers and acquisitions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR OTHER STATE PUBLIC UTILITY COMMISSIONS?

A. Yes. I have testified before the North Carolina Utilities Commission and have filed testimony on behalf of Piedmont Natural Gas in my prior role as Piedmont's Chief Financial Officer.

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

A. My testimony will address DE Carolinas' financial objectives, capital structure, and cost of capital. I will also discuss the current credit ratings and forecasted capital needs of DE Carolinas. Throughout my testimony, I will emphasize the importance of DE Carolinas' continued ability to meet its financial objectives.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. As detailed in my testimony, DE Carolinas faces substantial capital needs over the next several years. The Company competes for capital in the open market and must appeal to debt and Duke Energy's equity investors to attract the capital it needs. As Roger Morin, a leading expert on utility finance, indicates, "[t]he … prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Morin, Roger A., *Utilities' Cost of Capital* (Public Utilities Reports, Inc. 1984), at 20. Investors have a variety of investment opportunities available to them, and require a return commensurate with the risk they incur. They will invest elsewhere if they feel the expected return provided by a company is inadequate, and lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles. For this reason, it is critically important that the Company maintain strong, investment-grade credit quality to assure its financial strength and flexibility and ensure access to capital on reasonable terms.

The Company is making significant capital investments to provide cost-effective, safe, and reliable electric service to its customers well into the future. The Company's proposed rate increase will allow it to recover prudently incurred costs, compete in the capital markets for needed capital, and preserve its financial standing with both equity and debt investors as well as the credit rating agencies, to the long-term benefit of customers.

Q. WHAT ARE DE CAROLINAS' FINANCIAL OBJECTIVES?

A. Financial strength and access to capital are necessary for DE Carolinas to provide cost-effective, safe, and reliable service to its customers. The Company, at all times, seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, ensuring reliable access to capital on reasonable terms. Specific objectives that support financial strength and flexibility include: (a) maintaining at least 53 percent common equity for DE Carolinas on a financial capitalization basis; (b) ensuring timely recovery of prudently incurred costs; (c) maintaining sufficient cash flows to meet obligations; and (d) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the Company and its customers, and each of these specific objectives helps the Company both to maintain its investment-grade credit ratings and to meet its overall financial objectives.

Q. DO DE CAROLINAS' CUSTOMERS BENEFIT FROM THE COMPANY'S STRONG CREDIT RATINGS?

A. Yes. To ensure reliable and cost-effective service, and to fulfill its obligations to serve customers, the Company must continuously plan and execute major capital projects. This is the nature of regulated, capital-intensive industries like electric and gas utilities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. The financial markets can experience periods of volatility, and DE Carolinas must be able to finance its needs throughout such periods. Strong investment-grade credit ratings provide DE Carolinas with greater access to the capital markets on reasonable terms during such periods of volatility.

Q. WHAT RATEMAKING TREATMENT IS BEING REQUESTED IN THIS PROCEEDING AND HOW WILL THE COMPANY'S FINANCIAL OBJECTIVES BE IMPACTED?

A. As explained in the Company's Application and by Witness Jane McManeus, DE Carolinas is requesting an overall rate increase of approximately 6.0 percent, equating to an increase in pre-tax revenue requirement of approximately $291 million. The proposed capitalization in this request is comprised of 47 percent debt and 53 percent equity.

In addition, the requested increase reflects, in part, an increase in the Company's cost of equity capital from the level approved by the Commission in the Company's last general rate case. The testimony of the Company's Return on Equity ("ROE") Witness, Robert Hevert, indicates that the Company's cost of equity capital is in the range of 10.0 percent to 11.0 percent. Based on his quantitative and qualitative analyses including the risk profile of the Company, Witness Hevert's view is that 10.5 percent is a reasonable and appropriate estimate of the Company's cost of equity capital.

The Company fully supports Witness Hevert's testimony and analysis. However, as a rate mitigation measure, and in recognition of the Company's ongoing efforts to keep rates affordable for customers, we have proposed rates to be set with an ROE of 10.3 percent. This requested ROE is within Witness Hevert's range, but 20 basis points below Witness Hevert's point estimate.

Approval of the Company's request in this case will support its financial objectives by allowing timely recovery of its investments in plant and equipment, providing sufficient cash flows to fund necessary capital expenditures and service debt, and providing a fair and reasonable return to equity investors.

Q. PLEASE EXPLAIN CREDIT QUALITY AND CREDIT RATINGS, AND HOW THEY ARE DETERMINED.

A. Credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. An assessment of DE Carolinas' creditworthiness is performed by two major credit rating agencies, Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"), and results in DE Carolinas' credit rating.

Many qualitative and quantitative factors go into this assessment. Qualitative aspects may include DE Carolinas' regulatory climate, its track record for delivering on its commitments, the strength of its management team, its operating performance, and the economic vitality and customer profile of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which DE Carolinas maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest expense in particular) based on internally-generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Q. WHAT IS THE ROLE OF REGULATION IN THE DETERMINATION OF THE FINANCIAL STRENGTH OF A UTILITY COMPANY?

A. Investors, investment analysts and credit rating agencies regard constructive regulation as one of the most important factors in assessing a utility company's financial strength. These stakeholders want to be confident that the Company operates in a stable regulatory environment that will allow the Company to recover prudently incurred costs and earn a reasonable return on investments necessary to meet the demand, reliability, service, and environmental requirements of its customers and service area. Important considerations include the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, and the strength of its capital structure. Positive consideration is also given for utilities operating in states where the regulatory process is streamlined, the time lag in capital investment recovery is minimized through cost recovery mechanisms such as riders and trackers, and outcomes are equitably balanced between customers and investors.

Q. HOW ARE DE CAROLINAS' OUTSTANDING SECURITIES CURRENTLY RATED BY THE CREDIT RATING AGENCIES?

A. As of the date of this testimony, DE Carolinas' outstanding debt is rated as follows:

Rating Agency	**S&P**	**Moody's**
Issuer / Corporate Credit Rating	A-	A1
Senior Secured	A	Aa2
Outlook	Negative	Stable

Obligations carrying a credit rating in the "A" category are considered strong, investment-grade securities subject to low credit risk for the investor. "A" rated debt is presumed to be somewhat susceptible to changes in circumstances and economic conditions; however, the debt issuer's capacity to meet its financial commitments is considered strong. By contrast, ratings in the "BBB" category are considered adequate and have less assurance of access to the capital markets in challenging market conditions. (AA and Aa category ratings for S&P and Moody's, respectively, are stronger than A ratings.)

S&P may also modify its ratings with the use of a plus or minus sign to further indicate the relative standing within a major rating category. An "A+" credit rating is at the higher end of the "A" credit rating category and an "A-" is at the lower end of the category. Moody's credit rating assignments use the numbers "1", "2" and "3", with the numbers "1" and "3" analogous to a "+" and "-", respectively. For example, Moody's credit ratings of "A2" and "A3" would be analogous to "A" and "A-" credit ratings at S&P, respectively.

The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years). DE Carolinas' "Stable" outlook at Moody's means that those credit ratings are not likely to change at this time; however, a change in outlook or rating could occur if the Company experiences a change in its qualitative or quantitative credit quality. S&P utilizes a family rating methodology, whereby the credit rating and outlook of the parent company, Duke Energy Corporation, is applied to each of the parent's subsidiaries. S&P revised its outlook to "Negative" on May 20, 2019 citing concerns of weaker financial measures due to 2018 storms, uncertainty over growing coal ash remediation costs and recovery in the Carolinas, regulatory lag during a period of robust capital spending, and delays related to the Atlantic Coast Pipeline. S&P stated in its May 2019 Duke Energy

Corporation report[1] that the outlook could be restored to stable if Duke Energy Corporation and its subsidiaries improve financial measures in the next 12-24 months without any deterioration in the Company's business risk profile.

Q. WHAT STRENGTHS AND WEAKNESSES HAVE THE CREDIT RATING AGENCIES IDENTIFIED WITH RESPECT TO DE CAROLINAS?

A. The rating agencies believe DE Carolinas operates in a generally constructive regulatory environment that supports long-term credit quality, and view the Company's position within the Duke Energy corporate family as credit supportive. However, the rating agencies have identified several challenges the Company faces in maintaining its credit ratings. In October 2018, Moody's identified several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios), which, in turn, could affect its ratings.[2]

- Regulatory Lag: Moody's is particularly focused on downward pressure on financial metrics due to regulatory lag, including in the recovery of coal ash basin closure costs.
- Tax Reform: Moody's also points to federal tax reform putting pressure on the Company's credit metrics due to reduced cash flows.

[1] *See* S&P Global Ratings, Research Update "Duke Energy Corp. And Subs. Outlook Revised To Negative On Coal Ash Risks, Regulatory-Lag, And Project Delays," May 20, 2019 ("May 2019 Duke Energy Corporation Report").

[2] *See* Moody's Investors Service, Credit Opinion, "Duke Energy Carolinas, LLC – Update to Credit Analysis," October 22, 2018 ("October 2018 DE Carolinas Report").

- Capital Expenditures: Moody's notes elevated capital expenditures, due to new generation, transmission and distribution upgrades and environmental compliance, including coal ash basin closure and remediation.

S&P identifies similar risks to Duke Energy Corporation and DE Carolinas in its September 2018 research update.[3] As indicated previously in my testimony, as of May 20, 2019, S&P revised its outlook for Duke Energy Corporation, as well as its subsidiaries including DE Carolinas, from "Stable" to "Negative." S&P highlighted "…several headwinds, including coal ash risks, project delays, regulatory lag, and high capital spending that we expect could pressure and weaken its financial measures over the next 12-24 months."[4] Furthermore, S&P includes recent regulatory directives in South Carolina within its Rating Action Rationale, "…which effectively lowers Duke Energy's authorized returns, and disallows recovery of certain coal ash costs, elevates both coal ash and regulatory risks for the company, signaling a potential change in the consistency and predictability of that state's regulatory construct." [4]

Q. HOW DO THE RATING AGENCIES VIEW THE IMPACT OF TAX REFORM ON UTILITY CREDIT QUALITY?

A. In January 2018, Moody's published a report outlining its initial assessment of the impact of tax reform on the regulated utility sector.[5] In its report, Moody's noted "the legislation was broadly credit positive for corporate cash flows but

[3] *See* S&P Global Ratings, "Summary: Duke Energy Carolinas LLC," September 13, 2018 ("September 2018 DE Carolinas Report").
[4] *See* S&P Global Ratings, Research Update "Duke Energy Corp. And Subs. Outlook Revised To Negative On Coal Ash Risks, Regulatory-Lag, And Project Delays," May 20, 2019 ("May 2019 Duke Energy Corporation Report").
[5] *See* Moody's Investors Service, Sector Comment, "Tax Reform is Credit Negative for Sector, but Impact Varies by Company," January 24, 2018 ("January 2018 Report").

for regulated investor-owned utilities, which include electric, gas, and water utilities, the effect was the opposite."[6] In addition to outlining the negative impact of tax reform on utilities and the regulatory uncertainties related thereto, Moody's changed the rating outlook of 24 utilities (including Duke Energy Corporation) from "Stable" to "Negative."

In June 2018, Moody's updated its 2019 outlook for the regulated utility sector to "Negative" from "Stable."[7] A key factor in this outlook change was a decline in cash flows. Moody's stated that "the combination of a lower tax rate and the loss of bonus depreciation as a result of the federal Tax Cuts & Job Act ("TCJA") in December 2017 means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes on an ongoing basis."[8] Moody's estimated that since 2010, the cash due to deferred taxes averaged 14% of Funds from Operations ("FFO"), which is a measure of cash flow generated by a company's operations, on a consolidated basis.

Of the 24 utilities Moody's placed on "Negative" outlook in January 2018, Duke Energy was the first to have its outlook resolved. In August 2018, Moody's issued a credit opinion restoring Duke Energy's outlook to "Stable."[9] Moody's attributed this to an expectation that Duke Energy will maintain supportive regulatory relationships and highlighted credit supportive rate case outcomes across several regulatory jurisdictions. Moody's also described how

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[6] January 2018 Report, p. 1.
[7] *See* Moody's Investors Service, Outlook, "2019 Outlook Shifts to Negative Due to Weaker Cash Flows, Continued High Leverage," June 18, 2018 ("June 2018 Report")
[8] June 2018 Report, p. 2.
[9] *See* Moody's Investors Service, Credit Opinion, "Duke Energy Corporation – Update Following Change of Outlook to Stable," August 14, 2018 ("August 2018 DE Corporation Report").

Duke Energy's 2018 equity issuance and reduced capital program in response to tax reform helped reduce parent-level debt financing.

Q. MOODY'S HAS NOT CHANGED DE CAROLINAS RATINGS OUTLOOK. DOES THIS MEAN TAX REFORM DOES NOT MATERIALLY IMPACT DE CAROLINAS?

A. No. While the Moody's January 2018 Report identifies certain utility issuers whose credit metrics are weaker relative to their current ratings, it does not mean that Moody's will not take action on other utility issuers in the future. If unmitigated, the reduction in cash flows will erode DE Carolinas' credit metrics. In its June 2018 Report, Moody's included a financial forecast using a peer group of 102 utility operating companies. Moody's forecasted that the reduction in cash flow will cause operating company FFO/Debt metrics to drop "to 20% from 24% over the next 12-18 months."[10] This is an industry-wide analysis where some issuers will be affected more than others.

Q. HOW COULD TAX REFORM CREATE CONCERNS FOR CUSTOMERS AND FOR UTILITIES?

A. As I explain further below, deferred taxes are not large pools of money that the Company is holding in an account somewhere. Instead, they are collections that occur over time based on the life of the underlying assets, which the Company has used to invest in its business during the deferral period to better serve customers. As a result, customers have benefitted because the Company has used these "zero interest" loans to finance its business rather than incurring

[10] June 2018 Report, p. 2

financing costs that are passed on to customers. When the tax rate changes, either up or down, leveraging the over and under-collection of these funds in a proper and principled manner benefits both the Company and customers. If, however, adjusting rates to account for tax changes is done in a haphazard manner, it can cause rate volatility and harm to customers as well as the financial health of the utility as explained further below.

For example, if the Commission sets a precedent in this case that decreases in tax rates should be provided to customers as quickly as possible, then it logically follows that DE Carolinas would need to access capital markets to raise cash to provide for the shortfall in funds collected. The unplanned and possibly large capital raise could put stress on DE Carolinas' credit quality and rating. It also logically follows that any future tax increases should be collected from customers as quickly as possible in similar fashion. With a tax increase, customers would then experience an immediate, and perhaps dramatic, increase in rates, which is something the Commission attempts to avoid by deploying the concept of gradualism. That same concept of gradualism applies equally to tax decreases and must be considered just as it would with a tax increase.

Q. PLEASE EXPLAIN HOW DEFERRED TAXES ARE CREATED.

A. As noted by Witness Panizza in his testimony, the Company has Accumulated Deferred Income Taxes ("ADIT") where it has collected a book level of tax expense for tax liabilities from customers. Because the IRS rules provide certain financial incentives, such as accelerated depreciation and credits, actual tax expense can be lower for tax purposes than book, and create timing differences between when the costs are recovered from customers versus when the costs are payable to the government. Often, IRS income is lower in the early years because the IRS offers credits, accelerated depreciation, and other incentives so that the Company is collecting from customers at a level higher than what is actually being paid in cash taxes, which is common across the industry. As a result, a liability to pay those taxes in the future is recorded to the Company's balance sheet because it is not a permanent reduction in taxes; rather a delay in payment of cash taxes.

A deferred tax liability is a customer benefit. These ADIT are essentially a free loan the Company uses to finance its investments. Thus, instead of having to access third-party capital from either debt or equity investors (which, as a cost of service, customers pay for in rates), the Company can use these funds to invest in its business, amounting in essence to an interest free loan from the government. That liability also benefits customers because it serves as a reduction to rate base and, as the Company does not earn on rate base to the extent that we have deferred tax liability on the balance sheet, customers effectively save the weighted average cost of capital on the deferred tax balance. As such, the deferred tax balance is an additional source of capital to the Company, and a source of capital for which customers do not pay.

Over time, the deferred taxes become due and what was once a lower cash tax today versus what the Company collected on that same asset reverses, and the Company ends up paying more cash taxes than it has collected, depleting the ADIT balance for an asset (of course this process occurs on hundreds of thousands of assets in the Company over various windows of time).

Q. WHAT IS THE IMPACT OF THE TAX REFORM ON THE COMPANY'S DEFERRED TAXES AND HOW DOES THAT IMPACT CUSTOMERS?

A. Because of the change in the corporate tax rate from 35% to 21%, the Company now has Excess Deferred Income Taxes ("EDIT"), which is excess ADIT that must be returned to customers where the Company previously collected from customers at the higher 35% tax rate and will now have a lower payment obligation at the new 21% tax rate. However, those ADIT were used to invest in the business so the question becomes how to return those excess deferred taxes back to customers. Because the ADIT are currently being used to finance Company investments, in turn benefitting customers, as the Company pays the EDIT back to customers, it must find other sources of financing for these investments.

Q. WHAT POTENTIAL NEGATIVE IMPACT COULD THE TAX REFORM HAVE ON THE COMPANY AND HOW MIGHT THAT IMPACT CUSTOMER RATES?

A. For the EDIT not subject to a statutory flowback period, the question becomes what is the appropriate flow-back period to customers that balances both the best interest of customers and the financial strength of the Company and the cash flows of the Company. EDIT flowback has several effects, which move in sometimes contradictory directions – it reduces the Company's cash flow, but also results in an increase in rate base. Reduction in the Company's cash flow obviously negatively affects the Company, but it also negatively affects customers. Customers benefit from a financially strong utility, which can then access capital markets as needed on favorable terms. Increase in rate base ultimately leads to higher rates for customers – a negative for customers, although a positive for the Company. Thus, the EDIT issue is complex.

By using the deferred taxes to invest in the business, the Company avoided having to go to the capital markets to raise this portion of the funds that it invested, and customers saved the capital cost of its being able to use the interest-free loan from the government instead of investor-supplied capital. But having invested in the business, there is not a readily available reserve pool from which the cash needed to return the EDIT can be drawn. As previously explained, there is a property-related life cycle to deferred taxes and based on our analysis, the average flow-back, had those deferred taxes not become excess deferred taxes, is 23 years. Accordingly, the Company is proposing to flow these property-related excess deferred taxes back to customers over a 20-year period. An EDIT flow-back period that more closely matches the underlying asset lives smooths out the cash flow hit the Company must take as it returns EDIT to customers, and lessens the need for the Company to raise those funds from investors and third-parties. In contrast, had the tax rate increased, the Company would not request to recover the increased amount instantly or over a short-time frame for the same reason - because the higher taxes would be paid over the life of the asset.

Addressing the impact on customer rates over a longer period also helps avoid rate volatility. For example, if the Company were to return the EDIT instantly or over a two-year period, customers would experience a dramatic reduction in rates followed by a dramatic increase due to the expiration of the flow-back and higher rate base. In contrast, had the tax rate increased and the Company requested that payment from customers in two years, the converse would be true and if the Company requested that customers pay the increased taxes over a short period of time, customers would experience a dramatic increase in rates, followed by a dramatic decrease. Thus, addressing the customer rate impact of tax rate changes over a longer period serves to smooth out rate volatility and we propose it be applied to the unprotected excess deferred taxes in this case. In either situation, whether the tax rate decreases or increases, when considering the collection or return of funds through customer rates, it is appropriate to consider the life of the underlying asset, to achieve gradualism rather than rate volatility, consider impacts in cash flows to the Company, and fairly balance the interest of customers and the Company. to avoid negative impacts in cash flows to the Company, and to fairly balance the interest of customers and the Company.

Q. HAVE OTHER UTILITY COMMISSIONS TAKEN STEPS TO MITIGATE THE NEGATIVE IMPACTS OF TAX REFORM?

A. Yes. Examples include:

- In South Carolina, the Public Service Commission granted DE Carolinas and DE Progress the ability to use an EDIT rider to reflect the reduction in tax rates enacted in the TCJA, authorizing a 20-year amortization period of approximately $269 million of unprotected Federal EDIT related to property, plant, and equipment for DE Carolinas and approximately $58 million for DE Progress.

- In Florida, the Public Service Commission ordered Duke Energy Florida to accelerate depreciation of coal assets by $50 million per year. It also granted DE Florida the ability to use the remainder of the customer benefits of a lower tax rate to avoid a rate increase for power restoration costs associated with Hurricane Irma. In August 2018, Moody's stated that it views "these tax reform related developments as supportive of credit quality".[11]
- The Indiana Utility Regulatory Commission also issued a credit-supportive order to mitigate the near-term impacts of tax reform. DE Indiana was authorized a 10-year amortization period of approximately $167 million unprotected EDIT. However, the refund to customers is limited to $7 million per year in the first five years, increasing to $35 million per year until the entire deferral amount has been returned to customers. This back-end shaping of the deferral is credit-supportive as it limits the near-term negative impact from lower cash flows and allows the utility more time to prepare for and absorb the higher payback obligation.

[11] *See* Moody's Investors Service, Credit Opinion, "Progress Energy, Inc. – Update Following Upgrade to Baa1," August 13, 2018, p. 3 ("August 2018 Progress Energy Report").

- In Georgia, a settlement between Georgia Power and the Commission staff puts off EDIT issues for two years, and increases the equity portion of the utility's equity-to-debt ratio while flowing back to customers the effects of the tax rate decrease. Adjustments to the utility's ROE or equity layer are on the Moody's list of mitigation measures.[12]
- In Alabama, the Public Service Commission approved a plan to increase Alabama Power's equity ratio to 55 percent by 2025. It also authorized Alabama Power to offset $30 million of under-recovered fuel costs with its EDIT.

Q. WHAT IS DE CAROLINAS' PROPOSED CAPITAL STRUCTURE?

A. As mentioned earlier in this testimony, DE Carolinas' proposed capital structure is 47 percent long-term debt and 53 percent equity. The Company believes this proposed capital structure is optimal for DE Carolinas, as it introduces an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers. Approval of the proposed capital structure will help DE Carolinas maintain its credit quality. This level is also consistent with the Company's target credit ratings for DE Carolinas.

Q. DOES THE ACTUAL FINANCIAL CAPITAL STRUCTURE VARY OVER TIME?

A. Yes. It does. The specific debt/equity ratio will vary over time, depending on a variety of factors, including, among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of

[12] January 2018 Report, p. 4.

earnings, and dividend payments to the parent company. Achieving an approved regulatory capital structure of 47/53 is consistent with the Company's financial objectives and overall plan to maintain its ability to finance operations at rates favorable for customers and DE Carolinas will manage its capital structure within reasonable range of this base. As of December 31, 2018, DE Carolinas' capital structure was 48.5 percent long-term debt and 51.5 percent equity.

Q. WHAT IS DE CAROLINAS' COST OF EQUITY?

A. Witness Hevert, who has separately filed testimony, indicates that the Company's cost of equity is 10.5 percent and the Company supports Mr. Hevert's analysis. However, as indicated previously in my testimony, for rate mitigation purposes, the Company has proposed rates including an ROE of 10.3 percent.

Q. WHAT ROLE DO EQUITY INVESTORS PLAY IN THE FINANCING OF DE CAROLINAS, AND HOW WILL THE OUTCOME OF THIS CASE IMPACT THESE INVESTORS?

A. Equity investors provide the foundation of a company's capitalization by providing significant amounts of capital, for which an appropriate economic return is required. DE Carolinas compensates equity investors for the risk of their investment in Duke Energy by targeting fair and adequate returns, a stable dividend, and earnings growth – these are all necessary to preserve access to equity capital. Returns to equity investors are realized only after all operating expenses and fixed payment obligations (including debt principal and interest) of the business have been paid. Because equity investors are the last to receive surplus earnings and cash flows, their investment involves significantly more risk. For this reason, equity investors require a higher return for their investment. Equity investors expect utilities like DE Carolinas to recover their prudently incurred costs and earn a fair and reasonable return for their investors. The Company's proposal in this proceeding supports this investor requirement.

Q. WHAT EFFECT DOES CAPITAL STRUCTURE AND RETURN ON EQUITY HAVE ON CREDIT QUALITY?

A. Capital structure and return on equity are important components of credit quality. As mentioned in the previous answer, the greater the equity component of capitalization, the safer the returns are to debt investors, which translates into higher credit quality and lower borrowing costs. In addition, the allowed return on equity is a key component in the generation of earnings and cash flows. An adequate return on equity helps ensure equity investors receive fair compensation for their investment while also helping to protect the interests of debt investors.

A strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. High credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs. Conversely, a weak capital structure and an inadequate allowed return on equity produces lower earnings and cash flows, lowers credit quality, and may limit financial flexibility. As mentioned in my testimony above, regulatory directives in South Carolina, including lower authorized returns, were highlighted in S&P's Rating Action Rationale supporting their revised "Negative" outlook for Duke Energy Corporation and its subsidiaries in May 2019.

Q. DO YOU BELIEVE THAT DE CAROLINAS' CAPITAL STRUCTURE HAS AN ADEQUATE EQUITY COMPONENT TO ENABLE DE CAROLINAS TO ACHIEVE THE COMPANY'S FINANCIAL STRENGTH AND CREDIT QUALITY OBJECTIVES?

A. Yes. DE Carolinas' equity component, as requested in this case, enables it to maintain current credit ratings and financial strength and flexibility. This level of equity enables the Company to tolerate different business cycles while also providing more confidence to the Company's lenders and bondholders. Like many utilities, DE Carolinas is in a period of significant capital investment necessary to provide cost-effective, safe, and reliable service to its customers in a time of rising costs, lower load growth and rapidly evolving state and federal requirements. The magnitude of its capital requirements dictates the need for a strong equity component of the Company's capital structure to ensure access to capital funding at reasonable terms.

Q. WHAT IS DE CAROLINAS' AVERAGE COST OF LONG-TERM DEBT?

A. DE Carolinas' weighted average cost of long-term debt as of December 31, 2018 is 4.51 percent. Over the last several years, DE Carolinas has been taking advantage of low interest rates, steadily decreasing the weighted average cost of long-term debt as older bonds are replaced with new, lower cost, issuances.

Q. WHAT ARE DE CAROLINAS' CAPITAL REQUIREMENTS OVER THE NEXT THREE YEARS?

A. DE Carolinas faces substantial capital needs over the next several years to comply with environmental requirements, refurbish, replace and upgrade aging infrastructure; construct or acquire needed generation resources; strengthen and modernize our energy grid; and satisfy its debt maturities. The Company's capital requirements for the next three years (2020-2022) are projected to be approximately $9.1 billion. This amount consists of approximately $7.8 billion in projected capital expenditures and approximately $1.3 billion in debt retirements.

Q. HOW WILL DE CAROLINAS' CAPITAL REQUIREMENTS BE FUNDED?

A. DE Carolinas' capital requirements are expected to be funded from internal cash generation, the issuance of debt, and equity funding from Duke Energy.

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

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Karl W. Newlin, and my business address is 550 South Tryon Street, Charlotte, North Carolina, 28202. I am employed by Duke Energy Business Services, LLC as Senior Vice President, Corporate Development and Treasurer.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I filed direct testimony supporting Duke Energy Carolinas, LLC's ("DE Carolinas" or the "Company") financial objectives, capital structure, and cost of capital.

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

A. The purpose of my rebuttal testimony is to respond to portions of the testimony submitted by the following:

- Dr. J. Randall Woolridge and Mr. John R. Hinton, witnesses on behalf of the Public Staff of the North Carolina Utilities Commission ("Public Staff")
- Mr. Richard A. Baudino, witness on behalf of the North Carolina Attorney General's Office ("AGO")
- Mr. Kurt G. Strunk, witness on behalf of Apple Inc., Facebook, Inc., and Google, LLC (the "Tech Customers")
- Mr. Kevin W. O'Donnell, witness on behalf of Carolina Utility Customers Association, Inc. ("CUCA").

In my testimony, I will address their respective recommendations on the following:

- Capital structure and Return on Equity ("ROE") and the financial impacts to the Company from the overall revenue requirement;
- Reducing the amortization period of the unprotected excess deferred income taxes ("EDIT") related to the Company's investments in property, plant, and equipment ("PP&E") assets; and
- Recovery and treatment of costs incurred to comply with regulations relating to coal combustion residuals ("CCR") and the impacts on the credit quality of the Company.

Apart from the flaws in their positions, I urge the Commission to consider the negative consequences the positions put forth by the witnesses above will have on the Company and its customers. In sum, a reduction in return on equity from the proposed 10.30% to 8.75% (O'Donnell) or even 9.00% (Woolridge and Baudino); a reduction in the equity component of the capital structure from 53% to 51.5% (Baudino) or 50% (Woolridge and O'Donnell); EDIT refunding over five years rather than 20 years (Hinton); significant coal ash basin closure cost disallowances (multiple witnesses); an unprecedented CCR cost sharing program between customers and shareholders, contrary to pre-existing precedent established in the Commission's order in the Company's last rate case, Docket No. E-7, Sub 1146 (the "2017 Rate Case"); and the disallowance of a debt and equity return on billions of dollars of investments will severely harm the quantitative and qualitative aspects of DE Carolinas credit quality. Individually and in the aggregate, I believe these actions will lead to reduced cash flows, increased leverage and risk, further stressed credit metrics, higher borrowing costs, lowered financial flexibility, and, ultimately, higher cost of capital (both debt and equity), to the detriment of our customers. My position is further supported by the testimony of Company witnesses Steven K. Young, Robert B. Hevert, and Steven M. Fetter.

II. CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE KEY POINTS MADE BY INTERVENOR WITNESSES REGARDING YOUR RECOMMENDATION THAT THE COMPANY'S CAPITAL STRUCTURE BE 53% EQUITY AND 47% DEBT.

A. The key points are as follows:

- Mr. O'Donnell and Dr. Woolridge recommend a 50/50 capital structure based upon the "average" capital structure calculated for the companies that they utilize as "proxy" companies for purposes of their calculation of DE Carolinas' rate of return on equity (ROE), or cost of equity capital. That is, these witnesses compare the capital structure of DE Carolinas, a regulated utility operating company, with the capital structures of a multitude of publicly traded holding companies, with utility operating company subsidiaries. This is an inappropriate, applesto-oranges comparison, as I demonstrate in my testimony, and as the Commission has already held.

- Mr. O'Donnell also utilizes data from Regulatory Research Associates ("RRA") which purports to show capital structures approved by various utility regulatory commissions. This data is also inappropriate to utilize in this fashion, because it does not differentiate between various types of utility companies, which present radically different risk profiles.
- Mr. Baudino recommends that the Commission use the Company's actual capital structure as of December 31, 2018 (the end of the test year), which was 51.5% equity and 48.5% debt, in setting rates in this proceeding. As noted in my direct testimony, the specific debt/equity ratio will vary over time, depending on a variety of factors including the timing and size of debt issuances, seasonality of earnings, and dividend payments to the parent company. The assertion that a 51.5% equity ratio is reasonable ignores the practical reality that a capital structure will vary due to timing. Like witnesses Woolridge and O'Donnell, Mr. Baudino also supports his capital structure recommendation by comparison to a proxy group including holding companies.
- Dr. Woolridge addresses the concept of double leverage, and uses Duke Energy's holding company capital structure as support for his recommended 50/50 capital structure for DE Carolinas. This is an inappropriate comparison as DE Carolinas is a regulated utility

operating company, not a parent-level holding company. DE Carolinas is a separately rated entity that issues its own debt and maintains a capital structure that is separate and distinct from its parent, Duke Energy Corporation.

Q. DR. WOOLRIDGE, MR. O'DONNELL, AND MR. BAUDINO'S ANALYSES ARE BASED UPON A COMPARISON OF DE CAROLINAS' PROPOSED CAPITAL STRUCTURE TO THE CAPITAL STRUCTURES OF PARENT-LEVEL HOLDING COMPANIES. DO YOU HAVE ANY CONCERNS WITH THIS APPROACH?

A. Yes. All three witnesses utilize parent-level holding companies in their analysis, as shown by Woolridge Exhibit JRW-2, O'Donnell Table 9, and Baudino Table 3. It is inappropriate to compare the Company's capital structure to these groups, as DE Carolinas is a regulated utility operating company, not a parent-level holding company. The assets obtained by DE Carolinas to serve customers were financed in a manner consistent with the Company's capital structure as a regulated utility, not that of a parent-level holding company. Holding company capital structures differ from regulated utility operating company capital structures for a variety of reasons, and the risk profile for a consolidated entity can be very different than the risk profile of a single subsidiary. Arbitrarily imposing a holding company capital structure upon DE Carolinas would increase its leverage (and, therefore, risk), reduce its cash flows, and erode credit quality – all to the detriment of the Company's customers.

Q. COMPANY WITNESS HEVERT USES HOLDING COMPANIES FOR HIS ROE ANALYSIS. WHY DOES THAT MAKE SENSE FOR ROE BUT NOT FOR CAPITAL STRUCTURE?

A. Cost of Equity models require observable stock price data, which only occur at the parent level, and, therefore, those models must utilize parent company data. The appropriate capital financing structure for a given utility operating company is not dependent upon that kind of information, and there is no reason to conflate capital structure and ROE in this way.

Q. WHAT DO YOU THINK REPRESENTS AN APPROPRIATE COMPARISON GROUP FOR PURPOSES OF ANALYZING DE CAROLINAS' CAPITAL STRUCTURE?

A. If the objective is to compare DE Carolinas' capital structure against those of other companies, I believe a more appropriate group of companies against which to compare is a set of regulated utility operating companies. However, a meaningful comparison may still be complicated by the unique facts and circumstances surrounding each utility capital structure. Capital structure should not be viewed in isolation; it is part of an overall structure which considers capital structure, allowed ROE, and the various mechanisms used to recover costs.

Q. DID THE COMPANY PERFORM AN ANALYSIS OF THE CAPITAL STRUCTURES OF HOLDING COMPANIES VERSUS REGULATED UTILITY OPERATING COMPANIES?

A. Yes, Witness Hevert performed this analysis on behalf of the Company, and his findings are presented generally in his rebuttal testimony, as well as in Rebuttal Exhibits RBH-7 (for witness Hevert's updated proxy group), RBH-16 (for Dr. Woolridge's proxy group), and RBH-22 (for Mr. O'Donnell's proxy group). His analysis demonstrates that it is inappropriate to compare the capital structures of holding companies to operating companies. His analysis further demonstrates that the Company's proposed 53/47 capital structure is very consistent with the capital structures of other operating utilities.

Q. HAS THIS COMMISSION PREVIOUSLY ISSUED A DECISION FAVORING AN APPROACH WHICH UTILIZES UTILITY OPERATING COMPANY CAPITAL STRUCTURES, OVER THE WOOLRIDGE/O'DONNELL/BAUDINO APPROACH, UTILIZING PARENT-LEVEL CAPITAL STRUCTURES?

A. Yes. In the Company's 2009 Rate Case (Docket No. E-7, Sub 909), DE Carolinas sought approval of a 53% equity/47% debt capital structure, and a settlement agreement reached with the Public Staff recommended a 52.5% equity/47.5% debt capital structure. The Attorney General, through witness David Parcell, argued for a 50% equity/50% debt structure, which, he testified was more in line with the average equity ratio of most electric utilities. Witness

Parcell's analysis in that case was also based upon review of parent-level capital structures. Company witness Stephen DeMay's rebuttal testimony in that case analyzed certain operating utility level capital structures instead, just as Mr. Hevert did here. The Commission, in its *Order Granting General Rate Increase and Approving Amended Stipulation*, issued on December 7, 2009 in that docket ("2009 DE Carolinas Order"), approved the stipulated 52.5% equity/47.5% debt capital structure, indicating that "[b]ased on the evidence in this proceeding, the Commission simply finds the testimony of Duke Energy Carolinas witness De May more persuasive than the testimony of Attorney General witness Parcell with regard to the comparisons of capitalization ratios …." *See* 2009 DE Carolinas Order at 27-28.

Q. HOW DO YOU RESPOND TO WITNESS O'DONNELL'S CONCERNS THAT THE REQUESTED EQUITY RATIO OF 53% IS TOO HIGH?

A. Witness O'Donnell indicates the requested 53% "is a reflection of the amount of equity financing that DEC's owner, Duke Energy Corp, wishes to infuse into the utility relative to the amount of debt DEC issues" and that as a result "does not reflect market forces but, instead, represents a decision by its parent holding company as to the capital structure on which it wishes rates to be determined." The requested capital ratio proposed by the Company is not arbitrary and has much to do with the Company's credit metrics and the ultimate rate debt investors will demand – the very market Mr. O'Donnell references. In its October 31, 2019 Credit Opinion, Moody's Investor's Services ("Moody's") cites that DE Carolinas "historically strong financial coverage metrics have been under pressure in recent years," in describing the rising debt/capitalization and softening Funds from Operations ("FFO") metrics exhibited by DE Carolinas in recent periods.[1] Weakening credit metrics and a potentially lower rating will lead to higher debt funding costs in the marketplace which will ultimately be borne by customers. With a downgrade threshold of 25% on FFO to Debt having already been breached, the Company's request is designed to seek an adequate capital structure and equity return to "hold" its A-level rating.

Witness O'Donnell also states that the Commission should "examine similarly-situated utility holding companies and equity ratios set by utility regulators across the country to ascertain a more market-driven capital structure that is best used in setting rates." For the same reasons highlighted above with respect to the use of holding company ratios, I reject this analysis along with the assertion that utility regulators across the country set utility holding company ratios. Utility holding company equity ratios, including Duke Energy Corporation, are not governed by a specific state commission and have the benefit of providing additional liquidity for their utilities during periods of elevated capital investment as has been the case with DE Carolinas in recent years. DE Carolinas has not received any equity infusions from DE Corporation

[1] Moody's does not use the term FFO, but instead the term "CFO pre W/C" meaning Cash Flow from Operations, Pre Working Capital. Functionally that is the same as FFO, so I will refer in my testimony to this concept as FFO.

in the last five years and has been retaining more earnings and withholding more dividends to facilitate its capital plans.

Witness O'Donnell also mentions the average common ratio granted by regulators in 2019 to electric utilities was 49.9% citing *RRA's Regulatory Focus Major Rate Case Decisions – January – December 2018 published in January 31, 2019*. RRA's more recent *Regulatory Focus, 2019* highlights that the average Common Equity Ratio authorized for Electric utilities nationwide, excluding capital structures that include cost-free items or tax credit balances, "was 51.55%, in 2019, 50.53% in cases decided during 2018 and 50.02% in 2017." I discuss this further later in my testimony, but the data reflects an upward trend in the equity portion of capital structures.

Q. PLEASE DISCUSS MR. STRUNK'S ANALYSIS THAT DE CAROLINAS IS LESS RISKY THAN HEVERT'S PROXY GROUP.

A. Mr. Strunk cites data from RRA that most equity ratios awarded to other electric utilities in 2019 and 2020 were below the 53% requested in this rate case. Mr. Strunk goes further that Georgia Power is not directly comparable on ROE as it was awarded in the context of a settlement and a three-year rate plan. Georgia Power was also awarded a 56% equity ratio and a 10.5%allowed ROE. I would argue that Georgia Power has the benefit of a multi-year rate plan and the utility, commission, and its customers will benefit from an adequate cost of capital and capital structure over a longer period, avoiding a potentially repetitive and lengthy and costly rate case process. It should be noted that Georgia Power is consistently one of the most comparable peers to the Company and represents a similar vertically integrated electric utility in the Southeast with significant planned capital investments. More broadly, by making such comparisons, Mr. Strunk appears to advocate the incremental leverage, and the corresponding additional business risk that comes with it, is desirable and to the benefit of customers. I would argue that now, in light of the Company's continued robust capital needs and already challenged credit metrics, is precisely the wrong time to introduce additional leverage and reduced cash flows associated with a lower equity percentage. Again, such proposals must be viewed in the context of the other aggressive recommendations made by intervenors, a lower ROE, accelerated EDIT flowback period, and / or disallowed full debt and equity return on coal ash. These proposals will lower the credit quality of the utility and ultimately lead to higher financing costs for our customers.

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S POSITION REGARDING DOUBLE LEVERAGE WITH RESPECT TO DE CAROLINAS.

A. The concept of double leverage is that of a holding company borrowing money (i.e., incurring debt) and injecting the proceeds into the subsidiary operating company. This downstream flow of money is then treated as equity by the subsidiary. The implication of the double leverage concept is that this subsidiary equity is in some part truly debt and therefore makes the subsidiary enterprise more levered than it would appear. Dr. Woolridge compares Duke

Energy Corporation's capital structure to DE Carolinas, and notes that Duke Energy's capital structure includes more debt than DE Carolinas. In his capital structure recommendation, Dr. Woolridge notes a 50% equity ratio is more in line with DE Carolinas' parent, Duke Energy Corporation.

Q. SHOULD DOUBLE LEVERAGE BE CONSIDERED WHEN ESTABLISHING DE CAROLINAS CAPITAL STRUCTURE?

A. No. As I stated earlier in my testimony, DE Carolinas is a regulated utility operating company, not a parent-level holding company. The Company is capitalized in a manner that is consistent with similar, regulated utility operating companies, and its actual capital structure is managed around its current approved equity ratio of 52.0%. For the same reasons that it is inappropriate to use a proxy group of holding companies, it is inappropriate to apply a holding company capital structure to DE Carolinas. Furthermore, arbitrarily imposing a holding company capital structure on DE Carolinas would have detrimental effects on the Company's credit profile and ultimately customer rates. The more debt that is put into the capital structure, the more it will dilute cash flows and weaken credit coverage ratios – the consequence of which would weaken the Company's credit profile and have a negative impact on DE Carolinas' credit ratings. Duke Energy has not infused any equity into DE Carolinas for the last five years. Instead, DE Carolinas has reduced dividends to the parent and generally relied on retained earnings and access to the credit markets to meets its capital needs.

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1214
DR
38-8

Year	Dividend Payments ($ Millions)	Equity Infusions
2015	401	-
2016	2,000	-
2017	625	-
2018	750	-
2019	275	-

Q. IN HIS TESTIMONY, MR. BAUDINO STATES THAT DE CAROLINAS' ACTUAL TEST PERIOD CAPITAL STRUCTURE INCLUDES 51.5% EQUITY. DO YOU AGREE THAT IS THE APPROPRIATE EQUITY RATIO FOR PURPOSES OF EVALUATING DE CAROLINAS' REGULATORY CAPITAL STRUCTURE?

A. No. Mr. Baudino references two data points as his basis for proposing 51.5%: (1) DE Carolinas reported regulated equity ratio of 51.5% as of December 31, 2018 and (2) a calculated average equity ratio based on 2018 GAAP equity of holding companies derived from witness Hevert's peer group. DE Carolinas' current allowed regulated equity ratio is 52% and, as such, has been managed to approximate the authorized level. As noted in my direct testimony, the specific debt/equity ratio will vary over time, depending on a variety of factors. The assertion that the 51.5% equity ratio, 50 basis points below the Company's currently allowed equity ratio, will continue to be supportive of the Company's current credit ratings ignores the already stressed credit metrics of DE Carolinas and the qualitative and quantitative impacts expected from reduced cash flows and incremental leverage required with such a structure. It also ignores the practical reality that a capital structure will vary due to timing. In regard to (2), I also reject Mr. Baudino's calculated equity ratio based on GAAP equity at holding companies. As described above, such an analysis is not representative of a regulated utility's stand-alone capital structure.

Q. DO YOU CONTINUE TO BELIEVE THAT 53% IS THE APPROPRIATE EQUITY COMPONENT FOR DE CAROLINAS CAPITAL STRUCTURE?

A. Yes. As noted in my direct testimony, the specific debt/equity ratio will vary over time, depending on a variety of factors, including, among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company. However, a regulatory capital structure comprised of 53% equity is consistent with the Company's financial objectives and overall plan to maintain its ability to finance operations at rates favorable for customers. A healthy capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. High credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs for the benefit of customers.

Regulatory Research Associates ("RRA") Regulatory Focus, *Major Rate Case Decisions January – December 2019* highlights the fact many utilities have sought higher common equity ratios to offset the negative cash flow impact of federal tax reform and the average authorized equity ratios adopted by utility commissions in 2019 were higher than the levels observed in 2018. RRA states "the average authorized equity ratio for electric utility cases nationwide was 49.94% in 2019, 49.02% in 2018 and 48.90% in 2017." The aforementioned averages, however, include allowed equity ratios adopted by utility commissions in jurisdictions that typically authorize capital structures that include cost-free items or tax credit balances. Excluding those occurrences, RRA states "the average authorized equity ratio for electric utilities nationwide was 51.55% in 2019, 50.53% in cases decided during 2018 and 50.02% in 2017," an almost 150 basis point increase since 2017. This metric is more relevant to the Company as deferred taxes are excluded from both rate base and the Company's allowed capital structure. The proposed 53 percent equity ratio would result in a 100 basis point increase since the 2017 Rate Case, only two-thirds of the increase regulatory commissions across all electric utilities cited in RRA have allowed on average since 2017.

In addition to DE Carolinas' and Duke Energy Progress, LLC's ("DE Progress") allowed equity component of 53.0% in May of 2019 by the South Carolina Commission, several peers within the RRA data have been awarded equity ratios in excess of 53.0% including Wisconsin Electric Power Company

(54.46% in October 2019) and Georgia Power (56.0% in December 2019). Georgia Power, in particular, should be relevant as it is a vertically integrated utility located in the Southeast with extensive capital needs and a similar risk profile of the Company and is often a relevant peer for comparison.

Q. HOW WOULD LOWERING THE EQUITY COMPONENT OF DE CAROLINAS TO 50%, AS SEVERAL INTERVENOR WITNESSES SUGGEST, IMPACT THE COMPANY?

A. A 50.0% equity ratio would weaken the Company's credit quality, making access to capital on historically competitive terms more difficult. A 50.0% equity ratio represents a 200 basis point reduction to the Company's previously approved ratio of 52.0% and a 300 basis point reduction to the ratio of 53.0% that has been proposed in this case. Lowering the equity ratio by this magnitude would result in higher leverage, greater interest expense, and lower FFO. The combination of lower FFO and a higher amount of debt would further weaken the Company's FFO to Debt ratio.

Moody's has been keeping a close watch on the Company's FFO to Debt ratio and the impact of recent regulatory outcomes, noting that the Company's "historically strong financial coverage metrics have been under pressure in recent years."[2] Moody's stated further that the current rating outlook for the Company of Stable reflects "primarily credit supportive regulatory frameworks in both North and South Carolina" and factors that could

[2] See Moody's DE Carolinas Credit Opinion, October 31, 2019

lead to a downgrade include "a decline in the credit supportiveness of Duke Carolinas regulatory relationships in North or South Carolina" and a "ratio of [FFO] to debt remaining below 25% on a sustained basis."[3]

The three most recent FFO to Debt metrics in Moody's October 31, 2019 credit opinion are 27.2% (December 2017), 24.5% (December 2018), and 24.6% (Last twelve months, June 2019), demonstrating a recent downward trend already below the 25% downgrade threshold. Furthermore, 50% of Moody's Rating Methodology is driven by the Regulatory Framework (25%), including the consistency and predictability of regulation, and the Ability to Recover Costs and Earn Returns (25%). As such, a lower directed equity ratio will have more than just an impact on quantitative metrics and could be expected to also impact the qualitative aspects of Moody's credit rating methodology, particularly if taken holistically with other potentially credit negative determinations including a lower allowed ROE, accelerated EDIT flowback, and / or an altered view on the previously allowed full debt and equity return on coal ash. In short, a material reduction in the equity component of the Company's regulatory capital structure would weaken the already stressed quantitative (credit metrics) and the qualitative (credit supportive regulatory treatment) aspects that the Company's credit rating agencies and investors consider when evaluating credit quality. This, in turn, is expected to result in higher costs of capital for DE Carolinas and its customers. In my experience,

[3] *See supra* n. 1.

once a utility has been downgraded, the ratings agencies do not immediately implement upgrades even if the utility's financial profile improves. Rather, they wait for sustained improvement in the credit metrics and in the interim cite examples or scenarios that could lead to an upgrade within the Company's credit opinions.

III. EDIT FLOWBACK

Q. DO YOU AGREE WITH WITNESS HINTON'S RECOMMENDATION FOR RETURNING PP&E-RELATED UNPROTECTED EDIT OVER A 5-YEAR PERIOD?

A. No. On top of the other proposed credit weakening proposals made by several intervenors, with respect to the return of PP&E-related unprotected EDIT, Witness Hinton, advocates for an arbitrary five-year flowback period in the Company's revenue requirement to benefit customers following the Tax Cuts & Jobs Act (the "Tax Act") versus the Company's recommendation of a 20-year flowback period for property, plant, and equipment related balances.[4] Witness Hinton does not consider the longer-term benefits to customers of a longer flowback period, as EDIT balances offset rate base as a regulatory liability on the Company's balance sheet at a zero-percent cost of capital. Additionally, a faster flowback will result in rate base increasing at a faster rate and the

[4] In his testimony, Company witness Panizza states that the 20-year flowback the Company has proposed for unprotected property-related EDIT is tied directly to the underlying assets that created the deferred tax balances which became EDIT when the the federal corporate tax rate dropped to 21%. The 5-year flowback period advocated by witness Hinton is simply an arbitray number not connected to the actual assets at issue.

potential for future rate volatility. Furthermore, should tax rates be revised upward under a new administration, there will be a precedent for accelerated recovery going forward under an arbitrary five-year period. Through its proposed EDIT Rider, the Company advocates a 20-year amortization of the regulatory liability as supported by Company Witness John Panizza's direct testimony. Mr. Panizza further describes the rationale for the 20-year amortization as it more closely matches the remaining life of the underlying PP&E assets, lessens the cash flow impacts to the Company, and reduces the volatility in customer rates.

While it is clear that customers should, and ultimately will, benefit from the overall reduction in the revenue requirement, the Commission should also take into account other impacts of the Tax Act, particularly as it relates to cash flow. In October 2018, Moody's in its Credit Opinion of DE Carolinas identified tax reform as one of several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios). As indicated in my direct testimony, DE Carolinas faces substantial capital needs over the next several years necessary to meet the demand, reliability, service, and environmental requirements of its customers and service area. As highlighted in my direct testimony, the Company's capital requirements for the next three years (2020-2022) were projected to be approximately $9.1 billion. This amount consisted of approximately $7.8 billion in projected capital expenditures and approximately $1.3 billion in debt retirements. As of

February 2020, and as highlighted within the Company's Fourth Quarter 2019 Earnings Review and Business Update, DE Carolinas now projects $10 billion in projected capital expenditures over the same period, increasing my original estimate of total capital requirements for the next three years from $9.1 billion to $11.3 billion. Reducing the Company's cash flow through a more accelerated flowback of unprotected EDIT at the same time DE Carolinas is investing in large capital projects to benefit customers and is faced with large refinancing obligations will negatively impact its credit metrics, which must be taken into account.

Q. PLEASE COMMENT ON WITNESS STRUNK'S PROPOSED 5-YEAR FLOWBACK OF EDIT.

A. Witness Strunk cites 34 separate news articles in the past 12 months as evidence of shorter flowback periods, 13 of which include flowback provisions exceeding the five-year time period proposed and two which include flowback periods as long as 44 years. Without the full context of the associated orders, it is impossible to determine the size and scale of the deferred taxes returned and expected cash flow impacts in the context of the respective utility's credit metrics and capital needs. What we do know is DE Carolinas faces unprecedented amounts of capital needs in the coming years and already stressed credit metrics. The Company has proposed a 20-year amortization as it more closely matches the remaining life of the underlying PP&E assets, lessens the cash flow impacts to the Company, and reduces the volatility in customer rates. I believe the Company's proposal is a better alternative for these reasons.

Q. IS IT REASONABLE THAT CUSTOMERS SHOULD BENEFIT FROM THE CHANGES IN THE COMPANY'S COST TO SERVE AS A RESULT OF THE TAX ACT?

A. Yes. Customers should benefit, and they will. As this Commission is well aware, electric utilities are one of the most capital-intensive industries in the country and DE Carolinas is no exception. The Company invests in infrastructure not because of federal tax policy, but because it is critical, necessary and often legally-required that it do so to serve customers. Our statutory obligation to serve requires the financial strength to support our commitments to our customers on a reliable and cost-effective basis. Credit quality drives access to affordable capital, and for this reason it is in the best interest of customers to prevent a weakening of the Company's cash flow and credit quality from pre-Tax Act levels.

Without the Commission's thoughtful consideration regarding all aspects of the Tax Act, the Company could be adversely affected by the legislation, particularly through a reduction in cash flow, which is vital to the Company's credit quality. The Tax Act represents a unique opportunity to deliver savings to customers, but, as with all ratemaking actions, the interests of customers and the Company must be balanced. Adjusting utility rates solely to account for the impact of the reduction in the federal corporate tax rate and an accelerated flowback of excess deferred taxes without giving consideration to the impact of all other ratemaking considerations is not appropriate.

Q. COULD THE COMPANY'S FINANCIAL CONDITION BE HARMED AS A RESULT OF A 5-YEAR FLOWBACK OF PP&E RELATED UNPROTECTED EDIT?

A. Yes. An accelerated return of EDIT over an arbitrary five-year period would adversely impact the Company's cash flow to fund ongoing operations and new infrastructure investments. An unmitigated cash flow shortfall could force the Company to rely excessively on third-party capital to fund itself, to the ultimate detriment of its financial condition.

In Hinton Exhibits 1 and 2, Witness Hinton uses 7 years of FFO to Debt metrics (2017 / 2018 based on historical data and 2019-2023 based on projected data as provided by the Company) and focuses on a 3-year moving average to determine a 42 basis point degradation in FFO to Debt based on a 5-year flowback as compared to the flowback as proposed by the company in this rate case (a 20-year period for PP&E-related EDIT and a 5-year flowback for non-PP&E). While Moody's presents a 3-year trend in its credit opinions, credit metrics are a snapshot of an issuer's potential default risk as of a point in time and there is an inherent emphasis on forward looking metrics when providing credit opinions, as the overall rating represents the risk of default on a prospective basis. As summarized in Hinton Exhibits 1 and 2, individual periods are impacted by as much as 90 basis points over the five-year period and in one projected year forces the pivotal FFO to Debt[5] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. As already indicated in my testimony, the Moody's downgrade threshold is an FFO/Debt ratio of 25%. Furthermore, this analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other potentially credit negative proposals by the Public Staff including reduced ROE, a more leveraged capital structure, disallowance of a full debt and equity return on coal ash, and other measures that would reduce cash flows and increase debt. As Moody's highlights, the Company's credit metrics are already stressed, and the compounded impact would further impact credit quality.

Conversely, the 20-year flow back of unprotected PP&E-related EDIT is proposed to balance the interests of customers with the financial strength and cash flows of the Company. The Federal tax law changes provide the Commission an opportunity to help reduce and levelize customer rates over the short- and longer-term, while maintaining the utility's ability to provide safe, reliable and affordable rates.

Witness Hinton also suggests the Company should moderate upstream equity dividends to Duke Energy Corporation to alleviate potential credit pressures as a result of accelerated EDIT flowback. Duke Energy Corporation has a long-term targeted dividend payout ratio of 65-75% and subsidiaries can

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[5] *See supra* n. 1.

be expected to contribute at a similar level over the long-term. DE Carolinas' payout ratio over the last three years has been below this threshold to facilitate its ongoing capital plans, large expenditures related to coal ash remediation, and investments to better serve our customers. For example, during 2019, DE Carolinas only provided $275 million in dividends to the parent, its lowest contribution in the last five years.

Witness Hinton also suggests Duke Energy Corporation can use funds from its $2.5 billion November common equity issuance to allow DEC to further decrease equity infusions to the parent. The equity issuance was intended to protect DE Corporation's credit in light of a range of scenarios related to the delay and regulatory uncertainty around the Atlantic Coast Pipeline, a key infrastructure project intended to provide low cost natural gas to our service territory and better serve our customers. Ultimately, preserving the credit quality of DE Corporation is likewise important to DE Carolinas and its sister companies because S&P uses a family rating methodology whereby weakness in the parent or some of the subsidiaries could lead to a lower credit opinion for the entire family of rated entities under the same parent.

Q. WHAT ARE THE IMPACTS, BOTH SHORT AND LONG TERM, OF A POTENTIAL CREDIT DOWNGRADE FOR DE CAROLINAS?

A. As highlighted above, Witness Hinton mentions that a downgrade from Aa2 to Aa3 is expected to cost the company 5 basis points in today's market. That is an estimate I provided based on current historically low interest rates and near record tight credit spreads. Financial markets, like any market, are a function of supply and demand. In light of continued easing by central banks and negative yields in certain global markets, investors as of recent have been in search of yield. The Company, and our customers, have benefited as capital has been available and borrowing costs have been economical. We would caution, however, that credit spreads can widen significantly during periods of uncertainty and market volatility. The better an issuer's credit quality, the more flexibility and optionality it has with financing during these periods and the more likely it can access the market at reasonable rates. Issuers with lower credit ratings and more stressed financial metrics will experience greater borrowing costs and heightened pricing pressures during such periods.

Witness Hinton also assumes a downgrade will "***only***" last five years. Five years is a long time and his presumption is overly optimistic for a number of reasons. Moody's mentions a downgrade "would occur if [FFO[6] to Debt] is below 25% on a sustained basis." However, an upgrade would require significantly higher metrics. For example, as an order of magnitude, an upgrade to Aa1 would require a 30% FFO to Debt level on a sustained basis as calculated by Moody's. As calculated in Moody's October 31, 2019 credit opinion and holding debt constant at $10,463 million, FFO would need to increase from $2,844 to $3,139 to move from 27.2% to 30% FFO to Debt, or approximately $300 million in incremental cash flows annually on a sustained basis with no

[6] *See supra* n. 1.

incremental leverage. Incremental cash flows of such a scale would likely require significant rate increases to customers over prolonged periods.

Q. HOW IS SECURITIZATION VIEWED BY THE RATING AGENCIES?

A. Generally, S&P ignores the impacts of securitization in quantitative metrics. Moody's typically views securitization debt of utilities as on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, Moody's adjusts the company's financial ratios by including the securitization debt and related revenues in their analysis. While overall securitization is viewed positively by Moody's in terms of certainty of cash recoveries, certain quantitative metrics can be negatively impacted by its inclusion in FFO to Debt. Securitization is structured with amortizing debt and based on the relatively constant cash flows from recovery, FFO to Debt can generally be expected to be degraded in the early years (due to the immediate incremental leverage relative to supporting cash flows) with improvements in later years. This may further challenge stressed credit metrics in the early years at DE Carolinas and could be amplified by any other credit negative decisions including lower revenues from a reduced ROE, a lower equity ratio, or disallowance of a full debt and equity return on coal ash.

IV. RECOVERY AND TREATMENT OF CCR COMPLIANCE COSTS

Q. WHAT IS THE CREDIT IMPACT OF LOSING THE FULL DEBT AND EQUITY RETURN ON COAL ASH RECOVERY?

A. DE Carolinas' senior unsecured credit ratings of A1 and A- from Moody's and S&P, respectively would likely be downgraded if the utility were to lose the full debt and equity return on coal ash remediation costs. Following the 2017 Rate Case, which provided recovery of deferred coal ash costs over a 5-year amortization period with a full debt and equity return at DE Carolinas' weighted average cost of capital (WACC), both credit rating agencies modified their methodology when calculating a key credit metric (FFO to Debt). This metric is the primary financial measure used by the rating agencies to determine the credit quality of utility companies, including DE Carolinas.

GAAP requires expenditures related to the settlement of current liabilities, including the current portion of asset retirement obligations be included as a reduction in cash flows from operating activities in a company's statement of cash flows. When the Commission issued its order in the 2017 Rate Case, granting DE Carolinas a full debt and equity return on coal ash expenditures during the recovery period, both rating agencies began treating these expenditures as ordinary, regulated investments. By treating the spend associated with the settlement of coal ash AROs as an investing activity, rather than an operating activity, the rating agencies were essentially removing a sizeable operating cash outflow from the utility's computation of FFO, which results in a stronger FFO to Debt ratio.

Moody's explains in its October 31, 2019 credit opinion of DE Carolinas that "as a result of this rate base like treatment, we currently view the spending for coal ash remediation to be akin to a capital expenditure." The Company tries to replicate the Moody's FFO/Debt calculation methodology when it reports its own calculation of FFO/Debt. By replicating Moody's post-2017 Rate Case treatment of coal ash spend as investing activity, the corresponding adjustment to FFO in the Company's FFO/Debt metric as of December 31, 2019 provided approximately 230 basis points of support to DE Carolinas' FFO to Debt metric, making that metric 26.1% as of December 31, 2019. Without the full debt and equity return, the Company's FFO to Debt ratio would fall approximately 230 basis points, which is well below Moody's downgrade threshold of 25%.

Q. IS THERE A THREAT THAT THE RATING AGENCIES COULD MODIFY THE DOWNGRADE THRESHOLD IF THE PREVAILING TREATMENT FOR COAL ASH RECOVERY WERE TO CHANGE?

A. Yes. The credit rating agencies consider both qualitative and quantitative factors when assessing overall credit quality of a regulated utility. Positive consideration is given for regulatory environments that provide consistency and predictability of regulation. As I highlight above, Moody's rating methodology for electric and gas utilities incorporates the regulatory framework and the ability to recover costs and earn sufficient returns as 50% of their overall credit scoring. In Moody's October 31, 2019 credit opinion on DE Carolinas, the agency describes four specific credit strengths:

- the credit supportive regulatory environment
- approved recovery of coal ash-related expenditures
- a growing service territory, and
- the utility's position as part of the Duke Energy utility system.

These qualitative benefits allow DE Carolinas to maintain strong credit ratings even with FFO to Debt that is below the midpoint of Moody's allowed range for 'A' rated utilities. With 25% of Moody's credit scoring derived from consistency and predictability of regulation with respect to recovery and earnings potential, it is logical to expect a change in regulation that weakens a utility's credit quality would cause the rating agencies to seek stronger credit metrics to maintain the same credit rating now that the regulatory environment in which that utility operates has introduced a higher degree of credit risk.

Q. WHAT IS THE IMPACT OF A CREDIT DOWNGRADE AT DE CAROLINAS?

A. If a credit rating downgrade occurred at DE Carolinas, the utility's overall cost of capital would increase. If the downgrade were caused by a change in the method of recovery of coal ash remediation costs, both debt and equity investors would perceive the change in consistency and predictability of the utility commission's rate making as a heightened risk to the utility. In the debt capital markets, utilities with lower ratings are charged higher credit spreads to compensate investors for the additional risk assumed, which leads to higher overall pricing of new debt issuances. Likewise, equity investors would require a higher economic return on invested capital to be properly compensated for assuming additional risk. Any incremental financing costs incurred by the utility would be passed on to customers through higher rates.

Q. WILL A DOWNGRADE TO DE CAROLINAS IMPACT THE CREDIT QUALITY OF DUKE ENERGY CORPORATION?

A. Yes. Duke Energy Corporation is a holding company that relies on stable and predictable cash flows from each of the subsidiary utilities to pay fixed payment obligations and dividends to equity investors. Given the relative size and position of DE Carolinas within the overall portfolio of utilities, a negative rating action at DE Carolinas would negatively impact the credit quality of Duke Energy Corporation. In Moody's most recent credit opinion of Duke Energy Corporation, October 13, 2019, the agency states that a factor that could lead to a downgrade is a deterioration in the credit supportiveness or emergence of a more contentious regulatory relationship. This would negatively impact cash flows or the timeliness of cost recovery, particularly with respect to coal ash remediation recovery in North Carolina.

Q. IF DUKE ENERGY CORPORATION IS DOWNGRADED, WHAT IMPLICATIONS ARE THERE TO THE SUBSIDIARY UTILITIES?

A. Each of the utility subsidiaries directly benefit from a healthy and stable holding company. During periods of elevated capital expenditures, including large amounts of coal ash impoundment closure investments, the utilities are able to retain more of their earnings as equity capital to maintain the regulated capital structure. During these periods of lower dividend payouts from the utilities to the holding company, the holding company can access capital markets on favorable terms to supplement the cash shortfall in the near term. A rating downgrade at the holding company would increase the cost to access certain investor classes, which in turn would increase its cost of capital. In turn, the utilities would likely need to reduce investments that were intended to provide customer benefits.

V. FINANCIAL IMPACTS OF THE PUBLIC STAFF RECOMMENDATION

Q. DO YOU HAVE ANY CONCERNS WITH THE OVERALL PUBLIC STAFF AND OTHER INTERVENORS' RECOMMENDATIONS?

A. Each of the Public Staff's and other intervenors' positions discussed above do not exist in isolation, but rather is part of an overall recommendation by the Public Staff to decrease the Company's requested revenue requirement by approximately $334 million in the first year, as summarized in Boswell Exhibit 1, Schedule 1. To fully understand the adverse impact to the Company's credit quality, the entire recommendation must be considered. Among other things, Boswell Exhibit 1, Schedule 1 outlines a reduction of the current allowed ROE by 120 basis points to 9.0%, an increase in leverage of 300 basis points resulting from a revised capital structure of 50% debt-to-equity, accelerated EDIT flowback over an arbitrary 5-year period, no return on CCR environmental compliance costs during a 26 year amortization period, and extending the period of recovery for other costs.

Adopting the Public Staff position would exacerbate the magnitude of regulatory lag cited by the rating agencies and weaken the Company's credit metrics. On a quantitative basis, leverage would increase and cash flows to fund operations and service debt would decrease. In recent credit reports, both Moody's and S&P view the Company's current regulatory framework as generally constructive, supporting long-term credit quality. Adopting the Public Staff position with a significantly lower ROE, more leveraged capital structure, accelerated EDIT flowback, and insufficient recovery of and on CCR environmental compliance costs the Company has and will expend, will weaken this view.

As I have described throughout my testimony, when considering a company's credit rating, the rating agencies contemplate both qualitative and quantitative components of a borrower's credit quality. Moving one component changes how a rating agency will view other components. For example, if the agencies' qualitative assessment of a company is lowered, they may then require stronger quantitative metrics to offset the change to avoid a credit downgrade. Again, if the Public Staff's recommendations are adopted, it would have an adverse impact on both the qualitative (less constructive regulatory environment) and quantitative (weaker credit metrics) aspects in evaluating the Company's credit quality, which would compromise its ability to undertake investments designed to improve the customer experience.

DE Carolinas has maintained A1 / A- (Moody's / S&P) credit ratings since 2015. Additionally, from 2004 to 2015, the Company worked constructively to improve its credit profile while continuing to make investments to better serve customers. As other witnesses state, this has allowed the Company to provide customers excellent service at low rates. Given the Company is facing unprecedented capital requirements, including billions of dollars in required CCR compliance costs, and is experiencing continued pressure on credit metrics, I believe now is the time to continue to preserve credit strength and flexibility so the Company may meet its capital obligations on behalf of customers. The aggregate impact of a lower ROE, more leveraged capital structure, accelerated EDIT flowback, and delayed or inadequate coal ash recovery without a full debt and equity return would stress the quantitative and qualitative credit aspects of DE Carolinas and would be expected to lead to increased risk and higher costs for customers.

Lastly, Witness Woolridge asserts a "prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities and their ability to attract capital." A lower ROE will most certainly be viewed in totality with other potentially credit negative aspects of this rate case – both by rating agencies and potential investors. The more punitive the impacts of reduced cash flows or incremental leverage, including those driven from a lower ROE or a more leveraged capital structure, the higher the risk and greater the impact on credit quality and future borrowing costs.

Q. GIVEN YOUR CONCERNS WITH HOW THE OVERALL PUBLIC STAFF AND OTHER INTERVENOR RECOMMENDATIONS WILL ADVERSELY IMPACT CREDIT QUALITY, HOW DO YOU BELIEVE FIXED INCOME INVESTORS WILL REACT IF THESE RECOMMENDATIONS WERE TO BE ADOPTED?

A. When evaluating investment alternatives, fixed income investors use a set of criteria similar to that of the rating agencies. As previously stated, if the Public Staff and/or other intervenor recommendations were to be adopted, the Company's leverage would increase, and cash flows would decrease. For a fixed income investor, the risk of investing in DE Carolinas' debt securities would increase. To compensate for the increased risk, investors would require a higher interest rate for loaning money to the Company. Additionally, based on a data request during discovery, I provided an estimate that moving from an Aa2 to an Aa3 senior secured first mortgage bond borrowing at DE Carolinas would be expected to add 5 basis points to the cost of debt in today's historically low interest rate and credit spread environment. While that may be the case today, during periods of dramatic market volatility as in during the 2009 financial crisis, credit spread will, and have historically, widened out dramatically. Strong investment grade credit provides protection, flexibility, and access to issuers with higher credit ratings during these periods.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. To summarize, the aggregate impact of a lower ROE, more leveraged capital structure, accelerated EDIT flowback, and delayed or inadequate coal ash recovery without a full debt and equity return will harm the quantitative and qualitative aspects of DE Carolinas credit quality. Individually and in the aggregate, I believe these actions will lead to reduced cash flows, increased leverage and risk, further stressed credit metrics, higher borrowing costs, lowered financial flexibility, and, ultimately, higher cost of capital (both debt and equity) to the detriment of our customers, who must bear that cost, now and for years to come.

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

A. Yes.

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl W. Newlin. My business address is 550 South Tryon Street, Charlotte, North Carolina, 28202.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Senior Vice President, Corporate Development and Treasurer. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. DID YOU OFFER DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the capital structure proposed in the Second Agreement and Stipulation of Partial Settlement by and between DE Carolinas and the Public Staff (the "Second Partial Settlement") when that provision is viewed as part of the overall terms of the Second Partial Settlement. My Direct and Rebuttal Testimony remain effective as applicable to the testimony of any non-settling Party, and as to the point that cash flows, including from the unresolved issue of coal ash, have an adverse impact on DE Carolinas' financial health.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. The 52 percent to 48 percent equity-to-debt capital structure is reasonable and appropriate when viewed in the context of the overall Second Partial Settlement. All other things equal, credit rating agencies view the constructiveness of the regulatory environment and the Company's ability to timely recover prudently incurred costs as important ratings criteria in their assessment of the Company's credit quality. The Second Partial Settlement, on a stand-alone basis, demonstrates an ability to do this and I believe its approval would be viewed by the rating agencies as constructive and equitable.

The Second Partial Settlement, however, leaves some issues unresolved, including particularly the issue of the Company's recovery of coal ash basin closure costs, as well as a return on those costs. The potential impact of coal ash cost recovery upon the Company's cash flows is consequential, as I indicate in my Rebuttal Testimony, and the potential impact upon cash flows has a corresponding impact upon the Company's credit metrics, liquidity, and credit ratings. This is a different matter than earnings. Even if a Company's earnings are reasonable, if it lacks the cash to fund operations and provide an adequate return to investors, then the Company's ability to raise capital – both debt and equity – on reasonable terms is weakened. Ultimately, adverse cash flow impacts also have an adverse impact upon customer rates – DE Carolinas' customers benefit through lower electricity rates when the Company has lower financing costs, ready access to capital, and more timely cash recovery of its investments.

III. SECOND PARTIAL SETTLEMENT

Q. PLEASE DESCRIBE YOUR INTERACTION WITH CREDIT RATING AGENCIES.

A. One of my primary responsibilities is to manage the relationship with each of the major credit rating agencies for Duke Energy and all of its utility subsidiaries, including DE Carolinas. I and my team maintain frequent and regular contact with the agencies, providing them with information and updates on Duke Energy and DE Carolinas.

Q. HOW DO YOU BELIEVE THE AGENCIES WOULD LIKELY REACT IF THE COMMISSION WERE TO APPROVE THE COMPANY'S SECOND PARTIAL SETTLEMENT AGREEMENT WITH PUBLIC STAFF?

A. DE Carolinas' credit rating agencies view the constructiveness of the regulatory environment and the Company's ability to recover prudently incurred costs as important ratings criteria in their assessment of the credit quality of DE Carolinas. The Second Partial Settlement demonstrates this ability, and I believe its approval would be viewed by the rating agencies as constructive and equitable. Approval of the Second Partial Settlement will support the Company's ability to achieve its financial objectives, all other things being equal and depending on the outcome of the unresolved issues in the case.

Q. WHAT ARE DE CAROLINAS' FINANCIAL OBJECTIVES?

A. As I discussed in my Direct and Rebuttal Testimony, the Company at all times seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, ensuring reliable access to capital on reasonable terms. Financial strength and access to capital are necessary for DE Carolinas to provide cost-effective, safe, environmentally-compliant, and reliable service to its customers. Specific objectives that support financial strength and flexibility include: (a) maintaining a reasonable common equity component for DE Carolinas on a regulatory capitalization basis; (b) maintaining current credit ratings; (c) ensuring timely recovery of prudently incurred costs; (d) maintaining sufficient cash flows to meet obligations; and (e) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the DE Carolinas and its customers, and each of these help the Company meet its overall financial objectives.

Q. HOW DO CUSTOMERS BENEFIT FROM THE COMPANY'S STRONG CREDIT RATINGS?

A. To assure reliable and cost-effective service, fund infrastructure projects, and refinance maturing debt, DE Carolinas must be able to finance without interruption, regardless of capital market conditions. The lack of access to capital can force interruption of capital projects to the long-term detriment of customers, and both the financial crisis of 2008-09 and the COVID-related market volatility during 2020 illustrate the importance of maintaining financial strength and flexibility. Although market conditions have improved somewhat from the extreme volatility of late March, they remain uncertain, and increased volatility can return at any time. Strong credit ratings result in lower debt costs for our customers and greater assurance of access to capital, even in challenging market conditions.

Q. WHAT ISSUES COULD AFFECT THE COMPANY'S CREDIT RATINGS IN THIS CASE NOTWITHSTANDING THE APPROVAL OF THE PROPOSED SECOND PARTIAL SETTLEMENT?

A. The Commission's ultimate resolution of the unresolved issues in the case – including timely recovery of and on coal ash basin closure costs – could affect DE Carolinas' credit ratings and the overall financial health of DE Carolinas notwithstanding approval of the Second Partial Settlement.

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

A. Yes.

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven K. Young and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am the Executive Vice President and Chief Financial Officer for Duke Energy Corporation ("Duke Energy"), the parent holding company for Duke Energy Carolinas, LLC. ("DE Carolinas" or the "Company").

Q. CAN YOU PROVIDE A BRIEF SUMMARY OF YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE?

A. Yes. I have a Bachelor of Arts degree in Business Administration from UNC-Chapel Hill and have also attended the Advanced Management Program at the Wharton Business School and the Reactor Technology Course for Utility Executives at the Massachusetts Institute of Technology. I joined Duke Energy in 1980 as a financial assistant and have held various positions of increasing responsibility at the Company, primarily in the areas of finance and utility regulation since that time. I was appointed to my current position in 2013.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes the fundamental financial profile of Duke Energy and DE Carolinas, the financial needs of our investors, how utility regulation impacts our profile and investors, and how having a financially healthy utility benefits customers and our state. Finally, I explain the Company's concerns with some of the proposals offered by Intervenors in this proceeding (and with the Commission's recent Dominion Energy North Carolina Order issued in Dockets E-22, Sub 562 and E-22, Sub 566), and why they should not be adopted by the Commission in this case.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR REBUTTAL TESTIMONY?

A. Yes. The following exhibits are attached to this testimony:

1. Moody's Sector In-Depth Report (March 2, 2020)
2. Duke Energy P/E Ratio, Growth Rate, and Rate Base Growth
3. Moody's Credit Opinion (October 13, 2019)
4. Moody's Credit Opinion (October 31, 2019)
5. BOA Securities Duke Energy Ratings Report (January 13, 2020)
6. Wolfe Research Duke Energy Report (February 13, 2020)
7. Fleishman Daily Duke Energy Report (February 25, 2020)

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. COULD YOU EXPLAIN THE FUNDAMENTAL FINANCIAL OPERATIONS AND PRESSURES FACING DE CAROLINAS IN ITS PROVISION OF ELECTRIC SERVICE TO NORTH CAROLINA CUSTOMERS?

A. Yes. We are a regulated provider of energy utility service in North Carolina, South Carolina, and several other jurisdictions. DE Carolinas operations, including pricing and ultimately earnings, are regulated by state and federal utility commissions. Price and earnings regulation exist across the United States primarily due to the capital intensive nature of the energy utility business.

As a consequence of this paradigm, virtually all of our services and the rates we are permitted to charge for those services are determined by public service commissions like the North Carolina Utilities Commission ("NCUC"). To fund the significant capital investments required to provide electric service, we must be able to attract debt capital and Duke Energy must be able to attract equity capital in the same financial markets utilized by our peers and by other non-regulated businesses to provide effective service to the public. If access to the capital markets is unduly impaired, our ability to provide customers with safe and reliable electric service at reasonable cost is jeopardized.

Q. CAN YOU DESCRIBE AT A HIGH LEVEL HOW DUKE ENERGY'S REGULATED UTILITY FINANCIAL OPERATIONS WORK?

A. Yes. Duke Energy generates roughly $8 billion a year in cash flow from its utility operations. This consists of net income (revenues remaining after the payment of all the costs of operating its utilities, including approximately $2 billion a year in interest expense on debt used to fund infrastructure investment) and the return of a portion of prior capital investment through depreciation. Of this amount, we allocate approximately $3 billion a year to our shareholders in the form of dividends. The dividend is necessary to attract equity capital investors who expect a quarterly cash dividend in addition to any hoped-for stock price appreciation. This leaves approximately $5 billion a year for reinvestment in our system.

Our current level of annual capital investment in our regulated utilities is approximately $10 billion a year – roughly twice the amount we have available after payment of dividends. This level of investment is needed to maintain, improve, and expand our system to meet customer demand and to meet our obligations to provide safe and reliable utility service to the public in the jurisdictions in which we operate. It is also required to meet our obligations associated with, among other investments, the ongoing closure of our North and South Carolina coal ash impoundments and for storm recovery activities.

Neither Duke Energy nor DE Carolinas have access to any established "reserves" to pay the carrying costs of their unavoidable need to incur debt (and equity) to support utility operations. Having to simply absorb those carrying costs could have significant negative implications to the financial stability of the enterprise as a whole.

Q. HOW DOES DUKE ENERGY PROVIDE FOR THE DIFFERENCE BETWEEN THE $5 BILLION AVAILABLE FOR REINVESTMENT FROM CURRENT EARNINGS AND THE $10 BILLION NEEDED ANNUALLY FOR NEW INVESTMENT?

A. We have to obtain the difference from the debt and equity markets, which we access on a regular and ongoing basis, and in which we compete against other utilities and non-utilities for such capital.

Q. PLEASE DESCRIBE DEBT AND EQUITY SOURCES OF FUNDS AND WHY THEY ARE IMPORTANT.

A. Virtually all utilities fund operations and capital investment with both long-term debt and equity. Debt typically carries a fixed yield or interest rate to the bond holder and is ahead of equity investors in a bankruptcy or liquidation scenario. For these reasons, debt financing is less risky and, therefore, cheaper than equity financing. Equity investors typically seek growth in the underlying stock value and/or a cash dividend. For utility stocks, the vast majority of the value sought by shareholders is in the security of the quarterly cash dividend.

Q. PLEASE DESCRIBE DUKE ENERGY'S DIVIDEND HISTORY AND POLICY.

A. Duke Energy has paid a cash dividend to its shareholders for 94 consecutive years. We target to pay between 65% and 75% of our net income to our shareholders in the form of a cash dividend.

Q. PLEASE DESCRIBE THE COMPOSITION OF DUKE ENERGY'S SHAREHOLDERS.

A. Duke Energy's shareholder base is about 60% institutional investors and about 40% retail or individual investors. Approximately 10% of our shareholders live in North and South Carolina.

Q. YOU MENTIONED EARLIER THAT DUKE ENERGY IS CASH-FLOW NEGATIVE. HOW DOES THIS WORK IF THE COMPANY IS INVESTING MORE THAN IT IS EARNING EACH YEAR?

A. As I stated earlier, energy utility operations are often cash flow negative due to the need to serve a growing customer base, repair and maintain existing infrastructure, and immediately respond to all service interruptions, such as those caused by major storms. Duke Energy's ability to fund these investments is based upon investor confidence that customer rates will be set at levels that allow all prudent utility operating and financing costs to be recovered.

Q. WHAT HAPPENS IF ALL PRUDENT COSTS OF PROVIDING SERVICE, SUCH AS THE CARRYING COSTS ASSOCIATED WITH DEBT AND DIVIDENDS TO SHAREHOLDERS ARE NOT RECOVERABLE IN RATES?

A. Fundamentally, as is discussed in the Rebuttal Testimony of DE Carolinas witness Newlin, if cash from operations declines then fewer funds are available for infrastructure investments and shareholder dividends. This means several things might happen:

1. The Company's liquidity ratios decline due to lower cash revenues;

2. Credit Rating Agencies may lower the Company's credit ratings; and/or

3. The dividend level may be constrained.

Items 1 and 2 above will result in higher financing costs on future infrastructure investment, which translates into higher rates for customers. Item 3 will result in challenges in obtaining competitive equity financing, also leading to higher costs to customers.

Q. WHAT CAN A UTILITY DO TO MINIMIZE ITS FINANCING NEEDS?

A. First, it can operate as safely and efficiently as possible to reduce its costs and maximize its cash from operations, something we are committed to doing. DE Carolinas' utility operations are outstanding in this regard. DE Carolinas, for example, has rates that are well below national averages. As rates are based on costs, this means that DE Carolinas' costs are well below national averages. Duke Energy's nuclear fleet was the lowest cost fleet in the country in 2019 (while having an outstanding capacity factor and safety record) and our overall transmission and distribution costs per customer are in the top quartile of electric utilities nationally. Company witness Hatcher includes many more examples of our service record in his direct testimony.

Q. CAN YOU MINIMIZE THESE CARRYING COSTS BY RELYING ON LESS EXPENSIVE DEBT TO FUND THE INVESTMENTS?

A. Not as a practical matter. The risk appetite for regulated utility investors anticipates utility capital structures that are relatively balanced between debt and equity. An over reliance on debt would increase our debt ratio (and decrease our equity ratio), which would cause Duke Energy to be riskier in the eyes of lenders and investors, who would then demand a higher return before providing debt and equity capital to us, leading to increased customer rates.

Q. GIVEN THESE FINANCIAL CONSTRAINTS AND THE ONGOING OBLIGATION TO PROVIDE SAFE AND RELIABLE SERVICE TO DE CAROLINAS' CUSTOMERS, WHAT CHALLENGES DO YOU SEE WITH SOME OF THE INTERVENORS' POSITIONS IN THIS CASE?

A. Let me discuss a few of the major issues I see. First, let's look at coal ash or CCR impoundment closure cost recovery. These costs for DE Carolinas and DEP, which are derived from our legal obligation to close our coal ash impoundments at various coal-fired generating plants (some of which are still in operation), are estimated to be in the range of approximately $8.5 billion over the next 15-20 years. These plants have provided for decades, and continue to provide in many cases, low cost power to our customers in North and South Carolina. Additionally, state environmental regulators have deemed our methodologies to permanently close the basins in North Carolina as reasonable, prudent and in the public interest. Nonetheless, some intervenors have stated that substantial portions of these costs should be shared by customers and shareholders or disallowed.

For example, the Public Staff has perpetuated its "equitable sharing" proposal for coal ash basin closure costs in this case that, if granted, would cause the Company to absorb hundreds of millions of dollars in this case (and billions of dollars over time) with no ready source for those funds.

In the recent Dominion Energy North Carolina rate case order, the Commission itself disallowed recovery of a significant portion of the financing costs associated with coal ash basin closure. Disallowances of the recovery of these costs in DE Carolinas' case would decrease the Company's cash-flow from operations and increase funding requirements from debt and equity investors as these costs are unavoidable and will continue to be incurred. As I described earlier, this would impair the credit quality of DE Carolinas and ultimately drive up financing costs and customer rates. As of the end of 2019, DE Carolinas is carrying over $700 million (NC retail allocation) of deferred CCR costs incurred as a regulatory asset on its balance sheet awaiting future recovery. These amounts, which represent actual expenditures by DE Carolinas, have clearly depended heavily on debt and equity financing.

The Commission's recent order in the Dominion Energy North Carolina rate case, if applied fully to DE Carolinas, would have significant negative impacts on the economic health of the Company because it would force DE Carolinas to incur carrying costs on billions of dollars of required coal ash basin closure costs over an extended period with no ability to recover those carrying costs.

Q. SOME INTERVENORS TESTIFIED THAT CCR COSTS ARE NOT CAPITAL COSTS AND, THEREFORE, SHOULD NOT EARN A RETURN. DO YOU AGREE?

A. No. If a utility prudently incurs costs, whether they are capital or O&M in nature and does not receive revenues sufficient to cover those costs until some future date, the costs will have to be financed in the interim. In this scenario, customers will benefit by delaying the time when they will be asked to begin paying such costs but the interim financing expenses that accrue in the meantime are real and should ultimately be borne by customers as they constitute the actual costs of the utility's business.

Q. HAS THIS PRINCIPLE BEEN PREVIOUSLY RECOGNIZED?

A. Yes. Both storm costs and post in-service plant costs are categories of O&M costs that, when deferred, the Commission historically has allowed a return on the unamortized balance through inclusion in rate base. More directly to the point, in DE Carolinas' last rate case, this Commission allowed DE Carolinas to recover its carrying charges on deferred coal ash basin closure investments as part of the amortization of the recovery of those investments from customers.

Q. ALSO, IN REGARD TO CCR COSTS, SOME INTERVENORS HAVE STATED THAT DUKE ENERGY KNEW OF THE NEED TO BEGIN COAL ASH REMEDIATION AS EARLY AS THE 1980s OR 1990s. GIVEN YOUR LONG HISTORY WITH THE COMPANY, CAN YOU PROVIDE ANY INSIGHTS ON THESE ASSERTIONS?

A. Yes. I have been involved in regulatory matters and particularly accounting related regulatory matters for virtually my entire career at Duke Energy. Until very recently, I do not recall any industry-wide requirement (or generally accepted practice) involving the inclusion of coal ash basin closure costs in either our operating expense budgets or depreciation expense calculations. In particular, I do not have any recollection of coal ash basin closure costs being the subject of any precedential legal, regulatory or accounting practices adopted by or applicable to the industry for the vast majority of my career.

Q. WHAT OTHER INTERVENOR POSITIONS CONCERN YOU REGARDING THE FUTURE FINANCIAL VIABILITY OF DUKE ENERGY AND DE CAROLINAS?

A. Some intervenors have proposed denial of a cost deferral (or denial of cost recovery) for grid modernization investments set out in our Grid Improvement Plan, as described in the testimony of DE Carolinas witness Oliver. This is problematic given the increased storm activity we are seeing in the Carolinas; the need to prepare to accommodate smaller-sized, multiple location renewable resources on our system; and the desire to advance our customer communications capability. Along with the other Megatrends identified in the testimony of Witness Oliver, the need for grid modernization is greater than ever. Grid investments are placed into service in smaller, more frequent increments than generation plants. Upon completion, they begin to accrue depreciation, interest and tax expenses without any offsetting increase in rates (until the Company's next rate case). In the absence of a rate case or deferral as requested by DE Carolinas, these expenses erode the Company's economic performance and, ultimately, shareholder returns. Given the extensive need to modernize our grid, this area is now the largest area of new capital investment for the Company. As such, the expense lag associated with these investments creates a significant financial gap for DE Carolinas.

Q. WHY ARE NEW REGULATORY MECHANISMS NEEDED NOW FOR GRID INVESTMENTS?

A. In the past, the major capital investment area for DE Carolinas was large generating facilities such as nuclear, gas, and coal generation plants. The accounting mechanisms in place for these types of facilities allowed all of the costs of the facility to be deferred up to and even beyond the commencement of service date for these facilities. The utility could book the earnings immediately and only recover the cash it had spent in a future rate case following the in-service date of the generating facility. The use of a deferral mechanism for Grid Improvement Plan costs would effectively allow these new major capital investments to have the same earnings profile as DE Carolinas' prior capital investments.

Q. WHAT IMPACT WOULD A GRID DEFERRAL MECHANISM HAVE ON DE CAROLINAS' FINANCIAL HEALTH?

A. The ratings agencies have clearly identified regulatory lag associated with new grid investments as a problem for the industry. The agencies look for recovery mechanisms such as riders, multi-year rate plans, and deferrals with full returns as critical to sustaining solid credit ratings. The March 2, 2020 Moody's Sector In-Depth report attached hereto as Young Rebuttal Exhibit 1 supports this focus on grid investment and cost recovery.

Q. ARE THERE ANY OTHER CRITICAL ISSUES IN THIS RATE CASE YOU WOULD LIKE TO DISCUSS?

A. Yes. Several intervenors, including the Public Staff, are proposing allowed rates of return on common equity ("ROE") that are at or below 9.0%. This level of ROE, if adopted by the Commission, would be well below any electric utility ROE allowed by the Commission during at least the last decade, and would also be inconsistent with DE Carolinas' operating performance and risk profile and would make it much more difficult for the Company to compete in the capital markets.

Q. HAVE THE ECONOMIC CHALLENGES YOU DESCRIBED ABOVE IMPACTED THE QUALITY OF SERVICE PROVIDED BY DE CAROLINAS?

A. No. We have continued to provide excellent service to our customers at very reasonable rates notwithstanding the financial challenges I have described. In addition to DE Carolinas' low-cost profile, our response to the three major storms we experienced in 2018, as described in the testimony of DE Carolinas witness Jackson, was superlative. We have also recently been recognized by EEI for our overall safety record and have demonstrated excellence in the operation of our nuclear generation facilities. From a customer service perspective, we are proud of our record of providing high quality service at reasonable rates – increasing reliability by 15% in 2019.

Q. HOW ARE DUKE ENERGY AND DE CAROLINAS CURRENTLY FARING FROM A FINANCIAL PERSPECTIVE?

A. From a debt investor perspective, Duke Energy and DE Carolinas enjoy strong credit ratings with stable outlooks from the agencies. Our credit metrics, however, are low for our ratings and, as evidenced by the various ratings agency and analyst reports attached as exhibits to this testimony, the agencies have directly expressed concern about CCR/Coal ash cost recovery in North Carolina, specifically citing the Commission's recent Dominion Energy North Carolina rate case order. If similar treatment is given to DE Carolinas (which has a dramatically larger spend on coal ash basin closures), it may become very difficult to maintain our current credit ratings.

Q. INTEREST RATES ARE CURRENTLY LOW. DOES A LOWER CREDIT RATING REALLY MATTER?

A. Witness Newlin discusses this issue in more detail in his testimony but even though interest rates have been at historically low rates, a lower credit rating would still result in higher financing costs for DE Carolinas. And although the increment in cost is currently relatively small, that has not always been the case. The difference could be more significant in periods of higher rates or increased market volatility.

Q. WHAT IS THE EQUITY INVESTOR VIEWPOINT?

A. Price to earnings (P/E) ratio, which is a company's stock price divided by its estimated earnings per share, is the most relevant measure in our industry of how attractive a stock is to investors compared to peers. As is reflected on Young Rebuttal Exhibit 2 attached hereto, as of February 21, 2020, Duke Energy's P/E on 2021 estimated earnings was 18.9x, compared to our regulated peer companies P/E ratio average of 22.2x. Therefore, Duke Energy is trading at a 15% discount to peer companies, representing approximately $10 billion in equity market capitalization. Note that while a portion of this discount can be attributed to Duke Energy's approximate $2 billion investment in Atlantic Coast Pipeline, we believe the majority of the discount is attributable to perceived regulatory risks in the Carolinas. Furthermore, as is also reflected on Young

Rebuttal Exhibit 2, Duke Energy's earnings growth rate is near the bottom of our peer group. This makes us a less attractive investment for potential equity investors than other similar companies with higher earnings growth rates and P/E ratios. When a utility company's stock underperforms, it is an indicator that equity investors view it as riskier than its peers, thus making equity investors more likely to invest in neighboring states with peers that trade at higher multiples.

As described further by Company witness De May, we are entering a critical period in the development of the State of North Carolina's energy and regulatory policy, which will require a strong utility in order to attract investors to fund the significant investments needed for our customers.

Q. DO YOU HAVE ANY DIRECT EVIDENCE THAT DUKE ENERGY'S REGULATORY ENVIRONMENT IS CAUSING CONCERN IN THE INVESTMENT COMMUNITY?

A. Yes. I deal directly with stock analysts and institutional investors frequently and concerns over our ability to fully and efficiently recover our utility investments from customers, including investments in grid modernization, storm cost recovery, and coal ash basin closures, are a frequent topic of discussion. Some of these concerns spill over into worries about the ability of the Company to receive favorable regulatory treatment with respect to recovery of these costs and those concerns are starting to be reflected regularly in equity and credit analyst reports.

Q. CAN YOU PROVIDE SOME SPECIFIC EXAMPLES OF THIS PHENOMENON?

A. Yes. Moody's, in its October 13, 2019 opinion on Duke Energy, attached hereto as Young Rebuttal Exhibit 3, commented on the circumstances that could lead to a ratings downgrade to include:

"A deterioration in the credit supportiveness or emergence of a more contentious regulatory relationship which negatively impacts cash flows or the timeliness of cost recovery, particularly with regards to coal ash remediation recovery in North Carolina." Moody's, in its October 31, 2019 opinion on DE Carolinas, attached hereto as Young Rebuttal Exhibit 4, highlights credit challenges as including "[i]ncreasing regulatory uncertainty surrounding coal ash remediation spending" and factors that could lead to a downgrade include "[a] decline in the credit supportiveness of Duke Carolina's regulatory relationships in North or South Carolina, particularly with regards to coal ash remediation recovery in North Carolina." This same report goes on to state that "[h]istorically strong financial coverage metrics are being impacted by storm activity, coal ash remediation spend rate and delayed rate relief" and indicates that "[g]oing forward, lag in the recovery of ongoing coal ash remediation spending and grid modernization will maintain negative pressure on financial credit metrics." Similar statements have been made by other agencies/analysts such as Bank of America Securities, which in a January 13, 2020 report, attached hereto as Young Rebuttal Exhibit 5, noted Duke Energy's trading discount from its peers and expressed concerns over coal ash recovery and uncertainty over potentially punitive recovery treatment for those costs. These same concerns have also been reflected in recent equity analyst reports such as those of Wolfe Research and Fleishman Daily attached hereto as Young Rebuttal Exhibits 6 and 7.

Q. DOES DUKE ENERGY VIEW THE REGULATORY TREATMENT IT HAS HISTORICALLY RECEIVED FROM THE NORTH CAROLINA UTILITIES COMMISSION NEGATIVELY?

A. No. The prevailing opinion in the financial markets for regulated utilities for some time has been that the NCUC has historically been a supportive and stable public service commission and we agree with that assessment. Under that regulatory regimen, we have been confident of our ability to operate successfully and fulfill our mission to provide safe and reliable utility service at reasonable rates. My testimony in this case does not challenge that conclusion but it does alert the Commission to some storm clouds on the horizon involving perceptions of material risk related to DE Carolinas' ability to recover significant and ongoing investments, including financing costs, in coal ash basin closure and grid modernization that are worrying investors and lenders.

Q. ARE YOU SAYING THAT INVESTORS VIEW THE REGULATORY TREATMENT DE CAROLINAS HAS RECEIVED FROM THE NCUC NEGATIVELY?

A. No. I am saying that investors are concerned with the Company's significant amount of investment at risk for recovery in this and other NCUC dockets. This concern, and the attendant uncertainty over when and how DE Carolinas will be permitted to earn on these investments is creating financial risk for the Company, which could result in diminished credit ratings for the Company and higher debt and equity costs for both the Company and customers. This concern is significant enough that it is being openly discussed in analyst reports and, accordingly, we thought it important enough to bring it to the Commission's attention: (i) so the Commission would be aware of this phenomenon as it considers the appropriate resolution of this case; and (ii) because we are faced with intervenor proposals (and recent Commission precedent) in this case that, if adopted, would significantly exacerbate the financial concerns I have described above and potentially harm both DE Carolinas and its customers.

Q. COULD YOU DESCRIBE WHAT DE CAROLINAS' GOALS ARE COMING OUT OF THIS RATE CASE?

A. Yes. Duke Energy is extremely proud of our long-time record of providing exemplary electric service to customers. To fund the significant capital investments required to maintain this level of electric service, we must be able to attract debt and equity capital in the same financial markets utilized by peers and by other non-regulated businesses. If our access to the capital markets is unduly impaired, then our ability to provide customers with safe and reliable electric service at reasonable rates is jeopardized. Intervenor's proposals, if adopted, would do just this to the detriment of customers over the long-term. We request that the Commission approve a reasonable capital structure reflecting the actual capitalization of the Company and an ROE that allows us to compete with our peers for capital and is reflective of the value and quality of the service we provide to our customers. We would also hope to mitigate the impacts of lag associated with needed investments in modernizing our grid for the benefit of customers. Finally, we would hope to receive treatment with regard to the recovery of coal ash basin closure costs consistent with the Commission's decision in the prior DE Carolinas rate case, which was positively received by the ratings agencies and which recognizes the very real carrying costs associated with closing those utility assets.

As witness De May states, we are at a cross roads in North Carolina regarding how we will dramatically reduce our carbon emissions, strengthen our grid, accommodate significantly more renewable and distributed energy resources on to our system, continue to meet the growth in our state, and keep rates low. A financially healthy and strong electric utility is critical to the success of our state in achieving these goals.

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

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Jane L. McManeus and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC, testifying on behalf of Duke Energy Carolinas ("DE Carolinas" or the "Company").

Q. WHAT ARE YOUR RESPONSIBILITIES IN THIS ROLE?

A. I have responsibility for certain rider filings for both Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, including the Fuel Cost Adjustment Riders, the Renewable Energy Portfolio Standard Riders, and the Joint Agency Asset Rider.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Wake Forest University with a Bachelor of Science degree in Accountancy and received a Master of Business Administration degree from the McColl Graduate School of Business at Queens University of Charlotte. I am a certified public accountant licensed in the state of North Carolina and am a member of the Southeastern Electric Exchange Rates and Regulation Section. I began my career with Duke Power Company ("Duke Power") (now known as Duke Energy Carolinas) in 1979 as a staff accountant and have held a variety of positions in the finance organizations. From 1994 until 1999, I served in financial planning and analysis positions within the electric transmission area of Duke Power. I was named Director, Asset Accounting for Duke Power in 1999 and appointed to Assistant Controller in 2001. As Assistant Controller, I was responsible for coordinating Duke Power's operational and strategic plans, including development of the annual budget and performing special studies. I joined the Rates Department in 2003 as Director, Rate Design and Analysis. In April 2006, I became Director, Regulatory Accounting and Filings, leading the regulatory accounting, cost of service, regulatory filings, and revenue analysis functions for DE Carolinas. I began my current position in the Rates Department in October 2006.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION RELATING TO YOUR CURRENT RESPONSIBILITIES?

A. Yes. I have testified before this Commission regarding DE Carolinas' previous general rate case proceedings in Docket Nos. E-7, Sub 1146 (the "2017 Rate Case"); E-7, Sub 1026 (the "2013 Rate Case"); E-7, Sub 989; and E-7, Sub 909. I have regularly testified before this Commission in rider proceedings, most recently including Docket Nos. E-7, Subs 934, 936, 941 and 979.

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

A. The purpose of my testimony is to discuss the results of DE Carolinas' operations under present rates based on an adjusted historical Test Period using the twelve-month period ended December 31, 2018 (the "Test Period"). I discuss the additional revenue required as a result of the cost of service based on the pro forma costs in the Test Period. I discuss several pro forma adjustments to the Company's Test Period operating expenses and rate base. I request permission to defer as a regulatory asset certain severance costs incurred during the Test Period to be amortized over a 3-year period. I explain the Company's request for approval to defer certain costs related to investments in the transmission and distribution grid under the Company's Grid Improvement Plan. I also request authorization to continue deferring costs related to compliance with coal ash regulations beyond the proposed January 31, 2020 cut-off in this case. In addition, I discuss the inclusion of the costs in this request related to a new solar generation facility owned by DE Carolinas, and the Company's proposal for recovery of costs related to the recent sale of certain hydroelectric generation facilities. Finally, I propose a rider to refund federal and state income tax related amounts owed to customers as a result of the 2017 Tax Cuts and Jobs Act and recent reductions to North Carolina state income tax rates.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. I have included four exhibits. McManeus Exhibit 1 sets forth the operating results under current and proposed base rates. McManeus Exhibit 2 summarizes the total revenue adjustments proposed in this proceeding, including the proposed increase in base rates and the reduction in revenues reflected in the proposed rider. McManeus Exhibit 3 supports the cost of recently constructed solar facilities for which the Company requests recovery in this proceeding. McManeus Exhibit 4 illustrates the proposed rider to refund Excess Deferred Income Taxes (EDIT) to customers.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. McManeus Exhibits 1 through 4 were prepared under my supervision.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN THE APPLICATION?

A. Yes. I provided the pro forma adjustment work papers included in Item 10 of the Form E-1, filed with the Company's Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets (the "Application").

II. DETERMINING THE REVENUE REQUIREMENT

Q. WHAT IS THE REVENUE REQUIREMENT AND HOW DID DE CAROLINAS CALCULATE IT?

A. The revenue requirement represents the annual revenues necessary for the Company to recover its operating expenses (including depreciation and taxes) and provide its investors with a fair rate of return on the investment in rate base. DE Carolinas determined its operating costs by identifying depreciation and amortization expense, operations and maintenance expense ("O&M"), fuel expense, taxes, and other expenses charged to utility operations and recorded in its accounting records for the Test Period. The amount of rate base is determined by adding the year-end balances in the Company's accounting records of plant in service, accumulated depreciation, materials and supplies (including fuel inventory) and components of working capital less deferred taxes and operating reserves, including certain regulatory assets and liabilities. Next, a cost of service study is prepared that allocates and assigns these actual Company operating costs and rate base amounts to determine the per book cost for providing electric service to the Company's North Carolina retail operations. The cost of service studies, filed as Item 45 of DE Carolinas' Form E-1, were reviewed by Witness Hager and she describes the allocation process and methodologies used by the Company in this proceeding within her testimony.

Following the cost of service study, the actual Test Period expense and rate base levels, as allocated to the North Carolina retail operations, were adjusted for known and measurable changes, as described below and in the testimony of Witnesses Pirro and McGee. DE Carolinas made certain accounting and pro forma adjustments to actual operating income and rate base for the Test Period to reflect known and measurable changes to (i) normalize for abnormal events; (ii) annualize part year recurring effects to a full year effect; and (iii) show actual changes in costs, revenues or the cost of the Company's property used and useful, or to be used and useful within a reasonable time after the Test Period, in providing service.

After the determination of operating expenses and rate base for the Company's North Carolina retail operations, rate base is split between the Company's debt investors and equity investors using the Company's proposed capital structure of 53 percent equity and 47 percent debt. Then, the annual cost of debt is calculated. The income available for the Company's equity investors is determined by subtracting the cost of debt from the operating income produced by the current revenues received from North Carolina retail customers less operating expenses. Finally, the required revenue increase necessary to produce the requested equity return on the amount of the equity invested in rate base is determined.

McManeus Exhibit 1 sets forth the rate base, operating revenues, operating expenses, and operating income the Company earned during the

Test Period and the adjusted amounts the Company supports for use in calculating its proposed revenue requirement. In my Exhibit 1, I have indicated by asterisk the items the Company plans to update in this proceeding.

III. RESULTS OF OPERATIONS UNDER EXISTING AND PROPOSED RATES

Q. PLEASE DESCRIBE MCMANEUS EXHIBIT 1 TO YOUR TESTIMONY.

A. McManeus Exhibit 1 sets forth the operating results and data required by Commission Rule R1-17(b) regarding operating income, calculation of additional revenue requirement, accounting adjustments, and rate base information. The operating results are based on the Test Period noted above, using the twelve months ended December 31, 2018, with appropriate adjustments. This information is also shown on Pages 1 through 4d of Exhibit C of the Company's Application.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 1 OF MCMANEUS EXHIBIT 1 ENTITLED "OPERATING INCOME FROM ELECTRIC OPERATIONS."

A. Page 1 summarizes the Company's operating income from electric operations for the Test Period both for total Company operations and North Carolina retail operations before the necessary accounting adjustments. It also shows the Company's operating income from electric operations for North Carolina retail operations after the necessary accounting adjustments and the rate of return on North Carolina retail rate base the Company would earn in the Test Period after reflecting those adjustments.

Column 1 and 2 set forth the actual operating revenues, expenses and rate base from the per book cost of service study (Form E-1, Item 45a) for the Company and for its North Carolina retail jurisdiction, respectively.

Column 3 summarizes the accounting adjustments allocated to North Carolina retail operations necessary to reflect a representative level of operating income and rate base based on known changes in costs. These adjustments are shown on McManeus Exhibit 1, Page 3 and are explained later in my testimony.

Column 4 shows adjusted North Carolina retail operations.

Column 5, Line 1 shows the additional base rate revenue requested in this proceeding of $445.3 million. This is the increase in revenues justified as necessary to cover the Company's cost of service, including a rate of return on members' equity of 10.30 percent as discussed in the testimony of Witnesses Newlin and Hevert. Column 5 also shows the effect of the revenue increase on the North Carolina Utilities Commission ("NCUC") regulatory fee, uncollectibles expense, income taxes, and cash working capital.

Column 6, Line 11 shows adjusted operating income after the proposed increase in revenues. Column 6, Line 12 shows the adjusted retail rate base. Dividing operating income by rate base produces the 7.58

percent overall rate of return that the Company is justifying in this case, as shown in Column 6, Line 13.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 2 OF MCMANEUS EXHIBIT 1 ENTITLED "CALCULATION OF ADDITIONAL REVENUE REQUIREMENT."

A. Page 2 sets forth the calculation of the additional revenue requirement necessary to produce a 10.30 percent rate of return on members' equity using the format required by Commission Rule R1-17(b)(9)e. To develop this figure, the North Carolina retail rate base was allocated to its capital source components of long-term debt and members' equity. This allocation was based on the capitalization ratios of 47 percent long-term debt and 53 percent members' equity. Witness Newlin discusses and supports these ratios in his testimony.

The amount of operating income needed to cover interest applicable to North Carolina retail rate base was computed using the embedded cost of long-term debt rate. This amount is shown in Columns 4 and 7 on Line 1. Operating income needed to cover interest, shown in Columns 5 and 8 on Line 1, was deducted from total operating income shown in Column 5 on Line 3, to derive operating income remaining for members' equity at present rates as shown in Column 5 on Line 2.

Applying the 10.30 percent rate of return on members' equity to that portion of the North Carolina retail rate base financed by members' equity, shown in Column 6, Line 2 produces the operating income requirement for members' equity as shown in Column 8, Line 2.

The total operating income requirement shown in Column 8, Line 3 is the sum of the requirements for long-term debt and members' equity. Comparing the operating income requirement to the operating income before the proposed increase in Column 5, Line 3 results in the additional operating income requirement shown in Column 8, Line 5. To realize this additional operating income, the Company must also collect in revenues the increase for the NCUC regulatory fee (less the uncollectible rate) at a rate of 0.12967 percent, uncollectibles expense at a rate of 0.2501 percent, state and federal income taxes at a composite rate of 23.3503 percent, and the return on cash working capital requirements. The additional operating income requirement and the additional taxes and fees produces an additional revenue requirement of $445.3 million.

Q. PLEASE EXPLAIN THE PURPOSE OF MCMANEUS EXHIBIT 2.

A. McManeus Exhibit 2 summarizes the total change in revenue requirement requested in this proceeding. As stated above, the requested increase in revenues from base rates is $445.3 million. In addition to increased revenue from tariff rates for electric service, the Company requests that customer rates be reduced by $154.6 million, through an EDIT Rider, for amounts owed to customers related to EDIT. This rider is discussed in detail later in my testimony. As shown on McManeus Exhibit 2, the total proposed increase in revenue is $290.8 million.

Q. HOW IS THIS ADDITIONAL REVENUE REQUIREMENT ALLOCATED AMONG THE CLASSES AND USED TO DEVELOP THE TARGET REVENUE REQUIREMENT FOR RATE DESIGN?

A. Witness Pirro's Exhibit 4 shows how the additional revenue requirement is spread among the classes and how the target revenue requirements for rate design are established.

IV. ACCOUNTING AND PRO FORMA ADJUSTMENTS

Q. PLEASE EXPLAIN PAGE 3 OF MCMANEUS EXHIBIT 1 CAPTIONED "DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL."

A. Page 3 sets forth the individual accounting and pro forma adjustments to operating revenues, expenses and rate base, including the income tax effects for North Carolina retail electric operations, that were shown in total on Page 1 of McManeus Exhibit 1 in Column 3. The totals of the columns shown on Line 35 of Page 3 are the amounts carried forward to Column 3 of Page 1 of McManeus Exhibit 1.

Q. PLEASE LIST THESE ACCOUNTING AND PRO FORMA ADJUSTMENTS.

A. The accounting and pro forma adjustments that were made by the Company are as follows (the chart below indicates which witness is sponsoring each adjustment):

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES (Page 3 of McManeus Exhibit 1)		
Line No.	**Adjustment Title**	**Witness**
1	Annualize retail revenues for current rates	Pirro
2	Update fuel costs to proposed rate	McGee
3	Normalize for weather	McManeus
4	Annualize revenues for customer growth	Pirro
5	Eliminate unbilled revenues	McManeus
6	Adjust for costs recovered through non-fuel riders	McManeus
7	Adjust O&M for executive compensation	McManeus
8	Annualize depreciation on year end plant balances	McManeus
9	Annualize property taxes on year end plant balances	McManeus
10	Adjust for post-test year additions to plant in service	McManeus
11	Amortize deferred environmental costs	McManeus
12	Annualize O&M non-labor expenses	McManeus
13	Normalize O&M labor expenses	McManeus
14	Update benefits costs	McManeus
15	Levelize nuclear refueling outage costs	McManeus
16	Amortize rate case costs	McManeus
17	Adjust aviation expenses	McManeus
18	Adjust for approved regulatory assets and liabilities	McManeus
19	Adjust for merger related costs	McManeus
20	Amortize severance costs	McManeus
21	Adjust for NC income tax rate change	McManeus
22	Synchronize interest expense with end of period rate base	McManeus
23	Adjust cash working capital for present revenue annualized and proposed revenue	McManeus
24	Adjust coal inventory	McManeus

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES (Page 3 of McManeus Exhibit 1)		
Line No.	**Adjustment Title**	**Witness**
25	Adjust credit card fees	McManeus
26	Adjust for new depreciation rates	McManeus
27	Adjust vegetation management expenses	McManeus
28	Adjust reserve for end of life nuclear costs	McManeus
29	Update deferred balance and amortize storm costs	McManeus
30	Adjust other revenue	Pirro
31	Adjust for change in NCUC regulatory fee	McManeus
32	Adjust for hydro stations sale	McManeus

Q. IN CALCULATING THE TOTAL REVENUE REQUIREMENT IN THIS PROCEEDING, DID YOU REVIEW EACH OF THE ACCOUNTING AND PRO FORMA ADJUSTMENTS?

A. Yes. I did.

Q. IN YOUR OPINION, DO THESE ACCOUNTING AND PRO FORMA ADJUSTMENTS REFLECT KNOWN AND MEASURABLE CHANGES TO THE COMPANY'S TEST PERIOD OPERATING EXPENSES, REVENUES, AND RATE BASE?

A. Yes. The adjustments set forth on Page 3 of McManeus Exhibit 1, as more fully supported below and in the testimonies of Witnesses McGee and Pirro, reflect known and measurable changes to the Company's Test Period revenues, expenses, and rate base.

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENTS YOU ARE SUPPORTING.

A. The following are descriptions of the pro forma adjustments:

1. Annualize retail revenues for current rates

This adjustment annualizes revenue based on the base rates in effect at the time of the application. In addition, the adjustment revises the fuel component of base rates. The adjustment removes Test Period revenues recovered through the Demand Side Management/Energy Efficiency ("DSM/EE") Rider, REPS Rider, BPM Prospective Rider and BPM True-up Rider ('the BPM Riders"), Existing DSM Program Rider, Job Retention Recovery Rider, EDIT-1 Rider, Coal Inventory Rider, and fuel Experience Modification Factor ("EMF"). This adjustment also includes the removal of the provision for rate refund recorded in the test period related to the federal tax rate change. This adjustment to revenues is discussed in more detail in the testimony of Witness Pirro.

2. Update fuel costs to proposed rate

This adjustment adjusts fuel clause expense during the Test Period to match the fuel clause revenues included in Adjustment Line 1. By matching the expenses to the revenue, the adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related expenses that are recoverable through the fuel clause. This adjustment is described in more detail in Witness McGee's testimony.

3. Normalize for weather

This adjustment adjusts revenue to normalize for the impacts of weather. The kWh weather adjustment was developed based on a 30-year history of weather. This kWh adjustment was then multiplied by an average rate for each class to derive the adjustment to revenue. The average rate is based on annualized Test Period revenues at current base rates, therefore excluding the rates for the riders identified in Adjustment 1. However, since the rate includes the base fuel rate proposed in this case, an adjustment is also made to fuel expense to reflect the change in kWh due to weather adjustment.

4. Annualize revenues for customer growth

This adjustment annualizes revenue to reflect expected changes in Test Period kWh sales related to changes in number of customers and usage per customer, using actual and estimated 2019 data and weather-normalized values. The net kWh adjustment was then multiplied by an average rate for each class to derive the adjustment to revenue. The average rate is based on annualized Test Period revenues at current base rates, therefore excluding the rates for the riders identified in Adjustment 1. However, since the rate includes the base fuel rate proposed in this case, an adjustment is also made to fuel expense to reflect the annualized change in kWh. This adjustment is described in more detail in Witness Pirro’s testimony.

5. Eliminate unbilled revenues

This adjustment eliminates unbilled revenue and related taxes recorded by the Company in the Test Period.

6. Adjust for costs recovered through non-fuel riders

This adjustment removes expense and rate base items recovered through the Company's non-fuel riders. The revenues, expenses and rate base items, if applicable, in each of these riders are reviewed each year in annual rider proceedings and should not impact the increase requested in this proceeding. Any deferred revenues related to these riders are also removed in this adjustment.

7. Adjust O&M for executive compensation

This adjustment removes 50 percent of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DE Carolinas in the Test Period. While the Company believes these costs are reasonable, prudent and appropriate to recover from customers, we have, for purposes of this case, made an adjustment to this item.

8. Annualize depreciation on year end plant balances

This adjustment reflects the annualization of depreciation expense using the current depreciation rates applied to the end of the Test Period level of plant in service. During the Test Period, the Company recorded depreciation for plant additions from the point in time when they went into service. This adjustment annualizes depreciation expenses to reflect a full year level of depreciation on plant in service as of the end of the Test

Period using the depreciation rates that were in effect by the end of the Test Period. Amounts for changes in solar depreciation expense included in this adjustment exclude the portion of costs expected to be recovered through the REPS Rider. Amounts for changes in catalyst depreciation expense are excluded from this adjustment due to catalyst depreciation expense being recovered through the Fuel Clause.

9. Annualize property taxes on year end plant balances

This adjustment annualizes Test Period property taxes on plant in service at December 31, 2018. Property taxes expensed in calendar year 2018 were assessed based on property balances at the end of 2017. Likewise, property taxes to be expensed in calendar year 2019 will be assessed based on property balances at the end of 2018. This adjustment increases property tax expense in the Test Period to reflect an annual level of expense for property taxes based on the end of the Test Period level of plant investment.

10. Adjust for post-test year additions to plant in service

This adjustment increases operating expenses and rate base for changes in plant, depreciation expense, and accumulated depreciation the Company has incurred and will incur from the end of the Test Period through January 31, 2020. Amounts for changes in solar plant, depreciation expense, and accumulated depreciation included in this adjustment exclude the portion of costs expected to be recovered through the REPS

Rider. Witnesses Capps, Immel, Schneider and Oliver discuss plant additions in their testimonies.

11. Amortize deferred environmental costs

In the 2017 Rate Case, the Commission granted the Company authority to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements as it relates to Coal Combustion Residuals ("CCRs" or "coal ash"). The nature of these costs is described in more detail in Witnesses Bednarcik and Immel's testimony. Most of the deferred compliance costs are related to ash basin closure and are subject to asset retirement obligation ("ARO") accounting per Generally Accepted Accounting Principles ("GAAP"). In addition, a portion of the deferred amounts are related to the continued operation of the active plants and are not subject to ARO accounting. These deferred amounts are revenue requirements related to capitalized plant in service amounts. No fines, penalties, or costs of which DE Carolinas has agreed to forego recovery are included in the deferral. This adjustment amortizes the deferred costs over a 5-year period. The compliance costs are based on actuals as of the end of the Test Period plus a projection through January 31, 2020. Over the 5-year amortization period, the annual amortization expense is $96.3 million, including regulatory fee impacts. When added together with the net of tax return on the unamortized balance of $27.3 million, the total revenue requirement requested in this case for deferred coal ash pond closure costs is $123.6

million. The Company requests Commission authorization to continue to defer this type of environmental cost beyond the January 2020 cutoff period, for cost recovery consideration in a future rate case.

12. Annualize O&M non-labor expenses

This adjustment annualizes certain Test Period operating and maintenance expenses to reflect the change in unit costs that occurred during this period. Operating and maintenance costs addressed in other adjustments are excluded from this adjustment. The excluded costs include fuel, purchased power, non-fuel rider costs, nuclear refueling outage costs, aviation expenses, atypical severance costs, vegetation management expenses, the NCUC regulatory fee, rate case amortizations, outside tax services, expiring amortizations, merger related costs, hydro sale related costs, and labor costs.

13. Normalize O&M labor expenses

This adjustment adjusts the wages and salaries, related employee benefits, and changes in related payroll taxes to reflect annual levels of costs as of June 30, 2019. This adjustment also restates variable short and long term pay to the target level.

14. Update benefits costs

This adjustment updates the Test Period cost of labor-related benefits to match the result of an updated study performed by the Company's consultants.

15. Levelize nuclear refueling outage costs

In the Company's 2013 Rate Case, the Commission approved an accounting mechanism that levelized certain costs related to nuclear refueling outages. Consistent with the 2017 Rate Case, this adjustment annualizes the amortization expense related to this mechanism incurred during the Test Period to the latest known and measurable level experienced through the capital cutoff period.

16. Amortize rate case costs

This adjustment amortizes the incremental rate case costs incurred for this docket over a 5-year period.

17. Adjust aviation expenses

This adjustment removes from expense 50% of certain corporate related aviation expenses incurred in the Test Period.

18. Adjust for approved regulatory assets and liabilities

This adjustment removes from Test Period costs the amortization of various regulatory assets or liabilities that have been approved by the Commission in previous general rate case proceedings. The amortization period for items removed will expire before proposed new rates are effective, and thus should not be included in Test Period expenses on which new rates are based. The adjustment also annualizes the Test Period amortizations that were approved in the 2017 Rate Case.

19. Adjust for merger related costs

This adjustment removes the impact of costs related to the Piedmont and Progress mergers included in the Test Period, as adjusted by other proformas.

20. Amortize severance costs

This adjustment removes atypical severance and retention costs included in the Test Period. The Company is also requesting permission in its Application to establish a regulatory asset to defer a North Carolina retail amount of $69.2 million of severance costs, and to amortize the regulatory asset over a 3-year period.

21. Adjust for NC income tax rate change

This adjustment adjusts current and deferred income tax expense to reflect the reduction in the North Carolina income tax rate from 3 percent to 2.5 percent effective January 1, 2019.

22. Synchronize interest expense with end of period rate base

This adjustment adjusts income taxes for the tax effect of the annualization of interest expense reflected in the pro forma cost of service.

23. Adjust cash working capital for present revenue annualized and proposed revenue

This adjustment adjusts cash working capital to incorporate the impact of the other pro forma adjustments. It also calculates the additional cash working capital required due to the proposed increase in rates. The adjustment is in accordance with the Commission's March 21, 2016 order in Docket No. M-100 Sub 137, and is shown on Line 2, Columns 3 and 5, of McManeus Exhibit 1, Page 4d.

24. Adjust coal inventory

This adjustment increases the Company's actual coal inventory at the end of the Test Period to reflect a targeted 35-day full load burn for each of the coal generating plants. This change in coal inventory for the North Carolina retail jurisdiction is shown on McManeus Exhibit 1, Page 4c, Line 1, Column 3.

25. Adjust for credit card fees

This adjustment increases operating and maintenance expenses to include fees the Company incurs related to acceptance of credit card payments. As described in the testimony of Witness Henning, the Company is proposing to implement a transaction fee-free payment program for residential customers. The Company proposes to recover the cost of the program from all customers.

26. Adjust for new depreciation rates

This adjustment adjusts the annualized depreciation expense to reflect the new depreciation rates based on the updated depreciation study prepared by Gannett Fleming and discussed and supported by Witness Spanos. The proposed new depreciation rates reflect revised life spans for certain coal plants, as noted by Witness Spanos. Implementing the new depreciation rates will result in an increase to depreciation expense of approximately

$108.5 million on a system basis, or $72.1 million on a North Carolina retail basis. The adjustment also increases depreciation reserves by an annual amount of the depreciation expense adjustment.

27. Adjust vegetation management expenses

This adjustment increases operating and maintenance expense in the Test Year to reflect known contract rate increases that took effect in 2019, which are applicable to completing the target trim mileage in the Company's on-going vegetation management program's 5/7/9 plan.

28. Adjust reserve for end of life nuclear costs

In the Company's 2013 Rate Case, DE Carolinas established reserves for end-of-life costs associated with nuclear materials and supplies and with nuclear fuel. This adjustment adjusts the Test Period amortization expense, reserve and related taxes to reflect updated estimates of the end-of-life costs.

29. Amortize deferred storm costs

This adjustment reflects an eight-year amortization of deferred costs related to incremental storm damage expenses incurred due to Hurricanes Florence and Michael, and winter storm Diego. These costs are the subject of the Company's Petition for An Accounting Order filed in Docket No. E-7, Sub 1187, pending before the Commission, and for which the Company is requesting consolidation with this proceeding. The Company is proposing to recover the incremental cost in excess of normal storm expenses, including a return on the unrecovered balance. The Company proposes to begin amortization of the costs when proposed new base rates become effective, and to include a return on the deferred balance through the end of the proposed amortization period. Over the 8-year amortization period, the North Carolina retail annual amortization expense is $24.3 million, including regulatory fee impacts. When added together with the net of tax return on the unamortized balance of $12.0 million, the total revenue requirement requested in this case for deferred incremental storm damage expenses is $36.3 million.

30. Adjust other revenues

This adjustment reflects proposed reductions to customer fees related to connection, reconnection, and returned payments, as described by Witness Pirro in his direct testimony.

31. Adjust for change in NCUC regulatory fee

This adjustment annualizes the Test Period regulatory fee at the current rate of 0.13 percent.

32. Adjust for sale of hydro stations

This adjustment removes Test Period operating expenses and rate base amounts related to five hydro stations sold August 16, 2019. The sale of the facilities and the transfer of the related certificates of convenience and necessity were approved by the Commission in Docket Nos. E-7, Sub 1181; SP-12478, Sub 0; and SP-12479, Sub 0. In addition, the Commission approved the establishment of a regulatory asset for the estimated loss on disposition of the facilities. Accordingly, this adjustment also includes amortization of the estimated loss on the sale over a 7-year period. This period was selected to closely align the revenue requirement amount associated with the loss on the sale to the revenue requirement amount associated with ownership of the facilities.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGES 4 THROUGH 4d OF MCMANEUS EXHIBIT 1.

A**.** Page 4 shows total Company and North Carolina retail components of original cost rate base. The total Company amounts and North Carolina retail components were taken from the Company's Cost of Service Study as of December 31, 2018.

Pages 4a, 4b, 4c, and 4d are details of components making up original cost rate base as of December 31, 2018 adjusted for known and measurable changes. On each of these four pages, Column 1 shows the total Company per book amounts at December 31, 2018; Column 2 reflects the amount for North Carolina retail electric operations; Column 3 sets forth the accounting adjustments allocated to North Carolina retail operations; and Column 4 reflects the North Carolina retail amounts including adjustments.

Page 4a is a summary of the Company's investment in electric plant in service as of December 31, 2018 by functional classification. Page 4b details accumulated depreciation and amortization for each of the classes of electric plant in service. The depreciation rates for each class of property are shown at the bottom of the page on Lines 8 through 15.

These depreciation rates are supported by Witness Spanos. Page 4c is a summary of the Company's investment in materials and supplies as of December 31, 2018 included in rate base. Page 4d reflects the working capital investment included in rate base.

V. UTILITY-OWNED SOLAR FACILITIES

Q. PLEASE DISCUSS THE CONDITIONS AFFECTING COST RECOVERY OF THE COMPANY'S NEW SOLAR FACILITY?

A. Since its last general rate case, DE Carolinas has placed in service one utility scale solar facility, Woodleaf Solar ("Woodleaf"). A certificate of Public Convenience & Necessity ("CPCN") was received for this facility in Docket No. E-7, Sub 1101. The Commission's order in that docket included several conditions. One condition requires DE Carolinas, in REPS Rider and general rate case proceedings, to itemize the actual monetization of certain tax benefits within its calculation of the levelized revenue requirement for each facility. Another condition requires that the incremental costs recovered through the REPS Rider be capped, and that the additional revenue requirements that exceed avoided costs and the REPS cost cap will be recovered only in base rates, based on the reasonableness and prudence of the additional costs. In addition, it is required that the costs recovered through base rates should be allocated among jurisdictions and customer classes in the same manner as any other plant in DE Carolinas' generation portfolio, and that the reasonableness and prudence of DE Carolinas' costs associated with the facilities and the methodology for recovering those costs should be addressed in future REPS Rider and general rate case proceedings. Finally, the Commission requires DE Carolinas to file a final cost accounting report within 180 days of the completion of construction of the projects.

Q. HAS THE COMPANY COMPLIED WITH THESE CONDITIONS?

A. Yes. In DE Carolinas' REPS Rider filing in Docket E-7, Sub 1191, the Company provided Williams Exhibit 7 incorporating the most current tax benefit monetization assumptions into the levelized revenue requirement shown for Woodleaf. Attached as McManeus Exhibit 3 is an update of the information previously included in Williams Exhibit 7, based on the revised costs filed in the June 20, 2019 cost accounting report.

Because Woodleaf was placed in service in late December 2018, before the end of the Test Period, Woodleaf costs are included in the Test Period amounts reflected in the cost of service studies and revenue requirement in this proceeding. The Company has excluded amounts that will be recovered through the REPS Rider. The amounts excluded represent the portion of project costs in excess of avoided cost but within the agreed upon REPS cap associated with these facilities. The Company has allocated the costs included in its proposed revenue requirements in this proceeding in the manner that it allocates the cost of other generating plants.

Q. WHAT IS THE COMPANY'S POSITION REGARDING THE PRUDENCY AND REASONABLENESS OF THE ABOVE-DESCRIBED COSTS FOR WHICH THE COMPANY IS REQUESTING RECOVERY IN THIS PROCEEDING?

A. DE Carolinas considers the costs to be reasonable and prudently incurred. In its 2019 REPS Rider filing, the Company updated its assumptions regarding timing of realization of tax benefits and explained any differences between original assumptions and updated assumptions. In filed testimony the Company noted no change in the assumptions regarding MACRS depreciation and 80% property tax abatement. The Company reported that the realization of certain other tax benefits has been delayed beyond the dates originally assumed at the time of the CPCN filings. The delay is because the Company anticipates lacking sufficient taxable income against which it can take federal investment tax credit for several more years. This circumstance is directly related to tax law changes regarding federal bonus depreciation. Although federal bonus depreciation is not one of the tax benefits to which the Commission's conditions in its CPCN orders applies, nor does it apply to the Woodleaf facility, because of changes in federal tax law, several of the Company's assets qualify for bonus depreciation, thereby reducing the Company's taxable income. In addition, the reduction of the federal income tax rate and the elimination of the federal Section 199 deduction results in increased levelized revenue requirements related to the Woodleaf facility.

The reduction in income tax rates affects two components for the revenue requirement calculation: 1) the rate base amount is increased by the lower accumulated deferred income taxes associated with the facility; and 2) the income tax associated with the equity return is decreased. The net impact is a small increase in levelized revenue requirement. The completed project costs for Woodleaf are lower than originally estimated. As a result, the updated revenue requirement, based on actual project costs and updated tax benefit assumptions, is not materially different from the originally estimated revenue requirement, as shown on McManeus Exhibit 3.

Because the delay in realization of certain other tax benefits is the direct consequence of the extension of another federal tax benefit to the projects (federal bonus depreciation), and the impact of the change in federal tax rate and elimination of a federal tax deduction cannot be avoided, the Commission should conclude that the costs of the Woodleaf facility investment were reasonably and prudently incurred, and therefore eligible for recovery.

VI. EXCESS DEFERRED INCOME TAX ("EDIT") RIDER

Q. HOW HAS THE COMPANY ADJUSTED ITS RATES TO REFLECT THE TAX IMPACTS OF THE TAX CUTS AND JOBS ACT?

A. In its most recent general rate case in Docket No. E-7 Sub 1146, the Company adjusted its rates to reflect reduced income tax expense related to the reduction in federal income tax rate, from 35% to 21%, as provided in the Tax Cuts and Jobs Act ("Tax Act") which became law December 22, 2017. The rates approved by the Commission and implemented August 2018 were reduced to reflect lower federal income taxes. The lower federal tax rate continues to be reflected in proposed rates in this proceeding.

In its order in the 2017 Rate Case, the Commission also addressed the disposition of EDIT that resulted from the reduction in the federal income tax rate; ordering that the Company should maintain the EDIT in a regulatory liability account for three years or until its next general rate case, whichever is sooner. In compliance, in this proceeding, the Company is proposing a method of returning EDIT to its customers through a rider.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED EDIT RIDER.

A. In his direct testimony, Witness Panizza discusses in detail the implications of the Tax Act and North Carolina retail's share of the federal income tax amounts that are addressed in the EDIT Rider (also referred to as EDIT-2 in Rate Design exhibits). The Rider contains the following five categories of benefits for customers, of which the first three are discussed by Witness Panizza in his testimony:

1. Federal EDIT - Protected
2. Federal EDIT – Unprotected, PP&E related
3. Federal EDIT – Unprotected, non-PP&E related
4. Deferred revenue - Federal income tax
5. NC EDIT

<u>Federal EDIT – Protected, Unprotected PP&E related, and Unprotected, non-PP&E related</u>

At the end of 2018, the Company had a certain amount of Accumulated Deferred Income Taxes ("ADIT") on its balance sheet. These are income taxes the Company has expensed for accounting purposes and collected from customers, but will not need to pay the IRS until some point in the future. Because the Company has use of this cash for a period of time, until it must pay the IRS, the ADIT is included as a reduction to rate base and is a source of financing for investments used to benefit customers – poles, lines, generating plant, etc. With the change in the federal tax rate, the amount of income tax that the Company must pay the IRS in the future has been reduced, and must be remeasured. At the end of 2018, the Company calculated this reduction and the difference was reclassified from ADIT to EDIT, although both ADIT and EDIT remain components of rate base. Instead of having an obligation to pay the EDIT amount to the IRS in the future, the Company now has an obligation to refund it to customers. Within EDIT, there are three subcategories, as described by Company Witness John Panizza.

- Protected – These amounts are generally related to Property, Plant & Equipment ("PP&E") and there are specific IRS requirements mandating that this amount be returned to customers no more quickly than as prescribed by the IRS. The amortization period the Company is using for Protected EDIT is called the Average Rate Assumption Method ("ARAM") and results in a Year 1 amortization rate for this category of 2.53 percent. Also, as Witness Panizza notes, protected amounts ultimately become unprotected over time. As such, the Company estimated this amount and captured this transition from the Protected to Unprotected category on McManeus Exhibit 4, Page 1, Line 3.
- Unprotected PP&E related – These amounts are also related to PP&E but do not fall under the IRS guidelines for protected status. Because the Company would have paid these amounts to the IRS over the remaining life of the underlying property, the Company is proposing to return these amounts to customers over a 20-year period. As noted by Witness Panizza, this approach balances the customer and the Company's interests; minimizing customer rate volatility and addressing the Company's cash flow concerns.

- Unprotected non-PP&E related – These amounts are not related to property, plant and equipment, but are related to items such as regulatory assets and liabilities, and other balance sheet items. As noted by Witness Panizza, these items have an average life of approximately 7½ years. The Company is proposing to return these amounts to customers over a 5-year period. In addition, the Company has included in this category amounts transitioning from the Protected category to Unprotected status.

NC EDIT

Like the EDIT that results from the reduction in the federal corporate income tax rate, there are EDIT balances that resulted from the reduction in the North Carolina state corporate tax rate. In the 2017 Rate Case, the Commission approved a 4-year State EDIT rider to return EDIT resulting from reductions in state tax rate in prior years. The State EDIT rider currently in place does not include EDIT related to the reduction in North Carolina state corporate tax rate from 3% to 2.5% effective January 1, 2019. The Company is proposing to incorporate the refund of these new state EDIT in the EDIT rider proposed in this case, over a 5-year period.

Deferred Revenue

As directed in Docket No. M-100, Sub 148, the Company began deferring, effective January 1, 2018, the impact on customer rates of the reduction in the federal corporate income tax rate from 35% to 21%. Beginning August 1, 2018, new rates approved by the Commission in Docket No. E-

7, Sub 1146 reflected the lower federal tax rate. After August 1, deferral amounts are related to continuing accrual of returns on the deferral balance. McManeus Exhibit 4, Page 1, Line 8, shows the projected balance of this liability as of January 31, 2020. The Company proposes to refund this amount to customers over a 5-year period. The Company will continue to defer the impact from February 1, 2020 through the new rates effective date in this case. Those additional amounts are not being estimated now, but will be included in the Year 2 EDIT rider calculation.

Q. PLEASE EXPLAIN HOW THESE FIVE CATEGORIES OF BENEFITS WILL BE INCORPORATED INTO THE EDIT RIDER.

A. The proposed rider will include the annual amortization for each of these five categories of benefits. The North Carolina retail amounts can be seen on McManeus Exhibit 4, Page 1, Columns A through E. Since these EDIT amounts are a reduction in rate base, as these amounts are refunded to customers, rate base will increase. As such, the rider also calculates the adjustment to return on rate base related to the increase in rate base resulting from the refund of EDIT to customers. This is shown in McManeus Exhibit 4, Page 2, Column L. Column M shows the revenue requirement equal to the sum of the amortization and return. Column N shows the revenue requirement grossed up for NCUC regulatory fee and uncollectible expense. The amount in the Year 1 row on McManeus Exhibit 4, Page 2 of $154.6 million decrease is the rider amount that is being proposed in this case.

The Year 1 rider amounts are based on the balance of EDIT at December 31, 2018 as described by Witness Panizza, and are updated to reflect the expected balance at July 31, 2020, when the proposed rider is expected to be implemented. This projection will be further updated to reflect actual January 31, 2020 balances, as well as the latest ARAM rate, prior to the hearing.

Years 2 through 5 are shown for illustrative purposes. The actual rider amounts for those years may change based on several factors. First, if there are additional adjustments to any of the balances on Rows 1 through 5 of McManeus Exhibit 4, the annual amortization amounts will be recalculated to accommodate the change in balance.

A second factor that would impact the calculation of the rider beyond Year 1 is changes in the ARAM rate. The Company updates this rate annually and the most current rate most be used when establishing customer rates.

A third factor that would impact the calculation of the rider beyond Year 1 is the impact of future rate cases. In future rate cases, the EDIT balance in base rates shown in Column J and the rate of return used to calculate Column L of McManeus Exhibit 4, Page 2 would be updated based on what is approved in that case.

Finally, the retention factor used to calculate Column N will be updated to reflect any future changes in the license fee or public utility assessment fee rates as needed.

The Company proposes to file the rider amounts, along with the spread to the classes and derivation of the rate for each subsequent year, with the Commission annually in this docket by April 30, for rider rates effective July 1.

The Year 1 EDIT revenue requirement, shown in McManeus Exhibit 4, was provided to Witness Pirro who explains the derivation of the rider rate in his testimony. Witness Hager explains how the amounts were allocated to the customer classes in her testimony.

VII. PETITION FOR ACCOUNTING ORDER TO DEFER GRID IMPROVEMENT PLAN COSTS

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING RECOVERY OF COSTS RELATED TO GRID IMPROVEMENT PLAN INVESTMENTS?

A. The proposed new rates requested in this proceeding include recovery of Grid Improvement Plan expenditures that are included in the Test Period and any supplemental updates that may be made for post Test Period plant additions. In addition, the Company requests permission to defer costs related to its Grid Improvement Plan in a regulatory asset, for cost recovery consideration in future general rate cases. The Company requests authorization to begin deferring incremental costs not included in this case beginning January 1, 2020. The Grid Improvement Plan is a three-year plan spanning calendar years 2020 through 2022.

Q. WHAT SPECIFIC COSTS ARE REQUESTED TO BE DEFERRED?

A. Company Witness Oliver extensively discusses the Company's Grid Improvement Plan in his direct testimony. In Oliver Exhibit 4, a listing of specific Grid Improvement Plan programs is provided, including thirteen Distribution programs, three Transmission programs, and five Enterprise programs. The Company is requesting deferral of North Carolina retail's share of the following types of costs for these identified programs: depreciation of capital investments, return on capital investments (net of accumulated depreciation) at the Company's weighted average cost of capital, O&M expense related to the installation of equipment, property tax related to the capital investments, and a return of the balance of costs deferred at the Company's weighted average cost of capital.

Witness Oliver's direct testimony provides estimated amounts to be spent as part of the Grid Improvement Plan in the state of North Carolina. However, for purposes of determining amounts to be deferred for future cost recovery from North Carolina retail customers, consideration is given to the nature of the expenditures, *i.e.*, whether the expenditures are related to improvement of the distribution system, the transmission system, or communications systems. Distribution expenditures made to improve North Carolina distribution infrastructure would be fully assigned to North Carolina retail customers. However, expenditures made to improve transmission infrastructure benefits all retail and wholesale customers, thus an appropriate share would be allocated to North Carolina retail customers. Expenditures made to improve communications systems would similarly be allocated among both retail and wholesale customers.

Q. WHAT IS THE BASIS FOR THE COMPANY'S REQUEST FOR DEFERRAL?

A. The request meets the Commission's traditional test for deferral. As described by Witness Oliver, the expenditures to be made under the Grid Improvement Plan are not simple, regularly occurring, inconsequential investments, but rather, are major non-routine investments, that produce substantial customer benefits. Further, absent deferral the Company will experience a significant adverse earnings impact. The earnings degradation is expected to grow to over 100 basis points by 2022, the third year of the plan. These effects are material to the Company's financial standing and could adversely impact the Company's financial strength and flexibility, impairing reliable access to capital on reasonable terms. As noted by Witness Newlin, the Company's capital requirements for the next three years are projected to be approximately $9.1 billon.

Q. ARE THERE ADDITIONAL REASONS WHY THE COMMISSION SHOULD AUTHORIZE DEFERRAL OF THESE COSTS?

A. Yes. The Commission has consistently demonstrated that deferral is not a rigid concept, but can be flexibly applied to ensure that its fundamental mandate of ensuring that rates are just and reasonable, set in a manner that balances the interests of the Company and its customers.

In the 2017 Rate Case, the Commission noted that regulatory lag is always present in an integrated, investor-owned utility market such as North Carolina. As the Commission is aware, this is particularly so in a jurisdiction (like North Carolina) that uses a historical test year to set rates. The Commission specifically noted that while grid improvement costs identified in the totality of that case were substantial, on an individual project basis the projects were by and large of insufficient length to qualify for CWIP or AFUDC prior to placement into service. The Commission noted that as a result, the Company risked erosion of its ability to earn its authorized return due to regulatory lag. However, as the magnitude of that erosion had not been quantified, the Commission declined to authorize a deferral in that case. Instead, the Commission noted that it would be willing to entertain a future deferral request outside the test year "were the Company to demonstrate that the costs can be properly classified as … grid modernization [and not customary spend]." (E-7, Sub 1146 Rate Order, p. 148.) The Commission indicated that a list of projects arising from a collaborative stakeholder process would aid it in the examination of a deferral request. Witness Oliver's testimony shows that the projects for which the Company seeks deferral do indeed arise from a robust stakeholder process. And, the Commission noted further, it could authorize deferral of "demonstrated" grid modernization costs incurred prior to the test year with "reliance on leniency in imposing the 'extraordinary expenditure' test." (E-7, Sub 1146 Order, p. 149.)

Another example of the flexibility with which the Commission may approach deferral requests is the recently decided Northbrook Hydro matter (Docket No. E-7, Sub 1181). There, the Commission looked to the benefits accruing to the Company's customers due to the sale of some of the Company's hydroelectric generation assets; found that those benefits were substantial; and allowed the Company to defer the loss experienced on the sale considering the relatively small cost that customers would have to bear in the future due to the deferral. As set out in the testimony of Company Witness Oliver, the benefit to customers of the Company's grid modernization program are significant.

VIII. <u>CONCLUSION</u>

Q. IN YOUR VIEW, ARE THE OPERATING EXPENSES AND RATE BASE CALCULATED BY DE CAROLINAS IN THIS PROCEEDING IN ACCORDANCE WITH THE PROVISIONS OF N.C. GEN. STAT. § 62-133 AND NCUC RULE R1-17?

A. Yes. They are. The Company generally experienced a level of ordinary business expenses and rate base that was reasonable and necessary to provide safe and reliable electric service to its customers for the twelve-month period ended December 31, 2018. To meet the requirements of N.C. Gen. Stat. § 62-133 and this Commission's Rule R1-17, the actual operating expenses and rate base levels for the Test Period were adjusted for known and measurable changes as described in Section IV of my testimony and in the testimonies of Witnesses McGee and Pirro.

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

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Jane L. McManeus, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. ARE YOU THE SAME JANE L. MCMANEUS WHOSE DIRECT TESTIMONY AND EXHIBITS WERE FILED IN THIS DOCKET?

A. Yes. I filed Direct Testimony and Exhibits on September 30, 2019 and filed Corrected Direct Testimony on October 23, 2019.

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

A. The purpose of my supplemental direct testimony is to present additional adjustments to the test period rate base, operating revenue, operating expense and operating income as shown on McManeus Supplemental Exhibit 1. I noted in my previously filed testimony that the Company planned to make updates to certain test period adjustments during the proceeding. I will discuss each adjustment below. I also update the Excess Deferred Income Tax Rider (EDIT) calculation, shown on McManeus Supplemental Exhibit 4, to reflect known changes to the EDIT balances and amortization amounts as of January 2020. Finally, I explain actions taken by the Company to review its test period electric operating expenses before filing its case.

The table below shows all pro forma adjustments to test period amounts. The particular adjustments that have been updated or revised are shown in bold text.

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES		
Line No.	**Adjustment Title**	**Witness**
1	Annualize retail revenues for current rates	Pirro
2	**Update fuel costs to proposed rate**	**McGee**
3	**Normalize for weather**	**Pirro**
4	**Annualize revenues for customer growth**	**Pirro**
5	Eliminate unbilled revenues	McManeus
6	**Adjust for costs recovered through non-fuel riders**	**McManeus**
7	Adjust O&M for executive compensation	McManeus
8	**Annualize depreciation on year end plant balances**	**McManeus**
9	Annualize property taxes on year end plant balances	McManeus
10	**Adjust for post-test year additions to plant in service**	**McManeus**
11	**Amortize deferred environmental costs**	**McManeus**
12	**Annualize O&M non-labor expenses**	**McManeus**
13	**Normalize O&M labor expenses**	**McManeus**
14	**Update benefits costs**	**McManeus**
15	**Levelize nuclear refueling outage costs**	**McManeus**
16	**Amortize rate case costs**	**McManeus**
17	Adjust aviation expenses	McManeus
18	Adjust for approved regulatory assets and liabilities	McManeus
19	**Adjust for merger related costs**	**McManeus**
20	**Amortize severance costs**	**McManeus**
21	Adjust for NC income tax rate change	McManeus

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES		
Line No.	**Adjustment Title**	**Witness**
22	**Synchronize interest expense with end of period rate base**	**McManeus**
23	**Adjust cash working capital for present revenue annualized and proposed revenue**	**McManeus**
24	Adjust coal inventory	McManeus
25	**Adjust credit card fees**	**McManeus**
26	**Adjust for new depreciation rates**	**McManeus**
27	Adjust vegetation management expenses	McManeus
28	Adjust reserve for end of life nuclear costs	McManeus
29	**Update deferred balance and amortize storm costs**	**McManeus**
30	Adjust other revenue	Pirro
31	Adjust for change in NCUC regulatory fee	McManeus
32	**Adjust for hydro stations sale**	**McManeus**
33 NEW	**Adjust for cash working capital for lead-lag revision**	**McManeus**

II. UPDATES TO THE COMPANY'S TEST PERIOD OPERATING REVENUE, EXPENSES AND RATE BASE

Q. PLEASE DESCRIBE MCMANEUS SUPPLEMENTAL EXHIBIT 1.

A. McManeus Supplemental Exhibit 1 presents the impact of additional adjustments to test period operating income and rate base that the Company is supporting at this time. Page 1 of the Exhibit summarizes the adjustments and the details for each adjustment are presented on the subsequent pages.

Q. WAS MCMANEUS SUPPLEMENTAL EXHIBIT 1 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes.

Q. PLEASE EXPLAIN THE ADJUSTMENTS THAT ARE PRESENTED IN MCMANEUS SUPPLEMENTAL EXHIBIT 1.

A. **Line 2 – Update fuel costs to proposed rate**

This adjustment has been revised to reflect removal of catalyst depreciation from fuel clause recovery. In its initial filing, DE Carolinas proposed to include this cost as a component of fuel rates. After discussion with the Public Staff, the Company has concluded that recovery of this cost in base rates is the most reasonable cost recovery approach.

Line 3 – Normalize for weather

Witness Pirro's supplemental direct testimony describes this adjustment. The responsible witness has been updated to Witness Pirro.

Line 4 – Annualize revenues for customer growth

Witness Pirro's supplemental direct testimony describes this adjustment.

Line 6 – Adjust for costs recovered through non-fuel riders

This adjustment has been updated to revise certain amounts removed from working capital. An adjustment related to state EDIT was eliminated and two adjustments related to costs associated with the CPRE were made. In addition, certain allocation percentages used to determine REPS rider amounts have been updated.

Line 8 – Annualize depreciation on year end plant balances

This adjustment is revised to include catalyst depreciation as a component of the adjustment. In its initial filing, DE Carolinas proposed recovery of this cost through fuel rates rather than base rates. After discussion with the

Public Staff, the Company has concluded that recovery of this cost in base rates is the most reasonable cost recovery approach. In addition, components of this adjustment related to amounts recovered through riders have been update to reflect changes in Adjustment 6.

Line 10 – Adjust for post-test year additions to plant in service

This adjustment has been updated to replace estimated data with actual amounts through January 2020. In addition, this item is revised to eliminate retirements of meters that have been previously approved for deferral as a regulatory asset, since the deferred amount continues to be amortized. Finally, components of this adjustment related to amounts recovered through riders have been update to reflect changes in Adjustment 6.

Line 11 – Amortize deferred environmental costs

This adjustment has been updated to replace estimated data with actual amounts through January 2020. In addition, the adjustment has been revised to incorporate accumulated deferred income tax benefits related to bonus tax depreciation for qualifying non-ARO projects.

Line 12 – Annualize O&M non-labor expenses

This adjustment has been updated to reflect the impact of revisions to Adjustments 6 and 20.

Line 13 – Normalize O&M labor expenses

This adjustment has been updated to reflect actual salary data as of January 2020, as well as updated allocation factors used to compute labor reimbursements for jointly owned electric facilities.

Line 14 – Update benefits costs

This adjustment has been updated to reflect projected 2020 costs based on the Company's most recent actuarial study.

Line 16 – Amortize rate case costs

This adjustment has been updated to reflect the actual costs incurred through January 2020.

Line 19 – Adjust for merger related costs

This adjustment has been updated to reflect the actual costs incurred through January 2020.

Line 20 – Amortize severance costs

This adjustment has been updated to reflect actual amounts through January 2020.

Line 22 – Synchronize interest expense with end of period rate base

This adjustment to income tax expense has been updated to reflect the impacts resulting from other updated and revised pro forma adjustments affecting rate base and the associated annualized interest expense.

Line 23 – Adjust cash working capital for present revenue annualized and proposed revenue

This adjustment uses amounts from other test period adjustments. It has been updated to reflect the changes made to other adjustments. In addition, the calculations have been updated to reflect revisions to the lead-lag study as discussed in the supplemental direct testimony and exhibits of Witness Speros.

Line 25 – Adjust credit card fees

This adjustment has been updated to reflect actual numbers of credit card transactions through January 2020.

Line 26 – Adjust for new depreciation rates

This adjustment is revised to include catalyst depreciation as a component of the adjustment. In its initial filing, DE Carolinas proposed recovery of this cost through fuel rates rather than base rates. After discussion with the Public Staff, the Company has concluded that recovery of this cost in base rates is the most reasonable cost recovery approach. In addition, components of this adjustment related to amounts recovered through riders have been update to reflect changes in Adjustment 6.

Line 29 – Update deferred balance and amortize storm costs

This adjustment has been updated to reflect actual storms costs and current depreciation rates for use in the computation of deferred depreciation expense.

Line 32 – Adjust for hydro stations sale

This adjustment has been updated to reflect final accounting entries related to completion of the sale. The original adjustment was based on estimated values. In addition, as a result of updating Adjustment 10 to reflect actual amounts as of January 2020, the removal of the sold hydro assets from electric plant and accumulated depreciation is accomplished in Adjustment 10 rather than this adjustment.

Line 33 – Adjust for cash working capital for lead-lag revision - NEW

This adjustment has been added to revise the test period cash working capital component of electric rate base. The revision is necessary to reflect the revisions to the lead-lag study as described in the supplemental direct testimony and exhibits of Witness Speros.

Q. **DOES MCMANEUS SUPPLEMENTAL EXHIBIT 1 REFLECT ANY CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?**

A. Although McManeus Supplemental Exhibit 1 does show an increase in the proposed amount of electric operating revenues, the Company is not requesting a change in its originally proposed revenue increase at this time. For this reason, the exhibit is marked for informational purposes only.

Q. **IN YOUR OPINION, DO THESE ACCOUNTING AND PRO FORMA ADJUSTMENTS REFLECT KNOWN AND MEASURABLE CHANGES TO THE COMPANY'S TEST PERIOD OPERATING EXPENSES, REVENUES, AND RATE BASE?**

A. Yes.

III. <u>EDIT RIDER</u>

Q. **PLEASE EXPLAIN THE CHANGES REFLECTED IN MCMANEUS SUPPLEMENTAL EXHIBIT 4.**

A. McManeus Supplemental Exhibit 4 includes revisions that reflect completion of Duke Energy's 2018 federal income tax return. The annual amortization percentage for Protected EDIT has been updated to an actual amount that aligns with the most recently filed federal income tax return, which is the Company's best estimate for the following year's protected EDIT amortization. This update is necessary to comply with federal tax normalization rules and was referenced in my Direct Testimony. A second amount that has been updated is related to the NC EDIT component of the rider, to reflect minor revisions to the EDIT amount.

IV. OTHER

Q. BEFORE FILING ITS CASE, DID DE CAROLINAS REVIEW ITS OPERATING EXPENSES AND REMOVE COSTS THAT IT DEEMED WERE NOT APPROPRIATE TO RECOVER FROM ITS ELECTRIC RETAIL CUSTOMERS?

A. Yes. While the Company's system of internal accounting controls and audits are in place to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper, the Company has experienced occasions when certain expenses have been improperly charged due to human error. To ensure that the proposed revenue requirement in the case does not reflect any amounts of electric expenses that are inaccurate, the Company took additional steps to eliminate the impact of potential mischarges due to human error. Specifically, prior to filing this rate case, the Company took preventive measures to review underlying cost data in particular accounts where errors could likely occur. The Company used a combination of data analytics to electronically scan source data and manual reviews of detail transactions to identify expenses that it deemed were not appropriate for cost recovery.

Q. DID DE CAROLINAS TAKE ADDITIONAL PRECAUTIONS TO ENSURE MISCHARGES WERE NOT INCLUDED FOR RECOVERY FROM ITS ELECTRIC RETAIL CUSTOMERS?

A. Yes. As an additional precaution, DE Carolinas elected to remove an additional $1.8 million of system electric operating expenses from allocation to North Carolina retail customers in case any other potential mischarges were discovered during the course of this proceeding. Any such mischarges that are discovered would be deducted against this amount, and, if any amount of this $1.8 million remains after any further mischarges are netted against it, the remaining balance will continue to be excluded from recovery for the benefit of customers.

Q. PLEASE DESCRIBE THE STEPS THE COMPANY TOOK TO REMOVE THE ADDITIONAL $1.8 MILLION IN ELECTRIC OPERATING EXPENSES FROM THE COMPANY'S REVENUE REQUIREMENT IN THIS CASE.

A. As part of the Company's Cost of Service study, electric operating expenses and electric rate base for North Carolina retail jurisdiction are determined by directly assigning or allocating DE Carolinas system amounts based on cost causation principles. It is normal in a Cost of Service study to evaluate DE Carolinas system costs for assignment or allocation to either North Carolina retail customers, South Carolina retail customers, to wholesale customers or to no customers (i.e. "other"). This practice is common, since there are certain electric operating expenses that are appropriate to assign to one particular rate jurisdiction, or to appropriately exclude from recovery from electric customers. However, this is the first time that the Company has used this process as a mechanism to help ensure that the costs assigned to a particular jurisdiction do not inadvertently reflect improper charges due to human error.

Q. PLEASE FURTHER DESCRIBE WHY THE COMPANY ELECTED TO TAKE THE ADDITIONAL PRECAUTION OF REMOVING $1.8 MILLION OF ELECTRIC OPERATING EXPENSES FROM ITS CASE.

A. The Company's goal in this instance was to reduce the potential for supplemental changes to its requested revenue increase. Should the Public Staff or another party, in the course of their audit of expenses, identify an amount of system cost that they and the Company agree were improperly included in North Carolina retail electric expenses due to human error, there would be no need for another party to propose an adjustment, so long as the amount of error does not exceed the additional $1.8 million as described above. If, however, mischarges are found that exceed the $1.8 million, the Company would make a supplemental adjustment to its filing to reflect further reduction of electric expenses assigned or allocable to North Carolina retail.

V. CONCLUSION

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

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Jane L. McManeus, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC, testifying on behalf of Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. ARE YOU THE SAME JANE L. MCMANEUS WHOSE TESTIMONY AND EXHIBITS WERE FILED IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on September 30, 2019 and filed corrected direct testimony on October 23, 2019. I also filed supplemental direct testimony and exhibits on February 14, 2020.

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

A. The purpose of my rebuttal testimony is to: (1) respond to certain accounting and ratemaking adjustments proposed by the Public Staff in their direct and first supplemental testimony; and (2) respond to certain issues raised in intervenor testimony, including the recovery of coal ash compliance costs, the Company's proposed EDIT Rider, and the Company's request for a deferral for Grid Improvement Plan costs. I also provide revisions to my supplemental direct testimony filed on February 14, 2020.

My review of the testimony filed by the Public Staff reflects the fact that their recommendations and comments regarding the Company's proposed revenue requirements are based on the Company's initial filing made September 30, 2019 and updates for post test year costs through November 30, 2019. As noted by the Public Staff, their testimony does not consider additional updates for actual post test year costs through January 31, 2020 as reflected in the Company's supplemental filing made February 14, 2020. It is my understanding that the Public Staff plans to file supplemental testimony in this case once they have completed their review of the Company's supplemental filing. Therefore, in my testimony that follows, I do not attempt to speak to or reconcile differences that naturally result from the difference in time periods. Instead, I focus on whether the Company and the Public Staff agree or disagree in concept on adjustments to test period amounts. Once the Public Staff completes their review of the Company's supplemental filing and makes their own responsive supplemental filing, both parties should be in a better position to more clearly address their respective positions on the Company's proposed revenue increase based on test period adjustments through January 31, 2020 and identify specific differences. I plan to supplement my rebuttal testimony accordingly.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes, I have included three exhibits. McManeus Rebuttal Exhibit 1 shows adjustments to the revenue requirements as presented in McManeus

Supplemental Exhibit 1. Explanations of the individual adjustments are provided later in my testimony. McManeus Rebuttal Exhibit 2 is DE Carolinas and DE Progress's Joint Brief filed before the Supreme Court of North Carolina on September 25, 2019 in response to appeals in Docket Nos. E-7, Sub 1146 and E-2, Sub 1142. McManeus Rebuttal Exhibit 3 is a copy of the rate impact information for PowerForward that was provided to intervenors in Docket No. E-7, Sub 1146 (the "2017 Rate Case").

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. McManeus Rebuttal Exhibit 1 was prepared under my direction and supervision. McManeus Rebuttal Exhibit 2 is a publicly available filing made by the Company in an ongoing proceeding. While I am not a lawyer and I do not provide legal opinions, I have reviewed and support the portions of the brief that respond to the Public Staff's position that I describe below. McManeus Rebuttal 3 is a response to a data request that I assisted in preparing and also support.

II. RESPONSE TO PUBLIC STAFF ACCOUNTING ADJUSTMENTS

Adjustments Not Opposed or Partially Opposed

Q. ARE THERE ANY ADJUSTMENTS RECOMMENDED BY THE PUBLIC STAFF THAT THE COMPANY DOES NOT OPPOSE OR PARTIALLY OPPOSES?

A. Yes. There are several adjustments by Public Staff, shown on Boswell Exhibit 1, Schedule 1, that the Company either does not oppose or opposes in part.

Line 8 – Adjust weather normalization to November 30, 2019

As explained in the rebuttal testimony of Company witness Pirro, the Company and the Public Staff have agreed on modifications to the adjustments to revenues related to customer growth and usage, and weather normalization. The Company has reflected these changes in McManeus Rebuttal Exhibit 1.

Line 9 – Update plant and accumulated depreciation to November 30, 2019

This Public Staff adjustment aligns in concept with portions of the Company's supplemental direct testimony filing filed February 14, 2020, which includes updated amounts through January 31, 2020. However, there are some differences between the Company's proposed update to plant and accumulated depreciation and the Public Staff's proposed update, which makes the Company unable to agree with the dollar amount of the adjustment proposed by witness Boswell. In its February 14, 2020 supplemental filing, the Company made a correction to the depreciation expense component of its original adjustment – a change related to treatment of retired meters which are approved for deferral as a regulatory asset. In the Public Staff's adjustment, this error is uncorrected. Also, the Public Staff adjustment does not properly handle plant and depreciation related amounts that are recovered through riders. Finally, the Company does not agree with the difference Public Staff witness Boswell described in her testimony on page 10, where she states that retirements are not reflected in the amount of plant used to compute depreciation expense, and, therefore, depreciation expense is overstated. In its February 14 supplemental filing, the Company has included retirements in the amount of plant used to compute depreciation expense; therefore, depreciation expense is not overstated.

Line 10 – Update ADIT for retired meters

This adjustment to ADIT aligns with the Company's supplemental direct testimony filing filed February 14, 2020, which includes updated amounts through January 31, 2020. However, although the calculation of the adjustment on witness Boswell's supporting Schedule 2-1(b) reflects a change in the Retired Meter Regulatory Asset Balance, this change is not carried forward to the adjustments made to rate base. The Company believes that adjustments to rate base related to retired meters should include both the change in the regulatory asset balance as well as the change in the ADIT balance.

Line 13 – Update revenues to November 30, 2019

As explained in the rebuttal testimony of Company witness Pirro, the Company and the Public Staff have agreed on modifications to the adjustments to revenues related to customer growth and usage, and weather normalization. The Company has reflected these changes in McManeus Rebuttal Exhibit 1.

Line 20 – Adjust outside services

The Company agrees with the items identified by the Public Staff related to certain outside services costs but believes these costs have already been removed from the revenue requirement. The amounts are mischarges to the outside services account due to human error. As explained in my supplemental direct testimony filed February 14, 2020, the Company proactively removed $1.8 million of system electric operating expenses from allocation to North Carolina retail electric expenses to cover any mischarges identified during the course of the rate case proceeding. As such, the Company believes no additional adjustment to the proposed revenue increase is required.

Line 26 – Adjust sponsorship and donations

The Company partially agrees with this adjustment. The Company disagrees with the adjustment for the Chamber-related items for the reasons set forth in the rebuttal testimony of Company witness Speros. The Company agrees with the remaining items of approximately $13,000. As explained in my supplemental direct testimony filed February 14, 2020, the Company proactively removed $1.8 million of system electric operating expenses from allocation to North Carolina retail electric expenses to cover any mischarges identified during the course of the rate case proceeding. As such, the Company believes no additional adjustment to the proposed revenue increase is required.

Line 30 – Adjust salaries and wages expense

This adjustment aligns with the Company's supplemental direct testimony filing filed February 14, 2020, which includes updated amounts through January 31, 2020. There are a few adjustments the Company understands the Public Staff plans to make to their salary and wages calculation. After the Public Staff reflects these adjustments, the Company still cannot agree with the total dollar amounts of the Public Staff adjustment due to their use of the Summer/Winter Peak and Average ("SWPA") allocation factors. As discussed by Company witness Hager in her rebuttal testimony, the Company disagrees with the use of the SWPA allocation method.

Line 31 – Adjust credit card fees

The Company partially agrees with this adjustment. The Public Staff made an adjustment to remove operating and maintenance ("O&M") expenses associated with the increase in fee-free program transactions from 2018 to 2019. The Company has accepted the concept of the Public Staff's adjustment but has updated the calculation to reflect avoided transaction costs related to payment by check. This change is reflected on McManeus Rebuttal Exhibit 1.

Line 32 – Adjust inflation to November 30, 2019

The Company does not oppose this adjustment to update inflation impacts as it is consistent with updates to other post test year expenses. However, since the Company does not agree with the Public Staff's other proposed adjustments that affect test year O&M amounts, the Company cannot agree with the total dollar amounts of the Staff's inflation adjustment. The Company's revisions to update non-labor O&M amounts to reflect inflation through January 31, 2020 are shown on McManeus Rebuttal Exhibit 1.

Line 33 – Adjust advertising expense

The Company partially agrees with the items identified by the Public Staff for the reasons set forth in the rebuttal testimony of witness Speros. His testimony identifies three categories of disputed charges. The first category includes electric O&M expenses that were inadvertently recorded to advertising Account 913 instead of distribution maintenance Account 596. The Company has reflected the reclassification of this amount to the appropriate O&M expense account in McManeus Rebuttal Exhibit 1 through a new pro forma adjustment to the test period, number 34 – Remove/reclassify certain test period expenses. The Company does not oppose the remaining categories of advertising expense adjustments as proposed by the Public Staff. New adjustment number 34 also includes removal of these costs from test period amounts.

Line 36 – Adjust retired hydro O&M

The Company does not oppose this adjustment. The Company has reflected this reduction in hydro O&M expense in McManeus Rebuttal Exhibit 1.

Line 37 – Adjust cash working capital under present rates, and Line 38 – Adjust working capital under proposed rates

The Company agrees with the changes made to reflect revisions to the lead-lag study. An updated study was filed as an exhibit to the Company's supplemental direct testimony of Company witness Speros. However, there are a few adjustments the Company understands the Public Staff plans to make to their cash working capital under present rates calculation. After the Public Staff reflects these adjustments, the Company anticipates agreeing with the calculation. Since the Company does not agree with all the Public Staff's proposed adjustments, to the extent the adjustments affect the working capital amounts, the Company cannot agree with the total dollar amounts of the Public Staff's two working capital adjustments.

Adjustments Opposed

Line 14 – Adjust distribution vegetation management

The Company opposes this adjustment. The Company's original vegetation management adjustment included a test year cost per mile of $9,041, which included the total expense associated with distribution vegetation management incurred in 2018. The Company responded to a data request providing a detailed view of the costs included in the cost-per-mile calculation but did not include accounting accruals booked in the test year in its original response. The Public Staff relied on the detailed view of the costs provided in the data request to propose an adjustment to the Company's vegetation management adjustment to use a test year cost per mile of $8,699. The Company has supplemented its response to the data request to include the accounting accruals, which supports a test year cost per mile of $9,041.

Line 15 – Include flowback of protected federal EDIT due to Tax Cuts and Jobs Act, and Line 16 - Remove EDIT refund from base rates for treatment as a rider

The Company does not oppose rider treatment for excess deferred income taxes ("EDIT") and has proposed refund through a rider in its initial filing. However, the Company does oppose the specific rider treatment as proposed by the Public Staff. The Company's objections are described later in my testimony.

Line 17 – Adjust for Hydro Station Sale

The Company opposes this adjustment. The Company is aware there are a few adjustments the Public Staff plans to make to the amortization amount they propose for the loss on the sale of hydro units. Even after these changes, the Company still opposes this adjustment. Public Staff witness Boswell recommends a 20-year amortization period of the deferred loss on the sale of the hydro assets. The Company believes its proposal to amortize the deferred loss over a 7-year period is fair and reasonable. The revenue requirement resulting from the annual amortization expense using the 7-year amortization period as proposed by the Company closely aligns with the amount of revenue requirement associated with test period annual O&M expense and annual depreciation expense of the hydro units being sold, resulting in minimal change to existing rates.

Line 18 – Adjust aviation expenses

The Company opposes this adjustment. In its initial and supplemental filings, the Company removed 50% of the Company's O&M costs related to corporate aviation to account for flights that may not be related to provision of electric service. For the test period, DE Carolinas was allocated approximately 35% of the corporate amount of aviation expense. All of the expenses of the corporate aircraft have been allocated in accordance with the Company's filed cost allocation manual. The Company's proposal to remove 50% of this amount results in inclusion of about 18% of corporate aviation expenses in the Company's adjusted test period cost. The Public Staff proposal would reduce the amount of aviation expenses to less than 2% of the corporate amount. The Company does not believe witness Boswell has provided sufficient support that the appropriate amount of aviation expenses to be included in DE Carolinas electric rates should be based on less than 2% of corporate aviation expenses. The Company's proposal in this case is based on its 2017 Rate Case in which the Public Staff and the Company agreed in partial settlement to remove 50% of the corporate aviation expenses allocated to DE Carolinas, which resulted in inclusion of 19% of corporate aviation expenses in the Company's rates.

Line 21 – Rate case expense

The Company opposes this adjustment. Public Staff witness Boswell's testimony states that they made the adjustment to 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. The average cost of the last three rate cases, adjusted for inflation, is over $4 million and the average time between rate cases since the case filed in 2013 has been 33 months. Therefore, had the Public Staff calculated the normalization of costs associated with the filing of a rate case based on the historical average costs and number of years between rate case filings, the amortization amount would have been approximately $1.5 million, which is higher than the Company's proposed amortization amount. Rather than normalizing, the actual adjustment the Public Staff made to working capital was only to remove all post-test year expenses from the regulatory asset balance in rate base. The Company contends that the post-test year amounts that the Public Staff has removed are known and measurable costs incurred, and, therefore, the balance in rate base should *include* these amounts. It is appropriate to include rate case expenses in rate base because they are incremental costs that will have been incurred and funded by investors prior to new rates becoming effective. To fully recover the cost of those expenses, the regulatory asset needs to be reflected in rate base. The Company has reduced the regulatory asset by the one year's worth of amortization expense as was also done in similar proformas, such as Company adjustment #10 – Adjust for post-test year additions to plant in service.

Line 27 – Adjust severance

The Company opposes this adjustment. Public Staff witness Boswell attempted to adjust the severance costs to reflect a normalized level over a five-year period. However, the adjustment made was just to change the proposed amortization period from 3 years to 5 years. Had the Public Staff calculated the 5-year normal level of severance expense, the North Carolina retail expense would have been $29 million, which is greater than the Company's proposed amortization amount. Public Staff witness Boswell then states, "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." Since the Public Staff has not established a normalized level to include in rates, the Company believes it is appropriate to include the deferred severance expense in rate base. To fully recover the cost of the deferred severance expenses over a 3-year period, the regulatory asset needs to be reflected in rate base. The Company has reduced the regulatory asset by the one year's worth of amortization expense as was also done in similar proformas such as Company adjustment #10 – Adjust for post-test year additions to plant in service.

Line 34 – Adjust storm deferral

The Company disagrees with removal of the storm cost deferral. The Company plans to pursue securitization of the particular storm costs as provided by recently passed legislation, North Carolina Senate Bill 559. However, as stated by Company witness De May in his rebuttal testimony, these costs must remain a part of the Company's request in this proceeding until the Commission reaches the same determination as the Company and the Public Staff[1] that the costs were prudently incurred, and the Commission subsequently approves a financing petition.

Line 35 – Adjust storm expense

The Company opposes this adjustment to normalize test period storm costs. In their comments in Docket Nos. E-2, Sub 1131, E-2, Sub 1193 and E-7, Sub 1187, the Public Staff stated they considered the Company's use of a normalization adjustment in its prior rate cases as a possible basis to oppose a deferral request in general. As a result, DE Carolinas has not proposed a normalization adjustment for storm expense. The Company will consider an adjustment should the Public Staff's position change.

Adjustments to Coal Ash Pond Closure Costs

Q. PLEASE EXPLAIN THE COMPANY'S RESPONSE TO THE PUBLIC STAFF ADJUSTMENTS REGARDING COAL ASH POND CLOSURE COSTS.

A. The Company opposes the two adjustments related to coal ash pond closure cost recovery, which are listed on lines 24 and 25 of Boswell Exhibit 1, Schedule 1:

Line 24 - Adjust deferred environmental costs

Line 25 - Adjust deferred non-ARO environmental costs

[1] *See* Testimony of Michelle M. Boswell Public Staff – North Carolina Utilities Commission, Docket No. E-7, Sub 1214 at 27-28 (February 18, 2020).

Q. PLEASE SUMMARIZE THE FIRST ADJUSTMENT.

A. This adjustment, addressing Asset Retirement Obligation ("ARO")-related coal ash expenditures, is based on three recommendations proposed by Public Staff witness Maness on pages 15-17 of his direct testimony. Witness Maness's first recommendation relates to the disallowance of certain coal ash management expenditures as recommended by several other Public Staff witnesses. Company witness Bednarcik addresses this recommendation in her rebuttal testimony.

Witness Maness's second and third recommendations are to lengthen the amortization period for recovery of the remaining coal ash pond closure costs; and to remove the unrecovered balance from rate base, thus disallowing a return on the unamortized balance. These two recommendations accomplish his objective that these costs be shared between customers and shareholders. Witness Maness states that the five-year amortization period proposed by the Company is "simply too short" given the magnitude and nature of the costs. His specific recommendation of a 26-year amortization period, in combination with no return on the unamortized balance, results in roughly 50/50 sharing of costs between customers and shareholders.

Witness Maness identifies two general reasons why this sharing is reasonable and appropriate. He explains that although the Public Staff alleges no specific imprudence or unreasonableness finding for the costs, it is appropriate that these costs must be shared for reasons of the Company's general culpability, and because of historical precedence for regulatory treatment of costs that do not result in any new generation of electricity for customers. In addition, witness Maness cites several additional reasons the costs should be shared, including the magnitude of costs in this case as well as expected future costs, the lack of customer benefits or economic advantages related to these costs, and concerns about intergenerational inequity.

Q. WHY DOES THE COMPANY DISAGREE WITH THIS ADJUSTMENT?

A. The Public Staff's "equitable sharing" adjustment runs directly contrary to well-established ratemaking and cost recovery principles and, in particular, the basic principle that a public utility's reasonable and prudently incurred costs are recoverable in rates.[2]

The particular costs at issue with this adjustment are the costs incurred by the Company in connection with its coal ash basin closure activities from January 1, 2018 through January 31, 2020. All of these costs were incurred due to a change in the law that required the Company to manage coal ash differently than it had done in the past, and to retire long-lived assets that the Company had been using for purposes of coal ash management and storage. Because of the asset retirement requirement, the costs are accounted for in AROs.

[2] I am not a lawyer, and I do not provide legal opinions. Public Staff witnesses Maness (in the Company's 2017 Rate Case) and Junis (in this rate case) have both referred to a lengthy legal memorandum to support the Public Staff's equitable sharing proposal, which was attached as an exhibit to witness Maness's 2017 Rate Case testimony. The Company's legal position on these issues is set out in detail in its post-hearing legal filings in the 2017 Rate Case as well as in its brief filed in the North Carolina Supreme Court in connection with the appeal by the Public Staff and other intervenors of the Commission's decision in that case. A copy of that brief is attached as McManeus Rebuttal Exhibit 2 to my testimony; see in particular Section IV. As previously noted in my testimony, the Public Staff's approach has already been rejected three times by the Commission.

Company witness David Doss discusses this from an ARO accounting perspective in his rebuttal testimony.

The Public Staff's "sharing" approach does not depend on any finding of imprudence in connection with the incurrence of these costs. Instead, the Public Staff's approach consists merely of removing the unamortized balance of coal ash expenditures from rate base in addition to amortizing the balance over an arbitrary period – 26 years. This lengthy amortization period is what is necessary in order for the Public Staff to achieve its desired goal – a 50/50 split between the Company and its customers of the deferred coal ash basin closure costs sought for recovery in this case. But there are no standards, according to the Public Staff, that guide the exercise of what it deems to be the Commission's discretionary power to put "equitable" sharing into effect – that is what makes the Public Staff's proposal arbitrary.

In the Company's 2017 Rate Case, the Commission explained why the Public Staff's equitable sharing proposal was arbitrary:

> [T]he concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2018 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2018 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 ...."

Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146 (June 22, 2018) ("2018 Rate Order"), at 273. I believe the Commission's assessment of "sharing" was correct and see no reason for the Commission to revisit the issue in this case. If the Commission determines that the deferred costs the Company has incurred for coal ash basin closure were prudently incurred, then those costs under traditional and long-standing ratemaking and cost recovery principles are recoverable from customers.

Q. IS IT ALSO APPROPRIATE FOR THE COMMISSION TO ALLOW THE COMPANY TO RECOVER ITS FINANCING COSTS IN CONNECTION WITH COAL ASH BASIN CLOSURE?

A. Yes. The Public Staff's proposal acknowledges that financing costs during the initial period of deferral – that is, from the time the costs are incurred until they are brought into rates – should include the Company's financing costs. It is during the period over which the costs are amortized after being brought into rates that the Public Staff indicates no financing costs should be allowed. This again runs contrary to well established ratemaking and cost recovery principles.

The costs at issue include the cost of money. The financing costs related to funds advanced by investors are no less costs associated with the provision of service to customers than the depreciation, O&M, or other costs of the power plants that generate electricity or the towers, poles, and lines that transmit and distribute that electricity to customers' homes and businesses. All of these costs are necessary and prudent to ensure reliable electric service. Furthermore, all of these costs were deferred by Order of the Commission in the Company's 2017 Rate Case and consolidated dockets. None of those costs have previously been brought into rates or paid for by customers. All of these costs have been funded by investors (both debt and equity). Because the costs are wholly financed by the Company and its investors, the Public Staff appropriately recognizes that the Company's financing costs during the deferral period are legitimately incurred and recoverable. That same principal applies during the amortization period as well.

Q. PLEASE EXPLAIN.

A. The Public Staff's sharing proposal removes coal ash basin closure costs (including financing costs during the initial deferral period) from rate base in order to implement its preferred "sharing" percentage. I testified to this at length in the Company's 2017 Rate Case. As I stated:

> [I]t is important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes. Certainly, construction of electric plant is one such purpose, but there are others – for example, to purchase fuel inventory, to provide cash working capital, etc. Further, to accurately determine the amount of investor-supplied funds, one must consider whether any amounts that have been used for such purposes have been advanced by customers, rather than investors. In this particular case, investors have advanced funds to pay for coal ash compliance costs.

Tr. Vol. 6, p. 317. I noted further that the "characteristic that makes the deferred coal ash cost a legitimate component of rate base" is the fact that the funds used to pay those costs were supplied by investors. Tr. Vol. 6, p. 318. The Commission's Order in that case relied upon this testimony and drew the correct conclusion, both as to the deferral period as well as the amortization period:

> The point of a deferral is that the costs to be deferred are of a magnitude that they need to be taken out of the normal ratemaking accounting process and set to one side for later inclusion in rates, lest the Company lose its ability to recover them. Tr. Vol. 9, pp. 123-24. Should the Company's ability to recover such costs be impaired, it will not be able to earn at its authorized rate of return. *Id*. at 124. Setting them to one side means that unless a return is allowed, the Company's ability to earn its authorized rate of return is again impaired. *Further, if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return*. Rates that impair the Company's ability to earn its authorized return are not just and reasonable, unless the Company should be penalized due to mismanagement, for example, and the Commission would act contrary to law were it to order them.

2018 Rate Order, p. 290. Denying the Company the opportunity to earn its allowed rate of return on prudently incurred costs results in rates that are unjust and unreasonable.

Q. WITNESS MANESS ALSO INDICATES THAT THE COMPANY'S CLASSIFICATION OF DEFERRED COAL ASH BASIN CLOSURE COSTS AS "WORKING CAPITAL" DOES NOT MEAN THAT THIS REGULATORY ASSET SHOULD BE INCLUDED IN RATE BASE. PLEASE COMMENT ON THIS POSITION.

A. Witness Maness appears again to have misinterpreted my testimony and the Company's position. This was a point covered in the Company's 2017 Rate Case.

It is not and never has been the Company's position that classifying the costs as "working capital" is in and of itself a justification for placing the costs in rate base. The Company's position, as described above in the quotations from my testimony in the 2017 Rate Case, is that rate base represents investor supplied funds, and it is this characteristic that makes the deferred coal ash cost a legitimate component of rate base. While the Company does separate total investor supplied funds into distinct categories (e.g., net electric plant, working capital, prepayments, etc.), these categories still represent funds advanced by investors prior to recovery from customers, and assuming the underlying expenditures are judged reasonable and prudent by the Commission, the associated financing costs should be eligible for recovery.

Q. DID THE COMMISSION IN ITS PRIOR ORDER COMMENT ON WITNESS MANESS' POSITION ON WORKING CAPITAL?

A. Yes. The Commission also stated that witness Maness had misunderstood my testimony. *See* 2018 Rate Order, p. 290.

Q. DID THE PRIOR ORDER ALSO ADDRESS TREATMENT OF FUTURE ARO RELATED COAL ASH EXPENDITURES?

A. Yes. In the 2017 Rate Case, the Company had requested a "run rate" to collect at least a portion of ongoing coal ash basin closure costs, which would have shifted the funding source for those costs from the Company and its investors to customers. The Commission rejected the Company's proposal. It stated:

> 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 "run rate" or the "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. Future annual costs, the evidence shows, are predicted to vary substantially from year to year. *Instead*, 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 (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEC's next general rate case, and, unless future imprudence is established, *will* permit earning a full return on the unamortized balance. While this ratemaking treatment will, in limited fashion, diminish the quality of DEC's earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery.

2018 Rate Order, p. 322-23. The Commission's ruling puts the focus of the Company's cost recovery request where it belongs – on the Commission's examination of the prudence and reasonableness of the costs for which the Company seeks recovery in this case.

Q. HAVE YOU REVIEWED THE COMMISSION'S RECENTLY ISSUED ORDER IN THE DOMINION ENERGY NORTH CAROLINA ("DENC") CASE, DOCKET NO. E-22, SUB 562, ADDRESSING RECOVERY OF DENC'S COAL ASH BASIN CLOSURE COSTS?

A. Yes, I have reviewed sections of the DENC Order that address Finding of Fact Nos. 53-55, which specifically focus on the Commission's decision regarding recovery of financing costs during the Deferral Period (that is, the period from the time the coal ash basin closure costs, which the Order refers to as CCR Costs, are incurred until the time the costs are brought into rates), as well as recovery of financing costs (a return) on the unamortized balance of CCR Costs during the period after the costs are brought into rates and are being amortized (the Amortization Period). On these issues the Commission decided that:

- DENC *would* be allowed to recover its financing costs during the Deferral Period; in this respect the Commission came to the same decision as it had in the Company's 2017 Rate Case.
- DENC *would not* be allowed to recover its financing costs during the Amortization Period, which the Commission decided should be ten

> years; in this respect the Commission's decision differs from its decision in the 2017 Rate Case.

The Commission made its decision to deny DENC a return during the Amortization Period even though it acknowledged that DENC's CCR Costs had been prudently incurred.

Q. DOES THE COMMISSION'S ORDER IN THE DENC CASE CAUSE YOU CONCERN?

A. Yes. It appears to run contrary to the Commission's Order in the Company's 2017 Rate Case in which financing costs, at the Company's weighted average cost of capital, were allowed during the Amortization Period.. I note that in the DENC case the Commission concluded, "based on the record as a whole … that it is appropriate to treat the CCR Costs as deferred operating expenses and not as costs of property used and useful within the meaning and scope of N.C.G.S. § 62-133(b) … ." (2020 DENC Order, p. 134). I am not familiar with the evidentiary record in the DENC case that underlies the Commission's decision but know that the classification of the CCR Costs that were at issue in the 2017 Rate Case was a hotly debated issue between the Company and the Public Staff. In its Order in that case, the Commission indicated that the Public Staff's insistence that CCR Costs were "deferred expenses" was "not persuasive, not supported by authority, and not determinative, given the nature of the deferral." (2018 Rate Order, p. 289). The Commission also found that the Public Staff's position was "incorrect as a matter of accounting," noting that "because under

GAAP and FERC guidance ARO costs are capitalized. The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not 'expenses.'" (2018 Rate Order, pp. 289-90). Per the Commission's October 29, 2019 order establishing this rate case, I understand that the Commission took judicial notice of the documents received into evidence in the Company's 2017 Rate Case, and so I see no reason for the Commission to come to a different conclusion using the same facts regarding the classification of the Company's CCR Costs at issue in this case.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS REGARDING THE COMMISSION'S ORDER IN THE RECENT DENC CASE?

A. Yes. While I am not a lawyer, it appears to me that the Commission is seeking to find a result that is "fair" to the utility and to customers. I will leave it to the lawyers to argue about whether this is the proper standard for the Commission to employ. But there are a number of factors, based upon the Commission's Order in the Company's 2017 Rate Case, that I think the Commission should consider in weighing "fairness" in this case.

As I have already noted, the Commission rejected the Company's request for a "run rate," representing an ongoing annual level of CCR Costs the Company reasonably expected would be incurred into the future. The Commission "instead" (as stated in its Order) required the Company to continue to defer those ongoing costs. Those are the same costs that are at issue in this case. The Commission's direction seems clear to me: "*Instead*, 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 (the net of tax rate of return, net of associated accumulated deferred income taxes)." (2018 Rate Order, p. 323).

As discussed in the testimony of Company witnesses Newlin and Young, the Company has done what it was ordered to do, and it has raised the money to fund its ongoing CCR Costs – for which it now seeks recovery – from its investors. Doing so costs money, as those investors require a return on their investments. Requiring the Company to absorb this cost of money would impair its ability to earn its authorized return, as the Commission already found in the Company's 2017 Rate Case. (2018 Rate Order, p. 290). Such a result would not seem to me to be the fair result that the Commission seeks.

Similarly, the Commission in the Company's 2017 Rate Case faced the issue of flow-back to customers of excess deferred income taxes (EDIT) – essentially, money previously collected from customers for future tax liabilities at the then prevailing tax rate, that needs to be returned to customers because the actual taxes to be paid will be at a lower tax rate. In effect, with respect to EDIT, customers prepaid for a cost which will now not materialize – and they should get their money back. In the Company's 2017 Rate Case, the Commission ordered with respect to EDIT that the Company should "continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case whichever is sooner at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%." (2018 Rate Order, p. 198). The interest portion of the flowback recognizes that customers are not getting their money right away.

With respect to the coal ash basin closure costs incurred during the period at issue in this case, the Company, with investor-supplied funds, in effect prepaid those costs rather than already having them funded by customers through the rates they pay. Ultimately, as those costs are brought into rates, and assuming the Commission finds that they have been prudently incurred, customers will pay – but the full costs to be paid include the cost of the funds advanced by investors. In my opinion, that treatment demonstrates the balance that the Commission indicates it seeks between the Company and its customers.

Q. DOES THE COMPANY AGREE WITH THE ADJUSTMENT PROPOSED BY WITNESS MANESS TO INCREASE THE AMORTIZATION PERIOD FOR DEFERRED AMOUNTS RELATED TO CAPITAL EXPENDITURES INCURRED THAT ARE NON-ARO RELATED?

A. No. As indicated by witness Maness, the requested amounts for recovery over five years are the return and depreciation associated with capital expenditures at active coal plants in compliance with coal ash closure requirements. His recommendation is to double the length of the amortization period to mitigate annual rate impacts to customers. The Public Staff has recommended extending amortization periods proposed by the Company when the amortization involves amounts to be collected from customers but recommends shortening amortization periods when the amortization involves amounts to be refunded to customers. The Company has considered annual rate impacts in its recommendation of the five year amortization and considered the Commission's decision in the 2017 Rate Case in determining the amortization period.

Q. WHAT IS THE COMPANY'S POSITION REGARDING THE RECOMMENDATION BY WITNESS MANESS TO DISALLOW FUTURE DEFERRAL OF FUTURE CAPITAL COSTS RELATED TO NON-ARO COMPLIANCE PROJECTS?

A. In his recommendation, witness Maness is asking the Commission to reverse its previous authorization to defer such costs. In the 2017 Rate Case, the Commission ruled on the Company's request to defer costs related to compliance with federal and state laws for coal combustion residuals. The Company's underlying petition to establish a deferral clearly articulated that the request was for the following:

> the deferral of 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 outlined in paragraphs five and seven.[3]

[3] *Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Petition for an Accounting Order*, Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, p. 14 (December 30, 2016).

Paragraphs five and seven referenced in this sentence identified federal regulations promulgated by the EPA regarding CCRs and state requirements under the Coal Ash Management Act. In its 2017 Rate Case order, the Commission noted in Finding of Fact number 66:

> DEC expects to incur substantial costs related to CCRs in future years. It is just and reasonable to allow deferral of those costs, with a return at the net-of-tax overall cost of capital approved in this Order during the deferral period. Ratemaking treatment of such costs will be addressed in future rate cases.

While the Commission's ruling did not make a distinction between CCR-related costs that are associated with compliance activities considered an Asset Retirement Obligation ("ARO") and those that are not, the Company maintains that its previous request for deferral of costs to comply with federal and state laws related to CCRs included both ARO and non-ARO costs was authorized by the Commission after review and consideration of the Company's petition for deferral. Therefore, the Commission should not reverse its previous authorization to defer these costs.

Remaining Adjustments Opposed by the Company

Q. OF THE REMAINING ADJUSTMENTS THAT THE COMPANY OPPOSES, WHICH ONES ARE RESPONDED TO BY OTHER COMPANY WITNESSES?

A. The following Public Staff adjustments from Boswell Exhibit 1, Schedule 1, are responded to by other Company witnesses in rebuttal testimony, using the reference numbers:

Line 5 - Change in equity ratio from 53.00% to 50.00% equity

The Company opposes this adjustment for the reasons set forth in the rebuttal testimony of Company witness Newlin.

Line 7 - Change in return on equity from 10.3% to 9.00%

The Company opposes this adjustment for the reasons set forth in the rebuttal testimony of Company witness Hevert.

Line 11 – Adjust Belews Creek DFO

The Company opposes this adjustment for the reasons set forth in the rebuttal testimony of Company witnesses Doss and Immel.

Line 12 – Updated working capital investments for changes in allocation factor

The Company opposes the Public Staff’s recommendations related to changes in allocation factors used in the Company’s Cost of Service Study, as explained in the rebuttal testimony of Company witness Hager. As a result, the Company opposes this adjustment to working capital.

Line 28 – Adjust lobbying expenses

The Company opposes the Public Staff’s recommendation for the reasons set forth in the rebuttal testimony of Company witness Speros.

Line 19 – Adjust executive compensation, Line 23 - Adjust incentives and Line 29 –Adjust Board of Directors expense

The Company opposes these adjustments for the reasons set forth in the rebuttal testimony of Company witness Metzler.

Line 22 –Adjust depreciation rates

The Company opposes this adjustment for the reasons set forth in the rebuttal testimony of Company witness Spanos.

Q. ARE THERE OTHER CHANGES INCORPORATED IN MCMANEUS REBUTTAL EXHIBIT 1 THAT ARE NOT YET ADDRESSED IN YOUR REBUTTAL TESTIMONY?

A. Yes. McManeus Rebuttal Exhibit 1 also revises amounts previously presented in McManeus Supplemental Exhibit 1, filed February 14, 2020, for the following pro forma adjustments to test period amounts:

Line 6 – Adjust for costs recovered through non-fuel riders

The amount previously shown on McManeus Supplemental Exhibit 1 filed on February 14, 2020 was incorrect due to a formula error on NC-0601 line 20, which is now corrected in McManeus Rebuttal Exhibit 1.

Line 22 – Synchronize interest expense with end of period rate base

This adjustment to income tax expense has been revised to reflect the impacts of revisions discussed earlier in my testimony affecting rate base and the associated annualized interest expense.

Line 29 – Update deferred balance and amortize storm costs

The Company has revised the deferred balance and associated amortization to reflect a new “deductible” amount. This amount is the highest annual storm cost in the most recent 10-year period. Storm costs eligible for deferral are amounts in excess of this deductible amount. This revision is shown on NC-2906.

Line 34 – Remove/reclassify certain test period expenses

This new pro forma adjustment is added to remove certain O&M amounts related to retired hydro units, as proposed by the Public Staff (Boswell Exhibit 1, item 36). The Company agrees with the Public Staff adjustment. This new proforma adjustment is used to make other revisions to advertising expense and distribution O&M expense as previously addressed in my rebuttal testimony.

III. DEFERRAL REQUEST FOR GRID IMPROVEMENT PLAN

Q. ARE THERE ISSUES RAISED BY INTERVENING PARTIES REGARDING THE COMPANY'S REQUEST FOR AUTHORIZATION TO DEFER GRID IMPROVEMENT PLAN COSTS THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. Many comments by intervening parties are addressed by Company witness Oliver in his rebuttal testimony, but there are a few topics that I will address with regard to cost recovery and ratemaking practices.

Q. HOW ARE CUSTOMER RATES AFFECTED BY AUTHORIZATION TO DEFER GRID IMPROVEMENT PLAN COSTS?

A. Cost recovery is a separate and distinct process from deferral of costs. Customer rates in this proceeding are not impacted by the Commission's decision to permit cost deferral.

Q. HOW DOES THE COMPANY BENEFIT FROM AUTHORIZATION TO DEFER COSTS?

A. Authorization to defer costs allows the Company the opportunity to avoid adverse financial impacts of regulatory lag, but only to the extent the Commission ultimately allows recovery of the deferred cost in a future rate proceeding. Although the Company has typically experienced adverse regulatory lag impacts related to its distribution and transmission investments in the past, the types of investments, the level of costs, and the overall scale of the Grid Improvement Plan leads the Company to request deferral of the associated revenue requirements. If allowed to defer Grid Improvement Plan related costs, the Company still bears risk of recovering the costs in a future rate proceeding.

Q. PLEASE CLARIFY COSTS FOR WHICH DEFERRAL IS REQUESTED

A. Contrary to what is implied in some intervenor testimony, the Company is not requesting deferral of its capital expenditures. DE Carolinas requests to defer the traditional revenue requirement amounts associated with the Grid improvement Plan capital expenditures. Following traditional ratemaking principles, when the Company makes capital investments as part of the Grid Improvement Plan, the cost to be deferred will be the depreciation and return on investment for the completed plant in service. For example, if the Company invests in a transmission related capital project that takes 6 months to complete, there would be no capital costs deferred during the 6-month construction period.

But once the project is completed and the transmission asset is in service, the associated deferral of costs would be the annual depreciation expense and return on the investment. For clarity, if the Company spends $1.2 billion in capital over a three-year period, the deferred cost associated with that amount is not $1.2 billion, but instead is three years of annual depreciation and return on that investment, beginning at the date the assets are completed and in service. In addition to these traditional revenue requirement amounts of depreciation and return on investment, the deferral would include the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when Company rates are updated to include cost recovery of the assets.

Q. DO YOU AGREE WITH THE RESTRICTIONS TO COST DEFERRAL RECOMMENDED BY PUBLIC STAFF WITNESS MANESS?

A. No. I do not think it is appropriate to exclude costs that are directly related to the Grid Improvement Plan programs for which the Company is requesting deferral. In his supplemental testimony filed February 25, 2020, witness Maness proposes to exclude deferral of a return on the balance of deferred incremental capital costs and incremental expenses. This return represents the financing costs the Company will incur between the time the Grid Improvement Plan costs are incurred and the time that such costs are approved for recovery in future rates.

The three-year Grid Improvement Plan comprises numerous projects that will have short construction periods and therefore will be quickly placed into electric service, e.g.. after one month, three months, six months, etc. Given the length of time to complete a general rate case, if the Company had a rate case every year, the delay in cost recovery, from the month that the grid improvement is placed in service to the month that the costs are reflected in the Company's new base rates, could be significant – on average more than a year. If rate cases did not occur every year, then this lag in the timing of cost recovery is multiplied. In contrast, such lengthy delays have been avoidable for large generation investments, where rate cases are often timed around the estimated completion date of the single large investment. In such rate cases, the Company frequently requests and is granted recovery of the costs incurred from the date the generating plant is placed into service to the date that new rates become effective, through a regulatory deferral and amortization of the costs. As a result, there can be minimal regulatory lag for this type of investment. In contrast, the impact of regulatory lag for the Grid Improvement Plan is substantial, and the Company believes it should be given the opportunity to recover <u>all</u> prudently incurred Grid Improvement Plan costs through future rate adjustments by being allowed to defer all of the costs associated with the Grid Improvement Plan, including all financing costs.

Q. PLEASE COMMENT ON THE ANALYSIS OF RETURN ON EQUITY (ROE) IMPACTS PREPARED BY THE PUBLIC STAFF AND ADDRESSED IN THE SUPPLEMENTAL TESTIMONY OF WITNESS MANESS?

A. Witness Maness performed an analysis of the estimated impact on the Company's ROE if deferral of Grid Improvement Plan amounts is not authorized. The Public Staff's analysis differs, in some respects, from the analysis prepared and filed by the Company as part of my direct testimony. The main difference is that the Public Staff analysis is based on a subset of six Grid Improvement Plan programs, and consequently a considerably smaller amount of capital expenditures. The negative impact in ROE as estimated by the Public Staff reached 38 basis points in the final year of the program (2022), as compared to over 100 basis points per the Company's computation. Witness Maness noted that under "normal circumstances" he would not recommend deferral for this magnitude of ROE impact. However, he concluded that he would not object to the Company's request for deferral of amounts related to the subset of six programs in this case for one reason. His single reason for not opposing the deferral was his consideration of the Commission's comments in its order in DEC's 2017 Rate Case, where it stated that it might rely on leniency in imposing the "extraordinary expenditure" test of deferrals when considering grid improvement program deferrals. I think it is worth noting, however, the extensive rebuttal testimony of Company witness Oliver addressing the Public

Staff's recommendation that only six programs should qualify for deferral. Witness Oliver's testimony provides substantial support for authorization of deferral for all Grid Improvement Plan amounts, and as such, I contend that the ROE impact presented in my direct testimony is the appropriate impact for the Commission to consider in making their decision.

Q. IS DEFERRAL OF COST AN EXAMPLE OF SINGLE ISSUE RATEMAKING?

A. No. Contrary to the allegation made by some intervenors, as noted above, deferral accounting is not ratemaking at all. Authorization to defer costs does not authorize cost recovery or result in a change in customer rates. Nor is it a pre-approval of cost recovery. Deferred revenue requirements must be considered for recovery in a general rate case proceeding, and in conjunction with all other electric costs subject to consideration in the proceeding.

Q. WHEN DEFERRED COSTS ARE PRESENTED IN FUTURE RATE PROCEEDINGS FOR RECOVERY, WILL THE COSTS BE AMBIGUOUS?

A. No. In the direct testimony of Witness Alvarez, he comments that "If deferral accounting is approved, we do not know what DEC (or DEP) will spend on the Grid Improvement Plan, and how the spending will be split among the programs. This ambiguity is extremely concerning to me, and I believe it should concern the Commission as well." For clarity, if the Commission authorizes the deferral of costs related to the Grid Improvement Plan, the Company will initially record the expenditures for all programs according to normal FERC accounting requirements. This means that expenditures will be classified functionally (i.e., production, transmission, distribution, general) and recorded to the appropriate electric plant or electric or operating expense account as if no deferral exists. As a second step, the Company will record special journal entries to reclassify the costs which it is authorized to defer into a regulatory asset account. The specific costs must be identifiable and tracked, according to the Grid Improvement Plan programs as described in Oliver Direct, Exhibit 10, to record the deferral accounting entry. As such, when the Company requests cost recovery of the deferred amounts in a future general rate case, the details of the deferred amounts will be known. Such details must be known in order for the Commission to assess the reasonableness and prudency of the expenditures, which is a prerequisite for approval of recovery.

Q. IS IT ACCURATE TO DESCRIBE THE AUTHORIZATION FOR DEFERRAL AS GRANTING THE COMPANY "A POT OF MONEY IT CAN INVEST AS IT WISHES"?

A. No. This characterization, made by the Center of Biological Diversity/Appalachian Voices witness Stephens, incorrectly infers that the investments for which the Company is granted authorization for cost deferral are not subject to review and scrutiny and a finding of reasonableness and prudency as a prerequisite for cost recovery. The implication is that the Company bears no risk with regard to amounts that the Company spends and thus is incented to spend indiscriminately. On the contrary, Grid Improvement Plan expenditures, like all expenditures, are at risk for recovery. The authorization to defer the costs does not guarantee recovery of the costs. Instead, it simply allows the Company to identify the costs for deferral and record them as a regulatory asset for *potential* future recovery through future rate adjustments.

The estimated amounts related to the Grid Improvement Plan are provided in the Company's filed testimony and exhibits to allow the Commission to determine whether the costs should qualify for deferral treatment. However, it is the actual costs incurred that are ultimately deferred and then brought forward for potential cost recovery. Recovery will ultimately be based on actual costs, not estimated costs, nor an estimated total amount for the entire program. A determination will be made as to the reasonableness and prudency of the actual program expenditures, and those found to be unreasonable or imprudent will be disallowed recovery. Intervenors express concern that customers bear the risk of cost overruns or scope shortcomings that could be addressed by the imposition of spending caps. I would note that although the Commission has the discretion to impose such caps on the amounts the Company is authorized to defer, the Commission at present has full authority to address cost overruns or scope issues during a future general rate case when the deferred cost are presented for recovery, and the Company bears the full risk of any disallowances the Commission could choose to impose.

IV. ISSUES RAISED BY OTHER INTERVENORS

Q. ARE THERE ANY OTHER ISSUES RAISED BY OTHER INTERVENING PARTIES THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. I would like to address comments by CUCA witness Kevin O'Donnell regarding customer rate impacts of "grid modernization" as presented in Table 3 of his testimony, and comments by Center of Biological Diversity/Appalachian Voices witness Greer Ryan that deferred capital costs related to storm damage should be treated as operating expenses. The grid modernization rate impact presented by witness O'Donnell is related to the PowerForward program, not the Grid Improvement Plan presented by Company witness Oliver in this proceeding. Witness O'Donnell uses information from February 2017 that he previously presented in his direct testimony filed in the 2017 Rate Case. He notes in his testimony that he is using these figures as "the Company has never submitted testimony in any public setting with a full set of cost estimates for the next 10 years." To the contrary, during the previous proceeding, while not in filed testimony, the Company submitted a supplemental data request response to CUCA and other intervenors providing updated rate impact information, as of February **2018** (supplemental update to CUCA Data Request 1-1). The updated customer rate impacts provided were substantially lower than what is presented in Table 3 of Mr. O'Donnell's direct testimony in this case. McManeus Rebuttal Exhibit 3 is a copy of the rate impact information for PowerForward that was provided to intervenors in the

2017 Rate Case. Moreover, not only is the PowerForward program data presented by witness O'Donnell outdated, but, as discussed in Company witness Oliver's rebuttal testimony, the Grid Improvement Plan is dramatically different in scope than the earlier PowerForward program.

Next, with regard to the recommendation by witness Ryan related to storm repair costs, witness Ryan gives an opinion that it "contravenes rate regulation principles" to capitalize costs incurred to restore electricity service to "status quo" and that such expenditures should be considered an operating expense. I disagree. In cases where storm repair costs have been capitalized, investor-supplied capital were invested in long-lived assets that will provide benefits to customers over many years, thus it would be inappropriate to treat them as operating expenses.

Further she states that a utility is generally entitled to earn a return on capital expenses made to "improve electricity service." This principle is not supported by traditional ratemaking policy. To the contrary, the utility is generally entitled to earn a return on capital expenditures made to PROVIDE electricity service, under its obligation to serve customers in its assigned service area. Under the principles espoused by witness Ryan, the Company would be denied recovery of financing costs for investor funds used to replace aging infrastructure to maintain existing electric service, to replace power poles and transformers destroyed by vehicle accidents to restore service, to repair transformers impacted by a lightning strike to restore service, to replace conductor or poles brought down by tree limbs falling due to wind gusts to restore service, or to restore to service equipment damaged during flooding at substations due to rainfall from a severe thunderstorm.

V. PROPOSED EDIT RIDER

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATIONS OF PUBLIC STAFF WITNESS BOSWELL AND TECH CUSTOMERS WITNESS STRUNK REGARDING THE FLOWBACK OF EDIT TO CUSTOMERS?

A. No. Both witnesses Boswell and Strunk recommend a much faster flowback of PP&E-related unprotected EDIT – over 5 years – than the 20-year flowback proposed by the Company. The Company continues to believe that the EDIT Rider it has proposed is a fair balancing of relevant issues. As noted in Company witness Newlin's rebuttal testimony, the proposed EDIT rider returns amounts that are clearly owed to customers. However, witness Newlin explains that it is prudent for any proposal for return of these amounts to customers to consider the impact on the financial strength of the Company, which ultimately affects its cost to serve customers. He explains in detail the adverse impact that will occur if a 5-year flowback is required.

Witness Boswell notes on page 34 of her testimony that the EDIT funds "rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible." The Company agrees. She also states that the Company's proposal is "not supportable by any logical accounting or ratemaking principle." As explained in the rebuttal testimony of Company witness Newlin, the ratemaking principles that the Company is considering in its proposed EDIT Rider are rate volatility and minimizing costs to customers – financing costs, in particular. On page 35 of her testimony, witness Boswell asserts:

> 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.

As explained in the rebuttal testimony of Company witness Newlin, the Company does not agree with her assessment that her recommendation will appropriately moderate cash flow issues.

Witness Boswell's recommended adjustments to the Company's proposal are to shorten the time period in which the Company returns funds to customers. As I noted earlier in my rebuttal testimony, the Public Staff's recommendations on amortization periods tends to be asymmetrical; extending amortization periods proposed by the Company when the amortization involves amounts to be collected from customers but shortening amortization periods when the amortization involves amounts to be refunded to customers. The Company continues to oppose this asymmetrical treatment, especially given the cash flow concerns raised by Company witness Newlin in his rebuttal testimony.

In addition to the Company's opposition to the Public Staff's overall proposal to return EDIT to customers, I would note that witness Boswell's exhibits reflect only one side of the $80 million transition of EDIT from the protected to the unprotected EDIT categories over 1/1/2019 – 7/31/2020. While her levelized Federal EDIT – Unprotected rider does reflect the effect of this transition and the resulting flowback of greater revenue reductions, her calculation of the protected EDIT in bases rate excludes the off-setting transition impact and consequent increase in rate base.

This is not correct and is not consistent with how this transition is treated in the McManeus Exhibit 4, filed with my direct testimony, which captures both offsetting effects of the transition on page 1, line 8 of McManeus Exhibit 4 when calculating rate base return impacts in the EDIT rider in page 2 of McManeus Exhibit 4 (columns A, K and L in year 1).

VI. <u>CONCLUSION</u>

Q. IS THE COMPANY PROPOSING ANY CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. No, not at this time.

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

A. Yes.

I. INTRODUCTION

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

A. My name is Jane L. McManeus, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on September 30, 2019 and filed corrected direct testimony on October 23, 2019. I also filed supplemental direct testimony and exhibits on February 14, 2020, and rebuttal testimony and exhibits on March 4, 2020.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Agreement and Stipulation of Partial Settlement ("Partial Settlement") between the Company and the Public Staff ("Stipulating Parties") by commenting on certain accounting and ratemaking adjustments agreed upon therein.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR SETTLEMENT SUPPORTING TESTIMONY?

A. No. As noted in my rebuttal testimony, I plan to supplement my rebuttal testimony after the Public Staff has completed their supplemental filings. At that time, I will file updated exhibits that reflect the Company's position, including incorporating the impacts of settled issues.

III. AGREEMENT AND PARTIAL SETTLEMENT WITH PUBLIC STAFF

Q. DOES THE COMPANY BELIEVE THE PARTIAL SETTLEMENT REPRESENTS A BALANCED COMPROMISE THAT PROVIDES AN EQUITABLE RESOLUTION FOR CERTAIN ITEMS IN THIS PROCEEDING FOR ITS SHAREHOLDERS, CUSTOMERS AND OTHER STAKEHOLDERS?

A. Yes. The Company believes the Partial Settlement with the Public Staff balances the financial impact of the rate increase on our customers with the Company's need to recover its revenue requirement, for the items included in the Partial Settlement, and our obligation to provide safe and reliable electric utility service to our customers.

Q. PLEASE EXPLAIN THE ACCOUNTING ADJUSTMENTS INCLUDED IN THE PARTIAL SETTLEMENT.

A. While the complete list of adjustments is described in the Partial Settlement, the following are additional comments on certain accounting adjustments identified in the Partial Settlement:

1. Storm costs

The Stipulating Parties agree to the adjustments proposed by the Public Staff related to storm cost deferral and amortization, and that the Company will proceed with filing a petition to securitize the storm costs incurred in response to

Hurricanes Florence and Michael and Winter Storm Diego. For purposes of settlement, the Stipulating Parties also agree upon the assumptions to be used in the subsequent securitization docket for purposes of demonstrating quantifiable benefits to customers of securitization. In addition, the Stipulating Parties agree that a storm cost recovery rider, initially set at $0, should be established in this rate case to provide the Company a mechanism to request recovery of its storm costs if the Company is unable to securitize its storm costs.

2. Adjust aviation expenses

The Stipulating Parties agree to an adjustment that removes 50% of the aviation costs allocated to DE Carolinas, as proposed in my direct testimony. In addition, the Company agrees with the Public Staff adjustment to remove aviation costs allocated to DE Carolinas related to commercial international flights.

3. Adjust O&M for executive compensation

As noted in my direct testimony, the Company has made an adjustment to remove 50 percent of the compensation of the five Duke Energy executives with the highest amounts of compensation. In the Partial Settlement, the Company has agreed to also remove 50 percent of the benefits associated with those five executives.

4. Amortize rate case expenses

The Stipulating Parties agree to amortize Company rate case expenses over a 5-year amortization period. The Stipulating Parties agree that the deferred balance will not be included in the Company's rate base, and therefore will not earn a return.

5. Adjust incentives included in O&M labor expenses

The Stipulating Parties agree to accept the Public Staff's adjustment to remove certain incentive pay related to earnings per share and total shareholder return for senior leaders within the Company.

6. Adjust sponsorships and donations expense

The Stipulating Parties agree that certain sponsorships and donations expenses, including amounts paid to the U.S. Chamber of Commerce, should be removed.

7. Amortize severance costs

The Stipulating Parties agree to amortize test period severance costs over a 3-year amortization period. The Parties agree that the deferred balance will not be included in the Company's rate base, and therefore will not earn a return.

8. Adjust lobbying, Board of Directors' related expense, retired hydro O&M expense

The Stipulating Parties agree that the adjustments proposed by the Public Staff to remove (a) certain O&M expenses considered to be related to lobbying activities, (b) a portion of the Company's expenses related to its Board of Directors, and (c) O&M expense related to retired hydro facilities, should be accepted.

9. Adjust credit card fees and advertising expenses

The Stipulating Parties agree that the Company's adjustments to credit card fees and advertising expenses as proposed in my rebuttal testimony and exhibits are acceptable.

10. Weather normalization, customer growth and customer usage

The Company accepts the Public Staff's updated recommended adjustments to weather normalization, growth, and usage as reflected in Boswell Supplemental and Stipulation Exhibit 1.

11. Flowback of protected federal EDIT

The Stipulating Parties agree to refund certain amounts owed to customers related to excess deferred income taxes, resulting from the reduction in federal corporate income taxes according to the Tax Cuts and Jobs Act, through a reduction in base rates rather than through a rider. The particular amounts are the "protected" EDIT amounts, generally related to Property, Plant and Equipment, for which there are specific ratemaking requirements prescribed by the IRS.

Q. IN YOUR OPINION, DOES THE PARTIAL SETTLEMENT REFLECT A FAIR, JUST, AND REASONABLE RESOLUTION OF THE ISSUES IT ADDRESSES?

A. Yes. As stated previously, the Partial Settlement is the result of negotiations between the Stipulating Parties and resolves many of the issues in the case between the Stipulating Parties without the necessity of contentious litigation.

Therefore, we respectfully request that the Commission approve the Partial Settlement in its entirety.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR SETTLEMENT SUPPORT TESTIMONY?

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Jane L. McManeus, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on September 30, 2019 and filed corrected direct testimony on October 23, 2019. I also filed supplemental direct testimony and exhibits on February 14, 2020, rebuttal testimony and exhibits on March 4, 2020, and settlement testimony on March 25, 2020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the supplemental and settlement testimony filed by the Public Staff on March 25, 2020. I also provide revisions to my rebuttal testimony and exhibits, based on the Agreement and Stipulation of Partial Settlement ("Partial Settlement") between the Company and the Public Staff ("Stipulating Parties") filed on March 25, 2020.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Yes. As noted in my settlement testimony, I am filing updated exhibits that reflect the Company's current position, including incorporating the impacts of settled issues. McManeus Supplemental Rebuttal Exhibit 1 shows adjustments to the revenue requirements as presented in McManeus Rebuttal Exhibit 1 and incorporates specific items for which the Company and the Public Staff have reached agreement, as identified in the Partial Settlement. McManeus Supplemental Rebuttal Exhibit 2 summarizes the proposed revenue adjustments in this proceeding, including the proposed increase in base rates and the reduction in revenues reflected in the proposed EDIT rider. McManeus Supplemental Rebuttal Exhibit 3 reconciles the revenue requirement as presented in my rebuttal testimony to the revenue requirement proposed in this supplemental rebuttal testimony. Finally, McManeus Supplemental Rebuttal Exhibit 4 is an updated proposed EDIT rider that reflects removal of protected EDIT to be refunded through base rates.

Q. PLEASE DESCRIBE CHANGES PROPOSED TO THE COMPANY'S REQUESTED REVENUE INCREASE.

A. The following table has been updated to reflect additional adjustments proposed by the Company, as a result of the Partial Settlement, for purposes of determining its requested revenue increase. The particular items revised in this filing are shown in bold text.

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES		
Line No.	**Adjustment Title**	**Witness**
1	Annualize retail revenues for current rates	Pirro
2	Update fuel costs to proposed rate	McGee
3	Normalize for weather	Pirro
4	**Annualize revenues for customer growth**	**Pirro**
5	Eliminate unbilled revenues	McManeus
6	Adjust for costs recovered through non-fuel riders	McManeus

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES		
Line No.	**Adjustment Title**	**Witness**
7	**Adjust O&M for executive compensation**	**McManeus**
8	Annualize depreciation on year end plant balances	McManeus
9	Annualize property taxes on year end plant balances	McManeus
10	Adjust for post-test year additions to plant in service	McManeus
11	Amortize deferred environmental costs	McManeus
12	**Annualize O&M non-labor expenses**	**McManeus**
13	**Normalize O&M labor expenses**	**McManeus**
14	Update benefits costs	McManeus
15	Levelize nuclear refueling outage costs	McManeus
16	**Amortize rate case costs**	**McManeus**
17	**Adjust aviation expenses**	**McManeus**
18	Adjust for approved regulatory assets and liabilities	McManeus
19	Adjust for merger related costs	McManeus
20	**Amortize severance costs**	**McManeus**
21	Adjust for NC income tax rate change	McManeus
22	**Synchronize interest expense with end of period rate base**	**McManeus**
23	**Adjust cash working capital for present revenue annualized and proposed revenue**	**McManeus**
24	Adjust coal inventory	McManeus
25	Adjust credit card fees	McManeus
26	Adjust for new depreciation rates	McManeus
27	Adjust vegetation management expenses	McManeus
28	Adjust reserve for end of life nuclear costs	McManeus
29	**REVISED Remove storm costs for securitization ~~Update deferred balance and amortize storm costs~~**	**McManeus**
30	Adjust other revenue	Pirro
31	Adjust for change in NCUC regulatory fee	McManeus
32	Adjust for hydro stations sale	McManeus
33	Adjust for cash working capital for lead-lag revision	McManeus
34	Remove/reclassify certain test period expenses	McManeus
35	**NEW Amortize protected EDIT**	**McManeus**
36	**NEW Adjust for certain settlement items**	**McManeus**
37	**NEW Normalize storm costs**	**McManeus**

II. UPDATES TO THE COMPANY'S TEST PERIOD OPERATING EXPENSES IN RESPONSE TO THE PARTIAL SETTLEMENT

Q. HOW HAS THE COMPANY INCORPORATED THE PARTIAL SETTLEMENT PROVISION RELATED TO STORM COSTS INTO THIS FILING?

A. To properly reflect the agreement of the Stipulating Parties for DE Carolinas to pursue securitization of storm costs of Hurricanes Florence and Michael and Winter Storm Diego, the Company has changed its original pro forma adjustment, which amortized the deferred balance of storm costs over 8 years, including a return on the unamortized balance, to an adjustment that removes amounts related to these storms from test period rate base and test period expenses. Specifically, pro forma number 29 removes the net book value of capitalized storm repair costs from rate base and removes the associated annual depreciation expense from electric expenses.

Q. WHAT OTHER ADJUSTMENTS ARE BEING PROPOSED AS A RESULT OF THE PARTIAL SETTLEMENT?

A. Three new adjustments identified in the table above are necessary to incorporate the Partial Settlement impacts into the revenue increase proposed by the Company.

35 – Amortize protected EDIT

Electric operating expenses are updated to reflect annual amortization of protected EDIT. The amount of amortization is based on compliance with Internal Revenue Service rules related to protected EDIT. In addition, the

Company's adjustment reduces the protected EDIT balance in rate base by one year of amortization.

36 – Adjust expenses for settlement items

This adjustment removes agreed upon amounts from electric expenses, as stated in the Partial Settlement. Items include sponsorship expenses, expenses the Public Staff considers to be lobbying-related, and Board of Directors expenses.

37 – Normalize storm costs

This adjustment incorporates the Public Staff's recommendation to normalize storm expenses, as agreed to in the Partial Settlement, based on a 10-year average of storm costs that are not significant enough to be considered for securitization.

In addition, the following previously filed adjustments are being updated as a result of the Partial Settlement.

4 - Annualize revenues for customer growth

7 - Adjust O&M for executive compensation

13 - Normalize O&M labor expenses

16 - Amortize rate case costs

17 - Adjust aviation expenses

20 - Amortize severance costs

Q. ARE THERE OTHER ITEMS IDENTIFIED IN THE PARTIAL SETTLEMENT THAT ARE NOT YET ADDRESSED IN THIS TESTIMONY?

A. Yes. Several other items for which the Stipulating Parties have noted agreement in the Partial Settlement do not require adjustment, as the amounts agreed to are the amounts filed by the Company in its rebuttal testimony. Those items are (1) normalize for weather, (2) retired hydro O&M, (3) credit card fees, and (4) advertising expense.

III. <u>OTHER ADJUSTMENTS/ITEMS</u>

Q. ARE THERE ANY OTHER ADJUSTMENTS THE COMPANY IS PROPOSING?

A. Yes. Upon review of the Public Staff witness Boswell's supplemental and settlement testimony and Public Staff witness Woolridge's supplemental testimony filed on March 25, 2020, the Company has updated the embedded cost of long-term debt rate, as shown on McManeus Supplemental Rebuttal Exhibit 1, Page 2, to the actual January, 2020 rate. In addition, certain test period adjustments by nature are affected by changes made to other adjustments. In this case, adjustment numbers 12, 22, and 23 are updated to reflect the impact of changes to other adjustments.

Q. PLEASE EXPLAIN THE REVISIONS TO THE COMPANY'S PROPOSED EDIT RIDER SHOWN ON MCMANEUS SUPPLEMENTAL REBUTTAL EXHIBIT 4.

A. As a result of the Partial Settlement, the Company has removed the amount of protected EDIT from its proposed rider and included the refund of this amount to customers in its proposed base rates. Other amounts to be refunded to customers, made up of unprotected federal EDIT, state EDIT and deferred revenue, are included in the revised rider as originally proposed.

Q. ARE THERE ANY ITEMS IN THE PUBLIC STAFF'S SUPPLEMENTAL AND SETTLEMENT TESTIMONY FOR WHICH YOU HAVE COMMENTS?

A. Yes. The Public Staff proposed an adjustment to remove Clemson CHP plant and depreciation expense as identified in the supplemental and settlement testimony of witness Boswell. The Company opposes this adjustment for the reasons set forth in the supplemental rebuttal testimony of Company witnesses Zachary Kuznar and Janice Hager.

IV. CONCLUSION

Q. DO YOUR SUPPLEMENTAL REBUTTAL EXHIBITS REFLECT A CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. Yes. The Company requests a revenue increase from base rates of $367.6 million. In addition, the Company requests that customer rates be reduced by

$123.8 million through its proposed EDIT rider. As shown on McManeus Supplemental Rebuttal Exhibit 2, the net proposed increase in revenue is $243.9 million. This is a $47 million reduction from the amount proposed in the Company's Application.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Jane L. McManeus, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on September 30, 2019 and filed corrected direct testimony on October 23, 2019. I also filed supplemental direct testimony and exhibits on February 14, 2020, rebuttal testimony and exhibits on March 4, 2020, settlement testimony on March 25, 2020, and supplemental rebuttal testimony and exhibits on April 6, 2020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to update the Company's proposed revenue increase. An update is necessary to incorporate certain known and measurable changes through May 31, 2020. The specific items updated are identified later in my testimony.

II. UPDATES TO THE COMPANY'S TEST PERIOD OPERATING REVENUES, EXPENSES, AND RATE BASE

Q. WHAT ADJUSTMENTS TO REVENUE REQUIREMENTS ARE PROPOSED BY THE COMPANY?

A. The Company is updating its proposed revenue requirements to incorporate certain known and measurable changes to its revenues, expenses, and rate base amounts previously filed in this Docket. These updates are limited, and are based on actual revenue, expense, and rate base amounts as of May 31, 2020. The updates are necessary and appropriate to provide the Company a reasonable opportunity to earn the return on equity approved by the Commission in this proceeding. Due to the extraordinary circumstances of the COVID-19 pandemic, the hearing and corresponding Commission order establishing rates in this case have been unavoidably delayed, and the Company voluntarily waived its right to implement permanent rates 270 days after. Consequently, updating the Company's costs closer in time to the start of the hearing gives a more recent depiction of the Company's actual costs to serve its customers, which should be reflected in the Company's rates.

Q. WHAT OTHER ADJUSTMENTS ARE BEING PROPOSED AS A RESULT OF THE UPDATES DISCUSSED ABOVE?

A. Since the Company is updating its post-test year capital additions to reflect completed electric plant in service as of May 31, 2020, it is appropriate to also update the timing of the Company's requested deferral period for Grid Improvement Plan ("GIP") costs. The Company is requesting deferral of investments that are not included in this rate case. Now, with the inclusion of plant in service through May 31, 2020, the Company's requested deferral of incremental GIP costs would start with plant placed in service beginning June 1, 2020 and continuing through December 31, 2022.

Q. WHAT ADDITIONAL INFORMATION IS BEING SUBMITTED IN THIS FILING?

A. DE Carolinas is also providing information which reflects the impact of the following settlement agreements it has entered into with intervenors (the "Intervenor Settlements"):

- Settlement Agreement with Harris Teeter, LLC filed May 28, 2020;
- Agreement and Stipulation of Settlement with Carolina Industrial Group for Fair Utility Rates III filed May 29, 2020; and
- Settlement Agreement with the Commercial Group filed June 1, 2020.

Commission approval of these agreements would result in revenue requirements based on 9.75% return on equity ("ROE") and a capital structure of 52% common equity and 48% long-term debt.

As described later in my testimony, the Company is submitting additional exhibits in this filing demonstrating the reduction to its proposed revenue increase (now based on post-test period updates through May 31, 2020) resulting from the ROE and capital structure agreed to in the Intervenor Settlements.

Q. WHICH "PRO FORMA" ADJUSTMENTS TO TEST PERIOD AMOUNTS ARE BEING UPDATED IN THIS FILING?

A. The following table shows the particular items revised in this filing in bold text.

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES				
Line No.	**Adjustment Title**	**Witness**	**May 2020 Update**	**ROE or Cap Str Change**
1	Annualize retail revenues for current rates	Pirro		
2	Update fuel costs to proposed rate	McGee		
3	Normalize for weather	Pirro		
4	**Annualize revenues for customer growth**	**Pirro**	**X**	
5	Eliminate unbilled revenues	McManeus		
6	Adjust for costs recovered through non-fuel riders	McManeus		
7	Adjust O&M for executive compensation	McManeus		
8	Annualize depreciation on year end plant balances	McManeus		
9	Annualize property taxes on year end plant balances	McManeus		
10	**Adjust for post-test year additions to plant in service**	**McManeus**	**X**	
11	Amortize deferred environmental costs	McManeus		
12	**Annualize O&M non-labor expenses**	**McManeus**	**X**	
13	**Normalize O&M labor expenses**	**McManeus**	**X**	
14	Update benefits costs	McManeus		
15	Levelize nuclear refueling outage costs	McManeus		
16	Amortize rate case costs	McManeus		
17	Adjust aviation expenses	McManeus		
18	Adjust for approved regulatory assets and liabilities	McManeus		
19	**Adjust for merger related costs**	**McManeus**	**X**	
20	Amortize severance costs	McManeus		
21	Adjust for NC income tax rate change	McManeus		
22	**Synchronize interest expense with end of period rate base**	**McManeus**	**X**	**X**
23	**Adjust cash working capital for present revenue annualized and proposed revenue**	**McManeus**	**X**	**X**
24	Adjust coal inventory	McManeus		
25	Adjust credit card fees	McManeus		
26	Adjust for new depreciation rates	McManeus		
27	Adjust vegetation management expenses	McManeus		
28	Adjust reserve for end of life nuclear costs	McManeus		

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES				
Line No.	**Adjustment Title**	**Witness**	**May 2020 Update**	**ROE or Cap Str Change**
29	**REVISED Remove storm costs for securitization** ~~**Update deferred balance and amortize storm costs**~~	**McManeus**	**X**	
30	Adjust other revenue	Pirro		
31	Adjust for change in NCUC regulatory fee	McManeus		
32	Adjust for hydro stations sale	McManeus		
33	Adjust for cash working capital for lead-lag revision	McManeus		
34	Remove/reclassify certain test period expenses	McManeus		
35	NEW Amortize protected EDIT	McManeus		
36	NEW Adjust for certain settlement items	McManeus		
37	NEW Normalize storm costs	McManeus		

Q. DO THE PROPOSED ADJUSTMENTS IMPACT THE AGREEMENT AND STIPULATION OF PARTIAL SETTLEMENT BETWEEN THE COMPANY AND THE PUBLIC STAFF FILED ON MARCH 25, 2020 (“PARTIAL SETTLEMENT”)?

A. No. In the Partial Settlement, the Company and the Public Staff agreed to certain adjustments to the revenue requirement in the Company’s supplemental filing on February 14, 2020. The updates through May proposed in this filing are new and were not included in the Company’s prior supplemental filing and therefore, were not part of the Partial Settlement with the Public Staff. However, to the extent a calculation methodology for a pro forma adjustment was agreed to in the Partial Settlement, the same methodology has been applied to the May updates.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR SECOND SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes. I am providing the following exhibits:

- McManeus Second Supplemental Exhibit 1 presents the impact of additional adjustments to test period operating income and rate base that the Company is supporting based on post-test period updates through May 31, 2020. Page 1 of the Exhibit summarizes the adjustments and the details for each adjustment are presented on the subsequent pages.
- McManeus Second Supplemental Exhibit 1-S takes McManeus Second Supplemental Exhibit 1 and layers in the additional impacts of the Intervenor Settlements – i.e., the 9.75% ROE and 52/48 capital structure.
- McManeus Second Supplemental Exhibit 2 summarizes the proposed total revenue adjustments in this proceeding, reflecting both the proposed increase in base rates and the reduction in revenues reflected in the proposed EDIT rider.
- McManeus Second Supplemental Exhibit 2-S takes McManeus Second Supplemental Exhibit 2 and layers in the additional impacts of the Intervenor Settlements – i.e., the 9.75% ROE and 52/48 capital structure.
- McManeus Second Supplemental Exhibit 3 is a reconciliation of adjustments to base revenue requirement. The reconciliation begins with the $367.6 million revenue requirement proposed by the Company in my

Supplemental Rebuttal testimony filed April 6, 2020.[1] Specific impacts related to May 2020 updates are itemized and summarized to show the resulting revenue requirement of $414.5 million after May updates. This total includes an adjustment to limit the net revenue requirement to the amount proposed in the Company's Application.

- McManeus Second Supplemental Exhibit 3-S takes McManeus Second Supplemental Exhibit 3 and layers in the additional adjustments related to the Intervenor Settlements to show the resulting base revenue requirement of $340.6 million.
- McManeus Second Supplemental Exhibit 4-S is an updated EDIT rider which incorporates the impacts of the Intervenor Settlements on the return component of the rider.

III. CONCLUSION

Q. DO YOUR SECOND SUPPLEMENTAL EXHIBITS REFLECT A CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. Yes. If the Commission approves the Intervenor Settlements, the Company requests a revenue increase from base rates of $340.6 million. In addition, the Company requests that customer rates be reduced by $123.6 million through its proposed EDIT rider. As shown on McManeus Second Supplemental Exhibit

[1] This amount incorporates impacts of the Agreement and Stipulation of Partial Settlement between DE Carolinas and the Public Staff filed on March 25, 2020.

2-S, the net proposed increase in revenue is $217 million. This is a $74 million reduction from the amount proposed in the Company's Application.

If the Commission does not approve the Intervenor Settlements, the Company requests a revenue increase from base rates of $414.5 million. In addition, the Company requests that customer rates be reduced by $123.8 million through its proposed EDIT rider. As shown on McManeus Second Supplemental Exhibit 2, the net proposed increase in revenue is $290.8 million. On this exhibit, the base rate revenue requirement amount from McManeus Second Supplemental Exhibit 1 has been adjusted such that the total requested increase equals the amount proposed in the Company's Application.

Q. DOES THIS CONCLUDE YOUR SECOND SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes.

I. INTRODUCTION AND PURPOSE

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

A. My name is Jane L. McManeus, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on September 30, 2019 and filed corrected direct testimony on October 23, 2019. I also filed supplemental direct testimony and exhibits on February 14, 2020, rebuttal testimony and exhibits on March 4, 2020, settlement testimony on March 25, 2020, supplemental rebuttal testimony and exhibits on April 6, 2020, and second supplemental direct testimony and exhibits on July 2, 2020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Second Agreement and Stipulation of Partial Settlement ("Second Partial Settlement") between the Company and the Public Staff ("Stipulating Parties"). The Second Partial Settlement was filed with the Commission on July 31, 2020.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR SETTLEMENT SUPPORTING TESTIMONY?

A. Yes. I am providing the following exhibits, all of which reflect the terms of the Second Partial Settlement:

- McManeus Second Settlement Exhibit 1 sets forth the operating results under current and proposed base rates.
- McManeus Second Settlement Exhibit 2 summarizes the total revenue adjustments proposed in this proceeding, including the proposed increase in base rates and the reduction in revenues reflected in the proposed EDIT rider.
- McManeus Second Settlement Exhibit 3 is a reconciliation of adjustments to base rate revenue requirements. The exhibit begins with the revenue increase amounts shown in my Second Supplemental Exhibit 3S and details the additional adjustments for which the Stipulating Parties reached agreement.
- McManeus Second Settlement Exhibit 4 provides the revised computation of the NC Retail amount of EDIT refund, based on the Public Staff's recommendation of a levelized rider.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

II. SECOND PARTIAL SETTLEMENT WITH PUBLIC STAFF

Q. DOES THE COMPANY BELIEVE THE SECOND PARTIAL SETTLEMENT REPRESENTS A BALANCED COMPROMISE THAT PROVIDES AN EQUITABLE RESOLUTION FOR CERTAIN ITEMS IN THIS PROCEEDING FOR ITS SHAREHOLDERS, CUSTOMERS AND OTHER STAKEHOLDERS?

A. Yes. The Company believes the Second Partial Settlement with the Public Staff balances the financial impact of the rate increase on our customers with the Company's need to recover its revenue requirement, for the items included in the Second Partial Settlement, and our obligation to provide safe and reliable electric utility service to our customers.

Q. IN YOUR OPINION, DOES THE SECOND PARTIAL SETTLEMENT REFLECT A FAIR, JUST, AND REASONABLE RESOLUTION OF THE ISSUES IT ADDRESSES?

A. Yes. As stated previously, the Second Partial Settlement is the result of negotiations between the Stipulating Parties and resolves many of the issues in the case between the Stipulating Parties without the necessity of contentious litigation. Therefore, we respectfully request that the Commission approve the Partial Settlement in its entirety.

III. CONCLUSION

Q. DO YOUR SECOND PARTIAL SETTLEMENT EXHIBITS REFLECT A CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. Yes. If the Commission approves the Second Partial Settlement the Company requests a revenue increase from base rates of $414 million. In addition, the Company requests that customer rates be reduced by $311 million through its proposed EDIT rider. As shown on McManeus Second Settlement Exhibit 2, the net proposed increase in revenue is $104 million. This is a $187 million reduction from the amount proposed in the Company's Application. These amounts may change based upon results from the Public Staff audit of the Company's May updates included in its July 2, 2020 second supplemental filing. The Public Staff audit is to be completed by September 8, 2020. In addition, these amounts assume the Commission accepts the Company's position on unsettled issues, thus are subject to change based on the Commission's decisions.

Q. ARE THERE OTHER CHANGES TO THE COMPANY'S APPLICATION FOR RATE INCREASE RESULTING FROM THE SECOND PARTIAL SETTLEMENT?

A. Yes. The Stipulating Parties agree that the Company will withdraw its request for deferral accounting for Grid Improvement Plan programs that are not named in the Second Partial Settlement as eligible for deferral. The Company hereby withdraws its request for deferral accounting of such programs.

Q. DOES THIS CONCLUDE YOUR SECOND PARTIAL SETTLEMENT TESTIMONY?

A. Yes.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jay W. Oliver. My business address is 400 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Solutions Engineering and Technology. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS GENERAL MANAGER, GRID SOLUTIONS ENGINEERING AND TECHNOLOGY FOR DUKE ENERGY.

A. My duties and responsibilities include planning for the grid and related system improvement efforts across Duke Energy.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology and a Master's degree in Business Administration from the University of South Florida. I am a licensed Electrical Engineer and a registered Professional Engineer in Florida. From 25 years working in the electric utility business, I have experience in electric transmission, distribution, and information technology and telecommunications systems that support utility transmission and distribution networks. I began working at Duke Energy in 1996, joining one of its predecessor companies, Florida Progress. Over the past 10 years, I have held the positions of Region General Manager, Director Distribution Services, Major Projects Manager, and Director, Grid Automation. I have been in my current role since January 2017.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER REGULATORY BODIES?

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC") in Duke Energy Progress, LLC's ("DE Progress") 2013 Demand Side Management/Energy Efficiency proceeding in Docket No. E-2, Sub 1030 and in DE Progress's 2014 Fuel Charge Adjustment proceeding in Docket No. E-2, Sub 1045. I also provided direct and rebuttal testimony in DE Progress and DE Carolinas' recent South Carolina base rate adjustment proceedings in Docket Nos. 2018-318-E and 2018-319-E.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying as an expert witness in this case in two separate capacities. In my capacity as the witness supporting ongoing operations, I describe and support the existing DE Carolinas' transmission and distribution ("T&D") system, the operation and performance of the T&D system, and the costs necessary to operate and maintain it. In my capacity as the witness supporting DE Carolinas' Grid Improvement Plan for North Carolina, I describe trends affecting the electric grid and how we plan to address those growing challenges through our Grid Improvement Plan.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following the introduction above, my testimony is organized as follows:

I. First, I will provide a description of DE Carolinas' T&D system, describing notable investments made in our system since the Company's last rate case in North Carolina and an overview of the operational performance of the Company's T&D system.

II. Second, I will describe the trends affecting the electric grid in the 21st century, how we analyze those issues, and how they will impact our grid if addressed through traditional means alone.

III. Third, I will describe the tools available to address the trends, explain how programs in the Grid Improvement Plan are evaluated, and present a foundational overarching Plan which addresses the issues in a stakeholder-informed manner.

IV. Finally, I will provide a three-year work plan for our 2020-2022 grid improvements with defined projects. I note we are requesting a corresponding deferral on future Grid Improvement Plan costs as further explained below and by Witness McManeus.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I have attached 18 total exhibits, described below:

Exhibit 1: Maintain Base Transmission and Distribution System Work- describing what work the Company does as base-level maintenance work;

Exhibit 2: Megatrends Impacting North Carolina - detailing key trends relevant to the Grid Improvement Plan;

Exhibit 3: North Carolina Grid Improvement Plan Implications - discussing how Megatrends are impacting operations in North Carolina;

Exhibit 4: North Carolina Grid Improvement Plan Program Summaries – describing the projects and programs in the Grid Improvement Plan;

Exhibit 5: Portfolio Prioritization Methodology – detailing how the Grid Improvement Plan is prioritized;

Exhibit 6: Cost benefit and Cost Effectiveness Evaluation Execution Protocol – showing how the Company evaluates potential grid improvement projects;

Exhibit 7: Cost Benefit Analyses

Exhibit 8: North Carolina Grid Improvement Plan Portfolio Cost Benefit Analysis Summary

Exhibit 9: Grid Improvement Plan Benefits Pyramid

Exhibit 10: North Carolina Grid Improvement Plan;

Exhibit 11: June 25, 2018 Power Forward Carolinas Technical Workshop Report - containing the results of the Company's first North Carolina stakeholder workshop;

Exhibit 12: November 2018 North Carolina Grid Improvement Plan Workshop Pre-Read - containing materials provided to stakeholders prior to the November 18, 2018 workshop;

Exhibit 13: January 9, 2019 North Carolina Grid Improvement Plan Workshop Report - containing the results of the Company's second North Carolina stakeholder workshop;

Exhibit 14: April 25, 2019 Webinar Materials

Exhibit 15: May 16, 2019 North Carolina Grid Improvement Plan Workshop Pre-Read - containing materials provided to stakeholders prior to the May 16, 2019 workshop;

Exhibit 16: July 2, 2019 North Carolina Grid Improvement Plan Workshop Report - containing the results of the Company's third North Carolina stakeholder workshop held on May 16, 2019;

Exhibit 17: March 12, 2019 Rebuttal Testimony filed in Docket No. 2018-319-E; and

Exhibit 18: June 2019 Webinar Presentations.

Q. WERE EXHIBITS 1 THROUGH 18 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. They were.

Q. DO THESE EXHIBITS CONTAIN ONLY INFORMATION ABOUT DE CAROLINAS?

A. No. Duke Energy has created a plan for the grid in North Carolina, and that includes both DE Progress and DE Carolinas. All information is shown in a utility-specific manner. I believe it is important to show these plans jointly as we think of the needs of customers in the state. Moreover, I believe it facilitates better discussions among parties and entities, who have interest in both service territories, to see the material presented together.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR OPERATIONAL TESTIMONY.

A. DE Carolinas reliably serves approximately 2.0 million customers in North Carolina through a multi-state electric system that includes approximately 13,100 miles of transmission lines, more than 105,000 miles of distribution lines, and more than 1,500 substations. For the DE Carolinas distribution system, approximately 1,393 distribution line miles and 12,847 transformers were added over the last two years.

As part of the Company's commitment to reliably serve customers and continually improve operations, DE Carolinas has invested $2.2 billion in electric plant in service for T&D infrastructure over the last two years. Maintenance work and reliability improvements included replacement of deteriorated wooden poles, replacement of obsolete line and substation equipment, and customer-driven line and substation expansions.

DE Carolinas also maintains a comprehensive vegetation management program across the state that works to proactively maintain trees both within and outside the rights-of-way on regular cycles. 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.

Overall, the DE Carolinas grid is reliable and well-maintained. While the Company has worked hard to maintain the system and reliably meet the needs of customers, we also understand more must be done to improve the state's energy infrastructure to meet the energy challenges and opportunities that lie ahead.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S GRID IMPROVEMENT PLAN.

A. Through a comprehensive assessment of the state of the grid and influences affecting the region, the Company has identified emerging trends, which I refer to in my testimony as "Megatrends," that drive the need to make improvements now to the electric system in North Carolina.

North Carolina is a growing state, especially in urban and suburban areas, where residential and business growth is becoming concentrated. With that growth comes growing consumer expectations for more interaction with their electric company and more control over the way they use electricity. And along with that, a higher reliance on "perfect power" – power that stays on – and when an outage does occur, is restored faster than ever.

As recent events have reinforced, the Company must be ready for severe weather before it strikes and reduce the impact of storms that are worsening in frequency and intensity. The Company must be vigilant and prepare now for the very real threat of cyber and physical attacks. And as renewable energy and distributed energy technologies like solar energy, battery storage, microgrids, and electric vehicles become more affordable and accessible, it is important to take steps now to ready the grid to support the growth of these technologies that are important to the state's energy future.

These influences come at a time of increasing environmental commitments and compliance requirements that drive change for the Company and the industry. But they also come at a time when grid technology is rapidly advancing and becoming increasingly intelligent, providing new tools and new opportunities to improve the way the Company serves customers.

To deliver on customer expectations and address these trends, the Company believes that we must do more than maintain the power grid; the Company must make the appropriate investments to transform it, making strategic, data-driven improvements to power a smart-thinking grid that is more reliable, more resilient, and built to meet the energy needs of customers today and into the future.

DE Carolinas' 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. The Grid Improvement Plan is built upon strategic, data-driven investments to improve reliability to avoid outages and speed restoration; harden the grid to protect against cyber and physical threats; expand solar and other innovative technologies across a two-way, smart-thinking grid; and give customers more options and control over their energy use and tools to save money. These foundational improvements will transform the grid and provide a new level of operation while providing benefits now and in the years to come.

Components of Duke Energy's Grid Improvement Plan operationally fall into one of three categories:

- Compliance-driven programs that **protect** the grid;
- Programs that leverage advanced technologies to **modernize** the grid; and
- Projects and programs that work to **optimize** the customer's experience.

1. Protect the grid

More must be done to harden and defend the grid against critical physical and cybersecurity risks. Compliance requirements in these areas are also driving improvements across the state. Examples of the Company's multi-layered improvements designed to protect the grid include installing protective devices to limit access to critical systems and minimize outages from physical or cyber-attack.

2. Modernize the grid

Technology is rapidly changing, and more must be done to incorporate and anticipate new technologies to better serve a growing state. Customers – more than ever – expect more options, greater reliability, and value. Self-selecting billing and payment dates, scheduling appointments, accessing real-time usage data, and information updates when outages occur are all examples of basic services consumers expect but require technology to deliver. And increasingly, consumers want access to information about how they use energy and tools to take control of that energy use and save money.

Examples of improvements designed to modernize the grid include:

- Smart meters to provide improved customer usage data, enhanced outage detection to improve customer service, and access to increased customer options to manage energy use and save money.
- Distribution automation and dispatch tools to improve power quality and reliability and support the growth of distributed energy resources and customer-owned technologies.

- Integrated system operations planning, automation, and system intelligence to prepare the grid for increased distributed resources and the dynamic power flows that these technologies bring.
- Communication improvements and expansions from high-speed, high-capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid. These upgrades help build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.

3. Optimize the customer experience

Customers want and deserve a better experience, built on the technology needed to meet their changing energy needs. To meet these expectations, we must optimize the total customer experience and transform the grid to prepare it for the energy opportunities that lie ahead.

Optimization upgrades in the grid improvement plan include:

- A self-optimizing, smart-thinking grid that anticipates outages and automatically reroutes service to keep power on for customers. Self-Optimizing Grid technology can reduce outage impacts on customers by as much as 75 percent. It will also provide the foundation for the two-way power flows needed to support more rooftop solar, battery storage, electric vehicles, and microgrids – technologies that will increasingly power the lives of customers.

- Expanded energy storage capabilities and infrastructure, which will help to power self-optimizing technologies in areas where building a redundant power line may not be feasible.
- Electric vehicle charging infrastructure improvements to expand transportation options for customers across the state. This component is filed in a separate Docket, No. E-2, Sub 1197.
- Voltage optimization and distribution of power to customers to improve reliability, increase system intelligence and support the two-way power flow needed to grow distributed resources.
- Upgrading breakers, transformers, and other grid equipment, as well as using advanced data to strategically underground the most vulnerable, outage-prone lines on the distribution system.

The Company has constructed the stakeholder-informed Grid Improvement Plan to address the risks and opportunities that the analysis revealed. The Plan seeks to balance the pace, scope, location, and timing of our work to address a diverse set of customer and stakeholder needs. As we built the Grid Improvement Plan proposed in this case, the Company has also kept the needs of our rural and low-income customers in mind and sought to develop a strategy that maximizes benefits to all customers and the State, while keeping costs as low as possible.

In developing this informed plan, the Company layered data analytics with significant input from customer and advocacy groups, and other stakeholders. Finding common ground on important topics that affect all our customers is very important to Duke Energy. The Company realizes that plans that look good on paper may not translate the way we think they will when executed in the real world. That is why the Company has sought out customer and stakeholder perspectives, including multiple stakeholder workshops, as part of the process before presenting this plan.

Consistent with the Commission's Order in the last rate case, I describe the steps taken by the Company to collaborate with stakeholders to produce a list of projects, referred to as the North Carolina Grid Improvement Plan that I believe can effectively serve customers now and in the years ahead. Exhibit 10 shows numbers for a three-year plan for North Carolina based on budgeting methods, which differs from ratemaking allocations.

The Grid Improvement Plan is about making smart foundational choices now to make the state's energy grid more reliable, more secure, and ready for the energy opportunities that lie ahead. Just as the past decade modernized the way Duke Energy generates electricity, the years ahead will transform the way we deliver electricity and serve customers. With each improvement, we can improve the overall reliability of the grid and enhance service for every customer, regardless of the type of customer or their location.

I. DE CAROLINAS' T&D SYSTEM OVERVIEW AND INVESTMENTS SINCE THE COMPANY'S LAST RATE CASE IN NORTH CAROLINA

Q. PLEASE GENERALLY DESCRIBE DE CAROLINAS' T&D SYSTEM IN THE CAROLINAS.

A. DE Carolinas' T&D system delivers electric service to approximately 2.6 million retail customers located throughout a 24,000-square mile service area in central and western North Carolina and western South Carolina. Approximately 2 million of the Company's retail customers are in North Carolina. In addition to its retail customers, DE Carolinas also sells electricity at wholesale rates to municipal, cooperative, and other investor-owned utilities.

DE Carolinas operates as a single balancing authority to economically manage the Company's integrated electric delivery systems in both North Carolina and South Carolina, collectively. This system interconnects with other balancing authority areas[1] and includes approximately 13,100 circuit miles of transmission lines. The distribution system is comprised of approximately 66,600 miles of overhead distribution lines and 38,500 miles of underground distribution lines. DE Carolinas' T&D system also includes 170 transmission substations, and 1,339 distribution substations with a combined capacity of approximately 92 million KVA. In addition to power lines and substations, the system includes various other equipment and facilities such as control rooms,

[1] The PJM Regional Transmission Organization through American Electric Power ("AEP"), Duke Energy Progress ("CP&L East and CP&L West"), Dominion Energy South Carolina (formerly South Carolina Electric & Gas), South Carolina Public Service Authority, Southern Company, Tennessee Valley Authority ("TVA""), Cube Hydro Carolinas, and Southeastern Power Administration ("SEPA").

computers, poles, transformers, regulators, capacitors, street lights, meters, and protective relays. Together, these assets provide the Company considerable operational flexibility with its T&D system and allow DE Carolinas to provide safe, reliable, and economical power to the Company's customers in North Carolina.

Q. HAS DE CAROLINAS' T&D SYSTEM GROWN SINCE THE LAST RATE CASE?

A. Yes. The T&D system has expanded over time to ensure adequate system voltage and capacity, based on projected system loading, and contingency requirements related to providing safe and reliable service to our customers. Transmission system growth has also occurred because of new generation and/or decommissioning of existing generation assets. For the DE Carolinas distribution system, approximately 1,393 distribution line miles and 12,847 transformers were added over the last two years. Overall, we have added approximately $2.2 billion to electric plant in service for T&D infrastructure in the last two years.

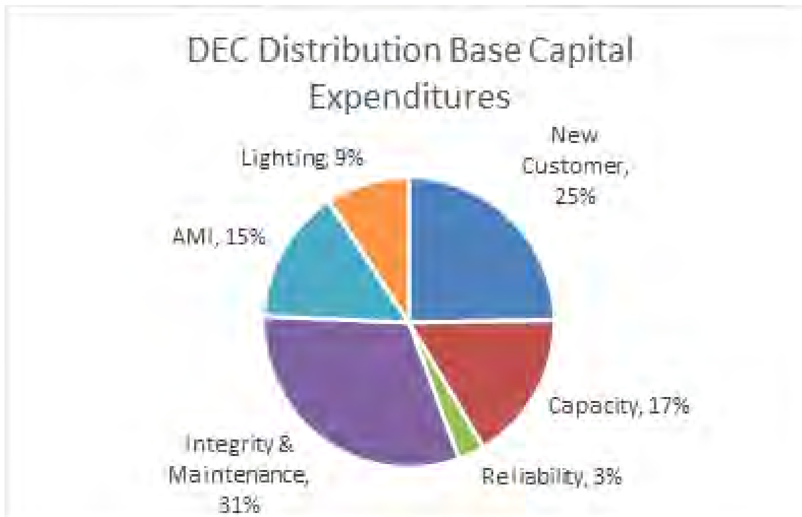
Q. CAN YOU PROVIDE MORE DETAIL ABOUT THE ADDITIONAL INVESTMENTS THE COMPANY HAS MADE IN ITS T&D SYSTEM SINCE THE LAST RATE CASE?

A. Additional investments in the Company's T&D system have been made to provide capacity to serve system growth, ensure adequate system voltage, support transmission-related infrastructure for both new generation and decommissioning of generation, and improve certain aspects of system reliability. Over the past two years, approximately $600 million was invested in the transmission system and $1.6 billion in the distribution system inclusive of additions through the Grid Improvement Plan which I discuss in the second part of my testimony.

The chart below illustrates the major categories of the transmission base system capital investment over the last two years.

In the transmission system, approximately 35 percent of investment was driven by capacity requirements to serve load and to meet the North American Reliability Council ("NERC") Planning Standards and generation driven by projects such as the Riverbed decommissioning and the addition of the Lee Combined Cycle Plant. Approximately 30 percent of investment was driven by standard reliability improvement programs. Approximately 19 percent of investment was driven by maintenance programs, including the replacement of deteriorated wood poles and replacement of obsolete substation and line equipment. Approximately 5 percent of the investment was driven by customer expansion work which includes new customer projects as well as line and substation upgrades driven by transmission service requests. Approximately 11 percent of the investment was driven by compliance projects including the ever-evolving cyber security and physical security programs driven by requirements defined in NERC CIP Standards CIP-002-5.1 and CIP-014-2.

The chart below illustrates the major categories of the distribution base system capital expenditures over the last two years.



North Carolina continues to be a desirable place to live and work, as evidenced by the more than 32,000 new retail customer meters added during the 12-month period ending December 31, 2018. Typically, new customers locate in areas where DE Carolinas must build new distribution facilities to serve them, including expenses for new customer connections or capacity work needed to support overall load growth. Approximately 51 percent of the Company’s distribution expenditures over the last two years are for load expansion-related work, including serving new customers, lighting installations, and additional capacity.

Approximately 34 percent of the investments on the Company's system relate to base-level work around standard reliability and integrity programs that address safety and environmental requirements and maintenance including service restoration. Approximately 15 percent was for the deployment of AMI.

Q. CAN YOU PROVIDE DETAIL ABOUT HOW THE COMPANY DETERMINES WHAT IS TO BE CATEGORIZED AS BASE T&D SPENDING?

A. Yes. The type and scope of transmission and distribution "Maintain Base" work that we perform on our system can generally be thought about as a product of the following equation: [Safety Requirements] + [Load Service Requirements] + [Reliability Requirements] + [Environmental Requirements] = Type and Scope of Work. What work goes into the four elements of this equation may be dictated by mandatory external requirements (such as laws, codes, and regulations), internal company standards, national industry standards, or a combination of these requirements and standards, but any base-level work done on the transmission and distribution system fits into one of these four categories. In Exhibit 1 to my testimony, I have provided more detail as to what general work fits into each one of the categories.

Q. IN YOUR OPINION, ARE ALL THE T&D FACILITIES INCLUDED IN DE CAROLINAS' BASE RATE REQUEST USED AND USEFUL IN PROVIDING SERVICE TO DE CAROLINAS' RETAIL ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. Yes. Including the projects that will be completed prior to the evidentiary hearing in this case, all of the reasonable and prudent additions to DE Carolinas' T&D system requested for recovery in base rates are used and useful to its 2 million customers in North Carolina.

Q. HAVE THE T&D INVESTMENTS THAT THE COMPANY HAS MADE ALLOWED IT TO MEET ITS OPERATIONAL PERFORMANCE GOALS?

A. Yes. They have, but as I discuss later in my testimony, we are seeing unfavorable trends that are making these goals more challenging to meet. DE Carolinas' principal goal is to deliver safe and reliable electric service at reasonable prices. We measure this principal goal based on customer satisfaction, safety, and reliability of the Company's T&D systems, while responsibly managing operational and capital expenditures for the benefit of our customers.

Q. PLEASE EXPLAIN THE METRICS THE COMPANY USES TO MEASURE THE EFFECTIVENESS OF ITS T&D OPERATIONS.

A. DE Carolinas utilizes several industry-standard metrics to assess the overall effectiveness of its T&D operations. These metrics include reliability indices to measure the performance of the T&D system and customer satisfaction scores to determine how well the Company is meeting the needs of its customers.

The Company uses several industry-accepted transmission and distribution performance metrics as defined in IEEE Standard 1366-2012:

- **System Average Interruption Frequency Index ("SAIFI")** is a ratio that indicates how often the average customer experiences a sustained interruption over a predefined period of time.
- **System Average Interruption Duration Index ("SAIDI")** is a ratio that indicates the total duration of interruption for the average customer during a predefined period of time.
- **Customers Experiencing Multiple Interruptions ("CEMI 6")** is a measure of the percentage of customers who experience six or more outages in a 12-month period.

Q. HOW HAS DE CAROLINAS' TRANSMISSION AND DISTRIBUTION SYSTEM PERFORMED UNDER THESE METRICS?

A. Our system has performed well, and we have continued to provide safe, reliable, and affordable electric service to our customers. Over the past ten years, however, both SAIFI and SAIDI show an unfavorable trend, with the frequency and duration of outages increasing across the DE Carolinas system despite our efforts and investments that I have discussed previously. Graphs displaying the trends for these metrics are set forth below:

Figure 1 – Duke Energy Carolinas' Historic System Average Interruption Frequency Index (SAIFI)

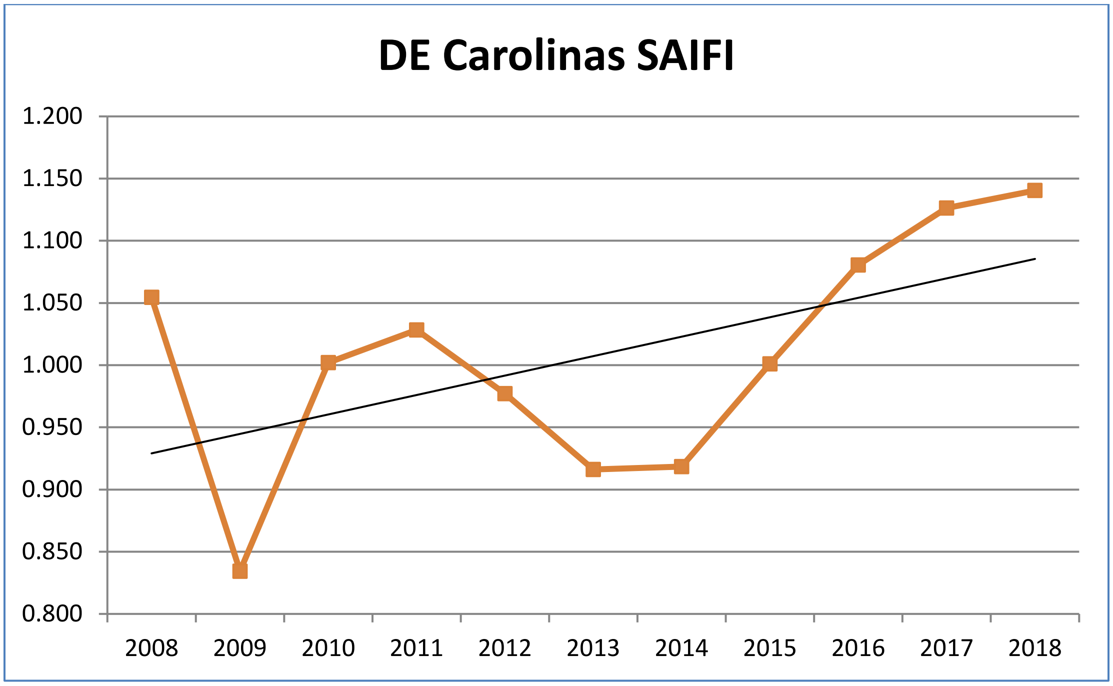
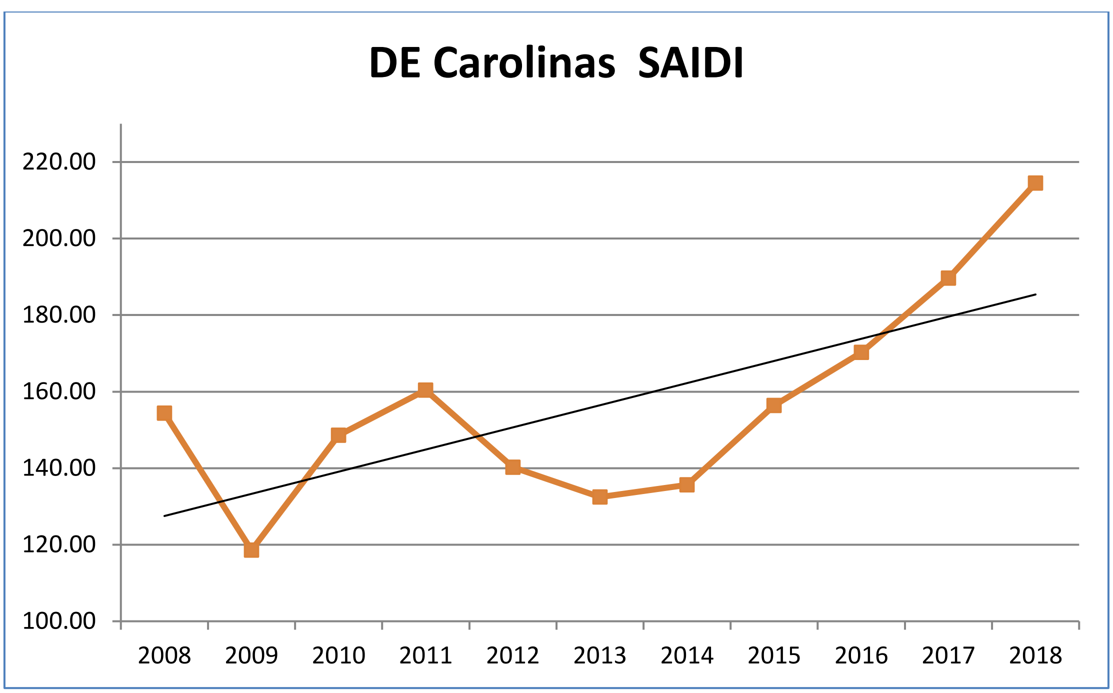


Figure 2 – Duke Energy Carolinas' Historic System Average Interruption Duration Index (SAIDI)



In summary, reliability performance is worsening due to the increase in the number of outage events. There are several factors and trends, which I address later in my testimony, contributing to the worsening reliability trends.

Q. WHAT ARE YOUR PROJECTIONS FOR DE CAROLINAS RELIABILITY PERFORMANCE IN 2019?

A. Based on performance through July 2019, we project DE Carolinas SAIDI to be 173 minutes. While this is a forecast, we feel confident that SAIDI for DE Carolinas will end 2019 between 157 and 193 minutes. This entire range represents a significant improvement from the 2018 performance of 214 minutes.

Q. CAN YOU EXPLAIN WHY RELIABILITY PERFORMANCE HAS IMPROVED?

A. In addition to system improvements such as Self-Optimizing Grid ("SOG"), Targeted Undergrounding ("TUG"), and other programs discussed in my testimony, there have been operational improvements focused on reducing outage durations. These improvements include refining the process by which crews are contacted during outages, developing more specific operational schedules, allowing employees to perform additional duties while on site during an outage, and weekly reviews of long duration outages.

Q. ARE THESE IMPROVEMENTS EXPECTED TO CONTINUE BEYOND 2019?

A. Yes. Our performance during the first six months of 2019 was driven in part by improvements in several processes and these changes have been institutionalized.

Q. PLEASE EXPLAIN THE COMPANY'S APPROACH TO DISTRIBUTION VEGETATION MANAGEMENT AND DESCRIBE ANY CHANGES THE COMPANY HAS MADE TO ITS APPROACH SINCE THE LAST RATE CASE.

A. Vegetation management is a critical component of the Company's customer delivery operations and the continued effort to drive performance for customers' benefit. DE Carolinas uses a combination of a reliability-based and a time-based prioritization model to drive its routine integrated vegetation management program. In addition to routine circuit maintenance, there are four other important components to the Company's overall vegetation management approach.

(1) Herbicide Program – The purpose of the annual Herbicide Program is to control re-growth of incompatible vegetation within the right-of-way "floor" in non-landscaped areas;

(2) Hazard Tree Program – This program is designed to identify/remove dead, dying, and diseased trees primarily located outside of the existing Distribution right-of-way;

(3) Reactive Program – This program is designed to address customer initiated requests as well as vegetation related power quality issues identified as part of outage follow-up investigations; and

(4) Disciplined vegetation management outage follow-up process tied to a formal internal reliability review process.

In 2013, Duke Energy completed a tree growth study, which established an optimal tree-trimming cycle with targeted trim dates by classification including old-urban 5-year cycle, mountain 7-year cycle, and other 9-year cycle, otherwise referred to by the Company as the 5/7/9 Plan.

Q. PLEASE MORE FULLY DESCRIBE THE 5/7/9 PLAN AND HOW DE CAROLINAS HAS IMPLEMENTED THIS PLAN.

A. The 5/7/9 plan is defined as follows:

- There are 2,171 old urban miles to be trimmed on the 5-year cycle. "Old Urban Circuits" are designated by Duke Energy as the overhead lines in older, high density neighborhoods or historic districts that consist of mature and/or over-mature, streetscape, and landscape trees. The line construction is typically in the public right-of-way along the street and rear, or in side lots along the property line between the neighborhood homes. Many trees on the Old Urban Circuits are directly under the line and are in direct conflict with the overhead distribution system. Thus, these trees will never be allowed to obtain normal form or development and have traditionally required height reduction pruning. Due to the reliability characteristics and clearance needed at the time of pruning, we target these circuits to be on a 5-year pruning schedule. The desired timeframe is driven by the growth characteristics of the trees and associated target clearance needs, as well as system reliability.

- There are 7,847 mountain miles to be trimmed on the 7-year cycle. "Mountain" circuits are characterized by a high percentage of the line miles being impacted by vegetation, lesser customer densities, and difficult terrain, as well as many of the lines being non-accessible to mechanized equipment.
- There are 41,686 other miles to be trimmed on the 9-year cycle. "Other" circuits are targeted for a 9-year average trim cycle and include all circuits that are not classified as Old Urban or Mountain.

The implementation of the 5/7/9 plan in 2018 created a "backlog" of miles that fell outside the targeted 5/7/9 trim cycles. To reconfirm its commitment to address this backlog by 2023, the Company filed its Revised Vegetation Management Plan, under Docket No. E-7, Sub 1146, detailing planned tree-trimming activities and spending from 2019-2023. The Revised Vegetation Management Plan reflects the Company's continued progress to eliminate the 13,467 miles of existing tree trimming backlog within five years, while still ensuring that all miles previously trimmed within their 5, 7, or 9-year timeframe based on the identified circuit category are trimmed on schedule per the Company's 5/7/9 Plan.

Q. DOES THE COMPANY PROPOSE AN INCREASE IN FUNDING FOR VEGETATION MANAGEMENT?

A. Yes. As explained by Witness McManeus, we have included a pro forma adjustment for the North Carolina retail portion of the incremental O&M expense associated with vegetation management. The need for the increase is two-fold. First, it will cover the known contract rate increases that took effect in 2019. The increase in contract rates is driven by a tightening labor market and the ability for vegetation suppliers to acquire and retain qualified workers, so we expect cost for vegetation management to further increase in the coming years. Second, the increase will cover the miles to be trimmed to meet the annual mileage requirements of the Company's 5/7/9 plan, which is higher than the mileage completed in the test year for this case due primarily to Hurricanes Florence and Michael and Winter Storm Diego.

We have also included a pro forma adjustment for the North Carolina portion of the incremental O&M expense for the Transmission Vegetation Management Program. This increase will cover known contract rate increases in 2019 and the requirement mileage for maintenance trimming and the herbicide program.

Q. WILL THE COMPANY'S 5/7/9 VEGETATION MANAGEMENT PLAN CURE ALL ADVERSE SYSTEM IMPACTS THAT THE COMPANY HAS SEEN DEVELOP IN THE RECENT PAST?

A. No. Vegetation events account for 20 to 30 percent of all outage events. It is important to understand that approximately 70 to 80 percent of all outages on the grid are due to other causes, such as equipment failure, public accidents, and environmental factors. In addition, for the events that are vegetation related, only 50 percent of these are related to vegetation inside the right-of-way where the Company can perform vegetation management. The other 50 percent occur due to trees outside the right-of-way that will fall into or otherwise impact distribution lines, and the Company does not have the ability to perform vegetation management on these trees that are located on private property. 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.

Keeping these facts in mind, the Company engaged in the Tree Growth Study that I previously discussed to determine the optimal right-of-way trimming cycles for our geographical areas. Trimming more often than these now pre-determined, optimal cycles will only provide diminishing returns and would not be cost effective. 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. Instead, programs such as Targeted Undergrounding, which will be discussed in more detail later in my testimony, can be effectively used to address vegetation outages caused by trees outside of the right-of-way, where the base vegetation plan stops.

II. NEW TRENDS AFFECTING THE NORTH CAROLINA ELECTRIC GRID

Q. HAVING DESCRIBED THE EXISTING T&D SYSTEM AND HOW THE COMPANY MAINTAINS ITS BASE-LEVEL OF SYSTEM PERFORMANCE, WHAT ARE SOME SYSTEM-WIDE TRENDS YOU HAVE OBSERVED AS IMPACTING THE T&D GRID?

A. There are seven major trends that we call "Megatrends" impacting Duke Energy's grid in North Carolina. The trends are summarized below and are discussed individually in detail in Exhibit 2:

1. Population and business growth continues in North Carolina and is heavily concentrated in urban and suburban areas;
2. Technology is advancing at a rapid rate in the areas of renewables and distributed energy resources ("DERs"), which means there are new types of load and resources impacting the grid;
3. Technology is also advancing rapidly within the devices and systems that operate and manage the T&D grids, offering new capabilities and requiring new functionalities;
4. Customer expectations and use of the grid are very different from generations past;

5. There has been an increase in environmental commitments from the international to local level in DE Carolinas' service territory;
6. The number, severity and impact of weather events on DE Carolinas' customers has been increasing significantly; and
7. The threat of physical and cyber-attacks on grid infrastructure is more sophisticated and is on the rise.

These seven Megatrends are the factors that are driving the need for the Company to have a Grid Improvement Plan that goes beyond the work that the Company performs to maintain base-level operations.

Q. HOW DID THE COMPANY IDENTIFY AND VALIDATE THAT THESE MEGATRENDS EXIST?

A. Over the past several years, we have seen these Megatrends develop in the day-to-day operation of our business. Some of these Megatrends, such as the increased number and increased sophistication of attempted cyber-attacks on our system, are easily identified and are evident as they happen. Other changes, such as the way our customers are using and depending on the power we provide them, are subtler and can be harder to identify. With all these Megatrends, however, our first step was to inventory facts and information that we saw from operating our grid that appeared different than the facts and information we had seen in the previous years of operation.

Once we had conducted the aforementioned inventory, we then looked across the industry to see if other utilities and industry stakeholders were seeing the same Megatrends developing in their operations. As we suspected, the same new Megatrends that we are seeing develop in North Carolina are also being seen throughout the industry.

Q. HOW DID THE COMPANY GO ABOUT ESTABLISHING THAT THE FACTS AND INFORMATION IT WAS SEEING ROSE TO THE LEVEL OF ESTABLISHING WHAT YOU HAVE CALLED MEGATRENDS?

A. During this process of identifying and validating the Megatrends, we collected objective information from our own operations in North Carolina as well as from our companies that function in other jurisdictions. From North Carolina to Florida, and in Kentucky, Ohio, Indiana, and South Carolina, we began to see commonality in the facts and information that evidenced the existence of these Megatrends. From there, we then began to look at objective national information that non-Duke companies and industry stakeholders were sharing publicly. That information also confirmed the existence and validity of the Megatrends. In Exhibit 2 to my testimony, I have included summary data, citations, and information that the Company collected on each Megatrend.

The 2016 South Carolina State Energy Plan also noted the existence of many of these trends, as the following passage reveals:

"In developing this State Energy Plan, it has become very evident that electric utilities are facing expanding customer expectations, increasing environmental regulation, and new technologies that have to be integrated seamlessly into the grid. The grid of the rapidly approaching future will function in ways never imagined when the original wires were installed. If South Carolina is to participate in the innovation coming to fruition in the electric sector — such as distributed energy resources like solar panels, wind turbines, electric vehicles, and microgrids — then the state will require an advanced, integrated grid to manage and optimize the increasingly dynamic flow of electricity."[2] Furthermore, reports from independent third parties as well as stakeholder interactions in North Carolina show that the Company has correctly identified the megatrends that are impacting our system.[3]

Q. WHAT WAS THE NEXT STEP IN THE DEVELOPMENT OF THE GRID IMPROVEMENT PLAN AFTER THE COMPANY IDENTIFED AND VALIDATED THE EXISTENCE OF THE MEGATRENDS?

A. Once we found that the Megatrends we were seeing in North Carolina were valid, and that those Megatrends were also impacting utilities across the nation, we then had to analyze whether the Megatrends mattered. Said another way, the Company had to evaluate whether any or all the Megatrends caused any problems or issues that warranted work in North Carolina that was above and beyond the Company's base-level T&D plan that I have previously discussed.

Q. HOW DID THE COMPANY PERFORM THIS EVALUATION?

A. To determine whether one or more of these Megatrends warranted the Company to develop an incremental Grid Improvement Plan for the state, the Company first listed out all the implications that the Megatrends would logically and objectively have on providing our customers safe, reliable, and affordable electric service. For example, one of the facts we discovered was that customers

[2] http://www.energy.sc.gov/files/Energy%20Plan%20Appendicies%2003.02.2018.pdf 2016 South Carolina State Energy Plan, Appendices, Page 121.
[3] http://gridlab.us/wp-content/uploads/2019/04/GridLab_SC_GridMod.pdf, Page 20.

with higher usage and higher expectations for power quality and reliability were beginning to concentrate more and more in urban and suburban areas such as Charlotte and Raleigh. These customers are the most likely group to embrace technologies like roof top solar and electric vehicles. Given this seemingly undeniable fact, we had to ask the question of what this fact means to our T&D operations. What we found is that our business as usual approach to serving this new load would not address the implications created by the Megatrends. We also realized that the capital required to serve high growth areas can undermine investment in rural areas of the state, causing disparity between customer demographics and geography. In Exhibit 3 to my testimony, I have included our evaluations of these Megatrends and what implications they will have on the Company's grid operations.

III. GRID IMPROVEMENT PLAN

Q. ONCE THE COMPANY IDENTIFED AND VALIDATED THE MEGATRENDS AND THE IMPACTS THEY ARE HAVING ON THE GRID NOW AND IN THE FUTURE, WHAT PROCESS DID THE COMPANY USE TO PUT ALL THIS INFORMATION INTO A GRID IMPROVEMENT PLAN?

A. At this point in our evaluation, the Company took the following overall steps to develop a proactive plan that addresses impacts of the Megatrends:

1. Identified "tools" (i.e. utility projects and programs) available to address the Megatrend impacts. In Exhibit 4, I have included detailed

descriptions of the programs and projects that the Company considered as "tools" to address Megatrend implications;

2. Determined constraints that impacted the creation of the plan such as equipment availability, personnel limitations, available time and schedule, any applicable prescriptive requirements, interplay with base-level work needs, and price impact;
3. Selected "tools" to use in the plan in an iterative process that built up from a foundation of protecting the grid first and foremost; establishing foundational, system-level programs that are needed for all aspects of operations and that impact all customers next; and then focusing on projects and programs that help address the most number of Megatrend implications for the best value to customers. We called this phase of the plan development "protect," "modernize," and "optimize," and I have included a series of graphics that help to explain this process as Exhibit 5 to my testimony; and
4. Developed a comprehensive Grid Improvement Plan that efficiently organizes the work to be completed based on where, when, and how much is appropriate.
5. Invited stakeholder feedback to ensure the plan addressed the diverse set of customer and stakeholder needs.

Q. YOU MENTIONED THAT THE FIRST STEP IN DEVELOPING THE GRID IMPROVEMENT PLAN WAS IDENTIFYING TOOLS THE COMPANY HAS TO ADDRESS THE MEGATRENDS. CAN YOU PROVIDE MORE DETAIL ON THIS PHASE OF THE PLAN DEVELOPMENT?

A. Yes. The programs and projects that are available to the Company to help address the implications of the Megatrends in North Carolina can be grouped into three basic categories based on how the Company brings those programs into its plan. These three categories are (1) compliance-driven programs that protect the grid, (2) rapid technology advancement programs that modernize the grid, and (3) various other projects and programs that work independently or together with other programs to optimize our customers' experience. I will further describe those categorizations below.

Q. WHAT CONSTITUTES COMPLIANCE-DRIVEN WORK THAT IS DESGINED TO PROTECT THE GRID?

A. Compliance-driven programs in the Grid Improvement Plan are efforts which need to be completed to reduce physical and cyber threats to the grid. These programs may be necessitated by an external law, rule, or regulation applicable to the company that requires the work; a binding legal obligation such as a contract, agency order, or other legal document that compels the work; or Operations Council approval of the work as being critical and imperative to the Company's operations. To qualify for inclusion in the Grid Improvement Plan, work in this category is limited to rapidly evolving threats to the grid that outpace the scope and timing of standard compliance work done in our base-level operations. The type of work to address these concerns includes applying physical and cyber protections to transmission substations and distribution assets that are not yet covered under mandatory federal regulations such as special protective fencing and barricades to help minimize the threat of gunshot attacks to equipment, intruder sabotage, and vehicle attacks to critical equipment, and installing tamper alarms and protective cyber "blocking devices" on electronic distribution equipment that are susceptible to hacking by a cybercriminal on our distribution assets in the field.

Q. HOW DO YOU EVALUATE COMPLIANCE-DRIVEN PROGRAMS?

A. When evaluating compliance-driven programs as part of the Grid Improvement Plan, we first focus on work that has a prescriptive mandate that dictates how, when, or where the work must be done. For example, if a federal regulation states that we must take certain activity on a certain set of grid assets at a certain time, we necessarily put that work into our plan first given that the Company has little discretion to do otherwise. Once that work is incorporated into the plan, the Company then focuses on non-prescriptive work that poses the highest risk to the grid and then continues to incorporate grid protection work into the plan on a risk-advised basis, taking plan constraints into consideration. Since this grid protection work must be done, the Company does not evaluate these compliance-based programs with cost benefit analyses, but instead takes measures to ensure that this work is done in a cost-effective manner. In Exhibit

6 to my testimony, I have included a "gating tool" that the Company uses to determine how to properly evaluate the costs and benefits of all the work in the Grid Improvement Plan. Compliance-driven programs include the following types of work and activities: electronic access blocking and gating restrictions on computerized systems and equipment; cyber defense computer programs and applications; physical access restrictions and protective devices to substations and critical equipment; and working with industry experts to determine best practices for electromagnetic pulse protections on certain critical assets.

Q. WHAT CONSTITUTES A RAPID TECHNOLOGY ADVANCEMENT PROGRAM THAT MODERNIZES THE GRID THAT YOU DESCRIBED AS THE SECOND CATEGORY OF WORK IN THE GRID IMPROVEMENT PLAN?

A. Rapid technology advancement work that is needed to modernize the grid consists of equipment, software, hardware, operating systems, or accepted system operating practices that have advanced at an atypical pace, causing the need for rapid and sometimes frequent changes within the utility at a system deployment level. Work in this category is usually related to system communication, automation, and intelligence and must be executed at a deliberate pace while ensuring not to deploy new technology before it has reached maturity. While not considered compliance activities, work in this category is essential for modern system operations. Rapid technology advancement programs include the following types of work and activities:

deploying new system-wide communications devices so that the transmission and distribution system can communicate back to us and with each other, replacing pneumonic and manually actuating equipment with modern electronic and intelligent equipment that is self-actuating and self-correcting, and installing advanced system intelligence devices that will allow our underground and overhead assets to proactively report their condition status and potential problems before they manifest into equipment failures.

Q. HOW DO YOU EVALUATE RAPID TECHNOLOGY ADVANCEMENT PROGRAMS?

A. In this area of the Grid Improvement Plan, the Company looks for "Enterprise" or system-level programs that enable interoperability and functionality to grid operations and thereby impact and provide value to all our customers. A grid that can communicate and provide information to us and our customers and that can automatically react to grid events is essential to meet the demands of our customers and the implications of the Megatrends in North Carolina. Programs that help the Company meet these requirements are selected for inclusion in this part of the Grid Improvement Plan. Since these programs are essential to enabling a modern-functioning grid, the Company ensures that they are deployed and selected in a cost-effective manner.

Q. WHAT CONSTITUTES A SYSTEM OPTIMIZATION PROGRAM THAT IS PART OF THE FINAL CATEGORY OF WORK IN THE GRID IMPROVEMENT PLAN?

A. Programs and projects in this category provide customers more benefits than costs and solve for one or more of the external Megatrends that can have negative impacts to customers and grid operations. Work in this category spans a wide range of assets but primarily includes a "bundled combination" of Integrated Volt/Var Control ("IVVC"), Self-Optimizing Grid deployments, and advanced power systems that, when working together, provide optimum system performance for our customers. 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 capacity to allow for two-way power flow and creating tie points between circuits. The IVVC program leverages the grid improvements from the self-optimizing technology and adds remotely-operated substation and distribution line devices such as regulator and capacitor controllable field devices that enable a grid operator to lower voltage as a way to reduce peak demand, thereby reducing the need to generate or purchase additional power at peak prices (peak shaving) or to operate in a conservation mode during periods of more typical electricity demand in order to reduce overall energy consumption and system losses.

Q. HOW DO YOU EVALUATE SYSTEM OPTIMIZATION PROGRAMS?

A. In selecting these programs for inclusion in the Grid Improvement Plan, the Company looks for programs that address the largest number of Megatrend implications at the lowest costs to customers. System optimization programs are justified by a qualitative and quantitative cost benefit analysis, and Exhibit 6 that I previously discussed provides more detail on how this is done at various stages of program implementation. When a system-level program like IVVC[4] or Self-Optimizing Grid[5] is deployed throughout our service territory in North Carolina, the Company utilizes a program-level cost benefit analysis. The Company also has a methodology for project-level cost benefit analysis, which examines the costs and benefits of deploying a specific project solution based on the nature of a specific site. For example, the Targeted Undergrounding[6] and Transmission Line Upgrade programs in the Grid Improvement Plan are evaluated on a site-by-site basis using project level cost benefit analyses. The

[4] IVCC is particularly notable because it provides multiple benefits and savings to all our various customer classes while at the same time allowing the Company to have maximum flexibility to react to multiple system conditions on the grid.

[5] Self-Optimizing Grid is an example of investments with multiple layers of benefits as it helps customers save money in avoided system costs; allows more distributed energy resources (such as rooftop solar) to be on the grid; and provides containment and mitigation of outages by reducing thousands of impacted customers in an outage down to hundreds or less.

[6] Target Undergrounding is the process of burying certain lines for cost saving and reliability purposes, and not for aesthetic purposes, and could yield savings for all our customers over what they would otherwise pay to maintain and repair and overhead system in addition to the improved reliability that it will provide.

cost benefit analyses and the underlying data sources and work sheets for all the programs and projects in the "Optimize" portion of the Company's proposed Plan, which encompasses more than seventy percent of the costs for the Plan, were placed in a virtual data room available to interested stakeholders leading up to this filing. This data room is discussed in more detail in the Stakeholder Engagement portion of my testimony. The cost benefit analyses and underlying workpapers are located in Exhibit 7.

Exhibit 8 to this testimony shows that the programs in the Company's plan designed to optimize the North Carolina grid have a positive net present value benefit to cost ratio of 4.7. This means that for every dollar spent on these programs and projects, customers should receive a payback of $4.70 in primary benefits. Also in Exhibit 8 of this testimony, I have included a total primary benefit analysis of the entire Grid Improvement Plan portfolio, and this document shows that all the costs in the plan (costs to protect, modernize, and optimize the North Carolina grid) have a positive total net present value benefit ratio of 3.6. This means that for every dollar spent on the total Plan, North Carolina customers should receive a payback of $3.60 in primary benefits.

In Exhibit 8 to this testimony, I have also included an analysis of the secondary benefits that the Grid Improvement Plan should provide to customers and residents. If both the primary and secondary benefits of the Grid Improvement Plan are considered together, the total Grid Improvement Plan (cost to protect, modernize, and optimize the grid) should provide customers and residents a positive total net present value benefit ratio of 6.4, meaning that every dollar spent on the Plan should provide a payback of $6.40.

Q. IN YOUR DISCUSSION OF THE BENEFITS OF THE GRID IMPROVEMENT PLAN, YOU REFER TO PRIMARY (DIRECT) AND SECONDARY (INDIRECT) BENEFITS. WOULD YOU PLEASE EXPLAIN THE DISTINCTION BETWEEN THESE TWO SETS OF BENEFITS?

A. Yes. Primary benefits consist of value that is directly captured by the Company and by customers. Examples of primary benefits captured by the Company are things like avoided deployments of outage restoration crews, avoided equipment replacement costs, avoided operations and maintenance savings, and other "hard costs" that can be estimated and quantified. Examples of primary benefits captured by customers are things like avoided lost product, avoided damaged equipment costs, avoided lost wages, and other expenses that cost customers money. In Exhibit 9 to this testimony, I have included a graphic example of a "benefits pyramid" that shows how the benefits of electric utility projects are thought about and evaluated in the industry. As can be seen from this graphic and from the cost benefit results in Exhibit 8, the Company's proposed Grid Improvement Plan is justified in its entirety just on primary benefits alone.

However, the proposed Grid Improvement Plan for North Carolina also provides indirect, secondary benefits to customers through risk reduction; value to third parties, and value to society as a whole, which are reflected on the top three rungs of the benefits pyramid displayed on Exhibit 9. Of these indirect/secondary benefits, the Company has estimated the indirect value of the plan to third parties, and the results of this evaluation are reflected in Exhibit 8. However, the Company has not attempted to value the indirect benefits of risk reduction and the benefits to society as a whole for the Grid Improvement Plan, which means that the benefits of the plan are understated and are greater than what the Company has calculated.

Q. SHOULD THE GRID IMPROVEMENT PLAN HAVE QUANTIFIABLE TARGETS AND METRICS TO MEASURE THE PERFORMANCE AND RESULTS OF THE WORK IN THE PLAN?

A. Yes. The cost benefit analyses in Exhibit 7 to this testimony provide those metrics for each of the projects and programs that are appropriate for such metrics.[7] Specifically, the cost benefit analyses performed by the Company detail, among other things, the amount of O&M savings the Company anticipates from the plan; the amount of avoided capital costs the Company anticipates from the plan; and the amount of outages that each of the programs and projects within the plan are anticipated to avoid.

Q. HOW HAS THE COMPANY SHAPED THIS COLLECTION OF PROGRAMS INTO A HOLISTIC GRID IMPROVEMENT PLAN?

A. Once the Company had selected the programs and projects that could meet customers' needs in the manner that I have previously discussed, the Company

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

then had to develop a formal, year-over-year work plan that can be achieved given the resource constraints that I discussed earlier in my testimony. Further, the final Grid Improvement Plan had to be developed not only in a risk-advised manner, but in a manner that is fair to all our customers. For example, a Grid Improvement Plan that was too heavily weighted to address only one of the Megatrends impacting North Carolina could be viewed as short-sighted, while a Grid Improvement Plan that was too "diluted" and lacked strategic focus would be ineffective. Similarly, a Grid Improvement Plan that focused too heavily on one type or class of customer could be viewed as unfair. The Company had to balance these and other considerations when forming the final Grid Improvement Plan work.

Q. HOW DID DUKE ENERGY BALANCE DIVERSE CUSTOMER AND STAKEHOLDER NEEDS?

A. The Grid Improvement Plan for North Carolina is designed with programs that benefit all our customers, and that is one of the primary ways that we have balanced our customers' needs and interests. Over our three-year plan, we have also balanced the pace, scope, location, and timing of our work to ensure that customer and stakeholder needs are met. Further, we have kept the needs of our rural and low-income customers in mind as we developed our plan, and programs such as IVVC provide these customers both increases to reliability and resiliency while at the same time providing decreases in fuel costs, future capacity and carbon costs, and lower monthly energy usage.

Q. WHAT IS YOUR RESULTING GRID IMPROVEMENT PLAN FOR NORTH CAROLINA?

A. After completing all the steps in our plan development process, we arrived at our Grid Improvement Plan, which is presented in Exhibit 10.

Q., **IS THE GRID IMPROVEMENT PLAN THAT YOU ARE PROPOSING IN THIS CASE SIMILAR TO THE GRID IMPROVEMENT PLAN THAT THE COMPANY RECENTLY INTRODUCED IN SOUTH CAROLINA?**

A. Yes. By design, the Grid Improvement Plan for North Carolina is identical to the South Carolina plan in substance, so that the two plans can work together to provide benefits to DE Carolinas customers.

Q. **DID STAKEHOLDERS IN SOUTH CAROLINA HAVE ANY FEEDBACK ON THE DE CAROLINAS GRID IMPROVEMENT PLAN THAT YOU PROPOSED?**

A. Yes. While most of the feedback we received from South Carolina stakeholders focused on the method for cost recovery to be used for grid improvement investments, many stakeholders did provide useful substantive questions and input on the plan that I outlined and addressed in my rebuttal testimony in the South Carolina rate cases dockets. For ease of reference in this testimony, I have included my rebuttal testimony from South Carolina Docket 2018-319-E as Exhibit 17 to this testimony rather than recounting all those questions and inputs here.

Q. **WAS THE COMPANION GRID IMPROVEMENT PLAN FOR SOUTH CAROLINA APPROVED?**

A. In the DE Carolinas and DE Progress rate cases for South Carolina, the parties entered into a stipulation that affords deferral accounting treatment for the SC Grid Improvement Plan, and that calls for the ongoing tracking and reporting of costs and achieved benefits under the Plan as work is completed. This is the same treatment and procedure that the Company is requesting for DE Carolinas in this case.

IV. <u>STAKEHOLDER ENGAGEMENT AND COST RECOVERY OF GRID IMPROVEMENT INVESTMENTS</u>

Q. DID THE NORTH CAROLINA UTILTIES COMMISSION GIVE THE COMPANY ANY GUIDANCE ON THE RECOVERY OF FUTURE GRID IMPROVEMENT COSTS IN THE COMPANY'S LAST BASE RATE ADJUSTMENT PROCEEDING IN NORTH CAROLINA?

A. Yes. In Docket No. E-7, Sub 1146, the Commission issued an order stating:

> "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 the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during the test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside the 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 on 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."

Q. WHAT STEPS HAS THE COMPANY TAKEN TO ADDRESS THE COMMISSION'S RECOMMENDATION FOR COLLABORATING WITH STAKEHOLDERS?

A. The Company has held three in-person stakeholder workshops in North Carolina and a series of webinars since the previous North Carolina rate case. The first workshop was conducted in response to the settlement agreement approved by the NCUC on February 23, 2018, in Docket No. E-2, Sub 1142 for the DE Progress general rate case, and was held on May 17, 2018. Acting as a neutral facilitator, a team from Rocky Mountain Institute ("RMI") convened 65 participants (inclusive of 18 Duke Energy and five RMI staff) for a day-long workshop. The objectives of this workshop were to develop understanding of proposed investments; hear and explore stakeholder feedback; and support a collaborative process going forward. At the conclusion of the workshop, RMI prepared a detailed, post project report which was filed with the Commission on June 26, 2018. I have included that report as Exhibit 11 to my testimony.

Q. DID THE WORKSHOP RESULT IN CHANGES TO THE COMPANY'S PLANS FOR GRID IMPROVEMENTS?

A. Yes. The feedback we received in this workshop led us to identify and validate the Megatrends as discussed earlier in my testimony. Because of the formalization of the Megatrends and stakeholder feedback, the Company made significant changes to the portfolio of investments. Most notably, the IVVC program was added, the Targeted Undergrounding program was significantly reduced, and much of the Distribution H&R work was moved out of the plan. In November 2018, the Company sent a detailed "pre-read package" to North Carolina stakeholders describing the development and proposed Grid Improvement Plan, in advance of the second North Carolina Stakeholder Workshop held on November 18, 2018. I have included that pre-read package as Exhibit 12. In this workshop, with RMI again acting as the neutral facilitator, 78 participants (inclusive of 19 Duke Energy and four RMI staff) convened for a day-long workshop. At the conclusion of that workshop, RMI prepared a detailed, post project report which was filed with the Commission on January 9, 2019, and I have included that report as Exhibit 13 to my testimony.

Q. WHAT ACTIONS DID THE COMPANY UNDERTAKE TO RESPOND TO THE LEARNINGS FROM THE SECOND STAKEHOLDER WORKSHOP?

A. The major themes we heard in the second workshop included: Grid Improvements should be supported by cost benefit analysis; the Company should provide further details on how it conducted its cost benefit analysis; and the Company should provide how much additional distributed energy and renewable resources the grid could support with the plan's improvements. In response, the Company provided cost benefit analysis and underlying data sources and work sheets for all applicable programs and projects in a virtual data room for stakeholders to review ahead of the third stakeholder workshop held on May 16, 2019. The Company also responded to the questions regarding distributed renewable energy resources. Prior to the May 16, 2019 workshop the company conducted a webinar with stakeholders on April 25, 2019 to address questions regarding the cost benefit analysis and gather feedback regarding the agenda for the next stakeholder workshop. The webinar materials are included in Exhibit 14.

Q. CAN YOU ELABORATE ON THE FEEDBACK RECEIVED FROM STAKEHOLDERS IN THE APRIL 25, 2019 WEBINAR?

A. Yes. During the webinar, the Company conducted a poll to determine what stakeholders wanted to discuss in detail in the May 16, 2019 workshop.

Seventy-six percent of the webinar participants stated that they wanted to discuss cost recovery issues regarding the Plan. Fifty-nine percent stated that they wanted more information and discussion regarding the Company's cost benefit analysis for the plan, and 41 percent stated that they wanted to further discuss plan prioritization and design. Finally, 55 percent stated that they wanted to further discuss distributed renewable energy resource enablement. Based on these responses, and with the help of RMI, the Company designed the agenda for the May 2019 workshop with these prioritized responses in mind. I have included that pre-read package as Exhibit 15.

Q. WHAT WERE THE RESULTS OF THE THIRD AND MOST RECENT STAKEHOLDER WORKSHOP?

A. In this workshop, with RMI again acting as the neutral facilitator, 52 participants (inclusive of 11 Duke Energy) convened for a day-long workshop. At the conclusion of that workshop, RMI prepared a detailed, post project report which was filed with the Commission on July 9, 2019 and I have included that report as Exhibit 16 to my testimony.

Q. WHAT ACTION HAS THE COMPANY TAKEN TO RESPOND TO STAKEHOLDERS' FEEDBACK IN THE THIRD WORKSHOP FOR MORE INFORMATION ON THE COST BENEFIT ANALYSES?

A. A series of three webinars focused on deep dives into the analysis behind Duke Energy's Grid Improvement Plan took place in June 2019. The first webinar took place on June 13 and focused on a deep dive into the Self-Optimizing Grid cost benefit analysis. The second webinar took place on June 17 and focused on a deep dive into the Targeted Undergrounding cost benefit analysis. The third webinar took place on June 24 and focused on a deep dive into several Transmission H/R projects. Highlights of the Grid Improvement Program were presented at the beginning of each meeting. Experts were on hand to guide participants through cost benefit analysis scenarios, address questions regarding the implementation, improvements and progress of the programs. Over 40 participants attended each webinar. The materials presented in the webinars are included in Exhibit 18.

Q. WHAT CONCLUSIONS HAVE YOU DRAWN BASED ON ALL THIS STAKEHOLDER ENGAGEMENT?

A. We have drawn several conclusions. First, it appears to us that stakeholders understand and accept the Megatrends that are facing the Company and our industry. Second, the combination of the substantive changes we made to the content of the plan and the detailed cost benefit analyses that we provided seems to have helped stakeholders gain a better consensus and understanding of our proposed three-year plan. Finally, most stakeholders remain highly interested in what future phases of the plan, if any, would contain and how costs for those phases would be recovered. We will keep this last observation front and center as we continue our stakeholder engagement efforts in the Carolinas.

Q. **CAN YOU PROVIDE MORE DETAIL ON WHAT OTHER GRID IMPROVEMENT WORK THE COMPANY PLANS TO DO IN ADDITION TO THIS THREE-YEAR PLAN?**

A. Yes. Our three-year Plan is a comprehensive package of well-coordinated grid improvements. It does not need a Phase 2 to be effective, and depending on what we see in the industry and what we hear from our stakeholders in our ongoing engagement with them, there may never be a second phase to the Grid Improvement Plan. That being said, the three-year Plan does set North Carolina up for other improvements that could warrant a second phase of the Plan, and we plan to engage and work with stakeholders before deploying any future phases of the Plan. Below are potential programs for consideration and stakeholder input:

1. **Phase 2 of Self-Optimizing Grid**. The current SOG plan enables approximately 344 - 430 circuits with approximately 628,000 - 785,000 customers. A Phase 2 project could focus on the next, most cost effective, group of circuits.
2. **Phase 2 of IVVC**. The current IVVC plan would enable approximately 152 - 190 substations and associated circuits. A Phase 2 project could focus on the next, most cost effective, group of substations and circuits.
3. **Increased Implementation of Power Electronics**. The current IVVC and SOG programs set up the basic capacity, automation, and Volt/VAR control mechanisms to manage the 21st century grid. As privately owned

DER grows, power electronics will be essential to managing the rapid and dynamic effects of multiple, small scale intermittent resources.

4. **44 KV Upgrade Projects that Enable Solar Capacity**. Through continuing coordination with stakeholders and regulators, these projects may afford new opportunities that provide value to customers.

5. **ISOP Optimization**. As the Company and the industry continues to develop and deploy ISOP, best practices and lessons learned can be utilized to optimize the ISOP process.

6. **Increased use of Energy Storage.** Energy Storage is part of our three-year Plan but is still in a startup/pilot phase. We believe more opportunities may exist as batteries become more cost effective and as we learn more about their capabilities on the grid.

This list is certainly not comprehensive or prescriptive. It is intended to lay out options that build off the currently proposed three-year plan. Regardless, we are committed to continued stakeholder interaction to help inform any future actions that we may, or may not, take.

Q. WHAT COST RECOVERY MECHANISM IS THE COMPANY PROPOSING FOR FUTURE GRID IMPROVEMENT PLAN WORK?

A. As discussed more fully in the testimony of Witness McManeus, the Company is requesting deferral accounting treatment for the Grid Improvement Plan work as a mitigant to the debilitating effect that regulatory lag will have on the Plan absent a deferral.

Q. PLEASE EXPLAIN THE IMPACT THAT REGULATORY LAG WILL HAVE ON THE GRID IMPROVEMENT PLAN WORK ABSENT A DEFERRAL.

A. It is important for stakeholders to recognize that just like any other company that must manage a monthly budget and pay bills, a regulated utility has a limited amount of funds to pay a given amount of expenses. Unlike unregulated companies that can raise the price of their products as they see fit to cover incremental expenses, the Company's income stream to pay for projects needed to maintain a base level of service to customers in North Carolina is set by the Commission in base rate proceedings like this one and once that revenue stream is set, the Company cannot increase it without filing another base rate case. This means that every day, the Company must decide what projects and programs it will deploy and which ones that it will not, which, in turn, means that programs and projects must compete against each other for funding priority. Thus, to fund incremental work like the Grid Improvement Plan, the Company must obtain money between its rate cases to pay for new work, and obtaining money naturally comes with a cost.

In instances where the Company has large, centralized projects that take longer to complete (such as building a new power plant), I understand that regulatory rules allow the utility to apply a carrying charge to the funds that the Company must borrow and pay interest on to complete this work as a principle of fundamental fairness. In other words, one cannot reasonably expect the Company to borrow money and pay interest on that money on behalf of customers to build a power plant that will serve those customers and then not pay the Company back for the money it borrowed plus the interest it had to pay on it. However, I understand that smaller and quickly-installed project and programs, like many of those included in the Grid Improvement Plan, do not receive those same benefit for accumulating a carrying charge that apply to the large, time-intestive projects. To ensure that utilities are not discouraged from these smaller programs that deliver benefits more quickly to customers, I have seen regulators enact measures to avoid the problem of regulatory lag such as rider recovery, rate adjustment step ups, or deferral accounting treatment with returns for such projects.

Q. ARE YOU SUGGESTING THAT THE COMPANY WILL NOT PERFORM ANY OF THE WORK IN THE GRID IMPROVEMENT PLAN IF THE COMMISSION DOES NOT APPROVE SOME METHOD TO AVOID REGULATORY LAG ON THOSE PROJECTS?

A. No. However, without a reasonable means of mitigating the negative impacts of regulatory lag associated with significant ongoing and incremental spending under the Grid Improvement Plan, the Company would be required to reassess its ability to commit to the planned level of investment in this program given that the level of investment anticipated under the plan simply cannot be reasonably sustained in the absence of mitigation measures such as the deferral requested herein. As such, if the Commission determines not to grant the regulatory asset treatment for the Company's Grid Improvement Plan investment sought in this proceeding, the Company will be required to reassess its ability to implement that plan. In such a situation, the Company would have to try and perform small pieces of the Grid Improvement Plan over a much longer period with its existing revenues, which will delay important benefits and potentially essential improvements for customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

I. INTRODUCTION

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

A. My name is Jay W. Oliver. My business address is 400 South Tryon Street, Charlotte, North Carolina. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Strategy and Asset Management Governance. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to testimony from the Public Staff and Intervenors in this case regarding the Grid Improvement Plan ("GIP"). For organizational purposes, my rebuttal testimony is divided as follows:

- <u>Agreed programs for deferral</u>: Public Staff witnesses and some other intervenors recognize several of the GIP programs and projects as "extraordinary type of activity" that should be considered eligible for the deferral treatment sought by DE Carolinas in this case. The Company agrees with those determinations. Further, notwithstanding the Company's position that all of the programs and projects in the GIP should be eligible for deferral treatment, the Company believes that additional GIP programs and projects should also qualify for deferral treatment as "extraordinary in type," using the Public Staff's own criteria.

- Cost benefit analysis concerns: Public Staff Witness Jeff Thomas cited some concerns with the GIP cost benefit analyses ("CBAs") that DE Carolinas presented in this case. I will address his concerns, as well as concerns from witnesses representing other intervening parties.
- Performance measurement: DE Carolinas believes it would be appropriate to conform to the reporting measurements proposed by the Public Staff for programs deemed eligible for deferral treatment, and I will explain how we propose to do so.
- Projects/Programs that the Public Staff and intervenors did not find to be "extraordinary": I will address why programs that the Public Staff and intervenors found not to be "extraordinary" were included in the GIP in the first place and why the Company believes that those projects and programs should still be included in the GIP.
- Stakeholder engagement has been productive: Finally, I will respond to complaints from some intervenors regarding the stakeholder process used to form the Company's GIP. While the Public Staff recommends a productive next step in consideration of the GIP, other intervenors recommend inaction or misguided action without recognition that the

Company's GIP is a step down the path to a reasonable objective that is shared by many stakeholders.

I also respond to certain comments made by Commercial Group witness, Mr. Steve Chriss, regarding Green Button functionality.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR REBUTTAL TESTIMONY?

A. Yes. Oliver Rebuttal Exhibit 1 is attached hereto and incorporated herein by reference.

Q. WAS THAT EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

III. <u>AGREED PROGRAMS FOR DEFERRAL</u>

Q. AS AN INITIAL MATTER, DID ANY INTERVENOR OBJECT TO OR CONTEST THE MEGATRENDS THAT THE COMPANY IDENTIFIED AS THE DRIVERS OF THE GIP?

A. No. While some intervenors suggested that the Megatrends that are driving the need for the GIP have existed longer than the Company suggests, no intervenor credibly disputed that the Megatrends are real or that they are having an impact on the Company.

Q. WHY IS THIS FACT IMPORTANT?

A. I mention this general consensus regarding the Megatrends to show that there is no serious dispute that these forces exist and that they must be addressed. With this backdrop, I am pleased that the Public Staff and other intervenors did recognize that some of the programs and projects in the GIP are reasonable and prudent ways to address these Megatrends.

Q. THE PUBLIC STAFF CREATED A MATRIX FOR REVIEWING THE GIP TO DETERMINE IF PROJECTS/PROGRAMS SHOULD BE RECOGNIZED AS GRID MODERNIZATION. WHAT ARE YOUR THOUGHTS ON THIS MATRIX?

A. I applaud the Public Staff for deploying an objective approach to evaluating the various components of the GIP. I do, however, have some additional thoughts as to some of their methods and conclusions. First, the Public Staff sought to identify those programs that would "bring the current grid up to new standards of operation and reliability" and that would be transformative. I note that in Exhibit 3 of my direct testimony I highlight the implications of a "business as usual" approach to grid investments, and in Exhibit 4 of my direct testimony I review each program and highlight new or transformative grid capabilities and value to our customers. Each program within the GIP seeks to bring the current grid up to new standards of operation or reliability. Leveraging new equipment and analytics along with traditional equipment and work practices will transform the grid to a new level of operation. The equipment being installed in the GIP is not a like-for-like exchange that brings no other value other than being new, rather the new equipment often comes with advanced monitoring and control features not present on the grid today which will incrementally expand our ability to control the grid and provide more flexibility and reliability going forward.

Q. WHICH GIP PROGRAMS WERE RECOGNIZED AS "EXTRAORDINARY" AND DESERVING OF DEFERRAL TREATMENT IN PUBLIC STAFF TESTIMONY PER THEIR EVALUATION?

A. Public Staff Witnesses Williamson recognized the following programs as extraordinary: ISOP, SOG Segmentation and Automation, Transmission System Intelligence, SOG ADMS, Underground System Automation, IVVC.

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S ASSESSMENT OF THE PROGRAMS RECOGNIZED AS "EXTRAORDINARY" AND DESERVING OF DEFERRAL TREATMENT AS A REASONABLE STANDARD?

A. Yes. However, using Public Staff's evaluation methodology, the Company believes that several other GIP programs should also qualify for deferral treatment.

Q. WHAT OTHER GIP PROGRAMS SHOULD BE CONSIDERED EXTRAORDINARY AND DESERVING OF DEFERRAL TREATMENT, USING THE ANALYSES PROPOSED BY PUBLIC STAFF?

A. The following programs were analyzed further using the Public Staff's matrix and methodology, and the Company believes that they should be added to the "extraordinary" list using the Public Staff's methodology. Please see Oliver Rebuttal Exhibit 1 where I have prepared an analysis of these additional programs using the Public Staff's evaluation matrix.

- SOG Capacity and SOG Connectivity
- Transmission H&R – 44kV System Upgrade Subprogram

- Distribution Automation (note the Underground System Automation sub program is already included on Public Staff's list)
- Power Electronics
- DER Dispatch Tool
- Cyber Security

Q. WHY DOES SOG CAPACITY AND SOG CONNECTIVITY MEET THE PUBLIC STAFF'S CRITERIA AS EXTRAORDINARY?

A. Fundamentally, the distribution system was built for one-way power flow and not designed to accommodate the 2-way power flow needs generated by increased utilization of distributed energy resources ("DER"). Additional circuit capacity and connectivity are needed to begin to network and transform the current grid which has only limited ability to reroute or rapidly restore power and limited ability to optimize for the growing penetrations of DER. All of the major components of SOG work together to fundamentally redesign key portions of the distribution system and transform it into a dynamic, smart-thinking, self-healing grid. The benefits outlined in the SOG cost- benefit analysis cannot be achieved by leaving out capacity and connectivity. Therefore, using the Public Staff's methodology, I have normalized witnesses Williamson's matrix to score capacity and connectivity as a 3 for transformative and 2 for timing. This aligns with the Public Staff's view of the other components for SOG. SOG with all of its components is by far the cornerstone program to transform the distribution grid to better accommodate DER and it cannot achieve these goals if only partially implemented.

Q. WHY SHOULD THE 44KV SYSTEM UPGRADE SUBPROGRAM UNDER TRANSMISSION H&R MEET THE PUBLIC STAFF'S CRITERION AS EXTRAORDINARY?

A. The 44 kV System Upgrade subprogram under Transmission H&R both protects the 44 kV system from extreme weather and begins to pave the way for more DER interconnections. This system is not just being rebuilt like-in-kind, it is being transformed into a system that will withstand higher wind and ice loading, higher magnitude lightning strikes, and better resistance to both animal and vegetation caused outages. These improvements will directly reduce customer outage impacts. Wooden structures and other circuit assets on average are beyond their useful life and the rate of failures impacting customers is expected to increase over time. Along with the installation of steel and concrete structures, re-conductoring these circuits to the 100kV voltage standard increases circuit capacity and paves the way for future DER interconnections without the need to upgrade lines. Installing overhead fiber optic ground wire (OPGW) on these circuits as part of the rebuilds also improves the ability to monitor and control remote devices , giving grid operators better visibility into threats to the grid and the means to make real time adjustments to minimize customer impacts. This is why I recommend that the Public Staff's scoring of the 44kv line rebuild be adjusted to transformative as a two, timing as a two, and grid architecture as a three.

Q. WHY SHOULD DISTRIBUTION AUTOMATION MEET THE PUBLIC STAFF'S PROPOSAL FOR EXTRAORDINARY?

A. There are three core subprograms that the Public Staff deemed not extraordinary; 1) hydraulic to electronic recloser replacement, 2) system intelligence and monitoring and 3) replacement of standard tap line fuses with automatic reclosing devices known as ALDs (automatic lateral device).

First, with hydraulic to electronic recloser replacement, the Company shifts from old oil-filled reclosers to new industry standard electronic reclosers. Aside from the environmental benefit of replacing oil-filled equipment, and as the Public Staff notes, these new devices can allow for remote operation and provide ongoing and continuous monitoring of the distribution systems health. This transformative capability is not available today under the current equipment. Those new reclosers enabled with monitoring capability will feed data into the new ADMS system and will allow for more direct dispatch of crews while furthering the remote command and control capability available to the distribution grid operators that is needed in the dynamic energy future that lies ahead. For those reasons, I recommend that the Public Staff's scoring of hydraulic to electronic recloser replacement be adjusted to a three for transformative, two for timing and remain the same on the grid architecture.

Second, system intelligence and monitoring add significant new digital and analytical capabilities for devices on the grid. The work in this category is focused on advanced devices and tools that provide enhanced detection of events and remote monitoring of events for proactive maintenance, such as: enhanced asset grid intelligence, where small sensors are placed in hard to reach locations; in vaults to monitor major equipment; and transformers to detect oil level or moisture ingression. Additionally, systems will help enable distributed intelligence, where high speed/low latency decisions need to be made that allow the grid's mechanical and electronic devices to optimize their operation due to intermittency from DER. These and other efforts result in greater transformative grid intelligence capabilities that leverage enhanced sensors and control capabilities that allow the Company to proactively understand grid events. For those reasons I recommend that the Public Staff's scoring system intelligence and monitoring be adjusted to a three for transformative, two for timing and remain the same on grid architecture.

Third, as the Public Staff notes, the fuse replacement component will replace single-use fuses with an Automatic Lateral Device (ALD). The use of an ALD is truly a leap forward in capability not previously available to the electric industry. Due to advancements in technology, ALD's are now compact enough to fit in a standard fuse cut-out and will save momentary interruptions from reaching customers on the main feeder. Additionally, when an ALD does trip, the restore time is much faster as line technicians no longer have to change a blown fuse. Bringing this new capability to the grid has the ability to further increase reliability from day one of install. For those reasons, I recommend that the Public Staff's scoring of the fuse replacement be adjusted to a two for timing and remain the same for transformative and grid architecture.

Q. SHOULD POWER ELECTRONICS MEET THE PUBLIC STAFF'S PROPOSAL FOR EXTRAORDINARY?

A. Yes. As the adoption of DER continues to increase, protective device technology is also advancing so that we can appropriately detect and respond to rapid voltage and power fluctuations that often accompany non-dispatchable resources, such as solar. These intermittent power impacts occur and then change at rapid rates (in some cases sub-second) and frequently faster than the legacy electro-mechanical voltage management equipment, like regulators and capacitors, can handle. Integrating advanced solid-state technologies like power electronics, enhances the transformative capability of the distribution system to manage power quality issues associated with increasing DER penetration. The Company's Power Electronics for Volt/Var pilot project will pilot the use of this new modern technology to determine its potential use to combat Volt/Var issues caused by intermittent solar. Due to the significant possibilities of this technology compared to what is and has been available to the electric industry, I recommend that the Public Staff's scoring for this program be adjusted to a three for transformative and remain the same for time and grid architecture.

Q. WHY SHOULD THE DER DISPATCH TOOL MEET THE PUBLIC STAFF'S CRITERION AS EXTRAORDINARY?

A. The Distributed Energy Resources (DER) Dispatch Enterprise tool will coordinate with the Distribution Management System (DMS) and Energy Management System (EMS) to improve the way DERs are integrated into the energy supply mix, both at the Distribution and the bulk power level. Today, due to the explosive growth in DER on the North Carolina system, the Company only has a rudimentary ability to quickly shed large blocks of solar generation in emergency conditions to meet standards for real power control. The DER Dispatch tool will provide operators with a more automated and refined toolset to optimize management of both utility and customer owned DERs to meet system stability requirements. For these reasons, I recommend that the Public Staff's scoring remain the same for their transformative rating but adjust their ranking to a two for timing and a three for grid architecture.

Q. WHY SHOULD CYBER SECURITY MEET THE PUBLIC STAFF'S PROPOSAL FOR EXTRAORDINARY?

A. As the Public Staff notes, security is a major concern for all utilities across the country. Grid modernization and optimization efforts are deploying connected/networked intelligent electronic devices (IEDs) to the field enabling new capabilities for optimization, modernization, and automation. These devices increase the complexity, connectivity, and potential points of entry to our system. Purposeful threats to the electric grid are on the rise worldwide and as the grid transforms the threat landscape changes and we must adapt with it. The Government Accountability Office recently stated that the FERC Standards do not fully address leading federal guidance for critical infrastructure cybersecurity.[1]

[1] Critical Infrastructure Protection Actions Needed to Address Significant Cybersecurity Risks Facing the Electric Grid, August 2019, https://www.gao.gov/assets/710/701079.pdf

Additionally, the threat landscape focusing on electric utilities in North America is expansive and increasing, led by numerous intrusions into industrial control system (ICS) networks for reconnaissance and research purposes and ICS activity groups demonstrating new interest in the electric sector. Attacks on electric utilities can have significant geopolitical, humanitarian, and economic impact. Thus, state-associated actors will increasingly target power and related industries like natural gas to further their goals.[2]

The historic approach to defending our assets (including but not limited to physical barriers, firewalls, manual configurations, and manual work procedures) are appropriate and must be maintained; however, additional transformative and architectural measures must be taken to address new risks and the changing landscape. To mitigate the potential risks related to intelligent field equipment, the Company is focusing on three major efforts to ensure system security and reliability: 1) Device Entry Alert System: Physical Access Management – deploying a platform and organization to enhance physical access control/monitoring and response capabilities for field control devices; 2) Secure Access Device Management: User Access Management – deploying a platform to perform automated and remote Password Management, Access Logging, and Device/Event information retrieval for field devices; and 3) Distribution Line Device Cyber Protection and Windows-based Change Outs: Equipment

[2] North American Electric Cyber Threat Perspective, January 2020, https://dragos.com/wp-content/uploads/NA-EL-Threat-Perspective-2019.pdf

Management – replacing vulnerable legacy equipment with new devices capable of supporting Cybersecurity best practices. The utility industry is highly regulated, and the Company is subject to many compliance requirements (CIP, etc.). From a physical/cyber security perspective we are not falling into the trap of thinking that being compliant means we are adequately protected. Our cyber-related investments within the GIP are addressing real risks to the grid. Accordingly, I recommend that the Public Staff's scoring of all of the cyber related investments be adjusted to a two for transformative, two for timing, and a three for grid architecture.

Q. BASED UPON YOUR EVALUATION USING THE PUBLIC STAFF'S MATRIX WHAT IS THE SUMMARY OF THE INVESTMENTS THAT SHOULD BE DESIGNATED AS EXTRAORDINARY?

A. Below I have included all programs that scored a nine or higher utilizing the updated scoring matrix. The total investment in GIP programs deemed extraordinary under my revised application of the Public Staff analysis is $925M.

	DEC (millions)
Public Staff - Programs deemed "Extraordinary"	
SOG Automation and Control	$176
SOG: ADMS	$30
IVVC	$207
Transmission System Intelligence	$63
UG System Automation	$12
ISOP	$4
	$492
Duke Energy - Additional programs for consideration as "Extraordinary"	
SOG: Capacity and Connectivity	$214
Transmission H&R (44KV Line Rebuild)	$100
Distribution Automation (less UG System Intelligence)	$103
Power Electronics	$1
DER Dispatch Tool	$5
Cyber Security (SADM, DEAS, Line Device Protection)	$11
	$433
Public Staff + Duke Energy Additional Programs	**$925**

Q. **WHAT PROGRAMS IN THE GIP DID THE PUBLIC STAFF NOT QUALIFY AS EXTRAORDINARY USING ITS SCORING METHODOLOGY?**

A. Using Public Staff's methodology, the following programs did not "score as extraordinary":

	DEC (millions)
Additional Programs in GIP	
Targeted Undergrounding	$60
Distribution Transformer Retrofit	$8
Long Duration Int/High Impact Sites	$11
T-Transformer Bank Replacements	$34
Oil Breaker Replacements	$116
Transmission H&R	$2
Physical Security	$54
Enterprise Communications	$104
Enterprise Applications	$17
	$407

Q. DOES THIS MEAN THAT THE PROGRAMS ABOVE SHOULD NOT HAVE BEEN INCLUDED IN THE GIP?

A. No. I discuss why those programs are appropriate for the GIP in Section VI of my testimony. And to be clear, the Public Staff rating methodology is a rational way to approach the evaluation of our GIP programs, but it is also somewhat subjective (as the Public Staff acknowledges) and it is also not the only way to evaluate those programs.

Q. WHAT DOES THE PUBLIC STAFF RECOMMEND THE COMMISSION DO ABOUT GIP PROGRAMS NOT DESIGNATED AS EXTRAORDINARY?

A. The Public Staff is not recommending any of the GIP not be implemented. They only take issue with the requested deferral accounting for programs and projects that did not meet their standard of "extraordinary."

Q. APART FROM PUBLIC STAFF, DID ANY OF THE INTERVENOR WITNESSES SUPPORT ANY OF THE WORK PROPOSED IN THE GIP?

A. Yes, to some degree. In an alternative recommendation, NCJC et al. witnesses Alvarez and Stephens suggest that the Commission approve the following programs/projects should the Commission support the GIP.

Program/Subcomponent	Capital $ per Oliver Exh. 10 (in millions)	Suggested Adjustments	Capital $ per NCJC/NCSEA If GIP Not Rejected
Merits Approval w/Conditions	$ 374.16	$ -	$ 374.16
Integrated Volt/VAr Control	$ 216.66	$ -	$ 216.66
Transmission H&R -- Flood & Animal Mitigation Components	$ 13.18	$ -	$ 13.18
Long Duration Interruption/High Impact Sites	$ 27.10	$ -	$ 27.10
Enterprise Applications/ISOP Software/DER Software	$ 41.94	$ -	$ 41.94
Cyber and Physical Security, excluding substation physical	$ 23.04	$ -	$ 23.04
Enterprise Comm's excluding new data and voice networks	$ 52.24	$ -	$ 52.24
Merits Approval w/Material Modifications & Conditions	$ 843.05	$ (336.80)	$ 506.25
Self-Optimizing Grid/Advanced Dist Mgmt System	$ 722.48	$ (336.80)	$ 385.67
Transmission H&R (DER Capacity Upgrades ONLY)	$ 120.57	$ -	$ 120.57
Merits Rejection	$ 659.95	$ (659.95)	$ -
Targeted Undergrounding	$ 114.54	$ (114.54)	$ -
Distribution Transformer Retrofit	$ 118.02	$ (118.02)	$ -
Transfomer Bank Replacement	$ 116.39	$ (116.39)	$ -
Oil-Filled Breaker Replacement	$ 200.29	$ (200.29)	$ -
Substation Perimeter Security	$ 110.71	$ (110.71)	$ -
Merits Rejection Pending Further Evaluation	$ 440.27	$ (440.27)	$ -
Enterprise Comm's, new data & voice (tech/econ make/buy analyses)	$ 159.58	$ (159.58)	$ -
Distribution Automation (benefit-cost analysis)	$ 194.29	$ (194.29)	$ -
Transmission System Intelligence (benefit-cost analysis)	$ 86.41	$ (86.41)	$ -
GIP Components Being Considered in Other Dockets	$ 192.48	$ (192.48)	$ -
Energy Storage (NCUC #E-100, Sub 164)	$ 129.00	$ (129.00)	$ -
Electric Transportation (NCUC #E-2 Sub 1197 & E-7 Sub 1195)	$ 63.48	$ (63.48)	$ -
TOTALS	$ 2,509.92	$ (1,629.51)	$ 880.41

IV. COST BENEFIT ANALYSIS CONCERNS

Q. WHAT CONCERNS DID PUBLIC STAFF AND INTERVENORS RAISE REGARDING THE COST BENEFIT ANALYSES THAT SUPPORT THE GIP?

A. The Public Staff raised the following concerns regarding the CBAs prepared for the GIP: additional CBAs should be performed for certain programs; there should be sensitivity analyses for the cost benefit analyses; DE Carolinas should develop new resiliency cost survey data; and the Company should revise its cost benefit analyses for programs such as SOG, IVVC, Transmission H&R Line, and other programs with benefit estimates that could be affected by long-term outage values or vegetation management impacts. Other intervenors raised these additional concerns: the Company underestimated costs and overestimated benefits for its GIP; the Company should have conducted CBAs for programs such as those in Enterprise Communications; and the Company should have conducted sensitivity analyses on its cost benefit analyses. I will first respond to the issues that the Public Staff raised and then will address the concerns from other intervenors.

Q. WHAT WERE PUBLIC STAFF WITNESS THOMAS' RECOMMENDATIONS REGARDING THE GIP COST BENEFIT ANALYSES?

A. On pages 71-73 of his testimony, Witness Thomas recommends that DE Carolinas should:

- Perform CBAs for the Distribution Automation and DER Dispatch programs;
- Perform and file sensitivity analyses of its cost benefit analyses;
- Conduct an interruption cost study in the Carolinas or otherwise update interruption costs used in the Interruption Cost Estimate tool;
- Revise Transmission H&R Line cost benefit analyses to assign customer reliability benefits to customer classes;
- Remove or modify certain benefits, such as long-term reliability benefits, CO_2 emission savings, and avoided capacity;
- Revise SOG cost benefit analyses to include the effect of momentary outages; and
- Revise the SOG cost benefit analysis to account for increased vegetation management activity.

I will address each of Witness Thomas' recommendations regarding the GIP cost benefit analyses below. However, I first want to note that on page 74 of Witness Thomas' testimony, he includes a matrix showing how the GIP CBA results could be impacted under certain sensitivity scenarios that account for issues that he raises in his testimony. I observe that even under scenarios that have sensitivities that cut against the GIP, the projects and programs that were evaluated still are cost beneficial in some instances and are at or near break-even in others. Given the conservative assumptions that the Company included in the GIP CBAs, this gives me comfort that the work in question will positively benefit customers.

Q. WHY DID DUKE ENERGY NOT PERFORM A CBA FOR THE DER DISPATCH TOOL AND DISTRIBUTION AUTOMATION PROGRAMS?

A. The DER Dispatch Tool and Distribution Automation programs are part of the "modernize" portion of the protect/modernize/optimize framework used by the Company to evaluate the programs that were included in the Grid Improvement Plan. On pages 34-37 of my direct testimony on this matter, I describe the nature of the work we considered "modernize" as well as "protect" and why a cost benefit analysis is not the proper measure for approving this work.

Q. SHOULD DUKE ENERGY HAVE PERFORMED SENSITIVITY ANALYSES AROUND ITS CBAS?

A. A sensitivity analysis was not contemplated as a required function of the CBA process. For the CBA process, the concept of the AACE estimate classes associated with a project or program provide a reasonable measure of the expected cost estimate accuracy. Regarding the benefit component, the amount of combined operational and customer benefits for most projects and programs provided assurance the project or program was a positive benefit to our customers.

Q. SHOULD RELIABILITY BENEFITS BE EXCLUDED FROM CONSIDERATION OF THE GIP CBAS?

A. No. Provision of safe and reliable electricity is a foundational responsibility of the Company to its customers. As Witness Alvarez notes, the need for electricity is universal and ubiquitous. The issue is not that such a product has value, it is how to adequately quantify the benefit from providing greater reliability to our customers. The use of the ICE calculator data allows a utility to assign a projected value to that benefit from measurable improvements in reliability metrics.

Q. WHY IS IT APPROPRIATE FOR THE COMPANY TO HAVE USED THE ICE MODEL DATA TO ESTIMATE THE BENEFIT OF ITS GIP PROGRAMS?

A. The ICE model was designed for electric reliability planners at utilities and government organizations to estimate interruption costs. The underlying data supporting the model is based on extensive utility customer surveys and has been validated multiple times through on-going updates by LBNL/Nexant. This data analysis was judged by Duke Energy to be the best available means to assist in quantifying customer benefits related to reliability improvements. The Company was able to pair detailed project related outage and customer data with the published ICE survey data to calculate customized individual project and program estimated customer savings. It is important to note that all economic benefits calculated are estimates. These estimates should be considered statistically valid having been generated through the use of well-established and well-respected industry modeling techniques.

Q. HOW CAN CUSTOMER RELIABILITY BENEFITS BE VERIFIED?

A. The Company intends to track the actual customer reliability benefits by measuring the Customer Interruptions ("CI") and Customer Minute Interruptions ("CMI") saved for each of the respective programs compared to the expected CI and CMI saving represented in the CBAs for each of the respective programs supported by a CBA. The Company has already been tracking the CI and CMI savings from SOG segmentation and automation. Performance tracking is discussed further in Section V. of this testimony.

Q. IS IT APPROPRIATE TO COMPARE THE COMPANY'S GIP RELIABILITY BENEFITS AGAINST THE GDP OF NORTH CAROLINA?

A. While we acknowledge that from a pure math perspective the figure of $6B is approximately 1% of the 2018 NC GDP amount of $566B, any correlation of these two figures beyond that math exercise is pure speculation. For starters, the $6B figure is the NPV of 25-30 years of annual benefit streams. It would seem more appropriate to speculate on the impact each annual period could have on the state GDP, which is a much smaller portion.

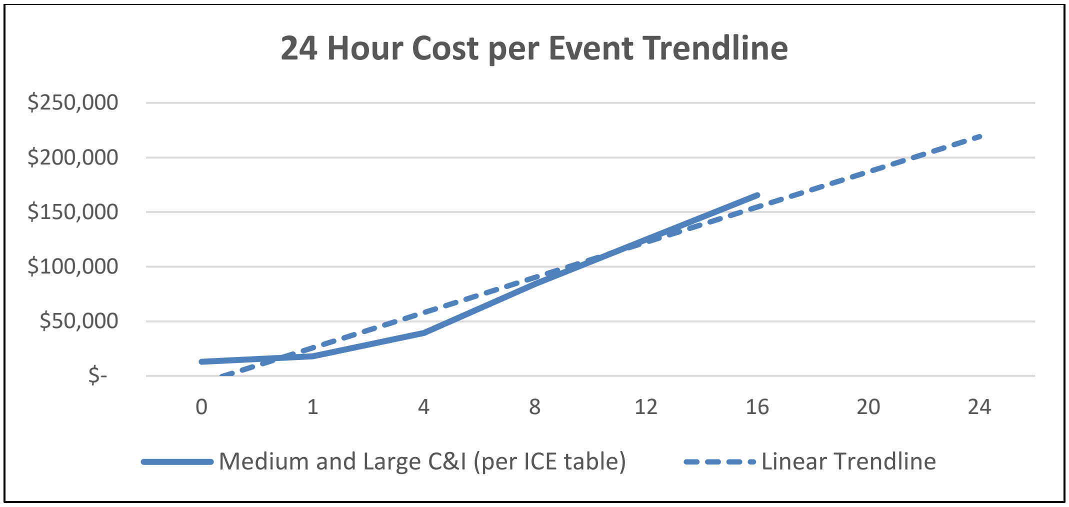
Further, the economic impact to the state of North Carolina resulting from increases (or decreases) in reliability benefits cannot be measured by simply examining changes in state-level GDP growth over time. For example, if GDP growth were to improve over a twelve-month period during which time reliability benefits simultaneously decreased, this would not constitute evidence that worsening reliability had no adverse impact on economic growth. One could just as easily make the case that GDP growth would have been higher if not for worsening reliability benefits. More generally, because GDP growth is affected by many variables, the correlation between changes in reliability benefits and changes in GDP growth cannot point to evidence of a relationship between these two specific variables unless all other variables are held constant. This is one of the principal features of the methodology used in the CBAs to estimate primary and secondary economic benefits. This methodology is specifically designed to estimate the benefits of improved reliability holding all other economic factors constant. The primary and secondary economic benefits resulting from improvements in reliability represents the marginal increase in economic activity that one would expect regardless of the current total GDP value for the state of North Carolina.

Q. WHY IS IT UNNECESSARY FOR DUKE ENERGY TO CONDUCT DIRECT CUSTOMER SURVEYS TO REVISE ITS RELIABILITY BENEFIT ESTIMATES?

A. There would likely be only marginal value in conducting an independent survey of customers in North Carolina for the purposes of evaluating customer savings associated with GIP reliability improvements. Specifically, the law of large numbers suggests that the statistical validity of estimates obtained using the relatively large sample size of customer data that is part of the ICE model is far greater than that of a small sample size of customer data in North Carolina. The significant cost, resource, and time requirements of conducting such a study without a guarantee of greater statistical value seems unwarranted at this time. Duke Energy representatives, along with our economic consultant, reviewed the ICE model process in late 2018 with representatives of Nexant and concurred that the data as provided would be satisfactory to use for reliability valuations.

Q. WHY DID DUKE ENERGY INCLUDE LONG-TERM RELIABILITY BENEFITS IN ITS CBAS (GREATER THAN 24 HOUR VALUES FROM ICE)?

A. Duke Energy recognizes the limitation applied in the LBNL document referenced by Witness Thomas. However, we also assert there is continued value to be gained from elimination of those longer-term outages and that the value does not significantly decrease after the initial 24-hour period. Our assumption of a continued linear progression to use for estimates was based upon a trendline imposed upon the Table ES-1 ($2013) referenced from the same LBNL report.



Estimated Customer Interruption Costs (2013$) by Duration Source: Table ES-1 from LBNL Report

Witness Thomas provides a similar graphical view of a cost profile; however, this view used a summer weekday version to represent a typical Major Event Day ("MED") outage profile. The Company's 10-year outage data represents a number of potential MED outage sources. In addition to summer thunderstorms during this time period, we would have likely experienced ice storms, hurricanes, tornadoes, and straight-line wind events which could result in various MEDs. Taking into consideration the caveat from LBNL around the 24-hour limitation, the Company utilized the best information available to provide an estimate of that benefit value. Reviewing the filed CBAs, a subjective capping of the ICE survey values at a 24-hour maximum as suggested would appear to have a minor impact on the overall reliability benefit totals. While LDI items would have the most potential variance, the others noted by Witness Thomas should have virtually no impact. Exceeding the 24-hour threshold are five TUG projects (with MEDs being a minor item for

TUG), one transmission H&R project (Whiteville substation replacement), and no distribution transformer retrofit items.

Q. WITNESS THOMAS RECOMMENDS THAT THE COMPANY SHOULD REVISE ITS TRANSMISSION H&R LINE PROJECTS CBAS TO ASSIGN CUSTOMER RELIABILITY BENEFITS TO CUSTOMER CLASSES. WHY DO TRANSMISSION H&R LINE PROJECT CBAS NOT APPEAR TO SHOW RELIABILITY BENEFIT VALUES BY CUSTOMER CLASS?

A. The transmission system does not work in the same manner as distribution circuits. Except for radial lines, customers are supplied from multiple circuits, and customers are not "assigned" to a specific circuit. For these reasons, the transmission model differs from the distribution model. However, although not explicitly shown, the reliability benefit values do consider the impact of the typical ICE model related customer classes (Residential, Small C&I and Medium/Large C&I). The methodology Copperleaf uses to calculate the quantified benefit value uses a single Duration Cost per Jurisdiction. That cost amount is derived through a factor of the three individual customer class ICE model values, determined via the ICE calculator tool, multiplied by a weighting of the regional customer mix. Because transmission interruptions typically impact a variety of customers, a standard assumed customer mix reflecting 95% Residential, 3% Small C&I and 2% Medium/Large C&I is utilized within the Copperleaf tool. As such, the reliability benefit line items may not show the individual customer detail, but their individual weighted contributions are taken into consideration.

Q. WHY IS IT APPROPRIATE FOR DUKE ENERGY TO INCLUDE A CO_2 EMISSION SAVINGS BENEFIT IN ITS IVVC CBA?

A. It is undeniable that IVVC provides the benefit of voltage reduction and therefore load reduction. That load reduction benefit results in lower CO_2 emissions. DE Carolinas has simply presented a valuation of that CO_2 reduction for consideration. If the Company had excluded a benefit for CO_2 reductions from its IVVC CBA, other stakeholders may be concerned that the Company is not properly valuing the CO_2 reduction benefits of IVVC.

Q. WHY IS IT APPROPRIATE FOR DUKE ENERGY TO INCLUDE CAPACITY BENEFITS FOR SOG/IVVC?

A. Deferral of capacity from SOG and IVVC are direct benefits of these programs and will be delivered according to the construction schedule of those programs, regardless of the IRP capacity need date (2026). As engineering and construction occurs over the proposed plan timeframe, reliability improvements will be delivered to customers prior to 2026 as well. All DE Carolinas customers would be able to benefit from these capacity deferrals even if they are not served from circuits where IVVC and SOG are deployed.

Q. HOW IS THE CAPACITY BENEFIT FROM SOG/IVVC DIFFERENT FROM CAPACITY AS CONSIDERED IN THE IRP PROCEEDINGS?

A. Duke Energy disagrees with the removal of capacity deferral benefits prior to year 2026 as recommended by Witness Thomas' testimony. Capacity benefits from the

SOG CBA are not part of formal EE/DSM programs, which are included in the IRP. IVVC and SOG should not therefore be subject to the same timing constraints for delivery of capacity. SOG and IVVC capacity deferral is not intended to offset the capacity needs in the IRP but are quantified only as one portion of the benefits provided by SOG and IVVC.

Q. WHAT IS YOUR EVALUATION OF THE SOG SENSITIVITY ANALYSIS PERFORMED BY WITNESS THOMAS?

A. As stated in Witness Thomas' testimony on page 29, footnote 25, the number of faults per mile used in the sensitivity analysis is "illustrative only" and "reflects a 30% reduction in the number of vegetation-related outages". Our analysis reflects that 0.24 faults per mile is the estimate we arrive at using historical outage data. There is no data supporting a 30% reduction of vegetation related outages.

Q. HOW DO YOU RESPOND TO THE STATEMENT ON PAGE 10 OF WITNESS THOMAS' TESTIMONY THAT IT IS POSSIBLE THAT MORE COST-EFFECTIVE SOLUTIONS EXIST THAT WOULD PROVIDE SIMILAR RELIABILITY BENEFITS TO SOG?

A. The driver for many of the GIP projects is the full portfolio of Megatrends and not just reliability. The SOG example cited presents an excellent opportunity to illustrate. In Exhibit 5 to my direct testimony, proposed GIP programs and investments are shown compared against the matrix of the Megatrends to illustrate beneficial impact, but also the driver behind why programs were included. SOG checks the box across all the Megatrends. When wide-spread, privately owned roof-top solar begins to be adopted in scale, a dynamic, automated, capacity-enabled two-way power flow grid is an essential component to be in place. During lightly loaded shoulder seasons (spring and fall) excess locally produced DER energy can be quickly re-routed to adjacent neighborhoods for local consumption, maximizing its value by reducing line losses.

Q. HOW DOES THE COMPANY ASSESS THE VALIDITY OF THE LBNL FLISR DOCUMENT?

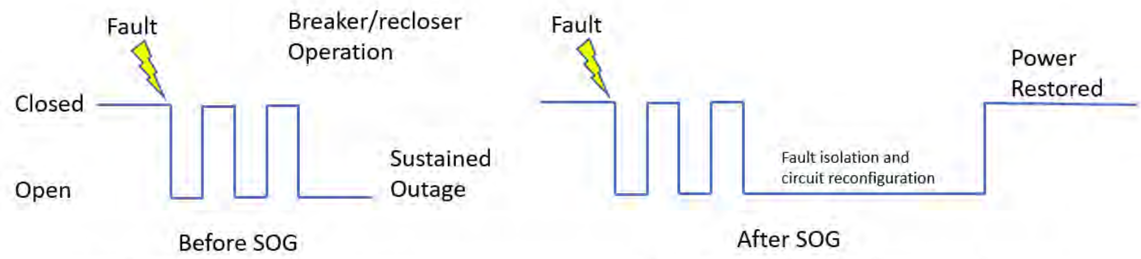
A. As shown in additional details in a question below, we believe that Witness Thomas' analysis of momentary outages is incorrect. Witness Thomas states that additional momentaries are experienced by customers due to SOG implementation. This is not correct. All customers experience momentaries while protective devices attempt to clear faults on the system. If a permanent fault occurs in a segment, then all customers past the protective device will experience momentaries until the device locks out. This process occurs whether SOG is implemented on a circuit or not. The difference is that on a SOG circuit the customers on un-faulted line sections are automatically restored post lock out.

Q. DOES SOG ONLY BENEFIT CUSTOMERS ON SELECTED CIRCUITS?

A. While SOG is deployed on the circuits, which have been identified as the most cost beneficial, there are benefits to all customers. The deployment of SOG will increase the efficiency of Company resources during outages, minor storms and also during MED events. Efficient deployment to circuits with SOG deployed will increase the availability of resources for assignment to non-SOG circuits and therefore benefit those customers also.

Q. WITNESS THOMAS MENTIONS THAT THE IMPLEMENTATION OF THE SELF OPTIMIZING GRID PROGRAM INCREASES MOMENTARY INTERRUPTIONS (PAGE 32, LINE 9). IS THIS THE CASE?

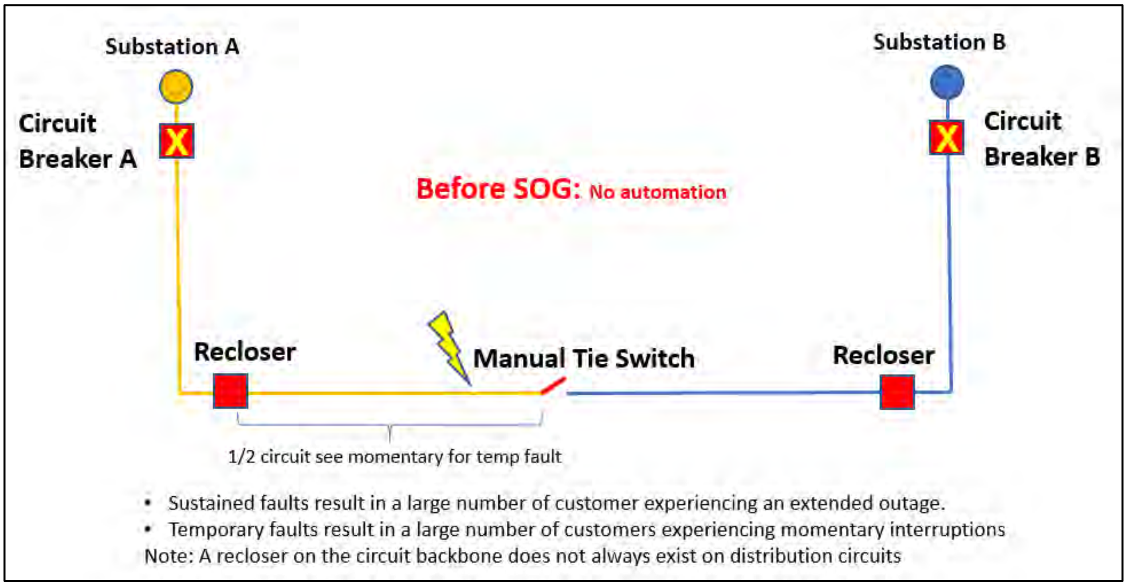
A. The addition of SOG does not increase momentary outages. Let me explain. System faults on the typical distribution circuit backbone result in either an upstream breaker or recloser opening, then reclosing in attempt to clear the fault without a sustained outage. All customers down stream of this protective device reclosing experience "momentaries". If the fault remains, these upstream devices continue to operate up to three or four times before eventually locking out, resulting in a sustained outage. These faults start as momentary blinks that can culminate to a sustained outage if the fault remains. Self-Optimizing Grid isolates faults after a lockout and restores all un-faulted line segments. Because of SOG, many customers will experience just the momentaries instead of momentaries followed by a sustained outage. The addition of SOG adds the faster restoration of un-faulted sections and does not increase momentary outages.

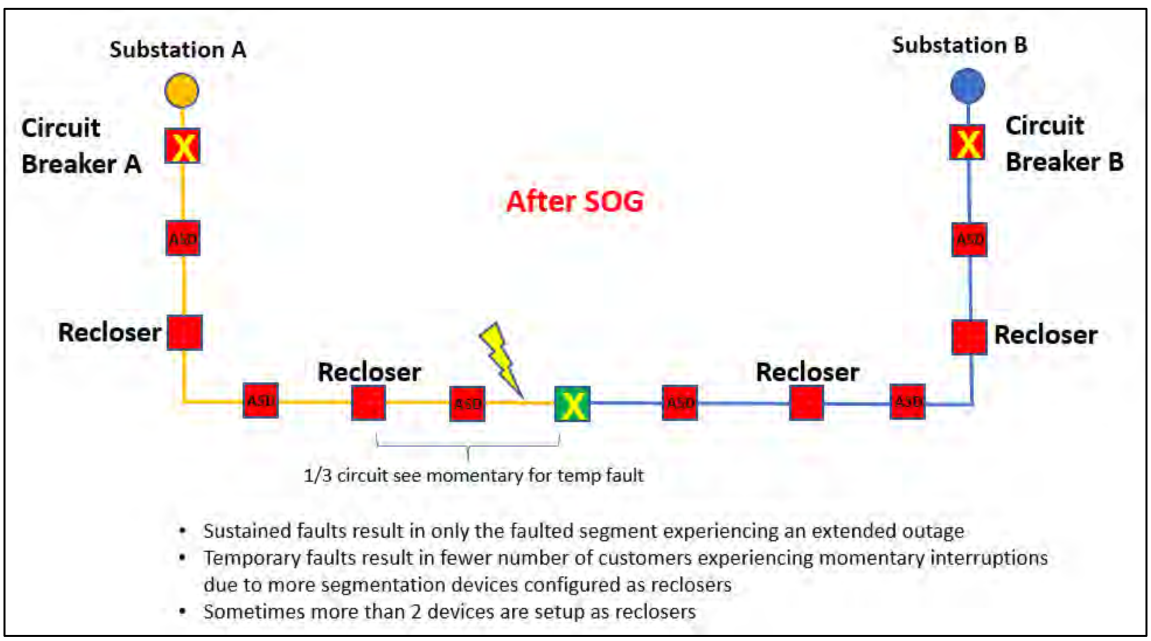


In both cases customers experience momentary operations. SOG reduces the impact of sustained outages while also reducing the number of customers that experience momentary operations during temporary faults with the addition of more segmentation devices.

Q. DOES THAT MEAN THAT THE IMPLEMENTATION OF SOG ACTUALLY RESULTS IN A DECREASE OF MOMENTARY INTERRUPTION INSTEAD OF AN INCREASE?

A. Yes. Faults on the circuit backbone usually result in breaker and recloser operations that can lead to sustained outages. However, the majority of faults are temporary in nature and are cleared resulting in a momentary outage instead of as sustained outage. On average, for every sustained outage there are approximately two to three faults that are cleared without a sustained outage. As a circuit is added to SOG, segmentation devices are added in accordance with SOG segment targets. These devices can be setup in different operational modes depending on protection needs and device protection coordination. As more devices are setup as reclosers, fewer customers are affected by temporary faults. Our protection engineers will cascade devices in recloser mode as coordination allows, which can be up to three or four. Consider the example below. Before SOG there is one downstream recloser, but after there are multiple. Now, when temporary faults occur fewer customers are affected, thus a reduction in number of customers experiencing momentary operations than before SOG.





Q. WITNESS THOMAS MENTIONS THAT THE BENEFITS NOTED IN THE SOG CBA ARE OVERSTATED DUE TO THE COMPANY INCREASING ITS ANNUAL TRIM MILES (PAGE 27, LINE 15). IS THIS THE CASE?

A. Possibly, but the difference would be very small. In fact, once the current back log is eliminated, the average increase in annual miles under 5/7/9 is only approximately 10% higher when compared to 2018 actual miles trimmed. Also, SOG benefits only derive from outages on the main circuit three phase switchable backbone. These line sections tend to run along larger roads and often have wider right of ways. Vegetation accounts for approximately 40% of Customer Interruptions on this type of line. It is also important to note that approximately 50% of this is caused by trees outside the trimmable right of way. Therefore, the potential reduction of SOG benefits can be approximated by multiplying 10% x 40% x 50% = 2%.

Q. IF DUKE ENERGY WERE TO CONDUCT A SENSITIVITY ANALYSIS OF ITS SOG CBA, ARE THERE ANY ADDITIONAL BENEFITS DUKE ENERGY WOULD PROPOSE EVALUATING?

A. If Duke Energy were to perform a sensitivity analysis for its SOG CBA, it could include a benefit for Major Event Day (MED) reliability that was not included in the filed CBA. Given that SOG is a system level program, and storms are variable, we took a conservative approach at the time the CBAs were developed. However, in retrospect, we left out an important benefit that our customers enjoy. In looking at actual results for DEC and DEP from 2016 through 2019, MED Customer

Minutes Interrupted (CMI) savings in total are 33% greater than non-MED savings for the existing Self-Healing Network installations. A recent example would be the tornadoes that occurred on 2/6/20 and 2/7/20. These were MEDs for both DEC and DEP. The SOG CMI saved during these events in DEC was approximately 5 Million and DEP was 5.3 Million. These savings would not show up in the conservative CBA methodology we used to justify the program but were invaluable for our customers. When viewed in its entirety, SOG is a "no regrets" investment that provides significant value for customers in multiple ways.

Q. DID ANY OTHER WITNESSES PROVIDE THEIR EVALUATION OF DUKE ENERGY'S GIP COST BENEFIT ANALYSES?

A. As mentioned previously, other intervenors made the following allegations regarding Duke Energy's GIP cost benefit analyses:

- Duke Energy underestimated costs for its GIP
    - GIP will cost ratepayers $9.1 billion over 30 years, compared to $2.3 billion presented by Duke Energy in Ex. 10 pg. 3 (Alvarez)
    - $424.5 million capital in Duke Energy's cost benefit analyses was not included in its 2020-2022 capital schedule (Alvarez)
    - $192.5 million for Energy Storage and Transportation Electrification are not included in the 2020-2022 capital schedule (Alvarez)
    - $1.1 billion in software and communications network replacement costs should have been included in the GIP (Alvarez)

  - $4.6 billion in estimated carrying charges should have been included in the GIP (Alvarez)
  - Costs for individual programs were not correctly evaluated (Alvarez)
- Duke Energy should have conducted cost benefit analyses for other programs such as those in Enterprise Communications (O'Donnell)
- Duke Energy should have conducted sensitivity analyses on its cost benefit analyses (O'Donnell, addressed above in Thomas' section)
- Duke Energy overestimated benefits for its GIP
  - Duke Energy's projected reliability improvement estimates are unsupported and the results from the ICE calculator are flawed (Alvarez)
  - Results from the IMPLAN secondary benefits analysis are flawed (Alvarez)
  - Duke Energy did not estimate the detrimental impact to GIP benefits that would come from GIP-related rate increases (Alvarez, O'Donnell and Strunk)

The concerns above come from the testimony of Witnesses Alvarez, O'Donnell and Strunk, and some were previously covered in my reactions to the Testimony of Public Staff Witness Thomas. These intervenors recommended that the Commission reject the proposed GIP program, as opposed to Public Staff's recommendation that the GIP work is reasonable and certain programs could be considered eligible for deferral treatment. Some intervenors recommended, as an alternative, that the Commission could approve certain GIP programs like IVVC, despite their concerns regarding the Company's cost benefit analysis process. I will address these intervenors' concerns regarding the GIP cost benefit analyses and explain why those concerns should not prevent the Commission from approving deferral treatment of certain GIP programs.

Q. HOW DO YOU RESPOND TO THE ALLEGATION OF WITNESS ALVAREZ THAT THE GIP WILL COST RATEPAYERS $9.1 BILLION OVER 30 YEARS, COMPARED TO $2.3 BILLION PRESENTED BY DUKE ENERGY IN EXHIBIT 10 PAGE 3?

A. Witness Alvarez conflates Duke Energy's three-year (2020-2022) capital budget for GIP in North Carolina (both DEC and DEP) with his unsubstantiated $9.1 billion 30-year cost estimate. I will explain below how the cost estimate is unsubstantiated and not useful for the Commission's determination of GIP deferral eligibility, but I must first point out that the comparison itself is not a valid starting point for serious consideration.

Q. CAN YOU EXPLAIN THE $424.5 MILLION IN CAPITAL IDENTIFIED IN THE TESTIMONY OF PAUL ALVAREZ AS SHOWING UP IN THE GIP CBAS BUT NOT IN THE GIP CAPITAL SCHEDULE?

A. Attempting to reconcile the values from the CBAs to the values from Exhibit 10 relative to the 2020-2022 period is not an accurate comparison. Each set of values serves a valid but different purpose. The collection of CBAs assists in validating the benefit-to-cost ratio for selected projects and programs. The Exhibit 10 amounts are budgetary in nature. Differences can evolve from: 1) some CBAs start in 2019 therefore their 2019 capital is not included in Exhibit 10, 2) other CBA's were intended to demonstrate the project or program value proposition, their 2020-2022 values did not always align with the 2020-2022 budget due to project timing and other budgetary variances, 3) a number of CBAs are for projects or programs that may have started in the 2020-2022 period but continue deployment into 2023 and beyond. For example, a TUG neighborhood project may be a 4-year deployment starting in 2021. The 2020-2022 budget amount would have two years of costs while the CBA would have four years of costs (2021-2024).

Q. CAN YOU EXPLAIN WHY THE $192.5 MILLION IN CAPITAL IDENTIFIED IN THE TESTIMONY OF PAUL ALVAREZ IS NOT INCLUDED IN THE GIP CAPITAL SCHEDULE?

A. As noted at Oliver Exhibit 10, Energy Storage Projects and Electric Transportation have been excluded from the GIP totals as they are being reviewed and evaluated in separate forums, and Duke Energy is not seeking to include them in the GIP deferral request.

Q. WHY WOULD IT BE UNREASONABLE FOR DUKE ENERGY TO HAVE PROJECTED THE $1.1 BILLION IN SOFTWARE AND COMMUNICATIONS NETWORK REPLACEMENT COSTS IDENTIFIED IN THE TESTIMONY OF PAUL ALVAREZ?

A. The majority of the line items Witness Alvarez noted in his Table 1 are categorized as Modernize, which are justified under cost-effective guidelines instead of a CBA. As such, there are only costs for the three-year GIP period of 2020-2022. There is no intention nor need to evaluate all programs over the same lifecycle. The replacement of those Modernize assets will be evaluated appropriately in the timeframe required.

Q. DID DUKE ENERGY CONSIDER ALTERNATIVES FOR ITS $160 MILLION IN COMMUNICATIONS NETWORK INVESTMENTS?

A. Witness Alvarez' generalized assertions and assumptions have taken specific detailed information related to a given component of Duke Energy's Communications Network and applied it to the broader, Enterprise-wide communications network. For example:

- Duke Energy has not stated that we did not perform any "technical or economic" analyses on the $160 million in communications network investment. Communications network investments made by Duke Energy follow documented enterprise supply chain processes including RFIs and RFPs to evaluate the available alternatives in the marketplace.

- Duke Energy's Core Data Network supports many applications. Where appropriate, considering the cost, security, speed to deploy and level of service required, external carriers are leveraged to provide services to the edge of Duke Energy's networks. Core Data Network requirements exceed the current capabilities that third-party cellular providers can provide given the 4G LTE and CatM1 typical bandwidth limitations.
- For the Land Mobile Radio program alternative services were included during the RFP process. Bidders were eliminated based on their inability to meet RFP requirements as noted in Alvarez Exhibit 9. Commercial cellular carriers noted that they could not meet mission critical requirements of the program.

Q. HOW DO YOU RESPOND TO WITNESS O'DONNELL'S SUGGESTION THAT DUKE ENERGY SHOULD HAVE PERFORMED CBAS FOR ADDITIONAL PROGRAMS?

A. Witness O'Donnell recommended that Duke Energy should have performed CBAs for its proposed Enterprise Communications programs. While Public Staff Witness Thomas recommended that Duke Energy perform CBAs for a few additional programs, he did not find it necessary to do so for Enterprise Communications. As explained in response to Witness Thomas, the Enterprise Communications programs are evaluated on a cost effectiveness basis. Furthermore, as noted in response to the allegations from Witness Alvarez regarding Enterprise Communications programs, the analysis for those programs involves considering alternative options for addressing the communications needs of the Company, not determining if those needs actually exist.

Q. ARE THE ENTERPRISE COMMUNICATIONS PROJECTS NECESSARY TO ACCOMPLISH ANY OTHER PROGRAMS IDENTIFIED IN GIP?

A. Duke Energy included the costs for communications in its CBAs for programs like SOG and IVVC, since incremental communications infrastructure will be needed to implement those functionalities. The Enterprise Communications programs are necessary to upgrade and secure the foundational telecom infrastructure needed to operate Duke Energy's grid as a whole. While the Company's telecom infrastructure is foundational for programs like SOG and IVVC, it would be unreasonable and inefficient from a cost perspective to pursue those grid-wide telecom upgrades as an ad hoc subproject of projects like SOG and IVVC that are more limited in scope.

Q. HOW DO YOU RESPOND TO WITNESS O'DONNELL'S SUGGESTION THAT DUKE ENERGY SHOULD HAVE PERFORMED SENSITIVITY ANALYES FOR ITS CBAS?

A. As stated in response to a similar suggestion from Public Staff Witness Thomas, a sensitivity analysis was not contemplated as a required function of the CBA process for Duke Energy's GIP.

Q. CAN YOU EXPLAIN WHY WITNESS ALVAREZ CONTENDS THAT DUKE ENERGY'S AGGREGATION OF INDIVIDUAL SERVICE OUTAGE IMPACTS DOES NOT RECONCILE WITH HIS CALCULATED OVERALL OUTAGE VALUES?

A. There are a number of reasons comparing an overall jurisdictional ICE model analysis by Witness Alvarez to the multitude of individual project analyses conducted by Duke Energy using consistent ICE model data is not a valid assessment. Even though Witness Alvarez's testimony notes a present value reliability benefit to customers of $4.8B, which is still substantially higher than the total 2020-2023 GIP request, there are still key differences that omit additional benefit value from his assertion. His calculation:

- Excludes the impact of a significant amount of individual project and program assumptions, including customized customer counts, customer mix, actual outage history, etc.
- Excludes the impact of MEDs
- Excludes several projects and programs included in the complete GIP summary as the SAIDI/SAIFI figures used are derived from only the most significant Distribution items
- Excludes the impact of Transmission projects completely

Q. IS WITNESS ALVAREZ'S REFERENCE TO BACKUP GENERATION AND UNINTERRUPTIBLE POWER SUPPLIES (UPS) A RELEVANT CRITICISM OF DUKE ENERGY'S CBA'S?

A. No. The study cited by witness Alvarez is a review of critical infrastructure facilities in the United States as defined by the Department of Homeland Security. This includes facilities such as hydroelectric dams, electric generation facilities, hospitals, water treatment facilities, wastewater treatment facilities, communications facilities, emergency services and others. The assertion that C&I benefits are in any way meaningfully overstated within the Company's CBA's is misleading.

Q. WHAT IS THE RELATIONSHIP BETWEEN DUKE ENERGY'S IMPLAN BENEFITS AND ITS CALCULATED ICE BENEFITS?

A. The secondary estimates of the calculated IMPLAN benefits are largely dependent upon the primary customer reliability benefits estimated using the ICE model. As such, changes in the ICE model parameters (either in a positive or negative direction) would affect the associated IMPLAN benefits. The main purpose of estimating both the primary and secondary economic benefits, however, is to provide perspective on the overarching significance and magnitude of these results.

Q. WHY DID DUKE ENERGY EXCLUDE THE IMPACT OF POTENTIAL RATE CHANGES IN ITS IMPLAN ANALYSIS?

A. The purpose of calculating both the primary economic benefits and the secondary economic benefits (via the IMPLAN analysis) was to estimate the aggregate benefit stream from the GIP that will accrue to the Duke Energy customer base as a whole. Or put another way, these estimated benefits provide a means to assign a value to the Duke customer base that would likely result from all GIP reliability improvements. This allows these estimates then to serve as a resource for others to do additional comparative analyses to evaluate various costs and benefits as part of the GIP evaluation process. As such, incorporating additional factors into these estimates such as the impact of rate increases, or the economic benefits of GIP-related construction activity falls outside of the scope of this analysis.

V. PERFORMANCE MEASUREMENTS

Q. WHAT IS YOUR RESPONSE TO WITNESS THOMAS AND WITNESS STEPHENS' ASSERTION THAT THE GRID IMPROVEMENT PLAN SHOULD HAVE QUANTIFIABLE TARGETS AND METRICS TO MEASURE PERFORMANCE AND THE COMPANY SHOULD BE REQUIRED TO REPORT ON THE RESULTS OF THE WORK IN THE PLAN?

A. I agree with this contention and the cost/benefit analyses included in my direct testimony provide metrics for the projects and programs, as appropriate. Specifically, the cost/benefit analyses performed by the Company detail, among other things, the amount of O&M savings the Company anticipates from the Plan; the amount of avoided capital costs the Company anticipates from the Plan; and the amount of outages that each of the programs and projects within the Plan are anticipated to avoid. Additionally, the Company can track the voltage reduction from the implementation of IVVC and sees this as a good metric that demonstrates the value of IVVC.

Q. DOES THE COMPANY PLAN TO TRACK DEPLOYMENT METRICS FOR THE GIP?

A. Yes. The Company intends to track project/program scope, schedule, cost and benefits as appropriate during implementation.

Q. SINCE THE COMPANY DOES HAVE QUANTIFIABLE METRICS AND TARGETS BUILT INTO ITS GIP, HOW DO YOU RESPOND TO WITNESS STEPHENS SUGGESTION THAT THE COMMISSION IMPLEMENT COST CAPS AND AUDITS?

A. I believe that the Company's performance is subject to prudence reviews that are already inherent in the regulatory process. To explain, unlike unregulated companies, a regulated utility must always prove to regulators that the work it performs delivers customers the value that they pay for. For example, if the Company builds a generation facility that is supposed to deliver 100 megawatts of power to customers, that unit must deliver 100 megawatts of power to customers unless the Company has a reasonable and prudent reason why it is not doing so. If the Company does not have a reasonable and prudent reason for work not delivering the value it is supposed to, the Company is subject to a disallowance for the cost of that work. The work to be performed in the GIP is no different. If customers do not get the value they pay for under the Plan, the Company remains at risk for a prudence disallowance unless the company can provide reasonable and prudent reasons as to why they did not.

Q. HOW DO YOU RESPOND TO WITNESS STEPHENS CONCLUSION THAT DEC & DEP GRID INVESTMENTS IN RECENT YEARS DO NOT APPEAR TO BE ACHIEVING THE INTENDED RESULTS?

A. The referenced growth in distribution base was largely driven by customer load growth in our DEC and DEP service territories. The portion of the distribution investment spent on maintaining service quality has remained constant relative to the total spend in the past 5 years. While the previous level of expenditures has maintained system performance, since 2013 we have seen a worsening trend in the SAIFI and SAIDI statistics due to an increase in number of outage events, and several other factors such as megatrends as discussed in my direct testimony. The analysis and Megatrends utilized to inform our GIP resulted in programs (i.e.- SOG, TUG) that were designed specifically to address these worsening trends (i.e. – weather). However, in 2019 the Company saw SAIDI and SAIFI improvements: DEC 171 & DEP 150 (SAIDI) and DEC 1.05 & DEP 1.31 (SAIFI) respectively.

VI. <u>ADDITIONAL PROGRAMS IN GIP</u>

Q. WHAT ARE THE OTHER PROGRAMS IN YOUR GIP THAT PARTIES GENERALLY AGREED WERE NOT EXTRAORDINARY IN NATURE?

A. See the table in Section III of this testimony.

Q. DO YOU AGREE WITH SEVERAL INTERVENORS WHO CLAIM THAT TRANSFORMER RETROFIT, BANK REPLACEMENTS, BREAKER REPLACEMENTS, TRANSMISSION H&R, AND UNDERGOUNDING ARE ALL BASE MAINENTANCE WORK THAT SHOULD NOT BE INCLUDED IN THE GIP?

A. All but targeted undergrounding has been performed in base work in the past, but a point is being missed. What is different is the pace of change required by the changing landscape of our industry. This changing landscape is a result of the Megatrends. Transformer retrofit took over twenty years to implement in DEC. We are seeking to finish the program in DEC and accelerate it in DEP to better manage changing customer expectations and deal with the increase in extreme weather events. Bank replacements, breaker replacements, and transmission line rebuilds are similar. The GIP accelerates the historical pace to better position the Company to deal with the future requirements. Targeted UG is not a historical base program. Targeted UG projects are specifically aimed to improve reliability and harden the system against increasing storm frequency and cost in the areas that are in fact the most prone to damage.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE TARGETED UNDERGROUNDING IN ITS GIP?

A. The scope of the targeted undergrounding program was scaled back by approximately 90 percent to balance stakeholder priorities. The portion that remains is highly cost beneficial, and in fact uses a refreshed targeting approach.

It now focuses on laterals that experience the highest outage events per year in a sustained pattern (ten years of history), correlated with significant age, high percentages of facilities inaccessible to trucks, and high vegetation management expenses. The high age and outage experience correlates to line section where the conductor is likely annealed and weakened from heavy fault duty exposure. It also means that a rebuild of these facilities (analogous to deteriorated conductor work) is imminent. Using a CBA comparison to evaluate between replacing these facilities with a brand-new antiquated design basis (rear lot overhead) from decades ago versus rebuilding with modern, updated and standard underground design represents modernization of antiquated infrastructure. This approach greatly increases the benefit to cost ratio from the statistics cited by Witness Stephens.

Further, this is the one program that has a very immediate and direct positive impact on customer satisfaction and for these reasons we felt it was important to keep some level of this work in the plan. We do not agree with those that say targeted undergrounding programs are not standard industry practice. Both Dominion in Virginia and Florida Power & Light in Florida have active targeted undergrounding programs. Dominion's program is branded "Strategic Undergrounding Program and has been active for multiple years, and FPL's program is known as "Storm Secure Underground Program." Both programmatic approaches have been further encouraged by legislation within each state SB 1473 in Virginia and SB 796 (Storm Protection Plan) in Florida. Further, we also do not agree with witness Stephens depiction of DE Carolinas system protection scheme and viable alternative actions to address the issue of upstream momentaries associated with faults in TUG areas. His recommendation would in fact increase sustained outages for our customers and accelerate damage to transmission and distribution equipment from fault current.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE LONG DURATION INT/HIGH IMPACT SITES IN ITS GIP?

A. Extreme weather events and concentrated population growth are Megatrends that the LDI/HIS program is designed to address. This program is designed to improve reliability in parts of the grid where duration of outages is much higher than average due to their accessibility. This program is also designed to improve the reliability of high-impact customers like airports and hospitals, and high-density areas that require a variety of solutions to improve power quality and reliability.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE TRANSMISSION TRANSFORMER BANK REPLACEMENTS IN ITS GIP?

A. GIP accelerates the historical pace of replacements to better position the Company to deal with for the future requirements. Witness Stephens asserts that Duke Energy is proposing replacing substation transformers in the absence of oil testing results. In fact, it is this oil testing along with other condition-based assessment triggers such as electrical testing and physical inspections that are the basis for which transformers are to be included in the Transformer Bank Replacement Program. Dissolved Gas Analysis (DGA) oil testing is the primary means relied upon by Duke Energy to determine substation transformer health and subsequent maintenance and replacement priority. Witness Stephens also discussed transformer failure rates calculated by Witness Alvarez. The calculation completed by Witness Alvarez is flawed and inaccurate. He states, "DEC reliability benefits are based on an estimate that 26 of the 50 transformer banks to be replaced would fail between now and 2034". The CBA for DEC substation bank replacement indeed accounts for 26 potential bank failures, but this is out of a population of approximately 3000 banks. These 26 represent the highest risk population out of that 3000 banks, so the failure rate would be 26/3000 not 26/50.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE OIL BREAKER REPLACEMENTS IN ITS GIP?

A. GIP accelerates the historical pace of replacements to better position the Company to deal with future requirements. Witness Stephens asserts that circuit breakers should be identified for replacement based on test results and operating counts; Duke Energy agrees. Duke Energy does inspect and test substation circuit breakers to determine their health and maintenance needs. This program is the primary feeder into the prioritization and sequencing of oil breaker replacements. All oil circuit breakers proposed for replacement in the GIP have been selected based on these criteria, and each represent a potential reliability threat to our customers. As laid out in the CBA, the majority benefit delivered through replacing these assets is reduced customer outage impacts. Witness Stephens also discusses breaker failure rates calculated by Witness Alvarez. The calculation completed by Witness Alvarez is flawed and inaccurate. He states, "Duke Energy estimates that of the 995

DEC oil-filled circuit breakers proposed for prospective replacement, 696, or 70%, would have failed by 2032." The CBA for DEC oil breaker replacement does account for 656 potential breaker failures through 2032, but this is out of a population of approximately 5400 oil circuit breakers in the DEC territory. This equates to an annual failure rate of approximately 1%.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE SUBSTATON PHYSICAL SECURITY IN IT'S GIP?

A. Threats to grid infrastructure is one of the top megatrends that has shaped the Grid Improvement Plan. This threat is widely accepted as valid throughout the utility industry. Duke Energy is committed and obligated to protect critical grid assets from external threats. Duke Energy has determined the top priority physical security improvement needs based on a threat and vulnerability assessment informed from the National Electric Reliability Council (NERC) Critical Infrastructure Protection (CIP) criteria for defining critical substations, which was reviewed by an independent industry third party. A graded approach is used with regard to physical security at substations not covered by NERC CIP-014 physical security requirements; the majority of substations will not necessitate security improvement projects. The ultimate goal of the Company is to provide our customers with reasonable assurance of reliable electric service through minimizing the risks of grid impacts associated with physical threats. Duke Energy is proud of the existing record of not having any instances of successful intrusions into our substations and intends to maintain this record.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE ENTERPRISE COMMUNICATIONS IN ITS GIP?

A. The Enterprise Communications program focuses on modernizing and securing the critical communications networks between intelligent grid management systems located at grid operation centers, data and controls systems located at substations, and sensing and control devices across the entire electric power network. As the Company places more and more intelligent two-way communicating devices on the grid, having a robust communications platform is a requirement of the modern grid. Some in the industry consider the expanding high-speed communications networks the third grid. I agree. A strong, secure, updated and robust communications system is a foundational pillar to any advanced grid needed to address the issues of today and the challenges of tomorrow. All the programs within the enterprise communications will work together to increase data capacity and/or bring new communications capability to areas of our system previously unserved. As noted by the Public Staff the Company is working diligently to replace all 2G/3G modems before cellular providers sunset those technologies.

Q. WHY DID THE COMPANY BELIEVE IT WAS IMPORTANT TO INCLUDE ENTERPRISE APPLICATIONS IN ITS GIP?

A. The Enterprise Systems focuses on delivering transformative, cross-functional solutions to the enterprise in non-disruptive ways. As an example, grid analytics can optimize the electric system health and performance through the deployment of the Health Risk Management (HRM) tool thereby helping to prevent equipment failures and improve asset performance on our transmission systems.

VII. STAKEHOLDER ENGAGEMENT

Q. HOW DO YOU RESPOND TO ALLEGATIONS FROM WITNESS ALVAREZ AND WITNESS FITCH THAT THE COMPANY'S STAKEHOLDER ENGAGEMENT EFFORTS WERE SOMEHOW "SUPERFICIAL" AND /OR "INADEQUATE"? PLEASE ALSO ADDRESS WITNESS WILLIAMSON'S CONCERN REGARDING "GLOBAL CONSENSUS."

A. During the last rate case (Docket No. E-7, Sub 1146), the Company uniformly heard that stakeholders wanted to be engaged and have their input heard in developing and deploying a grid improvement plan for the State. The Company accommodated this request in multiple ways prior to filing the GIP in this proceeding. As noted in my direct testimony, prior to submitting this plan to the Commission, the Company sought out customer and stakeholder perspectives, including holding multiple in-person stakeholder workshops and conducting deep dive webinars on topics specifically requested by stakeholders, as part of the engagement process. These efforts not only allowed for increased collaboration with stakeholders but also enhanced the transparency of the development of the GIP. During these workshops, the Company invited stakeholder feedback to ensure the plan addressed the diverse set of customer and stakeholder needs. While "global consensus" was not reached on all topics addressed during the stakeholder engagement process, as accurately noted by Witness Williamson, the feedback received in the workshops was used by the Company to validate the Megatrends, conduct additional analysis to support the programs in the GIP, drive future workshop discussions and make significant changes to the portfolio of investments. Further, the additional analyses (CBAs) conducted by the Company along with other meeting materials were published in a virtual on-line data room for stakeholder review during the stakeholder process, prior to the Company filing its GIP with the Commission.

Q. HOW DO YOU RESPOND TO INTERVENOR'S CRITIQUES THAT THE GIP IS IN MANY WAYS A SUBSET OF THE 10-YEAR, $13B POWERFORWARD PLAN?

A. No, this is not true. There are clear differences in the purpose, scope, and level of stakeholder engagement between Power Forward and the three-year GIP. Let me highlight a few key differences:

1. The GIP is a three-year plan while Power Forward was a ten-year plan. There is currently no "Phase 2" of the plan and any future plan would be built based on collaboration with stakeholders.
2. The scope of the two plans is dramatically different.
    a. Distribution Hardening & Resiliency and Targeted Undergrounding made up 64% of the Power Forward scope. These programs make up 11% of the three-year GIP.
    b. Large new programs exist in the three-year GIP. Significant examples are IVVC at 10% of the total and Physical & Cyber Security at 6%.

c. Self-Optimizing Grid, a program generally supported by all stakeholders, made up less than 10% of Power Forward. It is the largest program in the three-year GIP making up over 31% of the total.

CURRENT

Grid Improvement Plan Carolinas (NC)

dollars in (000's)	NC 2020-2022
Compliance: Cost Effectiveness Justified	**$134**
Physical Security	$111
Cyber Security	$23
Cost Benefit & Cost Effectiveness Justified	**$1,649**
SOG	$722
Incremental Distribution H&R	$145
IVVC	$217
Incremental Transmission H&R	$134
TUG	$115
Energy Storage	$129
Transmission Bank Replacement	$116
OIL Breaker Replacements	$200
Rapid Technology Advancement: Cost-Effectivenes	**$536**
T&D Communications	$212
Distribution System Automation	$194
Transmission System Intelligence	$86
T&D Enterprise Systems	$28
ISOP	$7
DER Dispatch Tool	$7
Electric Vehicle Charging	$63
Power Electronics for volt/var control	$2
Total	**$2.3 billion**

PREVIOUS

Power/Forward (NC)

dollars in (000's)	NC 2018-2027	
Compliance: Cost Effectiveness Justified		
Physical Security	$0	*new program*
Cyber Security	$0	*new program*
Cost Benefit & Cost Effectiveness Justified	**$11,804**	
SOG	$1,267	
Incremental Distribution H&R	$3,379	↓ 96%
IVVC DEC	$0	*new program*
Transmission	$2,195	
TUG	$4,962	↓ 98%
Energy Storage	$0	*new program*
Transmission Bank Replacement		
OIL Breaker Replacements		
Rapid Technology Advancement: Cost-Effectivene	**$926**	
T&D Communications	$447	
Distribution System Automation	$140	
Transmission System Intelligence		
T&D Enterprise Systems	$339	
ISOP	$0	*new program*
DER Dispatch Tool	$0	*new program*
Electric Vehicle Charging	$0	*new program*
Power Electronics for volt/var control	$0	*new program*
Total NC	**$13 billion**	

	GIP PROGRAMS	Megatrends: I - Phys & Cyber Threats	II - Adv Tech (Solar/Battery)	III - Environmental Policy	IV - Weather	V - Grid Improvement Techn.	VI - Concentrated Growth	VII - Customer Expectation	NC - DEC Total ($M)	NC - DEP Total ($M)	NC TOTAL ($M)	
Protect	Physical Security	x	x			x		x	$58.0	$64.7	$122.7	
	Cyber Security	x	x			x		x	$7.0	$4.0	$11.0	
Optimize	Self-Optimizing Grid	x	x	x	x	x	x	x	$420.0	$302.0	$722.5	1st
	Integrated Volt/VAR Control	x	x	x	x	x	x	x	$207.0	$10.0	$217.0	2nd
	Harden &Resiliency [T]		x	x	x			x	$102.4	$31.3	$133.7	
	Targeted Underground				x			x	$59.8	$54.7	$114.5	
	Energy Storage*		x	x	x		x	x	$56.5	$72.5	$129.0	
	Transformer Retrofit [D]				x			x	$8.3	$109.7	$118.0	
	Long Duration Interruptions				x			x	$11.3	$15.8	$27.1	
	Transformer Bank Repl [T]		x	x				x	$33.6	$82.7	$116.3	
	Oil Breaker Rpl [T]			x		x		x	$101.6	$42.8	$144.4	
	Oil Breaker Rpl [D]			x		x		x	$13.9	$42.0	$55.9	
Modernize	Enterprise Communications	x	x	x	x	x	x	x	$103.8	$108.0	$211.8	3rd
	Distribution Automation		x	x	x	x		x	$118.4	$70.9	$189.3	4th
	System Intelligence [T]		x	x		x		x	$62.7	$23.7	$86.4	
	Enterprise Applications		x	x		x		x	$17.0	$10.8	$27.8	
	ISOP		x	x		x	x	x	$4.1	$2.5	$6.6	
	DER Dispatch		x	x		x		x	$4.5	$2.9	$7.4	
	Electic Transportation*		x	x					$38.2	$25.2	$63.4	
	Power Electronics		x	x		x		x	$0.7	$1.1	$1.8	
											$2,314.2	

***Note:** *Energy Storage Projects and Electric Transportation have been excluded from these totals. These programs are important components of grid improvement but not included in the costs for the GIP given that they are being reviewed and evaluated in separate forums.*

(Oliver Direct Testimony - Exhibit 5)

The three-year GIP plan is the result of our compliance with Commission directives in the last rate case as to how to develop grid improvement initiatives. It is mainly in that regard it is related to Power Forward. The current three-year plan is a “no regrets” package of well-coordinated grid improvements. The plan begins preparing the NC grid for the implications resulting from the megatrends highlighted in my testimony. Also, the current stakeholder informed three-year plan begins to prepare the NC grid for growth in privately owned DER and electric vehicles, but even if this growth does not occur, the plan still is cost effective and warranted. This is proven in our CBAs.

Q. WHAT IS YOUR RESPONSE TO CONCERNS THAT THE PROPOSED GRID IMPROVEMENT PLAN DOES NOT ADDRESS DER ACCOMMODATION AS DISCUSSED DURING THE STAKEHOLDER ENGAGEMENT PROCESS?

A. I completely agree that the GIP does not address third party owned DER accommodation in North Carolina because that is not what the plan is designed to do, nor should it be. I understand that state and federal rules and policies dictate how these interconnection issues are addressed, and I further understand that vibrant discussions regarding these issues are ongoing in North and South Carolina in other forums. While there are some programs and projects in the plan that may provide ancillary benefits to interconnection issues, they are secondary to their primary purposes (such as voltage management, more capacity for distributed energy resources on the distribution system via aspects of the Self-Optimizing Grid program, and upgrades to certain transmission line structures and power transformation assets), the Company cannot and should not attempt to get ahead of federal and state rules and evolving policy issues regarding interconnection in the Grid Improvement Plan.

Q. WAS WITNESS ALVAREZ AN ACTIVE PARTICIPANT IN DUKE ENERGY'S GIP STAKEHOLDER ENGAGEMENT PROCESS?

A. I do not recall Witness Alvarez being an active participant in any of the GIP stakeholder proceedings. Therefore, I am confused as to his critique of a process in which he had virtually no involvement.

Q. WHY SHOULD THE COMMISSION IGNORE WITNESS ALVAREZ'S PRIMARY RECOMMENDATION TO "REJECT" DUKE ENERGY'S GIP AND INSTEAD "ESTABLISH A PROCEEDING TO DEVELOP A TRANSPARENT, STAKEHOLDER-ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESS FOR FUTURE USE IN NORTH CAROLINA?"

A. The Commission should ignore Witness Alvarez's primary recommendation for several reasons. First, if the Commission were to reject the GIP it could result in negative impacts as outlined in Exhibit 3 in my direct testimony. Second, contrary to Witness Alvarez's allegation and as discussed earlier in my testimony, the Company undertook an extensive and transparent stakeholder engaged planning process when it was deciding on which programs to include in its GIP and the associated budgets. A rejection of the stakeholder informed GIP would undermine not only the efforts of the Company but also each stakeholder involved in the stakeholder engagement process. Finally, if the Commission were to reject the Company's proposal, the work in the GIP would have to be sub-optimized, delayed, diminished in scope and effectiveness, and potentially not done at all. In such a situation, the Company would have to try and perform small pieces of the GIP over a much longer period of time within its existing revenues, delaying important benefits and potentially essential improvements for customers.

Q. HOW DO YOU RESPOND TO ARGUMENTS THAT THE GRID IMPROVEMENT PLAN SHOULD BE DELAYED UNTIL AN INTEGRATED DISTRIBUTION PLAN (IDP) OR INTEGRATED SYSTEMS PLANNING & OPERATIONS (ISOP) PROCESS IS DEVELOPED AND CONDUCTED?

A. I disagree. In fact, GIP programs such as Self-Optimizing Grid, IVVC, 44 KV Uplift, Transmission System Intelligence, and Distribution Automation will only improve the success of ISOP once implemented. These programs are foundational to the concept of two-way power flow and intelligent system control. Delaying them could in fact hinder the ability of ISOP to deliver its intended benefits. As discussed in my direct testimony, the Company is already engaging stakeholders in the development of our ISOP process. The Company held an in-person ISOP Stakeholder Workshop in Raleigh, NC on December 10, 2019 and an ISOP webinar on January 30, 2020. In addition, the Company has already scheduled the following stakeholder engagement events:

<u>ISOP</u>

- ISOP Webinar # 2 - March 3, 2020 from 1pm-3pm
- ISOP Workshop #2 - April 27, 2020 10am – 3pm in Columbia, SC

<u>IRP</u>

- IRP Workshop – March 17, 2020 9:30am-3:30pm in Columbia, SC
- IRP Workshop – April 16, 2020 10am – 3pm in Raleigh, NC *(tentative)*

When complete, ISOP will focus on the integration of the Company's planning disciplines for generation, transmission, distribution and customer programs in order to improve the valuation and optimization of energy resources across all segments to best serve our customers. The ISOP process will addresses key operational and economic considerations across all segments of the system through integration and refinement of existing system planning tools and, in some cases, development of new analytical tools to assess characteristics that have not historically been captured or considered in long-term planning. Some examples include locational values for distributed resources, system ancillaries and reserves needed to support future operations, and energy resource flexibility to support new dynamic operational demands on the system. As the ISOP process is currently being developed, the Company cannot reasonably be criticized for not having this tool in place now.

Q. IN HIS DIRECT TESTIMONY ON BEHALF OF THE COMMERCIAL GROUP, MR. STEVE CHRISS DISCUSSES DE CAROLINAS' PLAN TO ENABLE GREEN BUTTON DOWNLOAD MY DATA FUNCTIONALITY AND REQUESTS THAT THE COMMISSION REQUIRE THE COMPANY TO ALSO PROVIDE GREEN BUTTON CONNECT MY DATA FUNCTIONALITY. HOW DO YOU RESPOND?

A. First, data access issues, including Green Button functionality, are issues in the Commission's pending Docket No. E-100, Sub 161 and we believe that docket is the appropriate venue to consider these issues. As the Company has discussed with the intervenors in the data access docket, at this time our concerns with Green Button Connect My Data functionality include customer interest, cost-effectiveness, third party security and access, the timing and compatibility with the Company's new Customer Connect billing system, and uncertainty about how or if Connect My Data may fit within the data access rules the Commission may adopt. Having said that, the Company is currently providing all customers who have smart meters with data access functionality similar to the Green Button Download My Data functionality. In response to his testimony, Company representatives have spoken with Mr. Chriss to better understand Walmart's usage and interval data access interests and how the Company's existing functionality may address their needs. We will continue these conversations and are committed to seeking to resolve this issue with the Commercial Group.

VIII. GREEN BUTTON

Q. IN HIS DIRECT TESTIMONY ON BEHALF OF THE COMMERCIAL GROUP, MR. STEVE CHRISS DISCUSSES DE CAROLINAS' PLAN TO ENABLE GREEN BUTTON DOWNLOAD MY DATA FUNCTIONALITY AND REQUESTS THAT THE COMMISSION REQUIRE THE COMPANY TO ALSO PROVIDE GREEN BUTTON CONNECT MY DATA FUNCTIONALITY. HOW DO YOU RESPOND?

A. First, data access issues, including Green Button functionality, are issues in the Commission's pending Docket No. E-100, Sub 161 and the Company believes that docket is the more appropriate venue to consider these issues. As the Company has discussed with the intervenors in the data access docket, at this time our concerns with Green Button Connect My Data functionality include cost-effectiveness, third party security and access, the timing and compatibility with the Company's new Customer Connect billing system, and uncertainty about how or if Connect My Data may fit within the data access rules the Commission may adopt. Having said that, the Company is currently providing Green Button Download My Data functionality to all customers with smart meters. In response to his testimony, Company representatives have spoken with Mr. Chriss to better understand Walmart's usage and interval data access interests and how the Company's existing functionality may address their needs. The Company will continue these conversations and are committed to seeking to resolve this issue with the Commercial Group.

IX. CONCLUSION

Q. MR. OLIVER, YOUR REBUTTAL COVERS A LOT OF GROUND BUT DID YOU RESPOND TO EVERY CONTENTION REGARDING THE COMPANY'S PROPOSED GIP PROGRAM IN YOUR REBUTTAL?

A. No. Intervenor testimony on the GIP involved hundreds of pages of testimony and I could not reasonably respond to every single statement or assertion and, therefore, I focused on the issues that I thought were most important in my rebuttal testimony. As a result, my silence on any particular assertion in the intervenor testimony should not be read as agreement with or consent to that assertion.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214

In the Matter of:		
Application of Duke Energy Carolinas, LLC for Adjustments of Rates and Charges Applicable to Electric Service in North Carolina	)	**JOINT TESTIMONY OF JAY W. OLIVER AND JANE L. MCMANEUS IN COMPLIANCE WITH COMMISSION ORDER REQUESTING GIP INFORMATION**

I. INTRODUCTION AND PURPOSE

Q. MR. OLIVER, PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Jay W. Oliver, and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Strategy and Asset Management Governance for Duke Energy Corporation ("Duke Energy"), the parent holding company for Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on September 30, 2019. I also filed rebuttal testimony and exhibits on March 4, 2020.

Q. MS. MCMANEUS, PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Jane L. McManeus, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. I am a Director of Rates & Regulatory Planning for DE Carolinas.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on September 30, 2019 and filed corrected direct testimony on October 23, 2019. I also filed supplemental direct testimony and exhibits on February 14, 2020, rebuttal testimony and exhibits on March 4, 2020, settlement testimony on March 25, 2020, supplemental rebuttal testimony and exhibits on April 6, 2020, second supplemental direct testimony and exhibits on July 2, 2020, and second settlement testimony and exhibits on July 31, 2020.

Q. WHAT IS THE PURPOSE OF YOUR JOINT TESTIMONY?

A. The purpose of our joint testimony is to respond to the Grid Improvement Plan ("GIP") portion of the Commission's July 23, 2020 *Order Requiring Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs* ("Order") in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219. That Order, in relevant part, directs DE Carolinas to file certain supplemental economic analyses regarding DE Carolinas' proposed Grid Improvement Plan ("GIP") programs assuming, alternatively, that deferral of GIP costs is granted in one instance and denied in another. Our testimony and exhibits address this requirement and the revenue requirements computations requested by the Commission.

We also provide GIP analysis reflecting the Second Settlement and Partial Stipulation the Company entered into with the Public Staff and filed with the Commission on July 31, 2020 ("Second Partial Settlement"). The Second Partial Settlement is relevant since it includes a provision for the Company to withdraw its request for deferral accounting for certain GIP programs. Our analysis under this scenario thus shows the impact of the deferral of a smaller subset of GIP programs.

Q. PLEASE BRIEFLY DESCRIBE THE COMMISSION'S REQUEST FOR INFORMATION RELATED TO THE GRID IMPROVEMENT PLAN.

A. In its Order, the Commission requested an estimate of the North Carolina annual revenue requirement impact of the Company's GIP expenditures under two scenarios: one assuming the Company's request for an accounting deferral is granted and another assuming the Company's request for an accounting deferral is denied. The Commission also requested information on customer rate impacts under the two scenarios. The Commission provided instruction regarding several assumptions that are necessary to produce the requested information. Details requested include "the full impacts of the 2020-2022 GIP spending, as well as incremental operating and maintenance (O&M) costs associated with that GIP spending." Finally, the Commission ordered that the information should be "provided in spreadsheet form, with formulas intact, showing each major line item and explaining how it was calculated for each impacted year (2023, 2024, 2025, etc.), going out ten years."

II. DESCRIPTION OF SCENARIOS

Q. WITNESS OLIVER, HAS THE COMPANY PREPARED THE ANALYSES UNDER THE TWO SCENARIOS REQUESTED BY THE COMMISSION?

A. Yes. The Company has performed the analyses to the best of its ability with the information it has readily available.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "TO THE BEST OF ITS ABILITY."

A. As previously summarized, the Commission asked the Company for a rate impact analysis under two scenarios. The first is if the requested deferral of GIP costs is granted by the Commission and DE Carolinas files a rate case in 2023. The Commission's Order also provides various other necessary assumptions to perform that calculation. The results of the calculation of this "Deferral Granted" scenario are reflected later in this joint testimony. In addition, as further explained by witness McManeus, the Company has prepared another version of the "Deferral Granted" analysis to reflect DE Carolinas' Second Partial Settlement with the Public Staff.

The second analysis involves a "Deferral Denied" scenario and asks the Company to perform a similar rate impact analysis based upon any adjustment to the pace of GIP investment the Company might make based upon a denial of deferral treatment for GIP program costs. This scenario is problematic for the

Company because it would involve projecting the impacts of budget and capital management decisions that have not been made at this time and which would (and will) be influenced by many factors that are not currently known.

Like any large business, Duke Energy and its subsidiary utilities go through a very involved, protracted, and iterative budgeting process on an annual basis to determine projected capital spending for the following year. This process involves the evaluation of many factors, including operational needs, customer requirements, projected revenues, projected costs, required capital expenses, cash-flows, accessibility to the debt and equity capital markets, the management of short-term and long-term borrowings and stock offerings, and maintenance of a desirable capital structure and debt ratings to name just a few. A major example of a variable that will significantly impact the Company's annual budget moving forward is the outcome of this rate case on DE Carolinas' financial stability and credit metrics, as explained in Company witnesses Young, Newlin and De May's testimony.

Q. HOW DOES THIS IMPACT THE COMPANY'S ABILITY TO CONDUCT THE ECONOMIC ANALYSES REQUESTED BY THE COMMISSION IN ITS ORDER FOR A "DEFERRAL DENIED" SCENARIO?

A. In multiple ways. For example, the Company has not performed a budget analysis for the "Deferral Denied" scenario requested by the Commission so it cannot predict with any degree of certainty how much it would scale back GIP spending if deferred asset treatment is denied in the pending rate case. Those decisions will ultimately be made by management on an annual basis following the normal budgeting process by the Company. Nevertheless, I can say that the Company will likely delay significant portions of its intended GIP spending if all or a portion of accounting deferral treatment is denied. Without a reasonable means of mitigating the negative impacts of regulatory lag associated with significant ongoing and incremental spending under the GIP, the Company would be required to reassess its ability to commit to the planned level of investment in this program given that the level of investment anticipated under the plan simply cannot be reasonably sustained in the absence of mitigation measures such as the deferral requested herein. As such, if the Commission determines not to grant the accounting deferral treatment for all or a portion of the Company's GIP investment sought in this proceeding, the Company will likely be in a scenario where its level of GIP investment will vary significantly from year to year as it prioritizes and reprioritizes work to meet its capital plan. In such a situation, the Company would have to perform smaller pieces of the GIP over a much longer timeframe with its existing revenues, which would delay important benefits for customers.

Simply put, to perform the work identified in the GIP at the pace and scope that provides the most benefit for customers, the Company needs new and modern ways to recover costs and avoid the regulatory lag that can harm the Company's financial metrics which, in turn, can harm customers. While critical to the modernization of the grid, without deferral (or some other alternative ratemaking treatment), the Company's GIP investments would need to compete annually for the same capital as base work, much of which is mandatory (*e.g.*, replacing failed equipment, providing service to new customers, or to meet a regulatory requirement). Because capital funding is dependent on multiple variables, some of which have been previously mentioned, the Company's ability to forecast future GIP investments without a deferral is limited.

Q. ARE THERE OTHER FACTORS THAT MAKE THE "DEFERRAL DENIED" RATE IMPACT ANALYSIS IMPOSSIBLE TO PROVIDE AT THIS POINT IN TIME?

A. Yes. For the reasons described in witnesses Young, Newlin and De May's rebuttal testimony, the Company cannot know what its revenues for the requested period will be because the determination of what those revenues will be for future periods is largely tied up in this case and will also be impacted by the economic environment, which is further exacerbated by the ongoing COVID-19 pandemic. Even a cursory examination of the differences in position of the Company and intervenors reveals a difference in proposed possible outcomes that varies by hundreds of millions of dollars. Without having a reasonable approximation of what our revenues will be for the designated period, it is literally impossible to calculate prospective cash-flows or available capital for investment in GIP programs. A similar situation persists with our costs for the designated period. The Company cannot be confident in its costs for 2021 or 2022 at this point in time and does not have enough contextual information (and will not have that information for some time) to project what funds will be available to support GIP investment in the last two years of the period specified.

Q. ARE YOU TELLING THE COMMISSION THAT YOU CANNOT PROVIDE THE SECOND "DEFERRAL DENIED" ECONOMIC ANALYSES THEY REQUESTED?

A. No. What I am saying is that we do not have the information necessary to provide the requested "Deferral Denied" analysis exactly as it would play out in reality because there are too many unknown variables. What we can and have provided, however, is a hypothetical analysis showing comparative rate impacts of the "Deferral Denied" scenario based upon an assumption that DE Carolinas would reduce its original projected GIP spending by a factor of 80 percent. In order to avoid overly complicated calculations, in a short period of time, that result from trying to adjust the hypothetical to the status of the pending case, our hypothetical assumes GIP spending reduced by 80 percent for a period of three years at the end of which DE Carolinas files a rate case. The Company selected 80 percent to represent the myriad of aforementioned variables impacting decisions to invest in GIP expenditures on an annual basis. This hypothetical corresponds to the timing involved in the "Deferral Granted" analysis.

Q. WHAT ASSUMPTIONS ARE BUILT INTO THE HYPOTHETICAL "DEFERRAL DENIED" SCENARIO?

A. The assumptions we used in conducting this analysis are explained later in this joint testimony and in the exhibits attached hereto.

Q. DO THESE ASSUMPTIONS REFLECT REALITY?

A. Probably not. For example, the rate impact analysis for the "Deferral Denied" scenario is based on a 10.3% return on common equity ("ROE") and a 53% equity to 47% debt ratio, as originally proposed in our Application, and as directed by the Commission. However, given the Company's settlements with several parties in this case, including the Public Staff, on issues including ROE and cap structure, the Company expects the final, authorized ROE by this Commission to be lower than 10.3%. Furthermore, there are simply too many factors that are unknown to the Company at this time that are likely to vary from our assumptions in the "Deferral Denied" analysis. For example, the Company has no definite plans to file a rate case in 2023. The Company may file before or after that timeframe, or both. So, while the Company has conducted a "Deferral Denied" analyses for purposes of the Commission's Order, it is purely hypothetical in nature.

Q. DO YOU HAVE ANY OTHER THOUGHTS ABOUT THE HYPOTHETICAL ANALYSIS PROVIDED BY WITNESS MCMANEUS?

A. Yes. The analyses presented by witness McManeus represent a good faith attempt by the Company to provide comparative information that may be useful to the Commission in its evaluation of our GIP proposals, but I want to emphasize that a probative analysis would require a large and diverse set of assumptions about virtually every aspect of DE Carolinas' economic performance over the next several years. Accordingly, given so many economic uncertainties, we maintain that this analysis likely does not reflect decisions the Company will actually make during the period 2020-2023.

Q. IF DE CAROLINAS DOES FILE A RATE CASE IN 2023, WOULD YOU EXPECT THE RESULTS OF THE "DEFERRAL DENIED" ANALYSIS TO REFLECT WHAT ACTUALLY HAPPENED BETWEEN NOW AND THAT RATE CASE?

A. No. Again, the Company cannot currently know what factors will influence its capital budgeting and investment practices over the next three years. And given that its hypothetical is just that, it is not reasonable or rational to believe it will be reflective of reality during the next three years. Most importantly, it is not designed to serve that function. We developed it solely to try to provide, as best we could, a basis for comparing the first scenario, where deferred accounting treatment is allowed, to a situation where deferral accounting was denied for GIP spending in accordance with the Commission's Order.

III. <u>THE COMPANY'S ANALYSES</u>

Q. MS. MCMANEUS, CAN YOU PLEASE DESCRIBE THE EXHIBITS TO THE JOINT TESTIMONY?

A. We provide an exhibit for each scenario requested by the Commission: GIP Exhibit 1 – Deferral Granted and GIP Exhibit 2 – Deferral Denied. These exhibits are based on the Company's original request for deferral of GIP related costs pursuant to DE Carolinas' Application in this docket.

We have also provided additional analyses showing what the first scenario (Deferral Granted) would look like if the Commission were to approve the Second Partial Settlement: GIP Exhibit 3 – Deferral Granted (Settlement). This exhibit reflects the terms of the Second Partial Settlement, in which the Company has agreed to withdraw its request for deferral of costs related to certain GIP programs, resulting in a deferral request that is more limited than originally proposed.

Q. HOW ARE THE EXHIBITS ORGANIZED?

A. Each exhibit contains five pages, which show the results of the spreadsheet calculations performed to comply with the Commission Order. Each exhibit contains the following items:

Page 1 – Rate impacts by customer class

Page 2 – Income statement and rate base amounts – 10 years

Page 3 – Revenue requirements – 10 years

Page 4 – Assumptions

Page 5 – Summary of deferred amounts

The Excel spreadsheets provided, with formulas intact, include detail workpapers that support the filed exhibits.

Q. MS. MCMANEUS, WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

A. Deferral Request is Granted

Q. PLEASE DESCRIBE THE GENERAL APPROACH TO COMPUTING THE MONTHLY REVENUE REQUIREMENTS IF GRANTED DEFERRAL OF GIP COSTS.

A. The Company started with the estimated GIP program expenditures for years 2020, 2021, and 2022. The Company estimated when amounts spent would result in completed electric plant-in-service, *i.e.*, the length of the construction period. Monthly revenue requirements were computed for completed plant in service amounts, beginning the first month that the plant is in service. Revenue requirements include depreciation, return on net plant investment, installation O&M, and property taxes. The monthly revenue requirements were computed for electric plant in service added from January 2020 through December 2022. It was assumed that each month's revenue requirement was deferred as a regulatory asset, and a monthly return (*i.e.*, carrying cost) was accrued on the deferred asset balance.

Next, rate case timing was considered. As instructed by the Commission, we were to assume that a rate case would occur in 2023. Accordingly, we assumed that the test period would be calendar year 2022, and new rates would be effective January 1, 2024. During the period January through December 2023, before new rates would become effective, the Company assumed it would continue to defer the monthly revenue requirements on the completed plant in service as of December 31, 2022.

As a result, giving consideration to rate case timing, the deferred GIP amounts reflect the monthly revenue requirements for the period January 2020 through December 2023, for completed GIP plant in service as of December 31, 2022.

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE RECOVERY OF THE DEFERRED AMOUNTS IN A GENERAL RATE CASE.

A. In an assumed 2023 general rate case, the Company would seek recovery of the balance of deferred costs, amortized over a period proposed by the Company. This deferred balance represents the revenue requirement amount associated with the GIP investments during the period January 1, 2020 through December 31, 2023, that has not yet been reflected in rates, and therefore funded by investors.

To comply with the Commission's request, the Company must assume an amortization period. In a traditional general rate case, the selection of an amortization period would be determined based on several factors. For purposes of providing the information requested by the Commission, the Company has assumed an amortization period of five years. A longer amortization period would produce a lower annual rate impact of the deferral and a short amortization period would result in a higher annual rate impact.

In addition, in the general rate case, the ongoing revenue requirements associated with the GIP investments would be incorporated into future rates, since the test period operating expenses and rate base would include the GIP investments in service at the end of test period. The calculations assume that at the end of the five-year amortization period, base rates are reset to remove the recovery of the deferred GIP costs, and the on-going revenue requirements remain in base rates.

Q. WHAT ASSUMPTIONS DID YOU USE FOR ROE, CAPITAL STRUCTURE, AND COST ALLOCATION?

A. For purposes of calculating revenue requirements under the two scenarios, the Commission asks the Company to "use the return on common equity, capital structure, and cost allocation methodology that each Company has advocated in the present rate case dockets." The Company interprets the Commission's request to mean that it should use the positions on these items as advocated in its Application. In order to simplify the analyses, we are using the ROE, capital structure, and cost allocations included in the Company's Application as a proxy for all periods included in the analyses. The ROE, capital structure, and cost allocations that will be approved in this case are not the same as the ROE, capital structure, and cost allocations currently approved nor are they necessarily going to be the same as the ROE, capital structure, and cost allocation methodology approved in a future rate case.

B. Deferral Request is Denied

Q. PLEASE DESCRIBE THE GENERAL APPROACH TO COMPUTING THE MONTHLY REVENUE REQUIREMENTS IF DENIED DEFERRAL OF GIP COSTS.

A. The calculations prepared by DE Carolinas in response to the scenario in which the Company's request for deferral accounting is denied are identical to the calculations for the scenario in which a deferral is granted except estimated GIP expenditures are reduced and no deferral is assumed. Under the denial scenario, the original GIP expenditures are reduced by 80%. This assumption is explained above by witness Oliver.

The exhibits presented are the same as for the "Deferral Granted" scenario. A separate Excel file with the exhibits and workpapers is provided.

C. Deferral is Granted and Second Partial Settlement is Approved

Q. PLEASE DESCRIBE THE ADDITIONAL SCENARIO PROVIDED BASED ON THE SECOND PARTIAL SETTLEMENT.

A. Subsequent to the Commission's Order in this docket requesting these calculations, the Company and the Public Staff filed their Second Partial Settlement with the Commission, in which the Company agreed to withdraw its request for an accounting deferral for certain GIP programs, but retain its deferral request for specific programs for which deferral is supported by the Public Staff and other intervenors. As a result, the Company is providing an additional scenario assuming deferral of the costs for only those programs for which the Company request an accounting deferral under the terms of the Second Partial Settlement. This scenario includes deferral of GIP costs related to completed plant in service beginning June 2020. Amounts related to GIP completed plant in service for January through May 2020 are incorporated in the Company's proposed revenue increase in this docket.

Q. ARE THE CALCULATIONS PREPARED UNDER THE SETTLEMENT SCENARIO THE SAME AS FOR THE SCENARIOS REQUESTED BY THE COMMISSION?

A. The data provided and the underlying computations are the same, but the amount of GIP expenditures subject to deferral is reduced from the Company's "Deferral Granted" scenario based on the terms of the Second Partial Settlement. In addition, this exhibit also reflects the 9.6% ROE and 52% equity and 48% debt capital structure included in the Second Partial Settlement. For purposes of this exhibit, we are using the settled ROE and capital structure as a proxy for all periods included in the analyses. The ROE and capital structure that will be approved in this rate case are not the same as the ROE and capital structure currently approved nor are they necessarily going to be the same as the ROE and capital structure approved in a future rate case.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE SCENARIOS?

A. Yes. These scenarios contain several assumptions and should not be interpreted as a guarantee of what future rate impacts will be under any of the scenarios. For example, in allocating the costs to the customer classes, an allocator was developed based on the test year distribution plant in this rate case, using the allocation methodologies proposed in this rate case. When the next rate case is filed, distribution investments in the new test period may vary from the allocations used in these scenarios. In addition, as discussed previously, assumptions were made around rate case timing, cost of capital, and in-service dates of capital spend. Any changes in these factors, or changes in other factors (tax rates, other rate changes, etc.), will impact the ultimate rates for customers.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR JOINT TESTIMONY?

A. Yes.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is My name is Conitsha B. Barnes. My business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Carolinas, LLC as Regulatory Affairs Manager.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from North Carolina State University with a Bachelor of Arts in Political Science. I started my career with Duke Energy Carolinas in 1998. From 1998 to 2008, I worked in the call center organization in a variety of roles of increasing responsibility including customer service specialist, alternate shift supervisor and business analyst. In 2008, I joined the Marketing Department, where I managed the portfolio of energy efficiency income-qualified low income programs offered in North Carolina, South Carolina, Ohio, Kentucky and Indiana. I joined the Market Solutions Regulatory Strategy and Evaluation group in 2010 as a Strategy and Collaboration Manager – Carolinas, where I was responsible for analysis and support of DEC's Energy Efficiency ("EE") and Demand-Side Management ("DSM") programs. In 2015, I became Senior Strategy Manager, where I supported development and review of testimony for strategic initiatives and regulatory proceedings across Duke Energy's six regulated utilities. I assumed my current role as Regulatory Affairs Manager for DEC in 2017.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS REGULATORY AFFAIRS MANAGER.

A. I am responsible for leading and supporting DEC's North Carolina regulatory matters, including the development and support for regulatory initiatives such as new customer programs and offerings, special tariffs, cost recovery proceedings, investigation and response to customer complaints, and implementation of the Company's Service Regulations. I also identify, research and analyze emerging regulatory issues.

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. No, I did not.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION?

A. Yes, I testified on behalf of DEC in its DSM/EE cost recovery rider proceeding in Docket No. E-7, Sub 1023. I have also appeared before the Commission at various staff conferences, including to support DEC's Prepaid Advantage program application in Docket No. E-7, Sub 1213.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to portions of the direct testimony of Jack Floyd, filed on behalf of the Public Staff, and portions of the direct testimony of John Howat, filed on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy regarding the Company's proposed Prepaid Advantage program and the Company's low income support and programs, and customer affordability issues. I will also briefly address customer affordability issues raised by Mr. Floyd, Mr. Howat and Rory McIlmoil on behalf of the Center for Biological Diversity and Appalachian Voices.

Q. PLEASE GENERALLY DESCRIBE THE COMPANY'S PROPOSED PREPAID ADVANTAGE PROGRAM.

A. As described in DEC's August 2, 2019 petition for approval of its Prepaid Advantage Program, by utilizing the benefits of smart meters, the Prepaid Advantage Program will offer customers the voluntary billing option to prepay for service, thereby avoiding the need for a deposit, reconnect fees, or late fees, and other customer benefits. Prepaid Advantage is similar to an existing prepaid advantage program in our South Carolina service territory and has successfully delivered increased customer satisfaction and energy savings. In the South Carolina Prepaid Advantage program, 50% of participants ranked themselves as 'Completely Satisfied,' and 73% felt the Prepaid Advantage program had a positive effect on their overall satisfaction with the Company. On average, customers in the South Carolina Prepaid Advantage program have experienced an approximate 8.5% reduction in their energy usage. Prepaid Advantage offers an option for customers who are seeking another billing or budgeting option, and based upon our experience in South Carolina, this program has been very well received by our customers, including low income and fixed income customers. As part of the Public Staff's investigation of Prepaid Advantage subsequent to the filing of the petition, the Company agreed to waive the transaction fee for any transaction involving credit and debit cards or electronic checks for Prepaid Advantage participants and, also agreed to certain reporting requirements requested by the Public Staff.

Q. IN HIS DIRECT TESTIMONY, MR. FLOYD DISCUSSES THE PUBLIC STAFF'S INVESTIGATION OF THE COMPANY'S PREPAID ADVANTAGE PROGRAM AND THE DETAILED BASIS FOR THEIR RECOMMENDATION FOR APPROVAL. AT PAGES 36-38, MR. FLOYD DISCUSSES THE COMMISSION'S NOVEMBER 15, 2019 ORDER IN DOCKET NO. E-7, SUB 1210 GRANTING A LIMITED WAIVER OF CERTAIN DISCONNECTION RULES AND RECOMMENDS THAT THREE CONDITIONS (CONDITIONS 1, 5 AND 6) FROM THAT ORDER BE APPLIED TO THE PREPAID ADVANTAGE PROGRAM. HOW DO YOU RESPOND?

A. First, DEC and I appreciate the Public Staff's thorough review of our Prepaid Advantage Program and their support for its approval. In its Prepaid Advantage petition, the Company requested a waiver of certain Commission Rules, which contemplate a traditional monthly paper bill and payment and disconnection procedures for bills rendered for usage previously incurred. Mr. Floyd discusses the Company's request in Docket No. E-7, Sub 1210 for relief from physically visiting customers' premises prior to disconnection as required by Commission Rule R8-12, and the Commission's subsequent order granting that request with six conditions. First, DEC agrees with Condition 1, which prohibits disconnections before 3:00 p.m. The Company also agrees with Condition 6, which requires the Company to make all reasonable efforts to have on file a third-party designee, selected by the customer, who will receive any notice of termination in addition to the customer. DEC's Prepaid Advantage vendor, PayGo, has the capability to allow up to two individuals to consent to receive electronic notifications. Regarding Condition 6, which would limit the waiver of Commission Rule R12-11(m)(2) until June 30, 2021, unless otherwise extended by the Commission, the Company requests that the limited waiver be extended until September 30, 2021, to align with the Company's request filed on February 10, 2020 in Docket No. E-7, Sub 1210. Otherwise, depending upon the date the Commission would issue an order in this general rate case docket approving its Prepaid Advantage Program and the time necessary to implement, the Company might have less than twelve months for the Prepaid Program's availability.

Q. TURNING TO MR. HOWAT'S PRE-FILED DIRECT TESTIMONY, ON PAGES 5-6, HE APPLAUDS COMPANY WITNESS STEPHEN DE MAY FOR RECOGNIZING THE NEED FOR ENHANCED AND EXPANDED PROGRAMMING TO SUPPORT LOW-INCOME AFFORDABILITY, BUT ASSERTS THAT DEC'S MONTHLY DISCONNECTIONS FOR NONPAYMENT MORE THAN DOUBLED FROM JANUARY 2016 TO JANUARY 2020. WHAT IS THE COMPANY'S EXPLANATION FOR THIS INCREASE IN SUCH DISCONNECTIONS OVER THAT TIME PERIOD?

A. I agree that DEC's monthly disconnections for nonpayment (or "non-pay disconnects") increased from 4,948 in January 2016 to 11,276 in January 2020, as reported in Docket No. M-100, Sub 61A. The information reported monthly, however, does not detail factors such extreme weather impacting the suspension of non-pay disconnects. In January 2016, the Company suspended non-pay disconnects for 13 days in comparison to 3 days in January 2020. This the primary driver of the difference in the number disconnects between January 2016 and January 2020. In the most recent 12-month period, an average of 0.63% of the total DEC NC customers were disconnected for non-payment. In 2019, 93% of the customers who received a disconnection notice took action that including paying their bill or making a payment arrangement and avoiding a disconnect for non-payment. The Company actively works with our customers to avoid disconnecting their power only as a last resort.

Q. ON PAGES 24-27 OF HIS PRE-FILED DIRECT TESTIMONY, MR. HOWAT DISCUSSES HIS CONCERNS WITH UTILITY PREPAID PROGRAMS, IN GENERAL, AND CONCLUDES THAT THE COMPANY'S PROPOSED PREPAID ADVANTAGE PROGRAM SHOULD NOT BE APPROVED. HOW DO YOU RESPOND?

A. I disagree with Mr. Howat's opinion that DEC's proposed Prepaid Advantage Program is punitive to low income customers. First, Prepaid Advantage is a voluntary program for any customer who wants an alternative billing and payment arrangement, it is not limited to low income customers. By avoiding the payment of deposits and allowing customers to make payments in advance for their electricity usage, on a schedule and in an amount the customer chooses, however, the Prepaid Advantage Program has advantages for some low-income or fixed-income customers. As I discussed earlier, DEC has a similar prepaid advantage program in South Carolina that has earned positive customer feedback. As filed in its report to the Public Service Commission of South Carolina, many of the Company's South Carolina prepaid participants indicated that the payment flexibility the program provides was beneficial to low income and fixed income participants. Mr. Howat also references the letter from Mr. Al Ripley of the NCJC filed with the Commission in Docket No. E-7, Sub 1213. Although I respect Mr. Howat and Mr. Ripley's positions, I respectfully disagree that the Prepaid Advantage Program's would unfairly remove consumer protections related to notice and disconnection. The Company has an obligation to attempt to avoid write-offs from delinquent accounts, which are ultimately paid for by all customers. I agree with Public Staff witness Floyd that Prepaid Advantage has many customer protections built in and appropriately balances customer protections, the many benefits to participating customers, as well as the need to have appropriate disconnection procedures to protect all customers.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING PREPAID ADVANTAGE?

A. On behalf of the Company, I ask that the Commission approve the Prepaid Advantage Program for all the reasons contained in my testimony, in the Company's petition, and as discussed in the Commission's November 12, 2019 staff conference agenda meeting.

Q. IN THEIR TESTIMONY, MR. FLOYD, MR. HOWAT AND MR. MCILMOIL ALL DISCUSS VARIOUS CUSTOMER AFFORDABILITY ISSUES AND PROGRAMS. WHAT IS THE COMPANY'S POSITION ON THIS TOPIC?

A. The Company fully understands that many of our customers have difficulty paying their energy bills, and affordability is an important issue for all customers. In his direct testimony, Mr. De May acknowledged these concerns and proposed a collaborative process to seek input on and recommend ways we can expand DEC's low income energy assistance programs. In their testimony, Mr. Howat and Mr. McIlmoil propose various definitions of, and approaches to, affordability issues. This is why the Company believes that a stakeholder process, with guidance from the Commission, is the most effective forum to discuss these issues, propose and evaluate options, and then make recommendations to the Commission in a future docket. In particular, Mr. Floyd set forth some parameters for a stakeholder process at pages 58-59 of his direct testimony, and DEC agrees with the Public Staff's recommendations.

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

A. Yes.

MR. ROBINSON: Next on my list. On July 16, 2020, the Commission granted the Company's motion to excuse the following witnesses from appearing in the DEC proceeding. Those witnesses are Steven Capps, Kimberly McGee, Rufus Jackson, Renee Metzler, Teresa Reed, and Rudolph Bonaparte. Subsequently, on August 13, 2020, the Commission granted the Company's motion to excuse from the DEC proceeding Dylan D'Ascendis and Zachary Kuznar.

Therefore, at this time we ask the following testimony and exhibits be moved into the record:

The direct testimony and exhibit of Kimberly McGee; the direct testimony and two exhibits of Rufus Jackson; the direct testimony and one exhibit of Teresa Reed; the rebuttal testimony of Renee Metzler; the rebuttal testimony and two exhibits of Rudolph Bonaparte; the direct -- excuse me, the rebuttal testimony of Zachary Kuznar; and the direct and rebuttal testimony of Steven Capps.

CHAIR MITCHELL: All right. Mr. Robinson, hearing no objection to your motion, the testimony of -- and exhibits of those witnesses that has been prefiled will be admitted into the record of this proceeding and will be copied into the record at this time.

(McGee Direct Exhibit 1, Jackson Exhibits RSJ-1 and RSJ-2, Reed Direct Exhibits 1 and 2, and Bonaparte Rebuttal Exhibits 1 through 3 were admitted into evidence.)

(Whereupon, the prefiled direct and rebuttal testimony of Steven Capps, prefiled direct testimony of Kimberly McGee, prefiled direct testimony of Rufus S. Jackson, prefiled direct testimony of Teresa Reed, prefiled rebuttal testimony of Renee Metzler, prefiled rebuttal testimony of Rudolph Bonaparte, and prefiled rebuttal testimony of Zachary Kuznar were copied into the record as if given orally from the stand.)

I. INTRODUCTION AND OVERVIEW

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven D. Capps and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy"), with direct executive accountability for Duke Energy's South Carolina nuclear plants, including Duke Energy Carolinas, LLC's ("DE Carolinas" or the "Company") Catawba Nuclear Station ("Catawba") in York County, South Carolina; the Oconee Nuclear Station ("Oconee") in Oconee County, South Carolina; and Duke Energy Progress, LLC's ("DE Progress") Robinson Nuclear Plant ("Robinson"), located in Darlington County, South Carolina. I am responsible for providing oversight for the safe and reliable operation of these nuclear plants. I am also involved in the operations of Duke Energy's other nuclear stations, including DE Carolinas McGuire Nuclear Station ("McGuire") located in Mecklenburg County, North Carolina.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a B.S. in Mechanical Engineering from Clemson University and over 32 years of experience in the nuclear field. I joined Duke Energy in 1987 as a field engineer at Oconee. During my time at Oconee, I served in a variety of leadership positions at the station, including Senior Reactor Operator, Shift Technical Advisor, and Mechanical and Civil Engineering Manager. In 2008, I transitioned to McGuire as the Engineering Manager. I later became plant manager and was named Vice President of McGuire in 2012. In December 2017, I was named Senior Vice President of Nuclear Corporate for Duke with direct executive accountability for Duke Energy's nuclear corporate functions, including nuclear corporate engineering, nuclear major projects, corporate governance and operation support and organizational effectiveness. I assumed my current role in October 2018.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I provided testimony in DE Carolinas' 2019 fuel and fuel-related cost recovery proceeding in Docket No. E-7 Sub 1190. I also filed testimony and appeared before the Commission in DE Carolinas' 2018 fuel and fuel-related cost recovery proceeding in Docket No. E-7 Sub 1163.

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

A. The purpose of my testimony is to provide information in support of the Company's request for a base rate adjustment. To this end, I describe DE Carolinas' nuclear generation assets, update the Commission on capital additions since the prior rate case, explain key drivers impacting nuclear operations and maintenance ("O&M") costs, and provide operational performance results for January 1, 2018 through December 31, 2018 (the "Test Period").

Q. WHAT ARE THE PRIMARY CAPITAL AND O&M DRIVERS WITHIN THE NUCLEAR FLEET DRIVING THIS REQUEST?

A. Since the 2017 rate case, capital investments have been made to enhance safety, comply with new or revised regulatory requirements, enhance reliability, and manage aging and obsolescence.

Since the Company's last rate case, O&M expense has declined slightly. DE Carolinas has effectively managed O&M challenges driven primarily from inflationary pressure on labor and materials. External supplemental labor is critical to the safe and efficient execution of refueling outages. Most of the supplemental labor required during refueling outages is highly trained, skilled, and specialized, and the Company competes with other nuclear companies to secure the supplemental labor required. Inflationary pressures among this labor pool have exceeded routine inflation. By leveraging the size of the Company's nuclear fleet and the number of refueling outages, the Company has been successful in mitigating some of this inflationary pressure. However, despite these aggressive and significant efforts, DE Carolinas continues to face new costs and inflationary pressures.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized as follows:

II. NUCLEAR FLEET: Generation Capacity and Asset Descriptions

III. CAPITAL ADDITIONS: In-Service For This Proceeding

IV. O&M AND OTHER ADJUSTMENTS

II. NUCLEAR FLEET

Q. PLEASE LIST DE CAROLINAS' NUCLEAR FLEET.

A. The Company's nuclear generation portfolio consists of 5,389 megawatts ("MWs") of power capacity made up as follows:

Oconee -	2,554 MWs
McGuire -	2,316 MWs
Catawba -	519 MWs [1]

Q. PLEASE GENERALLY DESCRIBE DE CAROLINAS' NUCLEAR GENERATION ASSETS.

A. The Company's nuclear fleet consists of three generating stations and a total of seven units. Oconee began commercial operation in 1973 and was the first nuclear station designed, built, and operated by DE Carolinas. It has the distinction of being the second nuclear station in the country to have its license, originally issued for 40 years, renewed for up to an additional 20 years by the NRC. The license renewal, which was obtained in 2000, extends operations to 2033, 2033 and 2034 for Oconee Units 1, 2 and 3, respectively.

McGuire began commercial operation in 1981 and Catawba began commercial operation in 1985. In 2003, the NRC renewed the licenses for

[1] Reflects DE Carolinas' 19.2 percent ownership of Catawba Nuclear Station.

McGuire and Catawba for up to an additional 20 years each. This renewal extends operations until 2041 for McGuire Unit 1, and 2043 for McGuire Unit 2 and Catawba Units 1 and 2. The Company jointly owns Catawba with North Carolina Municipal Power Agency Number One, North Carolina Electric Membership Corporation and Piedmont Municipal Power Agency.

III. CAPITAL ADDITIONS

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING MAJOR CAPITAL PROJECTS FOR NUCLEAR BEING INCLUDED IN THIS CASE.

A. Since the 2017 Rate Case, DE Carolinas has invested, or will invest by January 31, 2020, approximately $440 million in capital projects. These capital improvements were required to enhance safety, address regulatory requirements, and preserve performance and reliability of the plants throughout their extended life operations.

Catawba and Oconee have completed main power open phase detection system upgrades. The main power open phase detection system upgrades have also been completed at the Keowee Hydro Station. Most equipment installations at McGuire are complete, and the project is scheduled to close at the McGuire station in October 2019. These upgrades address an industry event that occurred at Exelon’s Byron Generating Station and subsequent NRC bulletin 2012-01. The upgrades provide a fully redundant open phase protection system, thus improving safety margins related to offsite power.

Catawba and McGuire partnered on the design of multi-phase projects to install emergency supplemental power source ("ESPS") diesel generators at both stations. The supplemental diesels provide increased safety margins related to emergency backup power, and allow additional time and schedule flexibility in maintaining the stations' emergency onsite power systems. This schedule flexibility increases the amount of emergency diesel generator ("EDG") maintenance that can be performed with the units on-line versus during refueling outages.

Catawba and McGuire also partnered on the design and modifications relating to the distributed control system ("DCS"). Catawba completed DCS installations on both units in 2018. McGuire completed installation on Unit 1 in the spring of 2019, and is scheduled to complete Unit 2 installation in early 2020. The DCS projects involve the replacement and upgrade of components such as controllers, servers, and software used to support the nuclear steam supply system. These projects address aging components that are no longer supported by the vendor, as well as address reliability, performance enhancements, and cyber security requirements.

Catawba, McGuire, and Oconee also completed IT infrastructure upgrades in 2019. The upgrades consist of installing new backbone fiber networks. The new fiber networks build on the existing networks, modernizing each station's IT capabilities and supporting additional automated plant monitoring functions.

Other capital investments at Catawba since 2017 include upgrades to the station's EDGs. A multi-phase project replacing the station's EDG governors completed with the replacement of the 1A governor in 2018. The new governors provide enhanced slow start capabilities of the EDGs and address both obsolescence issues and reliability enhancements. The station, in a multi-phase project, is also upgrading the EDG voltage regulators. The regulator on the 2A EDG is scheduled for replacement in the fall of 2019. Replacement of the other voltage regulators is scheduled to complete by 2021. The new regulators support better thermal management and provide a more robust surge suppression capability. These enhancements improve both the safety and reliability of the station's EDGs.

In 2019, McGuire completed a multi-year project to replace the station's four main step up transformers. During the spring 2019 refueling outage, the final transformer was replaced. The existing transformers had approached the end of their useful life.

Modernization upgrade projects continue at Oconee, enhancing safety margins, regulatory margins, and reliability. Examples of these modifications include enhancements to the spent fuel pool cooling system, feedwater heater replacements, replacement of selected reactor coolant pumps, and electrical upgrades including replacement of molded case circuit breakers, upgrades to main power relays, selected main transformer replacements and the replacement of one of the Keowee Hydro Station stator assemblies. Oconee Unit 2 will replace low pressure turbine ("LPT") rotors and associated diaphragms during the late fall 2019 refueling outage. Oconee Unit 1 and Unit 3 LPTs are scheduled for replacement in 2020. The LPT replacements improve the reliability of the turbines and reduce inspections and maintenance.

Q. ARE THE CAPITAL ADDITIONS AND ENHANCEMENTS YOU HAVE DESCRIBED IN YOUR TESTIMONY USED AND USEFUL IN PROVIDING ELECTRIC SERVICE TO DE CAROLINAS' ELECTRIC CUSTOMERS IN NORTH CAROLINA?

A. Yes. These capital additions and enhancements are used and useful in safely and efficiently providing reliable electric service to DE Carolinas' customers. As a result of the Company's successful efforts to renew the licenses, refurbish obsolete equipment and systems and enhance safety margins in compliance with new NRC requirements, customers will continue to benefit from the power provided by this reliable, efficient, cost-effective and greenhouse gas emissions-free 24/7 power source of energy for many years to come. These investments have positioned the Company to maintain high levels of operational safety, efficiency and reliability that is reflected in the nuclear performance results I discuss later in my testimony.

Q. HAS DE CAROLINAS ATTEMPTED TO CONTROL COSTS FOR CAPITAL ADDITIONS AND O&M?

A. Yes. The Company controls costs for capital projects and O&M using a rigorous cost management program. For example, the Company routinely conducts executive oversight of project budget and activity reporting, with new projects requiring approval by progressively higher levels of management depending on total project cost. The Company also controls ongoing capital and O&M costs through strategic planning and procurement, efficient oversight of contractors by a trained and experienced workforce, rigorous monitoring of work quality, thorough critiques to drive out process improvement, and industry benchmarking to ensure best practices are being utilized. Many of the capital projects I detailed earlier in my testimony were jointly designed and scheduled across multiple stations. These efforts reduce cost, and since many of the projects are scheduled across multiple time periods, allows the Company to apply learning and improve as the multi-station projects progress to completion. The Nuclear Generation Department works to leverage the size of the nuclear fleet whenever possible, benefiting the Company's customers in both cost and performance. However, despite these considerable efforts, DE Carolinas continues to face inflationary pressures.

IV. O&M AND OTHER ADJUSTMENTS

Q. PLEASE DESCRIBE SIGNIFICANT COST DRIVERS IMPACTING O&M EXPENSES FOR DE CAROLINAS' NUCLEAR FLEET.

A. During the Test Period, approximately 33 percent of the required O&M expenditures for DE Carolinas' nuclear fleet were fuel-related. A complete discussion of nuclear fuel costs can be found in Witness Houston's testimony filed with this Commission on February 26, 2019 in the Company's annual fuel proceeding in Docket No. E-7, Sub 1190. In his testimony, Witness Houston noted that the Company anticipates costs of certain components of nuclear fuel to reflect modest decreases in future years. Nuclear fuel costs on a cents per kilowatt-hour ("kWh") basis will continue to be a fraction of the cents per kWh of fossil fuel. Therefore, customers will continue to benefit from the Company's diverse energy mix and the strong performance of its nuclear fleet through lower fuel costs.

Non-fuel items compose the remainder of O&M expenditures for the nuclear fleet. Because nuclear power plant operations are labor intensive, a significant portion of O&M expenses are related to internal and contracted supplemental labor. The Company continues to face upward pressure on these ongoing labor costs and other challenges have occurred with rising costs for materials and supplies.

Q. WHAT EXAMPLES CAN YOU PROVIDE RELATED TO THE COMPANY'S EFFORTS TO CONTROL O&M COSTS AS NOTED ABOVE?

A. The Company has many efforts in place for controlling and/or saving costs. An area of focus in recent years has been outage optimization, focusing on duration, budget, dose and production. This approach applies strict controls to reduce outage durations, align typical maintenance work within duration templates, allocate costs based on duration templates, improve alignment of bulk work to minimize schedule impacts, and target dose to the five-year ALARA[2] plan. Outage optimization has also allowed some reduction in supplemental labor

[2] Code of Federal Regulations (10 C.F.R. § 20.1003) acronym for "as low as (is) reasonably achievable."

required to support refueling outages. In addition, the Company continues to identify ways to leverage technology to improve worker efficiency.

Q. WHAT IS THE COMPANY'S CURRENT STATUS WITH RESPECT TO COMPLIANCE WITH THE NRC REQUIREMENTS RELATED TO FUKUSHIMA?

A. DE Carolinas is in full compliance with current NRC requirements related to Fukushima. With the exception of one modification at Catawba and one modification at Oconee, all Fukushima related modifications are complete. Catawba will install a flood gate on a Unit 2 electrical penetration room door to strengthen the station's capabilities in a severe flooding event. The Catawba modification is scheduled to be completed in 2020. Oconee will install three letdown isolation values; one each per unit. The valve modification provides a means for alternate letdown isolation and strengthens the station's ability to respond to severe seismic challenges. The Oconee work is scheduled to complete on Unit 2 in the fall 2021 refueling outage, followed by Oconee Unit 3 in the spring of 2022 and Unit 1 in the fall of 2022. All McGuire Fukushima modifications have been completed.

Q. PLEASE DESCRIBE THE NRC REQUIREMENTS COMMUNICATED TO DATE WITH RESPECT TO CYBER SECURITY.

A. In 2009, the NRC published regulations[3] requiring licensees to protect digital assets associated with, and important to, safety, security and emergency preparedness functions. The Nuclear Energy Institute ("NEI") worked with the

[3] 10 C.F.R. § 73.54, "Protection of digital computer and communication systems and networks."

NRC and industry representatives (including Duke Energy) to develop NEI 08-09, "Cyber Security Plan for Nuclear Power Reactors," which was endorsed by the NRC in early 2010 as an acceptable means of meeting the requirements. NEI 08-09 utilizes cyber security controls from the National Institute of Standards and Technology standards,[4] which are heavily used throughout the U.S. government.

Q. WHAT IS THE STATUS OF THE COMPANY'S EFFORTS TO MEET THE NRC REQUIREMENTS COMMUNICATED TO DATE WITH RESPECT TO CYBER SECURITY?

A. DE Carolinas submitted its Cyber Security Plan and implementation schedule to the NRC and has received NRC approval. The activities outlined by the Company within its proposed Cyber Security Plan include examining current practices, developing cyber security program processes, reviewing critical digital assets, performing validation testing, and implementing new controls. The Company's necessary efforts to meet the NRC's cyber security requirements have introduced new upward O&M expense pressure with efforts such as labor and maintenance. The Company has completed the necessary actions for implementation of the NRC requirements.

[4] SP 800-53, "Recommended Security Controls for Federal Information Systems," Revision 2 and SP 800-82, "Guide to Industrial Control Systems (ICS) Security," Final Public Draft, September 2008.

VI. NUCLEAR OPERATIONAL PERFORMANCE

Q. WHAT ARE DE CAROLINAS' OBJECTIVES IN THE OPERATION OF ITS NUCLEAR GENERATION ASSETS?

A. The primary objective of DE Carolinas' nuclear generation department is to safely provide reliable and cost-effective energy to DE Carolinas' customers. The Company achieves this objective by focusing on a number of key areas. Operations personnel and other station employees are well trained and execute their responsibilities to the highest standards in accordance with detailed procedures. The Company reliably maintains station equipment and systems, and ensures timely implementation of work plans and projects that enhance the performance of systems, equipment, and personnel. Station refueling and maintenance outages are conducted through the execution of well-planned, well-executed and high-quality work activities, which effectively ready the plant for operation until the next planned outage.

Q. PLEASE DISCUSS THE PERFORMANCE OF THE COMPANY'S NUCLEAR FLEET DURING THE TEST PERIOD.

A. As in years past, DE Carolinas' nuclear fleet continued to perform well and provided fifty-nine percent of the Company's total power generated in 2018. During the Test Period, the Company achieved a combined capacity factor of 95.29%, and 2018 represented the 19th consecutive year of DE Carolinas' nuclear plants exceeding a 90 percent annual capacity factor. This output above 90 percent has resulted in approximately 39.4 million MWs of additional generation, or 8.2 months of output, over the 19-year period. These performance results demonstrate DE Carolinas' continued commitment to achieving high performance and reliability without compromising safety.

Q. WHAT INITIATIVES HAS THE COMPANY TAKEN TO INCREASE EFFICIENCIES IN NUCLEAR OPERATIONS?

A. The Company uses benchmarking, long-range planning, work prioritization tools and other processes to continuously improve operational and cost performance. Over the years, the Company has gained efficiencies from the implementation of common policies, practices, and procedures across the Duke Energy nuclear fleet. In addition, efficiencies are sought by incorporating industry best practices. Since the merger, the Company continues to remain focused on improving fleet performance in various areas, and a focus on organizational effectiveness allows the Company to continue to identify and address work improvements. The goals are to align operations at a fleet level and take advantage of shared experiences and process improvement opportunities. Results of the Company's efforts have been demonstrated by successive output records and unit outage performance. In addition, the Company continues to identify ways to leverage technology to improve worker efficiency with electronic procedures and mobile worker projects. Overall, improvement efforts result in enhanced fleet reliability and efficiency on a cost per kWh basis.

Q. WHAT CHALLENGES DOES DE CAROLINAS FACE REGARDING ITS NUCLEAR OPERATIONS?

A. Despite the success of the Company's efficiency initiatives to mitigate cost increases, DE Carolinas continues to face upward pressure on O&M costs. A significant challenge facing the nuclear industry is the cost and technological requirements to maintain the existing U.S. nuclear fleet at the highest levels of safety and reliability, while also maintaining economic viability and ensuring these plants continue to provide emission-free energy in the future. Therefore, maintaining the Company's nuclear assets is critical to achieving significant reductions to current and future levels of greenhouse gas emissions, and ensuring the diversity of energy supply for our customers.

Q. HOW DOES THE COMPANY'S NUCLEAR FLEET COMPARE TO OTHERS IN THE INDUSTRY?

A. The Company's nuclear fleet has a history of top performance. In industry data for 2018, Duke Energy's nuclear fleet compared favorably to other large domestic nuclear fleets using Key Performance Indicators ("KPIs") in the areas of personal safety, radiological dose, manual and automatic shutdowns, capacity factor, forced loss rate, industry performance index, and total operating cost. On a larger industry basis using data for 2018 from the Electric Utility Cost Group, DE Carolinas' plants (Catawba, McGuire, and Oconee) all ranked in the top quartile in total operating cost among the 60 U.S. nuclear plants reporting. Industry benchmarking efforts are a principal technique used by the Company to ensure best practices are implemented and results are sustained.

These efforts further ensure overall safety, efficiency, and reliability of DE Carolinas' nuclear units.

II. CONCLUSION

Q. IS THERE ANYTHING YOU WOULD LIKE TO SAY IN CLOSING?

A. Yes. The Company has a proven history of cost competitive operation of its nuclear assets concurrent with maintaining safety, quality, and reliability. DE Carolinas is positioned to continue as a leader in the industry with a solid base of knowledge and experience, and with a nuclear fleet that is highly efficient and reliable. This base rate increase will allow the Company to continue the tradition of operational excellence and focus on safe operations, reliable generation, and strong performance that ultimately benefits our customers.

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

A. Yes.

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven D. Capps and my business address is 526 South Church Street, Charlotte, North Carolina.

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

A. I am Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy"), with direct executive accountability for Duke Energy's South Carolina nuclear plants. I am also involved in the operations of Duke Energy's other nuclear stations, including Duke Energy Carolinas, LLC's ("DE Carolinas") McGuire Nuclear Station ("McGuire") located in Mecklenburg County, North Carolina.

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this proceeding.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My rebuttal testimony responds to specific recommendations made by witness Dustin Metz of the Public Staff of the North Carolina Utilities Commission ("Public Staff") regarding post-hearing collaboration on project documentation and auditing of materials and supply (M&S) inventory.

Q. WHAT IS WITNESS METZ'S RECOMMENDATION WITH REGARD TO POST-HEARING COLLABORATION ON PROJECTS DOCUMENTATION?

A. Witness Metz recommends the Commission direct the Company to begin collaborating with the Public Staff within three months following conclusion of the rate case to clarify expectations for project evaluation and selection and document creation and retention.

Q. WHAT IS YOUR RESPONSE TO THIS PROPOSAL?

A. The Company does not oppose this recommendation.

Q. WHAT DOES WITNESS METZ RECOMMEND WITH RESPECT TO THE COMPANY'S M&S INVENTORY?

A. Witness Metz recommends that "the Company complete an independent audit of M&S inventory 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)."

Q. WHAT IS YOUR RESPONSE TO WITNESS METZ'S RECOMMENDATION WITH RESPECT TO PERIODIC INDEPENDENT AUDITS OF M&S INVENTORY?

A. The Company does not oppose witness Metz's recommendation, with the exception that DE Carolinas believes that the Company should utilize Duke Energy's own independent Audit Services Department to meet this recommendation. The Audit Services Department is required to maintain independence from the business units that it reviews and to maintain objectivity in its work. It reports to the Audit Committee of the Board of Directors and to Duke Energy's senior ethics and compliance officer. The Department is authorized to have full, unrestricted access to all Duke Energy functions, records, property, and personnel, and to obtain the necessary assistance of personnel in audited units, as well as other specialized services from within or outside the Duke Energy enterprise. It is already familiar with the tools and processes used by the business units. Company witness Immel will address this recommendation with respect to DE Carolinas' fossil and hydroelectric facilities.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kimberly D. McGee and my business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am a Rates & Regulatory Strategy Manager supporting both Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company" or "DEC") and Duke Energy Progress, LLC ("DE Progress" or "DEP").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from the University of North Carolina at Charlotte with a Bachelor of Science degree in Accountancy. I am a certified public accountant licensed in the State of North Carolina. I began my career in 1989 with Deloitte and Touche, LLP as a staff auditor. In 1992, I began working with DE Carolinas (formerly known as Duke Power Company) as a staff accountant and have held a variety of positions in the finance organization. From 1997 until 2009, I worked for Wachovia Bank (now known as Wells Fargo) in a variety of finance and regulatory positions. I rejoined DE Carolinas in January 2009 as a Lead Accountant in Financial Reporting. I joined the Rates Department in 2011 as Rates & Regulatory Strategy Manager.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES & REGULATORY STRATEGY MANAGER.

A. I am responsible for managing DE Carolinas' and DE Progress' rider cost recovery processes, including fuel and renewable compliance; providing guidance on compliance with regulatory conditions and codes of conduct; and providing regulatory support for retail rates.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC" or the "Commission") in DEP's general rate case proceeding supporting the base fuel factors in Docket No. E-2, Sub 1142 and provided testimony in DEC's general rate case proceeding supporting the base fuel factors in Docket No. E-7, Sub 1146. I also testified supporting cost recovery in the 2013 Demand Side Management and Energy Efficiency Rider in Docket No. E-7, Sub 1031. I submitted testimony in DEC's fuel and fuel-related cost recovery proceedings in Docket No. E-7, Subs 1190, 1163 and 1129 and DEP's fuel and fuel-related cost recovery proceedings in Docket No. E-2, Subs 1045, 1069 and 1107.

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

A. My testimony supports the fuel component of proposed base rates for all customer classes.

Q. YOUR TESTIMONY INCLUDES ONE EXHIBIT. WAS MCGEE EXHIBIT 1 PREPARED BY YOU OR AT YOUR DIRECTION AND SUPERVISION?

A. Yes. It was.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN EXHIBITS SPONSORED BY OTHER COMPANY WITNESSES?

A. Yes. I provided the proposed fuel rate and annualized fuel expense for the Company's Test Period to Witness McManeus.

II. <u>BASE FUEL FACTORS</u>

Q. WHAT BASE FUEL FACTORS DOES DE CAROLINAS PROPOSE TO USE IN THIS DOCKET?

A. The Company proposes to use the following base fuel factors by customer class (excluding gross receipts tax and regulatory fees):

- Residential 1.8126 cents per kWh
- General Service 1.9561 cents per kWh
- Industrial 1.8934 cents per kWh

These proposed factors are equal to the total prospective fuel and fuel-related cost factors filed in Docket No. E-7, Sub 1190. These factors represent the fuel-related amounts that the Company will be collecting from its North Carolina retail customers as of September 1, 2019. The Company's intent in using the fuel-related factors that are expected to be effective September 1, 2019 as a component of its proposed new rates is to make it clear that we are requesting a rate increase that relates to non-fuel revenues only, *i.e.*, a request that includes neither an increase nor a decrease related to recovery of fuel costs.

Q. WHAT LEVEL OF FUEL COSTS HAS THE COMPANY INCLUDED IN COST OF SERVICE?

A. As shown on McGee Exhibit 1, the Company's North Carolina retail adjusted fuel and fuel-related costs expense for the Test Period was $1,099,577,339. This amount was calculated using the base fuel cost factors identified above and North Carolina retail Test Period actual kWh sales by customer class as adjusted for weather and customer growth. I provided this amount to Witness McManeus broken into three categories: 1) the amount related to unadjusted kWh sales, 2) the amount for the weather adjustment, and 3) the amount for the customer growth adjustment. These amounts were used in the pro forma adjustment calculations and are incorporated in the operating expenses shown on McManeus Exhibit 1, page 1.

Q. PLEASE EXPLAIN THE DERIVATION OF THE FUEL COST FACTORS BY CUSTOMER CLASS.

A. The fuel cost factors by customer class were filed in Docket No. E-7, Sub 1190 and supported by the 2019 McGee Exhibits[1] filed in that proceeding. In summary, the costs presented in that proceeding and exhibits are based on: (1) forecasted kWh sales for the billing period September 2019 through August 2020 and estimated fuel and fuel-related costs to supply those sales; and (2)

[1] McGee Revised Exhibits 1 through 4 filed May 15, 2019 in Docket No. E-7, Sub 1190 (collectively "2019 McGee Exhibits").

adjustments for over or under recovery from the preceding twelve-month period. These factors represent the most recently approved billing factors at the time the Company prepared its rate increase application and supporting exhibits in this proceeding.

Q DOES THE USE OF THESE BASE FUEL FACTORS AFFECT THE COMPANY'S REQUESTED RATE INCREASE?

A. No. The Company's requested increase in revenues in this case is related to non-fuel revenues. There will be no change to customers' bills because of inclusion of these fuel cost factors in the Company's proposed base rates. The Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings.

III. PRO FORMA ADJUSTMENTS

Q. ARE YOU SUPPORTING ANY ACCOUNTING AND PRO FORMA ADJUSTMENTS IN THIS PROCEEDING?

A. Yes. As discussed by Company Witness McManeus, I provide support for the fuel adjustment.

Q. PLEASE DESCRIBE THIS PRO FORMA ADJUSTMENT.

A. The pro-forma adjustment I support is as follows:

Line 2 in McManeus Exhibit 1, Page 3 adjusts fuel and fuel-related expense in the Test Period to reflect the fuel rates filed with the North Carolina Utilities Commission in Docket No. E-7, Sub 1190, effective September 1, 2019. When applied to the actual Test Period kWh, this produces fuel and fuel-related expense of $1,123.0 million. When this amount is added to the adjustments to fuel expense for weather and customer growth on lines 3 and 4 in McManeus Exhibit 1, Page 3 of ($26.2) million and $2.8 million, respectively, the three components add to the $1,099.6 million shown on page 2 of McGee Exhibit 1.

IV. CONCLUSION

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

A. Yes.

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Rufus S. Jackson. I am employed by Duke Energy. My business address is 411 Fayetteville Street, Raleigh, North Carolina.

Q. PLEASE TELL US YOUR POSITION WITH DUKE ENERGY, AND DESCRIBE YOUR DUTIES AND RESPONSIBILITIES IN THAT POSITION.

A. I am the Vice President for Carolina East Operations. I direct operations of Duke Energy in the eastern portions of North Carolina and South Carolina to ensure customer expectations are met through direct management of the construction and maintenance workforce. I am responsible for the Duke Energy and contractor workforce that performs day-to-day construction and maintenance as well as storm restoration. I am also the Operations Section Chief in the Carolinas Incident Command Structure. My testimony addresses Duke Energy Carolinas, LLC's ("DE Carolinas" or the "Company") distribution storm plan and the execution of that plan for Hurricanes Florence and Michael, and Winter Storm Diego (the "Storms").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science degree in Mechanical Engineering from North Carolina Agricultural and Technical State University. Prior to assuming my current roles for the Carolinas, I have held various engineering, operational, and leadership positions over a 33-year electric utility/manufacturing career.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I am testifying on behalf of the Company in support of its request for recovery of the Company's deferred storm-related costs incurred due to Hurricanes Florence and Michael, and Winter Storm Diego.

Q. CAN YOU SUMMARIZE YOUR TESTIMONY?

A. My testimony begins by describing our Distribution Storm Response Plan. I then discuss the major storms we encountered during 2018 and provide an assessment of our response to those storms. Finally, I discuss the scope of costs incurred by the Company in response to those storms and our successful efforts to restore electric service safely and efficiently to our customers.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. I am sponsoring two exhibits to my testimony. Exhibits RSJ-1 and RSJ-2 detail the costs incurred by the Company in responding to Hurricanes Florence and Michael, and Winter Storm Diego.

Q. WERE EXHIBITS RSJ-1 AND RSJ-2 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. They were.

III. DE CAROLINAS' DISTRIBUTION STORM PLAN

Q. DOES DE CAROLINAS HAVE A PLAN TO DEAL WITH MAJOR STORMS AND OUTAGES THEY CAUSE?

A. Yes.

Q. PLEASE DESCRIBE DE CAROLINAS' DISTRIBUTION SYSTEM STORM PLAN.

A. DE Carolinas engages in planning for major storms on a continuous, year-round basis. Hurricane season readiness begins several months before the start of the season and includes training, drills, and implementation of lessons learned from the prior year. Our comprehensive storm plan is modeled on Homeland Security's Incident Command Structure ("ICS") and incorporates the best practices we have developed from experiences with past storms. The ICS affords rapid scalability in response to a specific threat.

In addition to using the ICS, the Company also has an Emergency Preparedness organization solely focused on planning, which incorporates lessons learned from industry experience and other events specific to the Duke Energy system, in North Carolina and elsewhere.

The scalability of ICS is reflected in DE Carolinas' three distinct levels of restoration response (Level I – III). Level I corresponds with typical summer storms, whereas Level III is designed for restoration on the scale of a hurricane. The same basic functions are performed at all storm levels, but as required resources are increased to match the storm's anticipated threat, the organization expands to ensure efficient restoration of our system. While it is appropriate for an individual to perform parts of several storm roles in a lower level event, those same roles are broken out and staffed by an increasing number of dedicated resources as the scope of restoration work increases. The decision to activate at a particular response level is made by the storm management team, and is guided by weather forecasts, resource modeling, and expected restoration duration. The flexibility of the storm plan is such that, for any given restoration event, we may have a region that is operating within the Level III model while another region is operating within a Level I model. This allows regions within the Company operating at a lower restoration level to finish sooner and release resources to work in regions operating at a higher restoration.

At a high level, the ICS plan is built around three phases of storm restoration; pre-storm activation, outage restoration, and returning the distribution grid to normal. Pre-storm activation begins as early as 120 hours prior to the storm, and includes detailed weather forecasting, modeling of damage and resource requirements, and preparation for support of logistics needs. The outage restoration phase includes the operational activities following impact from the storm that restore service to all customers capable of receiving it. Returning the grid to normal is necessary to restore our electrical infrastructure to its pre-hurricane condition.

Q. CAN YOU PLEASE DESCRIBE THE DIFFERENT ROLES WITHIN DE CAROLINAS' STORM PLAN?

A. Yes. Within the storm plan there are a multitude of roles that facilitate an efficient restoration process. These roles are organized along four functional lines: (1) Operations; (2) Planning; (3) Logistics; and (4) External Coordination. Operations is focused on restoration of service; Planning on forecasts, modeling, and situation awareness; Logistics on staging, material, and supplies; and External Coordination on outreach and communication to customers, local emergency operations EOCs, state and local leaders.

The participants are assigned roles under the storm plan that may differ from their regular, daily responsibilities and, as a result, it is imperative that they are effectively trained. This training is normally completed in the second quarter of each year throughout the system and within each of the functional areas of responsibility. To further ensure our storm preparedness, we conduct storm readiness drills to test the effectiveness of the training program and the ability of our employees to execute their assigned storm roles.

Q. WHEN AND HOW DO YOU ACTIVATE YOUR ICS MAJOR STORM ORGANIZATION?

A. Duke Energy meteorologists continuously monitor the Atlantic basin and Tropics and begin to issue alerts as early as two weeks before expected impact. Our formal ICS activation process kicks off 120 hours prior to the projected storm event. Our initial focus is to ascertain the most detailed weather information available including date, time, and strength of the storm, when it is forecasted to impact our system, forecasted path of the storm, size and strength of the wind fields, associated amount of precipitation, when the wind is anticipated to exceed and fall below 39 mph, and strength of gusts. Up to five days prior to a predicted significant weather event, we use predictive analytics to estimate the numbers of customers impacted by the weather event and the estimated number of line resources, vegetation personnel and damage assessors needed to restore power in a reasonable period. This analytic model is based on years of operating history and is updated and refreshed following significant events.

After an event occurs, we rerun the model based on the actual weather outcomes. At this juncture, we also start using an internally developed model, Storm Caster. This model uses the number of events and type of isolating devices from the Outage Management System ("OMS") to forecast the number of resources needed to restore power in an adjustable time frame. To help predict resources needed and the time of restoration, this model estimates the number of nested (embedded) outages behind larger sectionalizing devices. Storm Caster is run continually throughout the restoration effort. As outages are restored and more information is gathered through damage assessment, the accuracy of the model results improves.

With each forecast update we use storm modeling tools to predict the amount of damage to our system, where that damage will likely occur, and the amount of resources required to restore the projected outages. More specifically, the tools estimate the number of personnel required, such as linemen, vegetation crews, and damage assessors. This gives us an estimate of the necessary scale of restoration response. With that information we conduct a system storm call that includes management teams representing the four functional areas of our storm response plan. As noted above, storm plan activation typically occurs 120 hours before onset of the storm. At this point, efforts are focused upon notifications to our customers and employees of a potential impact and the beginning of our storm readiness activities and our initial efforts to procure resources. A progression of checklists follows each day thereafter prior to system impact.

Q. HOW DOES DE CAROLINAS USE THE INFORMATION FROM PREDICTIVE STORM MODELS?

A. Once we have estimated the amount of resources required, where and to what extent each region within our territory will be impacted, several processes begin in unison. Our Resource Management function secures commitments for restoration manpower, and Staging and Logistics prepares to open mustering and base camp sites to receive them.

Resource Management first deploys DE Carolinas and Duke Energy Progress, LLC ("DE Progress") employees and native contractors currently working on our system to staging sites. The second step is to secure internal line and vegetation resource commitments from the other states served by Duke Energy. Internal Duke Energy personnel are available immediately and can be moved into forward positions to expedite restoration. Next, we contact the Southeastern Electric Exchange ("SEE") Mutual Assistance Group to secure commitments from the participating companies for remaining needs. SEE Mutual Assistance is governed by an existing agreement between all participating utilities. Most Mutual Assistance utilities are also assessing impact to their systems and will hold resources until in the clear. Those utilities not in the storm's projected path typically must travel from significant distance and must be activated several days prior to landfall.

Depending on the time, path, and confidence in the storm's expected impact, decisions are made concerning when committed crews are activated, paid to be mobilized, and sent to mustering locations prior to landfall. To expedite restoration, we mobilize crews to mustering sites located along the routes from their home base to their assigned work location. We want sites that are as close as possible to expected damage; however, safety is our highest priority, so the sites ultimately used depend upon the path of the storm to ensure we are not unnecessarily placing anyone in harm's way. As such, the number of crews mobilized and where they are mustered depends greatly on confidence in the forecast.

Concurrent with the acquisition of resources, our Logistics function establishes a coordinated schedule to open mustering sites, base camps, and secure anticipated lodging needs. The use of mustering sites allows us to validate rosters and crew compliments for billing, orient non-native crews to our safety policies, switching practices, technical specifications, and to prepare them for reassignment to a forward base camp. Base camps accommodate truck parking, inventory storage, refueling, meals, and, in some cases, lodging.

Q. HOW DOES THE COMPANY RESPOND TO THE ONSET OF MAJOR STORMS?

A. When the storm-force winds commence in DE Carolinas' service territory, the Distribution Control Center ("DCC") is in constant communication with the Transmission Control Center ("TCC"), System Operations Center ("SOC"), and the distribution and transmission storm centers. The TCC gives both storm centers a thorough description of what transmission lines and substations are dropping out of service as the storm passes, giving us a real-time assessment of the location of the storm damage. Crews in the storms' direct path shelter in place. The ECC and the distribution and transmission storm centers jointly establish restoration priorities and coordinate the distribution and transmission restoration strategy to maintain grid stability.

Q. WHAT HAPPENS AFTER THE STORM PASSES?

A. Our initial response has three main components: (1) governmental and EOC support and response; (2) initial damage assessment; and (3) feeder backbone/substation restoration efforts. These three components enable the local and state governments to respond to the storm's impact, and enables DE Carolinas to both estimate the amount of storm damage incurred on the distribution and transmission system and begin restoration of the highest priority feeders.

As local governments and county EOCs encounter issues that require our immediate attention, we can promptly respond. These issues may involve, for example, support for road clearing teams, or removing a downed power line with police personnel standing by at the site. We have account managers and community relations managers at local (zone) storm centers. They are the single point of contact for government and EOC officials.

As the outages are occurring, the ECC and DCC are identifying critical outages and grid stability issues, and are notifying local storm teams of high priority events. As soon as the storm winds drop below 39 miles per hour, local field crews assess and restore, based on their knowledge of the system in their area, starting with the major feeders and substations. In addition, damage assessment teams are activated to get a better understanding of the damage to the distribution and transmission system. The previously identified representative distribution line segments are assigned to damage assessment teams, who are responsible for a pole-by-pole survey of those representative segments to inventory the extent of damage incurred and return that damage information to be entered in a database. Based upon the storm damage found in this representative sample, we extrapolate the amount of storm damage for the rest of the local distribution network and aggregate those assessments to get a system-wide storm damage estimate. These estimates are used to confirm damage and to adjust as needed to the pre-landfall resource mobilization plan.

The circuit restoration process is a method by which we start at the substation and continue along the line to restore customers based on criticality and number of customers impacted. Highest priority is assigned to feeders that are critical to the health, safety, and welfare of the public.

Q. HOW IS THE RESTORATION PHASE OF THE STORM PLAN CARRIED OUT?

A. At this juncture of our restoration efforts, we begin to deploy restoration resources to the local operating areas to include them in the storm restoration plan. Restoration priorities begin with restoring our transmission system, which also facilitates restoration of end-use power. Repairs to our transmission system also allow restoration points of delivery to wholesale customers such as electric cooperatives and municipalities. Duke Energy gives first priority to facilities needed to ensure public health and safety as well as critical public infrastructure. We then focus on restoring as many customers as quickly as possible. Finally, we work on the individual neighborhoods and homes based upon availability to receive power. To efficiently use this first wave of resources, we assign them to the storm damage that was identified through our initial local field assessments. This allows us to assign them to the highest priority work on the most critical components of our distribution infrastructure.

Based upon the information collected from the initial assessment, any aerial storm damage assessments using helicopters, information reported to our outage management system, and the knowledge of local management, the management team has the information it needs to determine what feeders require detailed damage assessment. When the detailed assessment of a feeder segment is complete, the results of that effort are compiled into an associated work package. This work package allows us to effectively communicate the scope of the work to be completed and further assists us in managing productivity expectations of our line and vegetation crew resources. Additionally, the work package information assists local management in allocating resources and determining estimated times of restoration ("ETRs").

Throughout the storm event, the Company monitors outage events in the impacted areas daily to determine the areas with resource needs so we can redeploy and/or release resources to ensure we are appropriately addressing customer outages and costs.

Q. DOES THE COMPANY UPDATE ETRS DURING THE RESTORATION PROCESS?

A. Yes. We have three levels of ETRs: 1) an initial system level ETR; 2) a view of ETRs by city and county; and 3) device level ETRs. As the storm restoration progresses, we move from higher level ETRs to increasing levels of detail, letting customers know what we know when we know it. ETRs are continuously updated and expanded to greater levels of detail during restoration. Factors that influence the ETR updates include integrating any new information we have collected, the extent and severity of the storm damage, the critical and priority restoration needs we may receive from ECC, state and local governments and EOCs, and the availability of resources. Additionally, timing of resource arrival can be impacted by several external factors such as road and bridge closures, crews that must travel through the path of the storm (after it has cleared), roads, hotels and lodging clogged by evacuees, and lack of fuel along major routes into the state. As required, we shift line and vegetation crews, equipment, and material to address new priorities or to increase productivity. We are constantly striving during the restoration to improve our ETRs and meet or exceed our own ETR goals.

Q. HOW DOES THE COMPANY WIND DOWN ITS RESTORATION PROCESS?

A. As we near the completion of storm restoration work within any part of our service territory, we begin demobilization efforts. DE Carolinas believes it is imperative to use the most productive and cost-effective resources during our restoration efforts. As a part of our demobilization efforts, we survey local management and feeder coordinators to get their assessment on the productivity of the non-native line and vegetation personnel. Combining this information with the daily cost of the personnel, we build a plan that retains the safest, most productive, and most cost-effective resources.

Q. IS THERE ANYTHING ELSE THAT MUST BE DONE AFTER RESTORATION OF CUSTOMERS IS COMPLETE?

A. Yes. The final phase of our storm response is the restoration of the system to its pre-storm status. When in the storm outage restoration phase, we perform the necessary work to restore the fundamental operating characteristics of our distribution infrastructure. The primary focus is getting "lights on" and safety considerations rather than correcting all damaged facilities that are still capable of functioning. For example, during the storm outage restoration phase, DE

Carolinas will leave in place poles that are damaged and in need of repair but are able to safely provide service to our customers in the short term, capacitor banks and reclosers are returned to service only if immediately required, and animal mitigation hardware is not installed pursuant to our day-to-day standards. After the restoration efforts have concluded, we conduct electrical and physical condition sweeps of our circuits and identify the issues that require mitigation to return the distribution system to its pre-storm state.

The Company also conducts a "tree sweep," which is a detailed vegetation sweep of our circuits to identify any storm damage to trees that was not mitigated during the storm restoration phase. The tree sweep is focused on cracked or broken limbs that are tenuously hanging over-top of facilities and will eventually come down. The Vegetation Management Coordinator for that area and associated vegetation management personnel are responsible for identifying trees or branches damaged by the storm and immediately mitigating any such damage. This process requires considerable subject matter expertise because these issues can be camouflaged when the leaves are still green, meaning that only the most obvious can be easily identified.

Q. WHAT IS THE COMPANY'S OUTAGE MANAGEMENT SYSTEM?

A. The OMS is a series of complex interfacing systems that collect and analyze multiple inputs to provide a source for discrete outage level data and ETRs. Outage level data and ETRs are then communicated to customers via several channels, including the online outage map, VRU, and outbound email and text messages.

Q. HOW DOES THE COMPANY COMMUNICATE INFORMATION TO ITS CUSTOMERS PRIOR TO, DURING AND AFTER A STORM?

A. The Company has a three-phased communication strategy for storm response that focuses on providing customers and the general public important information 1) before a storm, 2) during a storm, and 3) after a storm. In each phase, messaging focuses on what to expect, how to prepare, how to be safe and how to stay up to date on restoration efforts.

The Company uses a variety of communication channels to disseminate information. For mass communication (information intended for multiple audiences), we share information with media outlets (TV, newspaper, radio), revise advertising to reflect storm-related information, post social media content on Facebook and Twitter, as well as our website – which is also viewable via mobile devices. For direct-to-customer communications, we use email, text messaging, outbound calls with recorded messages and, in some cases, live voice calls.

Before a storm, the Company issues news releases, posts social media information related to storm and safety tips, issues public service-like advertisements, sends customers emails focused on preparedness, and proactively pitches stories to the media (and subsequently conducts interviews) focused on our preparedness efforts and to encourage customers to be prepared. To address the needs of customers with medical or other special needs, we conduct outbound call campaigns to ensure these customers are aware of pending severe weather and to prepare for potentially extended outages. We also launch a dedicated webpage focused on the specific storm event where the public can find news releases, safety tips, videos, restoration information and links to other valuable resources, such as the Red Cross or state Emergency Management sites. Banners on the Company's main website direct customers to the storm and safety information and eventually to the new webpage once its launched.

All pre-storm communications include storm and safety tips and instructions on how to report outages through numerous options. Our proactive outreach to the media often results in interviews and stories focused on storm preparedness.

During a storm, the Company develops daily messages to be used with media, customers, social customer care and field personnel. The Company publishes daily updates via news releases and social media on various topics, including storm damage, estimated times of restoration, and out of town resources. We secure TV, print and radio advertising where we provide restoration updates. Customers participating in our proactive outage communications programs receive updates via email, phone and text on restoration progress and estimated times of restoration. Ongoing updates regarding the storm are also provided on the Company's dedicated storm page, which includes updated outage maps. Furthermore, during a storm event, updates are continuously provided to elected officials, community leaders and other stakeholders to ensure they have the information they need to share with their audiences and to plan accordingly.

After a storm, the Company prepares wrap-up messages to share with customers, community leaders and other stakeholders. News releases are published to provide final outage-related numbers, thank customers for their patience, and to thank local first responders and the companies that provided off-system resources. Messages of appreciation are also provided via email, social media posts and paid advertisements to customers, first responders, community agencies and other utilities who provided assistance. Location-specific messaging is also provided – generally in the field or other personal contact – to customers with unique situations that may delay a restoration, such as meter box damage, flooding or other issues that may prevent the safe restoration of electric service.

Q. PLEASE DESCRIBE THE COMPANY'S PROCESS FOR SEEKING MUTUAL AID FROM OUTSIDE SOURCES.

A. Once a storm system is identified that could impact DE Carolinas' service territory, mutual assistance calls are initiated for additional resources including native and non-native contractors and mutual assistance organizations. The mutual assistance calls are to discuss the availability of resources outside the projected impact area that may be able to aid our service territory as needed. Resources typically include: linemen, vegetation management, damage assessment, support, and logistics for both Distribution and Transmission restoration efforts. Depending on the projected event timing and intensity, the objective is to have some resources mobilized and pre-positioned ahead of the impact.

Q. HOW DOES THE COMPANY ON-BOARD CREWS AND WHAT STEPS DOES THE COMPANY TAKE TO ENSURE THEY ARE DEPLOYED EFFICIENTLY AND EFFECTIVELY?

A. The Company on-boards newly arriving crews at staging and logistics sites where actual roster complements are verified and arrival times documented. Crews go through a detailed overview of Company safety rules and protocols, as well as information on construction standards. Once on the system, crews are assigned to feeder coordinators. For DE Carolinas, the feeder coordinators are a key oversight resource responsible for managing the work of off-system restoration crews, including contractors. Each feeder coordinator assigns their crews daily work packages prepared in advance and monitors progress of restoration as the day progresses. They review time sheets daily, and provide feedback to the storm center about crew effectiveness. This information is used by Operations and Logistics during demobilization to sequence crew releases so that less productive crews are released first and high productivity, high value crews are released last.

IV. DESCRIPTION OF 2018 STORMS

Q. WHAT ARE THE THREE STORMS THAT MAKE UP DE CAROLINAS' REQUEST FOR STORM COST RECOVERY IN THIS PROCEEDING?

A. The three Storms included in DE Carolinas' request for storm cost recovery are Hurricanes Florence and Michael, and Winter Storm Diego.

Q. CAN YOU PLEASE DESCRIBE HURRICANE FLORENCE?

A. Just days before making landfall, Hurricane Florence approached the Carolinas' coast as a Category 4 hurricane with a projected inland path through the center of the Triangle, which splits the DE Carolinas and DE Progress service territories. In response, DE Carolinas and DE Progress mobilized an army of staff and crews of approximately 20,000 people, the largest in its history, to stage throughout the Carolinas to immediately deploy as soon it was safe to begin restoration efforts.

Actual landfall occurred near Wrightsville Beach early on September 14th at which time Hurricane Florence was a Category 1 storm. Maximum wind gusts associated with the storm exceeded 105 miles per hour and it created storm surges in the range of 9 to 13 feet. Because of a high-pressure ridge over the eastern United States, Florence made extremely slow progress once it made landfall, moving at only 2-3 miles per hour. This caused the storm to linger over eastern North Carolina for most of the next three days during which it dropped substantial amounts of rainfall – more than 35 inches in some locations.

The catastrophic flooding that followed Florence was of historic proportions and resulted in the City of Wilmington being completely cut off from the rest of the State by floodwaters. It also resulted in the major highways in eastern North Carolina – to include Interstates 40 and 95 and US Route 70 – being impassable in multiple locations for several days.

Florence caused 54 deaths, resulted in more than $24 billion in property damage in the Carolinas alone and downed thousands of trees. The flooding and wind damage also resulted in electrical outages across virtually the entire eastern half of North Carolina directly impacting DE Carolinas' (and DE Progress') service territory.

Hurricane Florence caused significant damage to DE Carolinas' electric system in North Carolina and South Carolina. The total number of DE Carolinas' customers impacted during the storm was 387,791 (330,785 in North Carolina and 57,006 in South Carolina). The peak number of customer outages for DE Carolinas in the Carolinas was approximately 76,606, which occurred Sunday, September 16, 2018, at 11:14 AM. More than 90% of customers had been restored within 48 hours of the hurricane leaving North Carolina. By September

19, 2018, full restoration was accomplished for all customers able to receive service.

DE Carolinas experienced extraordinary damage to both its transmission and distribution systems because of Florence. Specifically, the DE Carolinas transmission system had 6 substations and 8 lines out of service. DE Carolinas distribution system suffered almost 6 miles of downed wire, approximately 320 downed poles, and 340 damaged transformers across the Carolinas' system. The Company arranged for additional off-system linemen and support men and women from Alabama, Arkansas, the District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Texas, Wisconsin and Canada to assist with the restoration efforts.

To support this response effort, DE Carolinas was required to provide housing and logistical operations support for more than 20,000 employees, allies, and contractors in forward deployed areas directly impacted by the hurricane. DE Carolinas housed thousands of these utility workers at staging areas in the forward operating zones utilizing trailers and other local housing resources. DE Carolinas was also required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane impacted areas.

In addition to line crews, vegetation management professionals, and damage assessors, and other support personnel worked around the clock in call centers and operations centers to answer customer outage calls, assess damage and dispatch crews. Other support personnel handled logistics, such as meals, housing and refueling for the crews - all of which were complicated by the massive flooding and road closures caused by the storm. The Company also provided pre-storm preparation and post-impact restoration updates to customers through traditional and social media as well as text messages and emails.

In initiating, managing, and implementing this response to Hurricane Florence, Duke mobilized DE Carolinas employees for "storm duty" by diverting them from their normal day-to-day responsibilities to support storm response and recovery. This reallocation of internal assets occurred at virtually every level of the Company and resulted in hundreds of Duke employees working on a 24/7 basis – many of them forward deployed – to assist in the monumental task of restoring services and systems following the storm.

Q. HOW LONG DID THE MOBILIZATION/RESPONSE TO HURRICANE FLORENCE GO ON?

A. We mobilized for the storm on September 10, 2018 and demobilized between September 15 and September 23, 2018. Several crews remained on-system to assist with sweeps and additional repairs.

Q. DID THE COMPANY UTILIZE AMI DURING RESTORATION?

A. Yes. DE Carolinas has the capability to interrogate individual smart meters to determine if customers have power. During the damage assessment phase of a storm, the mass meter interrogation capability allows the Company to have a better view of where outages are located on the system. This functionality helps reduce the assessment time, thus reducing outage durations for customers. During the power restoration phase of a storm, the capability of mass meter interrogation enables the Company to determine whether power has been restored to each meter before leaving an area. During the cleanup phase of a storm, the capability of interrogating individual meters can tell the Company when a customer's power has already been restored, saving a truck roll to confirm power has been restored.

During Hurricane Florence in September 2018, the Company successfully interrogated 1,663 meters and avoided the need to send trucks to determine whether power had been restored to those locations. During Hurricane Michael in October 2018, the Company successfully interrogated 3,881 meters. And, during Winter Storm Diego in December 2018, the company successfully interrogated 2,986 meters.

Q. IS THE COMPANY SATISFIED WITH ITS RESPONSE TO THIS STORM?

A. It is. As with all events of this nature, the mobilization and restoration of service for this storm taught us lessons that will serve us well in the future but, overall, we believe that the storm proved the value of our response planning and that efforts taken to repair facilities and restore service following Florence were extraordinary. We are very pleased with the effort and results achieved by all parties involved in that process, including our own employees, allies, and contractors.

Q. CAN YOU PLEASE DESCRIBE HURRICANE MICHAEL?

A. Hurricane Michael came ashore in the Florida Panhandle on October 10, 2018 as a Category 4 storm with winds as high as 155 miles per hour. The storm was quick-moving and reached the Carolinas as a tropical storm on October 11. The storm brought heavy winds and rain to the already saturated DE Carolinas service territory, resulting in flooding, widespread damage and outages. This occurred just weeks after Hurricane Florence. DE Carolinas and DE Progress mobilized more than 9,000 personnel from Company, contractor, and off-system mutual assistance crews to restore the grid.

The total number of DE Carolinas customers impacted during Hurricane Michael was 688,679 (638,554 in North Carolina and 50,125 in South Carolina). The peak number of customer outages for DE Carolinas in the Carolinas was approximately 383,764, which occurred Thursday, October 11, 2018, at 5:44 PM. More than 83% of DE Carolinas' customers had been restored within 72 hours. As of Tuesday, October 16, 2018, full restoration was accomplished for all customers able to receive service.

DE Carolinas experienced extraordinary damage to both its transmission and distribution systems because of Michael. Specifically, the DE Carolinas transmission system had 31 substations and 16 lines out of service. DE Carolinas distribution system suffered almost 16 miles of downed wire, approximately 950 downed poles, and 700 damaged transformers across the Carolinas' system. The Company arranged for additional off-system linemen and support men and women from Alabama, Delaware, Florida, Georgia, Illinois, Kansas, Kentucky, Louisiana, Maryland, Maine, Michigan, New York, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, and Texas to assist with the restoration efforts.

To support this response effort, DE Carolinas was required to provide housing and logistical operations support for more than 9,000 employees, allies, and contractors in forward deployed areas directly impacted by the hurricane. DE

Carolinas housed thousands of these utility workers at staging areas in the forward operating zones. DE Carolinas was also required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane impacted areas. In addition to line crews, vegetation management professionals, and damage assessors, and other support personnel worked in call centers and operations centers to answer customer outage calls, assess damage and dispatch crews. Other support personnel handled logistics, such as meals, housing and refueling for the crews. The Company also provided pre-storm preparation and post-impact restoration updates to customers through traditional and social media as well as text messages and emails.

Q. HOW LONG DID THE MOBILIZATION/RESPONSE TO HURRICANE MICHAEL GO ON?

A. We mobilized for the storm on October 11, 2018 and demobilized between October 14 and October 20, 2018. Several crews remained on-system to assist with sweeps and additional repairs.

Q. IS THE COMPANY SATISFIED WITH ITS RESPONSE TO THIS STORM?

A. Yes. It is.

Q. CAN YOU PLEASE DESCRIBE HURRICANE WINTER STORM DIEGO?

A. Beginning on December 9, 2018, Winter Storm Diego blew into DE Carolinas' North Carolina and South Carolina service territories and dumped a mix of more than a foot of snow, ice and freezing rain in many locations through December 10, 2018. Winter Storm Diego caused widespread damage and outages and was the most significant early December storm since 2002's ice storm. The storm resulted in near record snowfalls in multiple locations throughout the State – Mt. Mitchell had a snowfall of 34 inches from the storm. DE Carolinas and DE Progress again mobilized more than 9,000 personnel from Company, contractor, and off-system mutual assistance crews to restore the grid. The total number of DE Carolinas customers impacted during Winter Storm Diego was 512,891 (358,140 in North Carolina and 154,751 in South Carolina). The peak number of customer outages for DE Carolinas in the Carolinas was approximately 234,891 which occurred Sunday, December 9, 2018, at 1:59 pm. More than 95% of DE Carolinas' customers had been restored by the end of the day Tuesday, December 11, 2018.

DE Carolinas experienced extraordinary damage to its distribution system because of Winter Storm Diego. Specifically, the DE Carolinas transmission system had 26 substations and 20 lines out of service. DE Carolinas distribution system suffered almost 7 miles of downed wire, approximately 390 downed poles, and 430 damaged transformers across the Carolinas' system. The Company arranged for additional off-system linemen and support men and women from Alabama, Delaware, Florida, Georgia, Illinois, Kansas, Kentucky, Missouri, Mississippi, Ohio, South Carolina, Tennessee, and Virginia to assist with the restoration efforts.

To support this response effort, DE Carolinas was required to provide housing and logistical operations support for more than 9,000 employees, allies, and contractors in forward deployed areas directly impacted by the hurricane. DE Carolinas housed thousands of these utility workers at staging areas in the operating zones. DE Carolinas was also required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane impacted areas.

In addition to line crews, many vegetation management professionals, damage assessors, and other support personnel worked in call centers and operations centers to answer customer outage calls, assess damage and dispatch crews. Other support personnel handled logistics, such as meals, housing and refueling for the crews. The Company also provided pre-storm preparation and post-impact restoration updates to customers through traditional and social media as well as text messages and emails.

Q. HOW LONG DID THE MOBILIZATION/RESPONSE TO HURRICANE MICHAEL GO ON?

A. We mobilized for the storm on December 6, 2018 and demobilized between December 11 and December 13, 2018.

Q. IS THE COMPANY SATISFIED WITH ITS RESPONSE TO THIS STORM?

A. Yes. It is.

V. <u>DE CAROLINAS'S RESPONSE TO FLORENCE, MICHAEL, AND DIEGO.</u>

Q. DID DE CAROLINAS FOLLOW ITS DISTRIBUTION STORM PLAN DISCUSSED ABOVE, INCLUDING CUSTOMER COMMUNICATIONS AND REQUESTS FOR MUTUAL AID, IN RESPONDING TO THE STORMS?

A. Yes. Each of these Storms was sufficiently threatening to cause us to implement our distribution storm response plan and we did so in each instance.

Q. HOW DID YOU IMPLEMENT THE PLAN YOU DESCRIBE ABOVE?

A. Notwithstanding significant infrastructure damage resulting from these Storms, we implemented our distribution storm plan as described. We strongly adhered to plan processes and methods including storm planning and management, resource mobilization and de-mobilization, materials and supply chain, damage assessment, and work prioritization and work package development. Regular updates on ETRs were provided to customers and were effective.

Q. HOW DO YOU MEASURE THE EFFECTIVENESS OF YOUR STORM PLANNING AND RESTORATION PROCESS?

A. To measure restoration effectiveness, one of the main measures that we use is the cumulative percentage of customers restored versus our projection of where we should be at the end of each day. Moving backward from our final ETR goals, we set milestones that must be achieved each day to achieve our overall goal. We generate these milestones down to the operations center level based on the amount of storm damage on our system, the level of resources that we have at our disposal, and our own restoration history. This analysis tells us whether we are being as effective as we need to be and, if not, helps to highlight or correct any issues that may be impacting our performance.

Effective planning comes down to ensuring we have the processes in place to provide maximum flexibility. Due to the nature of these storms, we will never be able to precisely predict the location and timing of storms, nor the extent of damage they will create. It is more important that our planning process ensures we have the flexibly to adapt to inevitable changes in the location, timing, and intensity of storms as they arise. In our judgment, our planning process did in fact provide us with the needed flexibility to cope effectively.

Another critically important measure of effectiveness is safety; in the three storms of 2018, we recorded a total of six injuries for our Duke Energy personnel (two in each storm) across all the Carolinas (DE Carolinas and DE Progress) and had zero electrical contacts. This is a significant accomplishment considering the vast number of people working during these restoration efforts. DE Carolinas is proud of the fact that all its workers, and the workers from outside the state, returned home safely to their families after the events.

Q. WHEN DID THE COMPANY REQUEST MUTUAL ASSISTANCE FOR THESE STORMS?

A. The Company initiated communications regarding mutual aid as outlined in the table below.

Storm	**Mutual Assistance Calls Began**	**Request for**
Florence	Monday, 9/10/18	Distribution Line & Veg- Mutual Assistance Organization
Michael	Thursday, 10/11/18	Distribution Line - Mutual Assistance Organization
Diego	Thursday, 12/6/18	Distribution Line - Mutual Assistance Organization

Q. WHEN DID THE COMPANY'S MUTUAL AID COSTS FOR THESE STORMS BEGIN TO ACCRUE?

A. As is industry standard, mutual aid costs begin to accrue when the responding entities begin taking actions towards providing mutual aid in response to a request (including, for example, preparing employees and equipment for travel). Specific dates vary depending on travel times and destinations.

Q. HOW DID THE COMPANY DETERMINE WHEN MUTUAL AID WAS NO LONGER NEEDED TO ASSIST IN RESTORATION EFFORTS?

A. Mutual aid resources are accepted throughout the duration of each storm and are deemed to be no longer needed when they can no longer contribute to achievement or acceleration of restoration times at a reasonable cost.

Q. IN ADDITION TO ITS INTERNAL CUSTOMER COMMUNICATION PROTOCOLS, DID THE COMPANY UTILIZE NON-DE CAROLINAS' LABOR TO ADDRESS CUSTOMER CONTACTS DURING THE MAJOR STORMS?

A. Yes. The Company deployed an additional 311 persons during Hurricane Florence, 304 additional persons during Hurricane Michael and 356 additional persons during Winter Storm Diego to address customer contacts.

Q. HOW MANY CUSTOMER CALLS DID THE COMPANY RECEIVE DURING THE STORMS?

A. The Company received the following:

Storm	**Outage**	**Regular Business**	**Total**
Florence	37,356	51,960	89,316
Michael	70,505	42,224	112,729
Diego	53,784	51,858	105,642

Q. DID THE COMPANY ISSUE PUBLIC ANNOUNCEMENTS REGARDING THESE STORMS?

A. Yes. To ensure the public was aware of the potential impact of these storms to the electric grid and their services, our preparedness to restore service quickly and safely, and our restoration progress throughout the events, we issued 29 news releases (English and Spanish) and conducted nearly 900 media interviews. In addition, we published 129 social media posts (Facebook and Twitter), which covered several topics including safety, storm damage, crews/resources, updated outage and restoration numbers and estimated times of restoration. All the information was aggregated and displayed on a dedicated storm page – www.dukeenergyupdates – on the Company's website. Additionally, we used direct-to-customer communication channels, including email, texting and outbound calls – to reach customers for whom we had email addresses on file; customers who had previously registered for Proactive Outage Notifications; and customers who participated in our "medical alert / special needs" programs. Also for these storms, we completed outbound call messages to nursing homes / assisted living facilities to encourage preparedness and to provide estimated times of restoration.

After each storm, we conduct an internal assessment of our communication efforts and incorporate improvement opportunities to better our performance in future storms. One such example occurred in the aftermath of Hurricane Florence when we implemented an "ETA for ETR" communication strategy. Since Hurricane Florence moved ashore and stalled, estimated times of restoration were delayed for many parts of the service area because crews were unable to access damaged areas. Instead of waiting until we had new information (which could have been days given the amount of flooding in some areas), we began communicating daily with customers a time for when they could expect to receive more information.

Q. DID THE COMPANY UTILIZE CONTRACT LABOR TO HELP RESTORE POWER IN RESPONSE TO THE STORMS?

A. Yes. DE Carolinas utilized the following contractors in responding to Florence, Michael and Diego:

Storm	Line Contractors	Veg Contractors	Damage Assessors
Florence	8,602	2,782	1,649
Michael	4,511	1,899	473
Diego	2,948	1,400	700

Q. WHEN WAS THE COMPANY FULLY-RESTORED FROM THE STORMS?

A. Restoration is considered complete when all customers able to receive power have been restored. DE Carolinas restored the following:

Storm	# customers impacted in NC	Days of Restoration	Full Restoration Date
Florence	330,785	6	9/19/18
Michael	638,554	6	10/16/18
Diego	358,140	3	12/11/18

Q. HOW WAS VEHICLE FUEL PROCURED FOR COMPANY PERSONNEL AND MUTUAL AID PARTNERS IN PREPARATION FOR THESE STORMS?

A. DE Carolinas has arrangements with several national vendors to provide fuel and fueling equipment. One week prior to potential landfall, the Company makes notification to vendors of projected need. If necessary, fuel vendors are staged in a safe location close to base camps. Once travel conditions are safe, they set up at the base camps across the impacted areas and provide the majority of fuel needed by Duke employees, contractors and mutual assistance resources.

V. COSTS OF RESPONDING TO FLORENCE, MICHAEL, AND DIEGO.

Q. PLEASE IDENTIFY WHAT INCREMENTAL COSTS THE COMPANY INCURRED DUE TO HURRICANE FLORENCE.

A. As reflected on Exhibit RSJ-2 page 1, the incremental O&M storm-related costs incurred by the Company due to Hurricane Florence totaled approximately $90.0 million for the DEC system. Total capital costs for Florence were approximately $5.4 million.

Q. PLEASE IDENTIFY WHAT INCREMENTAL COSTS THE COMPANY INCURRED DUE TO HURRICANE MICHAEL.

A. As reflected on Exhibit RSJ-2 page 2, the incremental O&M storm-related costs incurred by the Company due to Hurricane Michael totaled approximately $79.6 million for the DEC system. Total capital costs for Michael were approximately $11.5 million.

Q. PLEASE IDENTIFY THE INCREMENTAL COSTS THE COMPANY INCURRED DUE TO WINTER STORM DIEGO.

A. As reflected on Exhibit RSJ-2 page 3, the incremental O&M storm-related costs incurred by the Company due to Winter Storm Diego totaled approximately $54.7 million for the DEC System. Total capital costs for Diego were $6.8 million.

Q. WERE THESE EXPENSES REASONABLE AND NECESSARY TO RESTORE SERVICE TO CUSTOMERS AND TO PROVIDE FOR THE SAFETY, STABILITY, AND CONTINUITY OF DE CAROLINAS' SYSTEM?

A. Yes. Each of the named Storms caused extensive damage and widespread outages to DE Carolinas' distribution system and required a robust response from the Company. This response involved the activation and deployment of storm response assets internal to the Company, utilization of outside contractors, and the need to seek mutual aid from other electric utilities and allies in the industry.

Q. PLEASE EXPLAIN HOW STORM-RELATED COSTS WERE TRACKED AND ACCOUNTED FOR DURING AND AFTER EACH STORM, AND EXPLAIN THE PROCESS THE COMPANY USES TO VERIFY THAT COSTS ASSIGNED TO THE STORMS WERE IN FACT RELATED TO THE STORMS AND WERE INCREMENTAL.

A. When a potential major storm event is approaching the DE Carolinas service territory, the Company creates separate project codes (e.g., distribution, transmission, etc.) to be used by employees for processing and aggregating the total amount of storm restoration costs incurred for financial reporting and regulatory recovery purposes. The Company uses these project codes to account for all costs directly associated with restoration, including incremental and non-incremental costs. All storm restoration costs charged to these storm projects were initially captured in FERC Account 593, normal operations and maintenance ("O&M") expense, capital, or below the line expense.

Q. PLEASE FURTHER EXPLAIN THE PROCESS FOR ACCUMULATING ACCOUNTING DATA RELATED TO STORM COSTS.

A. Major storm costs are initially accumulated in these storm project codes, including charges that are considered non-incremental or capital. There are separate storm projects for each function (transmission, distribution, customer operations, fossil/hydro generation) charged during storm restoration. Capital costs are also identified and subsequently credited from O&M FERC Accounts 593 and debited to FERC Account 107, Construction Work in Progress. In discussing the nature of the costs incurred for these major storms, it is essential to have a clear understanding of what constitutes incremental and non-incremental costs. The Company defines incremental costs as all costs incurred to respond to the storms from resources external to DE Carolinas and all costs incurred within DE Carolinas, except for internal base company labor and base fleet costs. All other costs are considered non-incremental.

As outlined in Exhibit RSJ-2, the storm damage costs incurred by the Company because of Florence, Michael and Diego fall into the following categories:

1. Company Labor – amounts represent regular and overtime payroll for employee time spent in direct support of storm restoration. During the storms, payroll costs were incurred related to DE Carolinas employees as well as

Duke Energy affiliate employees from outside of North Carolina assisting in the storm response. All regular payroll amounts associated with DE Carolinas employees and all bonuses have been removed from our recovery request as either non-incremental or capitalized. All amounts related to Duke Energy affiliates, such as linemen from Duke Energy affiliates in Florida, the Carolinas and Midwest that were used in lieu of third-party contractors, are included for recovery in this filing, or were part of the capitalized amounts for the units of property replaced.

2. All overtime paid to employees of Duke Energy affiliates was incremental to DE Carolinas and thus is included for recovery in this filing, similar to contractor costs. The majority of overtime for DE Carolinas employees incurred due to storm restoration-related activities was also deemed incremental and thus included for recovery in this filing.
3. Contractor Labor costs – includes actual incurred costs associated with mutual aid utilities, line contractors, staging and logistics personnel and other outside contractors used in storm-restoration related activities.
4. Vegetation Management Labor costs – includes actual incurred costs associated with all vegetation contractors, both native and off-system, used in storm restoration related activities.
5. Materials and Supplies – includes the materials and supplies used to repair and restore service and facilities to pre-storm condition, and excludes the portion of materials and supplies used in restoration activities that are included in capitalized cost.

6. Internal fleet costs – the costs included in the net recoverable request include only the fuel component in this filing.
7. Other expenses – include other minor amounts of storm-related expenses not coded to one of the categories above.

For each of the Storms, the cost category amounts are outlined in Jackson Exhibits 1 through 3.

Q. PLEASE EXPLAIN THE AMOUNTS CAPITALIZED TO PROPERTY, PLANT AND EQUIPMENT BY THE COMPANY.

A. The Company has a process to ensure all units of property installed during storm restoration are capitalized at reasonable material and labor amounts (i.e., resulting in capital amounts at the normal cost for the removal, retirement and replacement of those facilities). During major storm events, only the Company's Distribution Operations and Transmission Operations installed capital units of property.

For Transmission Operations, given the much smaller number of individual repair and replace events, specific projects were issued for capital versus O&M work, allowing real-time tracking of those capital projects. As capital work was performed, those associated material and equipment costs were charged to capital projects.

For Distribution Operations, the nature of repair work is so voluminous and time of the essence that the issuance of individual projects for capital versus O&M work is not feasible. However, the Company's tracking of materials allows it to do an accounting of all units of property used during storm restoration, resulting in the proper capitalization of those units of property. This is accomplished by having DE Carolinas' Supply Chain organization issue the materials directly to the storm project as they ship them from the distribution center to the various base camps and having Supply Chain personnel at the operating centers issue materials used during the storm to the storm project. Once the restoration effort has been completed all materials from the base camps are picked up and brought back to the distribution center where it is placed in a specific area for return processing. All the returned materials are segregated and tagged so they can be identified as materials initially charged to the storm restoration. The material is returned to the same accounting that was used during the restoration effort, properly resulting in only the actual units installed during storm restoration being capitalized.

Once the number of units of property were confirmed, the Company's Finance organization determined a normal, reasonable total dollar amount to capitalize for those units of property.

- Material Quantities: the number of units of property ("UOP") were identified and grouped (i.e. poles, transformers, wire, etc.). The quantities for UOP replaced during the storm become the basis of the calculation to determine the estimated total capital amount.
- Baseline UOP Replacement Cost: Twelve months of historical data received from the Company's Asset Accounting group was used to determine a baseline total capitalized cost of each UOP category. Finance calculated the total cost and the total number of each UOP installed during the twelve-month period. Finance divided the total cost into labor, fleet, indirect, material, and

all other costs. Once the categories were determined, a unit cost was determined for each category under normal, non-storm, conditions.

- Labor Hours Adder: For each grouping of UOP, DE Carolinas' Operations group estimated the average number of hours and the number of line resources needed to install that type of UOP under normal conditions. The average number of hours multiplied by the number of resources generated the total hours to install that UOP. The DE Carolinas Operations group then estimated the average number of hours and the number of line resources needed under storm conditions to install that type of UOP to determine the total hours for storm conditions. The total hours under storm conditions was then divided by the total hours under normal conditions to develop a gross-up factor for storm conditions.
- Labor Rate Adder: A calculation is performed to compare the blended rate for DE Carolinas and contractor line resources during normal operating conditions to a blended rate during storm conditions, which includes the impact of off-system contractor and Duke affiliate labor. The calculation results in a labor rate adder that is applied to the baseline UOP cost.
- Staging and Logistics Adder: During major storm restoration, DE Carolinas incurs incremental costs for staging sites, hotels, and meals to support resources needed for restoration. These are costs that would not be incurred under normal conditions but are necessary costs associated with replacement of UOP's following a storm. As such, a portion of these costs are included in the amount to capitalize. The total Staging and Logistics cost is multiplied by

the ratio of capitalized labor to the total labor to determine the portion of Staging and Logistics costs that should be capitalized.

- Amount to Capitalize: The baseline unit cost for labor for each UOP is escalated by the Hours Adder and by the Labor Rate Adder to determine the escalated unit cost for labor. The Staging and Logistics Adder is allocated to each UOP to create a staging and logistics unit cost. The escalated unit cost for labor and the staging and logistics unit cost are added to the baseline unit costs for material, fleet, indirect, and other costs to determine a total escalated unit cost for each UOP. This escalated unit cost per UOP is then multiplied by the associated UOP quantity to determine the amount to capitalize.

For each major storm, the amount of storm costs capitalized are outlined on Exhibit RSJ-2.

Q. IN ADDITIONAL TO TRANSMISSION AND DISTRIBUTION OPERATIONS, PLEASE DESCRIBE THE OTHER FUNCTIONAL AREAS THAT INCURRED COSTS RELATED TO THE STORMS.

A. In addition to the Company's Distribution Operations and Transmission Operations areas, the Company's generation plants (Fossil/Hydro Operations, or "FHO") were damaged during several of the aforementioned storms. And, as further described below, the Company's Customer Operations organization incurred significant costs directly related to the storms.

For Customer Operations, incremental costs include the same categories of costs as noted above (overtime costs, contractor costs, payroll of Duke Energy affiliate employees, employee travel expenses, etc.). The Company followed a similar process as that described above to ensure only incremental Customer Operations costs are being requested for recovery in this filing.

VIII. CONCLUSION

Q. DO YOU HAVE AN ASSESSMENT OF THE COMPANY'S IMPLEMENTATION OF ITS STORM PLAN DURING 2018?

A. Yes. The Company's restoration efforts were reasonable and prudent and resulted in the restoration of service to the vast majority of customers as quickly and safely as reasonably possible, and the Company's restoration costs were prudently incurred. I believe the strength of a storm plan is its flexibility to adapt to unexpected conditions. The Company faced a significant challenge because of the Storms and the storm plan proved to be an effective and efficient tool to achieve our goal of restoring customer service as safely and expeditiously as possible. The storm plan proved to be invaluable to us in preparing for and responding to these Storms.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Teresa Reed and my business address is 411 Fayetteville Street, Raleigh, North Carolina 27601.

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

A. I am a Pricing and Solutions Director for Duke Energy Business Services, LLC ("DEBS"). DEBS is a service company subsidiary to Duke Energy Corporate ("Duke Energy") that provides services to Duke Energy and its subsidiaries, including Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and its affiliated utility operating companies.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor degree in Government with a minor in Business Administration from California State University, Sacramento in 1993. I received a Master of Business Administration degree from the University of North Carolina, Chapel Hill in 2003. I also received a Juris Doctor degree from North Carolina Central University in 2010. I am a certified public accountant in North Carolina since 2005 and a licensed attorney in North Carolina since 2011.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I began working in the electric utility industry in 2008 as a senior financial auditor with Progress Energy. One of my first roles was auditing the company's financial records as well as performing various operational audits. In 2012, I became a senior compliance analyst in the Ethics and Compliance department of Duke Energy. I was responsible for implementing Duke Energy's FERC Compliance Program post-merger with Progress Energy and Duke Energy's Dodd-Frank Compliance Program. In 2014, I began as a Senior Strategy and Collaboration Manager. My primary responsibility has been to provide strategic regulatory support to outdoor lighting to help the Company modernize its offerings for DE Carolinas and its affiliate utility operating companies. In 2020, I became a Pricing and Solutions Director responsible for rate administration, rate design, and pricing primarily for Duke Energy Progress, LLC.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No. I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe DE Carolinas' outdoor lighting business to the extent that it impacts proposed rates. My testimony expands upon Witness Michael J. Pirro's testimony regarding the rate design for the Company's outdoor lighting products and services.

Q. PLEASE DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. The exhibits to my testimony are as follows:

- Reed Direct Exhibit 1 summarizes transition fees under existing and proposed rates for mercury vapor ("MV"), metal halide ("MH"), and high pressure sodium ("HPS") fixtures.
- Reed Direct Exhibit 2 summarizes the net book value analysis as of December 31, 2018 for MV, MH, and HPS fixtures, which serves as the basis for the newly proposed transition fees.

Q. WERE REED DIRECT EXHIBITS 1 AND 2 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S OUTDOOR LIGHTING EFFORTS.

A. Over the past seven years, the outdoor lighting industry has experienced tremendous change resulting from the advancement of light emitting diode ("LED") technology. Generally, LED outdoor lighting products are preferred by customers because they offer significantly reduced energy use; exhibit longer lifetimes; do not contain mercury; and provide a high color quality which provides better illumination. Thus, the industry is moving away from high intensity discharge ("HID") outdoor lighting products such as MV, HPS, and MH, and moving towards LED technology.[1] From 2010 to 2016, for instance, LED street and roadway installations have grown exponentially from

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[1] U.S. Department of Energy, Energy Efficiency & Renewable Energy, *Adoption of Light-Emitting Diodes in Common Lighting Applications*, July 2015, Page 32 (http://energy.gov/sites/prod/files/2015/07/f24/led-adoption-report_2015.pdf).

approximately .3 percent to 28.3 percent of the estimated 12.5 million street and roadway lights installed in the United States.[2]

In 2013, DE Carolinas began to formulate its Outdoor Lighting Modernization Plan (the "Plan"). The purpose of the Plan was to begin to adopt LED technology to offer newer, more efficient outdoor lighting systems to customers. In 2014, the Company began offering LED outdoor lights as a standard offering, which was approved by the Commission in Docket No. E-7, Sub 1026. In this same docket, the Company also received Commission approval to replace MV units upon failure for public (governmental) and private outdoor lighting customers. Over the past few years, the Company has worked to address concerns regarding the net book value of the HPS and MH fixtures.[3] The Company has also received Commission approval to proactively replace failed standard MV lights with LEDs for public and private outdoor lighting customers.[4]

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony recommends the following:

- The Company re-evaluated the outdoor lighting transition fees charged to customers who move from MH and HPS to LED. The Company proposes

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[2] U.S. Department of Energy, Energy Efficiency & Renewable Energy, *Adoption of Light-Emitting Diodes in Common Lighting Applications*, July 2017, Page 51 (https://www.energy.gov/sites/prod/files/2017/08/f35/led-adoption-jul2017_0.pdf).

[3] NCUC Docket Nos. E-7, Sub 1026, E-7, Sub 1094, E-7, Sub 1114, and E-7, Sub 1146.

[4] Order Approving Requested Revisions to Light Rate Schedule, June 20, 2016, NCUC Docket No. E-7, Sub 1114, Page 3. Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, June 22, 2018, NCUC Docket No. E-7, Sub 1146, Pages 97 - 99.

to lower the transition fees to balance take-rates while protecting the rate class from pre-mature retirement of assets.

- The Company proposes to proactively replace non-standard and/or decorative MV fixtures with decorative LED fixtures on Schedule OL (private lighting customers). While the Commission approved proactive replacement of standard MV fixtures in Docket Nos. E-7, Sub 1114 and E-7, Sub 1146, at the time of those approvals, affordable decorative LED options were not widely available. Now, there are more decorative LED options available for customers to choose from. The Company proposes to begin proactive replacement in 2020, if approved, and complete proactive replacement by the end of 2023. The Company will work with each customer individually to identify decorative LED options.
- The Company proposes to remove the "Inside Municipal Limits" and "Outside Municipal Limits" rate categories in Section A on Schedule PL and rename the rate category as "Existing Pole" to simplify the rates.
- The Company is requesting to add a new 530 Watt LED fixture as a replacement for the 750 Watt MH cube fixture.

II. OUTDOOR LIGHTING TRANSITION FEES

Q. EXPLAIN THE PURPOSE OF THE TRANSITION FEES ON THE COMPANY'S OUTDOOR LIGHTING TARIFFS.

A. In 2014 and 2015, the Commission approved recovery of a transition fee for DE Carolinas' customers who voluntarily chose to upgrade standard, decorative, and/or floodlight outdoor lighting fixtures from MH or HPS to LED.[5] The purpose of the transition fee was to recover the remaining book value of the MH and HPS lights being replaced to avoid adverse impacts on lighting rate base. If customers transition from MH or HPS technology to LED technology too rapidly, there would be a stranded net book value ("NBV") amount that all customers in the rate class would eventually absorb. As of December 31, 2018, the Company has a net book value of approximately $252 million for approximately 101,000 HID outdoor lighting fixtures. Reed Direct Exhibit 2 summarizes the net book value of HID outdoor lighting fixtures in North Carolina as of December 31, 2018.

Q. WERE THE TRANSITION FEES UPDATED DURING THE LAST RATE CASE PROCEEDING?

A. Yes. In Docket No. E-7, Sub 1146, the Company requested Commission approval to update and lower transition fees, as well as add a new LED to LED transition fee. In the Amended Partial Settlement Agreement with the North Carolina League of Municipalities, City of Concord, City of Kings Mountain and City of Durham, the Company agreed to:

- Lower transition fees as proposed;
- Add the new LED to LED transition fee as proposed;
- Eliminate the transition fee for HPS fixtures that completely fail;

[5] Order Approving Revised Lighting Tariffs, October 10, 2014, NCUC Docket No. E-7, Sub 1026, Page 5. Order Approving Requested Revisions to Lighting Rate Schedules, October 13, 2015, NCUC Docket No. E-7, Sub 1094, Page 2.

- Extend payment terms for transition fees up to four years, with no carrying costs; and
- Re-evaluate transition fees every two years in between rate cases and lower fees as applicable, but never petition to increase transition fees outside of a rate case proceeding.[6]

Q. DID THE COMMISSION APPROVE THE AMENDED PARTIAL SETTLEMENT AGREEMENT REFERENCED IN THE ANSWER ABOVE?

A. Yes. The Commission approved the amended partial settlement agreement in Docket No. E-7, Sub 1146.[7]

Q. HAS THE NET BOOK VALUE FOR HID FIXTURES DECLINED SINCE THE LAST RATE PROCEEDING?

A. Yes. As of December 31, 2016, the net book value for HID fixtures was approximately $267 million. As of December 31, 2018, the net book value for HID fixtures was approximately $252 million, a decline of approximately $15 million (or six percent).

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[6] Duke Energy Carolinas, LLC Amended Partial Settlement Agreement with the North Carolina League of Municipalities, City of Concord, City of Kings Mountain and City of Durham, Mar. 2, 2018, Docket No. E-7, Sub 1146, Pages 3 and 4.

[7] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, June 22, 2018, NCUC Docket No. E-7, Sub 1146, Pages 97 - 99.

Q. WHY HAS THE NET BOOK VALUE FOR HID FIXTURES DECLINED SINCE THE LAST RATE PROCEEDING?

A. Most of the decline is attributable to the annual depreciation rates for Federal Energy Regulatory Commission ("FERC") Chart of Accounts 371 and 373 (2.04 percent and 2.32 percent, respectively).

Q. HAS THE COMPANY COLLECTED TRANSITION FEES DURING THE TEST YEAR?

A. Yes. The Company collected transition fees of approximately $17,000 for FERC Account 371 and approximately $776,000 for FERC Account 373.

Q. PLEASE EXPLAIN WHY THE COMPANY IS NOW REQUESTING TO UPDATE THE TRANSITION FEES ON SCHEDULES PL AND OL AGAIN IN THIS RATE CASE.

A. DE Carolinas uses a NBV analysis tool to recommend an appropriate transition fee. Based on the remaining book value of the HID fixtures and the take-rates, the Company recommends lowering the transition fees.

Q. HOW DO THE REVISED ASSUMPTIONS IMPACT THE PROPOSED TRANSITION FEES?

A. Reed Direct Exhibit 1 outlines the current and proposed transition fees on Schedules PL and OL. DE Carolinas proposes to reduce the fee to transition from a standard MH or HPS fixture to an LED fixture from $40 to $36 on Schedule PL, and from $57 to $50 on Schedule OL. The Company proposes to reduce the fee to transition from a standard MH floodlight or HPS floodlight fixture to an LED and/or LED floodlight fixtures from $112 to $101 on

Schedules PL and OL. Reed Direct Exhibit 2 summarizes the net book value analysis which was used to develop transition fee rates.

Q. HOW IS THE TRANSITION FEE FOR NON-STANDARD AND DECORATIVE FIXTURES DETERMINED?

A. Due to the price variability of non-standard and/or decorative MH and HPS fixtures, DE Carolinas proposes to continue to calculate a loss due to early retirement fee ("LDER") on a per luminaire basis as approved in Docket No. E-7, Sub 1094.[8]

Q. IS THERE A TRANSITION FEE TO CONVERT FROM MV TO LED?

A. No. Industry data suggests that MV has reached obsolescence and the Company believes that since no new MV fixtures have been installed since January 2008 that early retirement will have a manageable impact on the lighting class net book value.

III. <u>MERCURY VAPOR NON-STANDARD AND/OR DECORATIVE FIXTURE REPLACEMENT</u>

Q. WHAT IS THE CURRENT STATUS OF THE COMPANY'S MV REPLACEMENT STRATEGY?

A. Currently, DE Carolinas has Commission approval to proactively upgrade standard MV fixtures to LED technology on Schedules OL and PL.[9] On Schedule OL, the MV conversion project is scheduled to be completed by December 31, 2019. The Company is currently working on the MV conversion

[8] Order Approving Requested Revisions to Lighting Rate Schedules, October 13, 2015, NCUC Docket No. E-7, Sub 1094, Page 2.

[9] Order Approving Requested Revisions to Light Rate Schedule, June 20, 2016, NCUC Docket No. E-7, Sub 1114, Page 3. Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, June 22, 2018, NCUC Docket No. E-7, Sub 1146, Pages 97 - 99.

schedule for Schedule PL, which is expected to begin in the first half of 2020. The MV conversion project for Schedule PL was expected to be completed by the end of 2023. However due to customer requested replacements and normal failure rates, the conversion project for Schedule PL may be completed prior to 2023.

Q. WHY IS THE COMPANY REQUESTING TO REPLACE NON-STANDARD AND/OR DECORATIVE MV FIXTURES?

A. The Energy Policy Act of 2005 prohibits the manufacture and importation of MV lamp ballasts after January 1, 2008.[10] Since 2008, no new fixtures can be sold with MV ballasts and no replacement ballasts can be purchased. This presents a challenge to replace or repair damaged MV fixtures. Essentially, due to technological advancements and/or the inability of the Company to source replacement fixtures and parts, MV outdoor lights have reached obsolescence.

Q. WHY DID THE COMPANY NOT REQUEST TO REPLACE NON-STANDARD AND/OR DECORATIVE MV FIXTURES DURING THE PREVIOUS RATE CASE PROCEEDING?

A. During the previous rate case proceeding, the Company stated that it would request approval from the Commission to replace non-standard and/or decorative MV fixtures when more LED replacement options were available.[11]

[10] Public Law 109-58 August 2005, 119 STAT. 632.
[11] Direct Testimony of James H. Cowling, Docket No. E-7, Sub 1146, Page 12 Lines 9 and 10.

Q. HOW MANY NON-STANDARD AND/OR DECORATIVE MV FIXTURES ARE REMAINING IN SERVICE?

A. As of December 31, 2018, there are approximately 3,200 non-standard and/or decorative fixtures remaining in service on Schedule OL.

Q. IF APPROVED, WHEN DOES DE CAROLINAS PLAN TO BEGIN PROACTIVE REPLACEMENT OF NON-STANDARD AND/OR DECORATIVE MV FIXTURES?

A. The Company is requesting to begin proactive replacement starting in 2020 and ending no later than 2023, which coincides with the timing of the proactive replacement of standard MV fixtures on Schedule PL, which was approved by the Commission in Docket No. E-7, Sub 1146.[12] The Company is seeking to replace all MV fixtures in DE Carolinas no later than the end of 2023. The replacement process may be completed prior to 2023 depending upon customer requested replacements and normal failure rates.

Q. IF APPROVED, WHAT IS THE PROPOSED CONVERSION PROCESS FOR CUSTOMERS?

A. If approved by the Commission, DE Carolinas will develop a conversion plan and will send a letter to the impacted customers explaining the reasons for the change and the conversion process. Prior to any conversion, the Company will seek input from customers on product selection due to the variety of decorative LED options available.

[12] Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, June 22, 2018, NCUC Docket No. E-7, Sub 1146, Pages 97 - 99.

Q. WHAT WILL BE THE AGGREGATE RATE IMPACT TO CUSTOMERS FOR UPGRADING NON-STANDARD AND/OR DECORATIVE FIXTURES?

A. Customers can choose from a wide selection of LED decorative fixtures as replacements for the currently installed MV fixtures. The rate impact will depend upon the LED fixtures selected by customers.

Q. WILL THE COMPANY CHARGE CUSTOMERS A FEE TO UPGRADE?

A. No. Customers will not be charged a fee and/or a transition charge to upgrade. Customers will be charged the new LED fixture rate on their bill following replacement of the MV fixture with an LED.

V. SCHEDULE PL MODIFICATIONS

Q. IN THIS RATE PROCEEDING, WHAT CHANGES ARE BEING PROPOSED WITH RESPECT TO SCHEDULE PL?

A. The Company is proposing to combine "Inside Municipal Limits Rates" and "Outside Municipal Limits Rates" in Section A on Schedule PL for HPS, MH, and MV fixtures. Further, the Company is requesting to label the new combined rate "Existing Pole." In addition, the Company is proposing to update the explanatory notes on Schedule PL to reflect this change.

Q. WHY DOES THE COMPANY WANT TO MAKE THIS CHANGE?

A. The "Inside Municipal Limits" and "Outside Municipal Limits" terminology developed in 1991 when Schedule PL was first created.[13] The rate differences

[13] NCUC Docket No. E-7, Sub 487.

were based on location of the light fixture, with the assumption that light fixtures outside municipal limits cost more for the Company to maintain. Over the years, municipal limits have expanded, and this distinction is no longer relevant to how the Company services light fixtures.

Q. IF APPROVED, WHAT IMPACT WILL THIS CHANGE HAVE TO CUSTOMERS ON SCHEDULE PL?

A. If approved, the Company believes this change will simplify billing. Customers on Schedule PL will pay essentially one rate for the same light fixture regardless of its location. Other fees may apply, as they currently do, for underground wiring, additional fixtures on poles, and excess poles. Witness Michael Pirro's direct testimony and exhibits display the rate impact to customers if approved.

Q. IF APPROVED, HOW MANY LIGHTS WOULD BE UPDATED RESULTING FROM THIS CHANGE ON SCHEDULE PL?

A. As of December 31, 2018, there are approximately 256,000 lights classified as "Inside Municipal Limits" and approximately 4,000 lights classified as "Outside Municipal Limits," all of which would be reclassified as "Existing Pole" if the Company's proposal is approved by the Commission.

VII. <u>ADDITION OF NEW LED 530 WATT FIXTURE</u>

Q. WHY IS THE COMPANY PROPOSING TO ADD A NEW LED 530 WATT FIXTURE TO SCHEDULES OL AND PL?

A. The Company is requesting to add a new LED 530 Watt fixture as a replacement for the 750 Watt MH cube fixture. Currently, replacement of a single 750 Watt MH cube fixture requires two 420 Watt LED fixtures. It is therefore more cost efficient for customers to replace a 750 Watt fixture with one 530 Watt fixture rather than two 420 Watt fixtures.

Q. IS THERE ANOTHER REASON WHY THE COMPANY IS REQUESTING TO ADD THE LED 530 WATT FIXTURE?

A. Yes. Duke Energy Progress, LLC, an affiliated utility, offers a LED 530 Watt fixture on its outdoor lighting tariffs in North Carolina. Customers who overlap jurisdictions prefer consistent light fixture options.

VIII. CONCLUSION

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

A. Yes.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Renee Metzler, and my business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services LLC ("DEBS"), as Managing Director – Total Rewards. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of Mary Washington with a Bachelor of Arts degree in Spanish Language and Literature. I also hold a Professional in Human Resources certification. I have over 30 years of human resources experience, primarily working with benefits and compensation programs. I joined Piedmont Natural Gas Company, Inc. ("Piedmont") in 2001 and have held various leadership positions in human resources. Most recently, I was the Managing Director – Total Rewards at Piedmont with responsibility for broad-based compensation, executive compensation, retirement benefits, health and welfare benefits, the human resources management system ("HRMS") and payroll. I have served in a leadership role on several projects, including the redesign of Piedmont's retirement (pension, 401(k) and retiree medical) program, the design and implementation of a consumer-driven health plan with a Health Savings Account, the implementation of the

Workday HRMS system, the design and implementation of Piedmont's wellness program, the redesign of Piedmont's long-term incentive plan and the integration of Piedmont employees into the Duke Energy compensation and benefits programs. I became an employee of DEBS in October 2016 when Piedmont was acquired by Duke Energy.

Q. PLEASE DESCRIBE YOUR DUTIES AS MANAGING DIRECTOR – TOTAL REWARDS.

A. I am responsible for all compensation, health and welfare and retirement benefits for Duke Energy, including all of Duke Energy's affiliated regulated and non-regulated companies, including DE Carolinas. Areas of responsibility include: management of key vendor relationships, compensation including executive compensation, benefit plan design and strategy, administration and compliance.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. No, I did not.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. Public Staff Witness Michelle Boswell recommends that certain compensation-related costs be disallowed, as follows:

Boswell Ex. 1 Line No.	Description	Dollar Impact
23	Adjust incentive compensation	$19,689,000
29	Adjust Board of Directors expense	$1,892,000
19	Adjust executive compensation	$174,000

In my rebuttal testimony, I demonstrate that Public Staff Witness Boswell's proposed adjustments are inappropriate and should be rejected by the Commission.

II. CUSTOMERS BENEFIT FROM MARKET-DRIVEN TOTAL COMPENSATION PROGRAMS

Q. WHAT IS THE COMPANY'S COMPENSATION PHILOSOPHY?

A. Duke Energy's overall compensation philosophy is to target total compensation of base pay and incentives, including both short- and long-term, at the median of the market when compared to peer companies, with the opportunity to earn more or less relative to the market median based on actual corporate performance. Therefore, it is not appropriate to consider the various components of total compensation in isolation, as does Witness Boswell. Doing so inappropriately ignores the Company's obligation to be responsive to the market for talent and assure the competitiveness of the total compensation package, consisting of base salary, cash based incentives, long-term incentive compensation, retirement and other benefits.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPENSATION PROGRAMS PROVIDED BY DUKE ENERGY.

A. Duke Energy's compensation programs consist of a base pay component and incentive pay components that together provide a market-competitive, total compensation package for all employees. The base pay component is a set amount, reviewed by management at least annually, and established at a level that: (1) provides compensation based on the nature and responsibilities of the employee's position; and (2) is fair relative to the pay for other similarly-situated positions in the organization. The short-term incentive ("STI") pay component is variable based on performance and is at risk to the employees. All employees have STI as a component of their total pay. Incentive pay is linked to the accomplishment of specific goals established in advance for the individual employee, his or her business unit, one or more of the Duke Energy companies and/or Duke Energy. The purpose of carving out a portion of employees' total compensation and delivering it through variable incentive pay is: (1) to encourage employees to accomplish specific objectives intended to ensure safe, reliable and economical utility service to our customers; (2) to ensure their business unit's and Duke Energy's overall success; and (3) to incorporate a component of any compensation package that is competitive based on the market. The long-term incentive ("LTI") plans round out a competitive total compensation package for certain employees in leadership positions. The purpose of carving out a portion of total compensation and delivering it through LTI programs is to reflect the market for human capital, which in turn is necessary to attract and retain high-caliber leaders needed to ensure safe, reliable and economical utility service to our customers. Simply put, competent management is beneficial to customers. The total compensation concept is depicted in Figures 1 and 2, below.

Figure 1

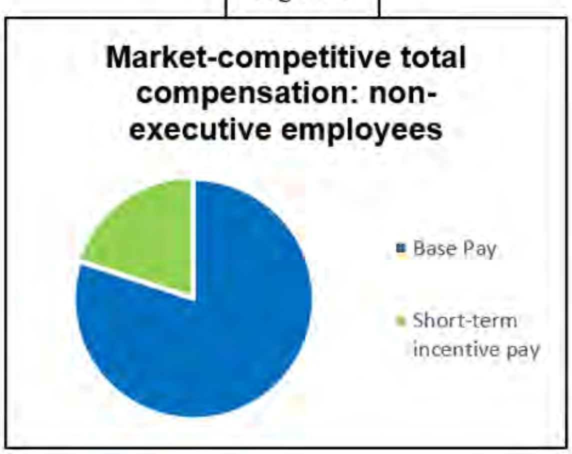


Figure 2

Q. DOES A COMPETITIVE TOTAL COMPENSATION PACKAGE FOR EMPLOYEES BENEFIT THE COMPANY'S RETAIL CUSTOMERS?

A. Yes. Our employees deliver critical services to our customers every day. The energy industry is a knowledge and experience-intensive industry where the tenure of employees matters. For example, we need to attract, develop and retain—over the long term—the engineering professionals that design, help build and operate our plants at a reasonable cost, just like we need to attract, develop and retain our power delivery professionals charged with maintaining and improving our infrastructure necessary to keep the lights on at a reasonable cost. The skills needed for employees to render safe, reliable and high-quality utility service take several years to develop. Line Technicians are highly skilled positions that require experience and knowledge that is acquired over several years. If we were to lose such employees, we would incur additional costs to train replacements for these positions, while experiencing additional risk with regard to reliability issues. Moreover, the industry is an aging industry. If we do not provide our talented employees competitive compensation that is consistent within and outside our industry, then other utilities and companies will hire our employees. Avoiding this circumstance becomes especially important as more experienced employees retire.

Finally, incenting a focus on long-term sustainable company performance provides a benefit to customers, as a financially strong company will have greater access to capital at a lower cost, which in turn benefits customers through a lower cost structure. In addition, the introduction of long-term incentive pay as a component of overall compensation ensures our leadership is focused on the long term, and not overly focused on the short term.

Q. HOW DOES INCLUDING EARNINGS PER SHARE AND TOTAL SHAREHOLDER RETURN METRICS AS PART OF INCENTIVE PAY BENEFIT CUSTOMERS?

A. The measures of our corporate incentive program are designed to drive results. Earnings Per Share ("EPS") is a performance measure included in the STI opportunity for all employees. To achieve strong incentive results, we must operate reliably, we must operate safely, we must deliver strong customer service, we must control our costs and we must grow our company. Including a goal for financial performance in our incentive program incents employees to pursue cost-effective ways to deliver these measures. Using this balanced scorecard approach benefits customers by delivering critical services at competitive rates. EPS and Total Shareholder Return ("TSR") measure overall financial performance, and overall financial performance in turn can reflect how employees take action on a routine basis to support the efficient delivery of safe and reliable energy to customers. In addition, finding sustainable cost savings is an important part of achieving our financial targets, and those sustainable cost savings benefit our customers. Incenting employees to work diligently to ensure costs are responsibly and prudently incurred is critical. These actions provide benefits to customers through competitive rates.

Q. IS THE COMPANY'S APPROACH TO EMPLOYEE COMPENSATION REASONABLE AND PRUDENT?

A. Yes. As I previously stated, the Company must maintain a competitive total compensation package to attract and retain talent needed to run a safe and reliable electric system. While the Company's employee compensation methodology is comprised of several components, including base salary and variable incentive pay, the reasonableness of the total compensation package is commensurate with the market. Further, the EPS/TSR metrics, as a subcomponent of the variable incentive pay formula, encourage eligible employees to reduce expense, operate efficiently and conserve financial resources, all of which benefit customers by keeping rates competitive. To eliminate any portion of incentive compensation would decrease employees' total compensation to less than competitive levels, compelling the Company to consider an offset to this reduction by an increase to its fixed costs through base pay adjustments or face severe workforce challenges. This is shown by Figures 3 and 4, below – removing either of the cross-hatched pie pieces, representing the portions of compensation that the Public Staff wishes to exclude from rates, would leave the compensation at a below-median level.

Figure 3

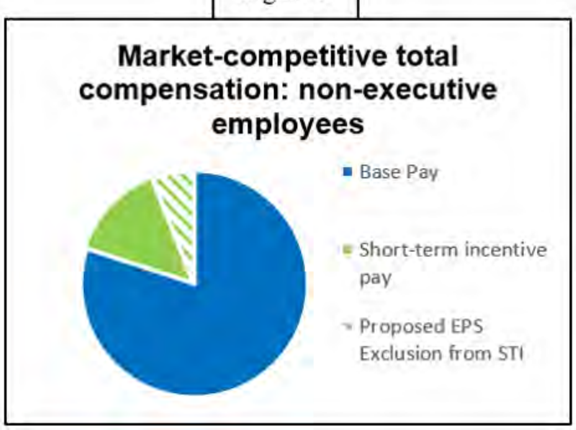
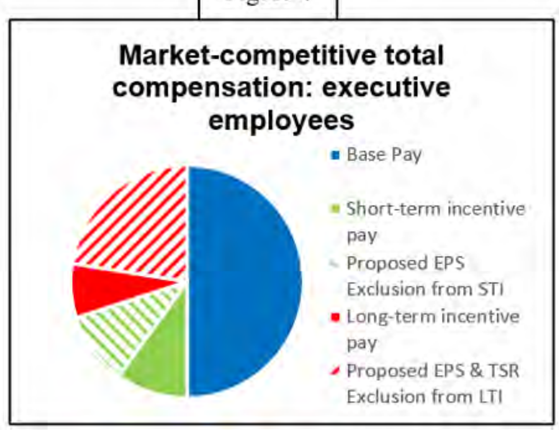


Figure 4



Q. WHAT WOULD BE THE IMPLICATIONS TO CUSTOMERS IF THE TOTAL COMPENSATION LEVELS WERE ALLOWED TO FALL BELOW MARKET-COMPETITIVE LEVELS?

A. Allowing total compensation to fall below market-competitive levels would have substantial negative implications for the cost of service to customers. Given the length of time necessary to fully train employees to safely perform all aspects of their jobs, allowing the turnover rate to escalate due to lowering the competitive levels of pay and benefits would be imprudent. Many craft positions require lengthy apprenticeships to learn the skills needed to perform work independently and safely. The expense incurred to hire and train new employees and the loss of productivity realized through high turnover rates would negatively affect the ability of the Company to provide safe and reliable service at a reasonable cost. This is also true for leadership positions. Duke Energy invests in developing highly effective leaders who carry out the organization’s mission and inspire employees to work together to achieve results the right way. Paying less than competitive levels of compensation would put the Company at risk of losing these valuable leaders to other companies and potentially having to pay more to attract the same level of leadership talent externally. The financial cost of turnover and negative implications from lost productivity, hiring, training and job vacancy can put a significant level of productivity and financial value at risk to the Company. Incentive pay is similar to the other costs related to producing and distributing electricity. It is a necessary cost to provide customers safe and reliable service. In the competitive market for talent, employees consider total rewards, including base pay, incentive pay and benefits, as a key determinant in deciding whether to work for a particular employer. The target incentive compensation provided by Duke Energy is necessary to achieve market-competitive compensation and, thus, is a reasonable and appropriate cost of doing business that should not be eliminated.

In my opinion, the Company's entire incentive pay expense is reasonable and necessary to attract and retain high quality employees with the critical skills necessary to provide safe, efficient and reliable service to customers, and, therefore, it should be recoverable in its entirety.

III. PUBLIC STAFF'S PROPOSED ADJUSTMENTS

Q. PLEASE DESCRIBE PUBLIC STAFF WITNESS BOSWELL'S PROPOSED ADJUSTMENT RELATING TO INCENTIVE COMPENSATION.

A. The incentive compensation Public Staff Witness Boswell seeks to disallow (Adjustment 23) is based upon the stance that EPS and TSR metrics provide a direct benefit to shareholders rather than to ratepayers.

As I have demonstrated in my testimony, employee compensation and incentives tied to metrics such as EPS and TSR benefit customers, because those metrics reflect how employees' contributions translate into overall financial performance. EPS, for example, is a measure of the Company's financial performance, and that performance is reflective of how certain goals – safety, individual performance, team performance and customer satisfaction (all of which are components of incentive pay) – are met in a cost-effective way. Divorcing employee performance from such an important measure of a rate regulated company's overall health makes no sense and is counterproductive.

The incentive components of employee compensation incent employees to be cost conscious, to work efficiently and to find the least cost solutions to issues and problems posed every day, which in turn reduces operations and maintenance ("O&M") costs. This benefits customers by rates being established on a lower O&M cost than what they would otherwise be. In short, incentive compensation tied to these readily measurable metrics incent employees to help DE Carolinas deliver safe, reliable and competitively priced energy to its customers, every day, day in and day out. For the Commission to abrogate these incentives would be a severe detriment to customers, not a benefit to customers, and would result in disallowance of a prudently incurred cost.

Finally, in order to attract a well-qualified and well-led workforce, the Company must compete in the marketplace to obtain the services of these employees. No witness in this proceeding, including Public Staff Witness Boswell, challenges the reasonableness of the level of compensation expenses reflected in the rate-making test period for the Company. No one has challenged that the compensation and benefit programs provided to employees of Duke Energy, including those who work on behalf of DE Carolinas, are necessary and critical in their entirety for attracting, engaging, retaining and directing the efforts of employees with the skills and experience necessary to safely, efficiently and effectively provide electric services to DE Carolinas customers. Instead, Public Staff Witness Boswell wants to have the benefit of the Company employing qualified and well-managed employees productively engaged in providing safe, reliable, and affordable electric service to our customers today and tomorrow, but not to reflect the business share of that cost of service.

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT TO EXECUTIVE COMPENSATION.

A. As noted in the direct testimony of Company witness Jane McManeus, as part of its initial filing, in the current rate case, the Company has already made an adjustment to remove 50 percent of the compensation of the five Duke Energy executives with the highest allocation to DE Carolinas in the test period. In the last DE Carolinas rate case, the Company made an upfront adjustment to remove 50 percent of the compensation of the four Duke Energy executives with the highest allocation to DE Carolinas in the test period, then later agreed to remove 50 percent of the compensation of a fifth executive, at the recommendation of Witness Boswell.

Q. IN THIS CASE, DOES WITNESS BOSWELL PROPOSE ADDITIONAL DISALLOWANCES FOR THESE FIVE EXECUTIVES?

A. Yes. Witness Boswell proposes the additional removal of corresponding benefits for these five executives. She offers no evidence to support this disallowance, one that diminishes the contributions these individuals make on behalf of DE Carolinas customers, misrepresents the focus and deliverables of their positions and ignores the common interests between shareholders and customers. The Company believes that Public Staff has not provided sufficient justification for such disallowance. Simply stated, the Company cannot operate without leaders. To address the known concern of Public Staff, the Company proactively removed 50% of the compensation for these leaders, despite its belief that would have been appropriate to include in cost of service—that should be enough to address the matter. Public Staff takes it too far in asserting the reduction is justified because such leaders address shareholder interests. Customers would be terribly affected if the Company did not have leaders to address shareholder matters because, simply stated, the Company needs shareholders to help finance operations and construction, and to ignore that need is unjust.

The Company's retail revenue requirement in prior cases has reflected incentive compensation plans required for efficient and prudent operations and customer service of the nature the Public Staff now proposes to disallow. For the reasons I have described, there is no justification with any substance for the proposed disallowances of reasonable and prudent retail operating expenses.

Q. DID WITNESS BOSWELL PROPOSE ANY OTHER CORPORATE-FOCUSED DISALLOWANCES?

A. Yes. She proposed, under the same theory, to exclude 50 percent of Board of Directors' expenses and compensations.

Q. DO YOU BELIEVE THIS DISALLOWANCE IS APPROPRIATE?

A. No. By definition, the Company is required to have a Board of Directors. We cannot pretend that an investor-owned utility is not an investor-owned utility. The costs of being one, including Board costs, are in fact costs of service. It is not fair or reasonable to penalize the Company for merely being an investor-owned utility with attendant requirements to that corporate structure.

IV. CONCLUSION

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

A. Yes, it does.

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Rudolph ("Rudy") Bonaparte. I am Chairman and a Senior Principal with Geosyntec Consultants, Inc. and my business address is 2002 Summit Blvd., N.E., Suite 885, Brookhaven, GA 30319. When providing services in North Carolina, I provide them through our North Carolina-based affiliated company, Geosyntec Consultants of North Carolina, P.C., with offices in Charlotte and Raliegh.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING YOUR TESTIMONY?

A. I am submitting my testimony before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Carolinas, LLC ("DE Carolinas").

Q. PLEASE SUMMARIZE YOUR EDUCATION QUALIFICATIONS.

A. I obtained my B.S. in civil engineering in 1977 from the University of Texas at Austing (UT). I received my M.S. and Ph.D degrees in civil engineering from the University of California, Berkeley in 1978 and 1982, respectively. At Berkeley, I was a National Sciene Foundation Graduate Research Fellow.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I am Chairman and a Senior Principal with Geosyntec Consulting, Inc. and have nearly 40 years of professional experience in the areas of geoenvironmental and geotechnical engineering applied to municipal, industrial, hazardous, and low-level radioactive waste disposal facility projects. In addition to this project experience, I was lead co-author of several technical resource and guidance documents on the design, construction, and performance of waste containment systems published by the United States Environmental Protection Agency ("USEPA"). My experience with CCR landfills and impoundments spans 25 years. I am knowledgeable regarding the physical and chemical characteristics of coal combustion residuals ("CCRs"), the Federal CCR Rule, and the design and construction of storage, disposal, and closure systems for CCRs. I am an elected member of the United States National Academy of Engineering ("NA"). I am also a Fellow of the American Society of Civil Engineers and received the society's 2016 Lifetime Achievement Award in Design. I received the 2019 Georgia Engineering Alliance Lifetime Achievement in Engineering Award, and I am a registered professional civil engineer in 19 states.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. Bonaparte Rebuttal Exhibit 1 includes my full educational and professional background. In addition, Bonaparte Rebuttal Exhibit 2 is a March 2020 report entitled "CCR Surface Impoundment Public Information Review".

Q. WAS EXHIBIT 2 PREPARED UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. Bonaparte Rebuttal Exhibit 2 was prepared under my direction and supervision.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. As outlined in Exhibit 2, under my direction and oversight, a team of professionals at Geosyntec Consultants of NC, P.C. ("Geosyntec") prepared a report entitled "CCR Surface Impoundment Public Information Review," dated

March 2, 2020. We prepared this report for DE Carolinas to document our observations and findings regarding closure planning of coal combustion residual (CCR) surface impoundments in the states of Georgia, North Carolina, South Carolina, and Virginia during the approximate timeframe of 2009 to 2011, or earlier. The report presents the results of a review of two sets of publicly available documents for coal-fired electric power plants for these states:

- reports presenting the results of safety assessments for CCR impoundment dams prepared by private engineering firms under subcontract to the USEPA in the timeframe 2009-2011 (hereafter referred to as "USEPA dam safety assessment reports"; and,
- for the CCR impoundments identified in the USEPA dam safety assessment reports, closure plans prepared by the utility owners/operators of the CCR impoundments (or their consultants) in or around 2016 pursuant to the Federal CCR Rule (40 CFR §257.102(b)); in a few instances, the posted closure plans were prepared pursuant to state regulations rather than the CCR Rule; for our report, these facilities are considered together and collectively referred to as CCR Rule closure plans.

From the USEPA dam safety assessment reports, Geosyntec recorded information regarding each CCR impoundment's location, year built, report preparer (engineering consultant), active/inactive status, lined or unlined condition, operating information, and most relevant to our report, whether there was any indication in the report that planning for, or implementation of, an engineered impoundment closure had occurred prior to or during the 2009-2011 timeframe.

From the CCR Rule closure plans, Geosyntec recorded information about each CCR impoundment's closure plan date, closure plan preparer, closure method (e.g., closure by removal, cap-in-place), details of the closure cover system, actual or anticipated closure construction start date, and whether the CCR Rule closure plans referenced or mentioned prior closure plans (in or prior to the 2009-2011 timeframe) and/or any earlier closure planning or closure construction activities.

The results of the review of this publicly available information are contained in two tables for each of the reference states, one presenting the results of the review of the USEPA dam safety assessment reports, and the second presenting the results of the review of the CCR Rule closure plans.

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

A. Yes.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachary Kuznar and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

A. I am employed by Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") as Managing Director, CHP Microgrid and Energy Storage Development.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Chemical Engineering from Purdue University in 1999, a Master of Engineering and Applied Science degree from Yale University in 2001, and a PhD in Chemical and Environmental Engineering from Yale University in 2005. I began my career with GE in 2005 and started with Duke Energy in 2008. Previous roles at Duke Energy include various roles within Duke Energy's Fossil/Hydro Generation group, Emerging Technology Organization and Business Development in the Distributed Generation Group.

Q. WHAT ARE YOUR DUTIES AS MANAGING DIRECTOR, CHP MICROGRID AND ENERGY STORAGE DEVELOPMENT?

A. As Managing Director of CHP, Energy Storage and Microgrid development, my primary responsibility is to develop and execute business strategies to add distributed resources to Duke Energy's asset portfolio across its six regulated, franchised businesses located in North Carolina, South Carolina, Ohio, Kentucky, Indiana, and Florida.

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

A. Yes. I recently provided testimony before this Commission in support of Duke Energy Progress, LLC's project update for the Hot Springs Microgrid (Docket No. E-2, Sub 1185). I have also testified before the Kentucky Public Service Commission and the Public Utilities Commission of Ohio in support of rate case filings of Duke Energy Kentucky, Inc. and Duke Energy Ohio, Inc., respectively, and before the Florida Public Service Commission as part of Energy Storage Projects.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to the supplemental testimony of Public Staff witness Dustin Metz filed on March 25, 2020, which recommended disallowance of all of the Company's costs associated with the combined heat and power ("CHP") project ("Clemson CHP Project" or "CHP Project") located on the campus of Clemson University (the "University").

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony recommends that the Commission reject the Public Staff's proposed disallowance of the Clemson CHP Project costs. My testimony discusses the background of the CHP Project and explains the numerous benefits that the CHP Project offers to all DE Carolinas customers. My testimony also identifies the fundamental flaws underlying the Public Staff's eleventh hour analysis of the CHP Project and explains why the Public Staff has failed to provide a proper basis on which these costs may be disallowed.

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S ASSERTED JUSTIFICATION FOR ITS RECOMMENDATION THAT THE CLEMSON CHP PROJECT COSTS SHOULD BE DISALLOWED.

A. As described in witness Metz's supplemental testimony, the Public Staff based its disallowance recommendation on its claims that the CHP Project is uneconomical, does not benefit North Carolina customers, and is not needed for the Company to maintain its required reserve margin.

Q. DOES THE COMPANY AGREE WITH THE PUBLIC STAFF'S RECOMMENDATION?

A. No. After a last minute review of the CHP Project costs, the Public Staff recommended that the Commission disallow all recovery of the cost of the Clemson CHP Project without a justifiable basis for its recommendation. The Public Staff did not do the work to analyze the CHP Project costs for reasonableness and prudence, instead relying on broad, superficial generalizations and mis-characterizations about the CHP Project that are not based on reasoned analysis and reflect inaccuracies and misunderstanding relating to the justifications for the CHP Project. In fact, the Public Staff failed to provide any verifiable evidence to support a conclusion that the Company's decision to invest in the CHP Project was imprudent or that the associated costs were unreasonable.

The Public Staff completely disregarded the benefits that North Carolina customers will receive from the Company's investment in the CHP Project. Particularly, the Public Staff failed to account for: (1) the steam revenues DE Carolinas will receive from the Project; (2) the production cost savings from operation of a CHP that uses less fuel to produce electric and thermal energy; (3) the line losses that the CHP Project will avoid; (4) the capacity value that the CHP Project brings to the entire DE Carolinas system; or (5) the cost-effective energy that the CHP Project will produce to the benefit of all DE Carolinas customers. Rather than carefully reviewing, analyzing, and understanding the CHP Project costs, cost categories, project economics, and benefits, the Public Staff relied on global statements characterizing the costs as too high without supporting those assertions with any concrete, verifiable evidence or identification of any particular project costs as unreasonable or imprudently incurred. In addition, rather than carefully reviewing the design of the CHP Project and its relationship to the University and to the Company's entire electric system, the Public Staff claimed inaccurately and simplistically that the CHP Project only benefits Clemson University. Finally, Public Staff's contention that the CHP Project does not have capacity value to the Company directly contravenes prior Commission orders that have ascribed capacity value to small generation resources.

As the Public Staff has provided no justifiable basis for disallowance, including no credible evidence of unreasonableness or imprudence, the Public Staff's position is fundamentally flawed. It would therefore be unreasonable for the Commission to adopt the Public Staff's position and disallow recovery of the North Carolina portion of the costs for the CHP Project.

II. BACKGROUND

Q. WHAT IS A CHP SYSTEM?

A. Combined heat and power ("CHP") systems, also known as cogeneration, generate electric energy and useful thermal energy in a single, integrated system. CHP systems capture heat that would otherwise be wasted as a by-product of the electric generation process to provide useful thermal energy—such as steam or hot water—that can be used for space heating, cooling, domestic hot water, and industrial processes. By capturing and utilizing heat that would otherwise be wasted from the production of electricity in a traditional process, CHP systems are more efficient than traditional generation because they require less fuel to produce the same amount of electric and thermal energy. This translates into less greenhouse gas emissions such as carbon dioxide (CO_2), as well as other air pollutants like nitrogen oxides (NO_x) and sulfur dioxide (SO_2).

Q. PLEASE DISCUSS THE COMPANY'S RATIONALE FOR EXPLORING CHP OPTIONS TO POTENTIALLY MEET FUTURE CUSTOMER DEMAND.

A. The Company is always pursuing new, energy efficient resources to reliably and economically meet future customer demand. The Company sees value in diversifying its regulated generation mix with more distributed, smaller assets that serve to reduce transmission and distribution losses and improve energy reliability. Consistent with those efforts, in the last several years, the Company has explored CHP as an option to expand its generation portfolio using an untapped and highly efficient resource – thermal energy.

CHP adds value across the Company's North Carolina and South Carolina balancing authority area given its potential to displace more expensive generating units. Detailed financial planning processes using the base plan in the Company's recent IRPs (*see* Docket No. E-100, Sub 147 and Docket No. E-100, Sub 157) identified CHP as a competitive resource as compared to traditional generation to cost effectively advance generation resource and customer energy planning. The CHP Project was specifically identified as part of the Company's long-term resource plan in the 2017 IRP Update, the 2018 IRP, and the 2019 IRP Update filed with the Commission in these dockets.

Q. PLEASE PROVIDE AN OVERVIEW OF THE CLEMSON CHP PROJECT.

A. The Clemson CHP Project is located on a site that the Company leases from Clemson University in Pickens County, South Carolina. Beginning in August

2015, the Company began working with the University to develop plans for a new substation, as campus load had exceeded the capabilities of the existing substation at that location and the University needed to increase the reliability and resilience of its campus distribution system. During the course of planning for the new substation, the Company brought to the University the idea for a CHP unit, which would provide the potential for backup power for the University in the event of a transmission outage as well as allow it to meet campus thermal energy needs more efficiently. The University's goals aligned with DE Carolinas' overall system goals as outlined in the 2016 IRP, and the Company saw tremendous value in partnering with the University on this innovative project.

The Clemson CHP Project consists of a natural-gas fueled turbine-generator set ("GTG"), and a single pressure heat recovery steam generator ("HRSG"), with associated mechanical and electrical auxiliary equipment. The GTG is fueled by natural gas from the local distribution system. The generator electrical output is connected to the substation at 12.47 kV distribution voltage through an underground duct bank system. The expected net output of the project is 13 MW.

As with other CHP units, the Clemson CHP Project will use the waste heat from the generation of electricity to produce the thermal energy to be used by the University. This high-tech process will make this plant one of the most efficient generating assets on the DE Carolinas system, while supporting the increased energy needs of a rapidly growing region.

The Clemson CHP Project is structured so that the Company owns and operates the CHP Project on its side of the electric meter and sells thermal energy (steam) produced by the unit to the University to meet its thermal energy requirements under a Steam Supply and Purchase Agreement ("Steam Agreement"). The electric energy produced from the GTG flows directly into the DE Carolinas energy delivery system. The Steam Agreement also provides that the University will purchase steam for thirty-five years, beginning on the term commencement date. Revenues received from the sale of steam will be credited back to DE Carolinas' electric customers through the Company's fuel clause.

Q. WHAT IS THE CURRENT STATUS OF THE CHP PROJECT?

A. The Company completed performance testing of the CHP Project on December 14, 2019 and placed it in service on December 18, 2019. Due to a delay in the University's construction of the steam interconnection facilities needed to enable the receipt of steam from the CHP Facility, the University was unable to receive steam by the commercial operation date. Accordingly, the University and DE Carolinas have amended the Steam Agreement to provide that the University will purchase steam for a period of 35 years beginning on the earlier occurrence of (i) June 30, 2020, or (ii) when the University's steam interconnection facilities are completed and operational. Construction of the steam pipe to run from the facility to the University is underway and expected to be complete in August of 2020.

Q. HOW WILL DE CAROLINAS CUSTOMERS BENEFIT FROM THE CLEMSON CHP PROJECT?

A. The Clemson CHP Project will benefit DE Carolinas customers in a number of ways. First, the steam sales revenues, which drive the cost effectiveness and value of the arrangement, will be credited back to North Carolina customers through the Company's fuel clause. The Company will begin receiving this revenue by June 30, 2020, in advance of when the new rates from this case go into effect. Additionally, the Company will realize efficiency gains by using the waste from CHP to produce steam, which by requiring less fuel to produce the same amount of energy, will lower overall greenhouse gas emissions in DE Carolinas by approximately 60,000 metric tons per year, or the equivalent of removing 12,700 passenger vehicles from the road per year. The CHP Project will also provide operational benefits by reducing grid line losses and line loading that otherwise would occur. Finally, as discussed further below, the CHP Project will reduce the amount of capacity needed on the DE Carolinas system.

Q. DID THE COMPANY OBTAIN A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") FOR THE CLEMSON CHP PROJECT?

A. Yes. The Public Service Commission of South Carolina reviewed and approved a CPCN for the sale of steam to the University under the Steam Agreement. *See* Order Granting Certificate of Public Convenience and Necessity, Docket 2017-47-E, Public Service Commission of South Carolina (July 18, 2017).

Q. DID THE PUBLIC STAFF MENTION THE CLEMSON CHP PROJECT IN ITS INITIAL TESTIMONY FILED ON FEBRUARY 18, 2020?

A. No. Until the Company received approximately 250 data requests, including subparts, pertaining to the Clemson CHP Project on March 12, 2020 (well outside of the procedural schedule contemplated for discovery requests on the Company's filing and less than two weeks before the originally scheduled start of the evidentiary hearing in this case), neither witness Metz nor any other member of the Public Staff raised a single question or concern regarding the Clemson CHP Project.

Q. DID THE PUBLIC STAFF HAVE OPPORTUNITY TO INVESTIGATE THE CHP PROJECT PRIOR TO FILING ITS INITIAL TESTIMONY?

A. Yes. The Public Staff had ample opportunity to review, analyze, and question the costs associated with the Clemson CHP Project. Estimated project costs were originally identified in the Company's E-1, Item 41 filed on September 30, 2019, the same day the Company filed its rate case application. In addition, the Clemson CHP Project was included in the Company's Comprehensive 2018 IRP and its 2017 and 2019 IRP Updates as well as DE Carolinas' 2020 fuel filing submitted on February 25, 2020, in Docket No. E-7, Sub 1128.

Q. DID THE PUBLIC STAFF ARGUE THAT ANY OF THE SPECIFIC COSTS ASSOCIATED WITH THE CLEMSON CHP PROJECT WERE IMPRUDENTLY INCURRED?

A. No. Through discovery, the Company provided information regarding the costs for the project, including information relating to contractors, bids, change orders, and project milestones. However, as discussed above, the Public Staff did not contend that any particular costs associated with the CHP Project were imprudently incurred. Instead, the Public Staff based its disallowance recommendation on superficial generalizations regarding the overall economic value of the project, incorrect and unfounded assertions that the CHP Project does not offer benefits to North Carolinas customers, and claims regarding the benefits of the project and the Company's reserve margin that contravene accepted Commission policy. I address each of these erroneous assertions below.

III. CORRECTIONS TO WITNESS METZ'S TESTIMONY

Q. DID WITNESS METZ CORRECTLY IDENTIFY THE CLEMSON CHP PROJECT COSTS THAT THE COMPANY IS REQUESTING TO RECOVER IN THIS CASE?

A. No. Witness Metz recommended that $50.3 million of Clemson CHP Project costs should be removed from the Company's rate base. However, that amount represents the total system cost; the North Carolina retail share of the CHP Project is actually $33.9 million.

Q. DID WITNESS METZ ACCURATELY IDENTIFY THE ANNUAL OPERATIONS AND MAINTENANCE ("O&M") COSTS FOR THE CHP PROJECT?

A. No. Witness Metz cited $3.3 million in annual O&M for the CHP Project. The projected annual O&M for the CHP Project is actually $2.17 million, including

$1.2 million for labor. Further, the Company is not seeking to recover the incremental non-labor O&M related to the Clemson CHP Project in this case.

IV. REBUTTAL TESTIMONY

A. The Clemson CHP Project Offers Economic Value To All DE Carolinas Customers

Q. WHY DID THE PUBLIC STAFF CONTEND THAT THE PROJECT IS UNECONOMICAL?

A. The Public Staff alleged that the cost for the CHP Project (approximately $4,000/kW in capital costs) is "extraordinarily high." Specifically, witness Metz argued that Clemson CHP Project costs are nearly six times greater than the combustion turbine ("CT") costs utilized as an input to DE Carolinas' avoided cost calculations, and compared the CHP Project cost, when combined with the cost for the new University substation, to the cost of combined cycle ("CC") plants.

Q. DO YOU AGREE THAT THE COST FOR THE CLEMSON CHP PROJECT IS "EXTRAORDINARILY HIGH?"

A. No. First, the Public Staff failed to consider the revenue that the Company will receive from the sale of steam from the CHP Project. Pursuant to the Steam Agreement, discussed further below, the University will take and pay for all of the steam produced and delivered by the new unit. While the University has not yet completed the interconnection facilities required to take the steam, pursuant to a recent amendment to the Steam Agreement the University must begin making payments no later than June 30, 2020 for steam regardless of whether it actually takes the steam. Since the unit will be the University's primary steam supplier and the University's steam need is year-round, the Company anticipates that the CHP Project will produce steam revenue on a nearly continuous basis. The steam revenues will help offset the cost of the CHP Project. Specifically, when the Steam Agreement was signed with the University, using the Company's 2016 fuel curve, the levelized steam revenue over 35 years per MWh was calculated to be $52.91. This equates to a levelized annual steam revenue of $5,724,289, or a total steam revenue of $200,350,138 over the 35 year life of the CHP Project. In the event that the University does not take the steam due to, for example, a failure of its steam delivery system or planned maintenance outage, the Company's system operations unit will replace the CHP Project with the next least cost resource available at that time, just as with any other system generating asset that becomes unavailable.

Q. IS IT APPROPRIATE TO COMPARE THE COST OF THE CHP PROJECT WITH THE COST OF A CT USED IN THE COMPANY'S AVOIDED COST CALCULATIONS OR WITH A CC UNIT?

A. Absolutely not. In addition to inappropriately ignoring the steam revenue, the Public Staff's comparison of the CHP Project cost to either a hypothetical CT or traditional CC unit fails to capture the full economic value of CHP. First, this comparison ignores the numerous benefits that the CHP Project offers all DE Carolinas customers. In addition, the CHP Project is part of a portfolio and should be modeled as such. Serving the capacity and energy needs of customers is a complex process; making one for one substitutions and comparisons does not generally add value. In particular, large-scale natural gas fired CCs are not always the best substitute for CHP projects, especially when CCs can be over 50 times the size of a CHP. Here, for example, the Clemson CHP Project has a capacity of 13 MW; in comparison, the Company's W.S. Lee Steam Station, which is a CC, has a capacity of 750 MW. While economies of scale might therefore show a cost advantage for the CC on a $/MWh basis, the CC might cost close to $1 billion dollars. Current avoided capacity cost calculations based on multi-unit CTs are also based on a more significant central station investment and similarly adjust for such economies of scale.

In contrast, smaller, distributed base load assets, such as the Clemson CHP Project, allow the Company to add smaller base load generation resources at locations with high thermal energy demand and place generation sources closer to load with almost no transmission losses. Another example is a similar CHP project owned by Duke Energy Indiana, LLC and located on the campus of Purdue University. As I have discussed, such facilities also require less fuel to provide the same amount of energy, resulting in lower CO2 emissions.

Q. WITNESS METZ INCLUDED THE COST OF THE UNIVERSITY'S NEW SUBSTATION IN HIS $/KW DISCUSSION. WAS THIS APPROPRIATE?

A. No. The University's need for a new substation was identified prior to any discussion of the CHP Project and the new substation would have been required independent of the CHP Project. In addition, the Company saved approximately $2.5 million for all DE Carolinas customers by tying the CHP to the transmission grid through the new substation, rather than constructing a separate substation dedicated to the CHP.

B. The Steam Agreement Offers Value to All Customers

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S POSITION REGARDING THE STEAM AGREEMENT.

A. The Public Staff contended that the Company's customers are at risk due to what witness Metz termed a "misalignment" between the steam price reflected in the Steam Agreement and the Company's costs. Witness Metz pointed to the difference between the steam sale price reflected in the agreement and the price used to model CHP resources in the 2016 IRP and questioned the basis for the contracted steam price. He also asserted that because the University cannot yet take the steam, customers are paying for the project but not receiving the benefit of the steam revenues. Finally, he took issue with the allowance for either party to terminate the Steam Agreement beginning in the eleventh year of the term, subject to a termination liquidated damage payment.

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S OVERALL POSITION ON THE STEAM AGREEMENT?

A. No. The Public Staff's criticisms of the Steam Agreement are misplaced and demonstrate the Public Staff's last-minute review of the CHP Project. The Steam Agreement was the product of careful analysis and collaboration between the Company's IRP, rates, regulatory, and distributed energy resource teams to develop a CHP arrangement that will offer the most potential value to all customers. As I discuss further below, the Company designed the structure of the Steam Agreement, including the steam pricing calculation, in a manner intended to mitigate risk for the Company's customers.

Q. HOW DO YOU RESPOND TO THE PUBLIC STAFF'S CONCERNS REGARDING THE FORMULA FOR CALCULATING STEAM PRICING UNDER THE CONTRACT?

A. The steam pricing reflected in the Steam Agreement was structured to offset the capital cost of the CHP Project and manage risk to the Company's customers if natural gas prices fluctuate, which is the exact opposite of the Public Staff's claim. Specifically, the amount of steam revenue is directly tied to natural gas prices and is calculated by taking a multiplier *multiplied by* steam volume *multiplied by* NYMEX pricing. The modeled gas price included in the Steam Agreement was based on the NYMEX forecast used in the most recently filed IRP at that time, which is consistent with how the Company models gas cost for any other gas-fired generation unit. When the Company decides to add a new unit to its fleet, it uses the best cost information available at that time, but actual costs may change by the time a new unit goes online. However, customers are protected if natural gas prices increase since this is considered as part of the formula to calculate steam revenue. Under this scenario, the University would be required to pay a higher price for the steam and the additional revenue would flow back to customers through the Company's fuel adjustment clause. Notably, because the steam pricing is reassessed each year of the Steam Agreement, it will be re-evaluated 35 times over the term of the arrangement.

Q. HOW DO YOU RESPOND TO THE PUBLIC STAFF'S CONCERN THAT CUSTOMERS ARE PAYING FOR THE CHP PROJECT BUT NOT RECEIVING THE BENEFITS OF THE STEAM REVENUE?

A. The Public Staff's concern is misguided. The CHP Project is not currently reflected in the Company's base rates, and DE Carolinas has not requested any deferral for the impact of the regulatory lag between when the project went in service and new rates reflecting the project's costs are anticipated to take effect. As such, customers are not paying for the CHP Project through their current rates and are also not losing the benefits of the steam revenue. Pursuant to the amended Steam Agreement, the University must start paying for steam on the earlier of June 30, 2020, or the date of completion of the facilities necessary to take delivery of the steam. Once the CHP Project costs are reflected in the Company's proposed new base rates, revenues from steam sales will have been incorporated into DE Carolinas' fuel clause computations (estimated July 1, 2020) as part of the net gain/loss from the sale of electric generation by-products.

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S POSITION ON THE TERMINATION PROVISION IN THE STEAM AGREEMENT?

A. I do not. Witness Metz noted that Section 15.1 of the Steam Agreement allows either party to terminate beginning in the eleventh year of commercial operation, with what he terms a "limited penalty" of twice the annual steam sale contract value. While acknowledging that the cost of the termination would depend on the cost of natural gas, he speculated that the Company would lose a significant amount of revenue if the provision were exercised, contrasted with the cost to customers.

During negotiations for the Steam Agreement, due to the 35-year term, the University required the inclusion of provision allowing it to terminate based on extenuating future market conditions or other circumstances. Such provisions in long term commercial agreements of any type are hardly atypical. However, since this will be the primary source of thermal energy for Clemson University, the Company determined that the risk of the University exercising the early termination provision is low. The termination liquidated damage payment escalates over time to provide the Company revenue to at least partially offset the loss of steam payments, during which it would likely seek a new host customer for the unit. Finally, while the CHP Project would not be run as a base load resource in the unlikely scenario that the University terminated the Steam Agreement, it could still be run as a peaking unit, or, due to the modularity of these gas turbines, could be repurposed to another site.

C. <u>The Clemson CHP Project Is A System Asset That Benefits All DE Carolinas Customers</u>

Q. WHAT IS THE PUBLIC STAFF'S POSITION ON WHETHER THE CLEMSON CHP PROJECT IS A SYSTEM ASSET?

A. The Public Staff argued that the Clemson CHP Project is more analogous to a behind-the-meter net metering arrangement that is connected to serve a single South Carolina system retail customer and is primarily designed to produce steam and electricity for the University, rather than to produce economically dispatched electricity for the overall DE Carolinas system.

Q. DO YOU AGREE WITH THE PUBLIC STAFF THAT THE CLEMSON CHP PROJECT IS ANALOGOUS TO A BEHIND-THE-METER ARRANGEMENT?

A. No. A thorough review of the CHP Project would have made clear to the Public Staff that the CHP unit is not a behind the meter unit, nor is it "analogous" to a behind the meter net metering arrangement. The Clemson CHP Project was built on the DE Carolinas side of the meter, and all of the electricity produced by the unit flows to the DE Carolinas bulk energy delivery system. Regardless of whether the University's electricity needs are supplied by the CHP Project or another generation resource, all electricity received by Clemson University will continue to be billed at the applicable retail rate. In addition, the CHP Project's electric generation output reduces the amount of generation required from the rest of the Company's fleet. It therefore provides a cost-effective energy resource to the benefit of all DE Carolinas customers and does not exclusively benefit the University. Given these considerations, the fact that the capacity of the CHP Project does not exceed the University's peak load is irrelevant, as the electrical output of the CHP Project will be delivered to the grid and not directly to Clemson University.

Q. DO YOU HAVE ADDITIONAL CONCERNS WITH WITNESS METZ'S SUGGESTION THAT THE CHP PROJECT COSTS SHOULD BE DIRECTLY ASSIGNED TO SOUTH CAROLINA CUSTOMERS?

A. Yes, I do. Witness Metz appears to be arguing that unless the electrical output of the project is confirmed to reach the Company's transmission system, North

Carolina customers should not pay for it. As Company witness Hager addresses in her supplemental rebuttal testimony, this approach is wholly inconsistent with the approach traditionally taken by the Company to allocate recovery of its costs between North and South Carolina customers, which this Commission has approved time and time again.

Additionally, my understanding is that the Public Staff appears to be trying to set a dangerous precedent that would upend historical treatment and have far-reaching implications for rate making in both North Carolina and South Carolina. The Company cannot distinguish where electrons travel, but rather allocates costs for generation across all jurisdictions because such generation serves the electric grid as a whole. Other examples of generation connected to distribution that serve as grid assets, such as solar QFs and batteries, demonstrate this point. The output of these resources may never or rarely enter the transmission system, but their costs are proportionately allocated between North and South Carolina as they have been for years. Even if distribution-connected solar generation is only received by retail customers on the same feeder, that does not justify excluding such resources from rate base. The reason is that these facilities serve the grid even if electrons do not enter the transmission system, by reducing transmission load and losses as well as providing firm capacity to meet DE Carolinas' long-term capacity needs. The Clemson CHP Project is analogous.

D. <u>The Public Staff's Analysis Of The CHP Project As It Relates To The Company's Reserve Margin Is Inconsistent With Commission Precedent</u>

Q. WHAT IS THE PUBLIC STAFF'S ARGUMENT REGARDING THE COMPANY'S RESERVE MARGIN?

A. The Public Staff asserted that although the Company identified the need for CHP in the 2016 IRP, the proposed impact to the 17 percent planning reserve margin at the time the CHP Project was built was minimal. The Public Staff argued that therefore, when the Company sought budget approval and decided to move forward with the Clemson CHP Project, it was no longer needed for planning reserve margin purposes.

Q. HOW DO YOU RESPOND?

A. Although I am not an IRP expert, it is my understanding that the Public Staff's approach to considering the relationship of the CHP Project to the Company's reserve margin is fundamentally flawed and inconsistent with the Commission's accepted approach to ascribing capacity to generation facilities in other contexts and proceedings before this Commission.

The Public Staff simply removed one small generating unit from the Company's planned resource portfolio and calculated the impact of that removal on the Company's reserve margin in a particular year. This is not appropriate because it improperly isolates the impact of a single small resource but ignores the reality that, from a generation planning perspective, a collection of small generation additions such as CHP, demand side management or "DSM," and batteries reduces or delays the need for larger additions. Considering that perspective, the Company developed a 100 MW "placeholder" for the 2016 IRP in recognition of the technical and economic potential for CHP projects to benefit customers in the future. Consistent with that perspective, the appropriate approach to ascribing capacity value to small generation facilities is to ascribe capacity value based on the year in which the Company's IRP first demonstrates an overall capacity need, and going forward from that point in time. The Commission has accepted this approach in recent biennial avoided cost cases (*see* Docket No. E-100, Subs 148, 158). Yet the Public Staff's approach ignores this reality and accepted methodology.

V. CONCLUSION

Q. WERE THE CLEMSON CHP PROJECT COSTS REASONABLY AND PRUDENTLY INCURRED ON BEHALF OF ALL CUSTOMERS IN NORTH CAROLINA AND SOUTH CAROLINA?

A. Yes, and as such, these costs should be recovered from both North Carolina and South Carolina customers.

Q. WHAT ARE THE REASONS FOR THE COMPANY'S POSITION?

A. The CHP Project offers numerous benefits to all DE Carolinas customers in addition to providing a solution for Clemson University's steam requirements. It will result in reduced transmission load as well as reduced overall CO2 and other emissions. It will provide firm capacity to DE Carolinas customers whether they are located in South Carolina or North Carolina. It allows the Company to not only diversify in terms of fuel source, but also in the size of base load generation. Finally, it will provide cost effective energy to the benefit of all customers through the steam revenues that will flow back to DE Carolinas customers through fuel.

The Public Staff's eleventh hour and fundamentally flawed review of the CHP Project unreasonably ignored these benefits and presented no verifiable evidence to support a conclusion that the costs for the CHP Project were unreasonably or imprudently incurred. These costs should therefore be recovered.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

MR. ROBINSON: Thank you, Chair Mitchell. The Company also notes for the record that, while Mr. Capps has been excused, on August 13, 2020, the Commission granted the Company's request to recall witness Steven Capps if needed as a result of the Public Staff's ongoing audit of the Company's proposed adjustments through May 2020. Just a note.

Chair Mitchell, next on my list, due to some anticipated scheduling conflicts, the Company seeks to reorder its eight witnesses appearing during the rebuttal phase of our case. The Company seeks to reorder as witnesses during that phase as follows:

The Doss and Spanos panel to be first, followed by Sean Riley, followed by Erik Lioy, followed by Jessica Bednarcik on rebuttal, followed by Steven Fetter, and then followed lastly by the Jim Wells and Marcia Williams panel.

Provided the Commission has no issues with this reordering, the Company will file an updated version of the spreadsheet reflecting these changes by close of business today.

CHAIR MITCHELL: Thank you,

Mr. Robinson. The Commission has no issue -- takes no issue with the reordering of the witnesses as you've indicated here this morning, but I do request that you file the updated order of witnesses before the close of business today.

MR. ROBINSON: Thank you, Chair Mitchell. Next on my list, I wanted to -- these are more notations. I wanted to flag for this Commission that the Company's original printed version of DEC Potential Cross Exhibits 1 through 3 had some formatting issues with pagination. Again, this is the printed version, not the electronic version. Since then, the Company reprinted corrected versions of Potential Cross Exhibits 1 through 3 and delivered them to each Commissioner. It is my understanding that all Commissioners did receive the corrected version. I'd just ask the Commission to please refer to the corrected versions of those exhibits at such time that the Company chooses to introduce them.

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

MR. ROBINSON: Thank you. And then last on my list, Chair Mitchell, I wanted to quickly provide the Commission a status update on the six late-filed exhibits that were requested during the consolidated phase of the hearing. The Company filed late-filed Exhibit Number 1, the FFO to debt hypothetical, on September 1. In addition, the Company is on track to provide most of the remaining late-filed exhibits by the end of this week, and any last ones by early next week. And that's it.

CHAIR MITCHELL: All right. Thank you for that update, Mr. Robinson.

All right. Anything further from Duke at this time?

MR. ROBINSON: Nothing from Duke.

CHAIR MITCHELL: Okay. Any additional preliminary matters from other parties?

MR. JENKINS: Madam Chair, Alan Jenkins for the Commercial Group. All parties have waived cross examination of Steve W. Chriss, and therefore I move into the record his direct testimony consisting of 18 pages of testimony with an Appendix A and four exhibits premarked as Chriss Exhibits 1 through 4.

CHAIR MITCHELL: All right.

Mr. Jenkins, I appreciate your motion, and you've reminded me that I need to make one more sort of housekeeping point.

So, at this point, I would like for you to hold your motion and renew it once we have completed the examination of Duke's witnesses offered on direct; and, at that time, when we move into the examination of the expert witnesses offered by the intervening parties, I will entertain your motion.

MR. JENKINS: Thank you.

CHAIR MITCHELL: And, you know, that's just an -- and that would pertain to any party -- any party -- any intervening party at this point in time. So just for purposes of the record, we will entertain motions from intervening parties subsequent to the presentation of Duke's direct. All right.

Any additional preliminary matters from the parties?

MS. CRESS: Chair Mitchell, this is Christina Cress with CIGFUR. Do intervenors need to submit a separate appearance slip for the DEC- and DEP-specific hearings if they've already submitted one that was to pertain to both dockets in the consolidated hearing?

CHAIR MITCHELL: If you have submitted your appearance sheet in the consolidated hearing, you do not need to resubmit an appearance sheet for the separate proceeding.

MS. CRESS: Perfect, thank you.

CHAIR MITCHELL: Any additional matters from the parties before we begin?

(No response.)

CHAIR MITCHELL: All right. Hearing none, the case is with Duke. You may proceed, Mr. Robinson.

MR. ROBINSON: Thank you, Chair Mitchell. At this time, the Company would like to call witnesses Mr. Steven De May and Mr. Larry Hatcher to testify as a panel.

CHAIR MITCHELL: All right. Let me make sure I can -- I see Mr. Hatcher, and there you are, Mr. De May. All right. Good morning, gentlemen. Let's go ahead and get you under oath, please.

Whereupon,

STEPHEN G. DE MAY AND LARRY E. HATCHER,

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

CHAIR MITCHELL: All right. Thank you very much. You may proceed.

MR. ROBINSON: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MR. ROBINSON:

Q. I will start with Mr. Stephen De May first.

Mr. De May, would you please state your name and business address for the record?

A. (Stephen G. De May) My name is Stephen G. De May. My business address is 410 South Wilmington Street, Raleigh, North Carolina.

Q. By whom are you employed and in what capacity?

A. I'm the North Carolina president for Duke Energy Carolinas.

Q. On September 30, 2019, did you cause to be prefiled in Docket E-7, Sub 1214 direct testimony consisting of 14 pages?

A. Yes.

Q. And did you on March 4, 2020, cause to be prefiled in that docket rebuttal testimony consisting of 12 pages?

A. Yes, I did.

Q. Mr. De May, if you don't mind, would you mind just speaking up a little bit, thank you.

A. Yes.

Q. Do you have any changes or corrections to your prefiled direct or rebuttal testimony?

A. No.

Q. And if I asked you the same questions here today, would your answers be the same?

A. They would.

Q. Mr. De May, did you, on March 25, 2020, cause to be prefiled in this docket, partial settlement supporting testimony consisting of seven pages?

A. Yes, I did.

Q. And did you, on July 31, 2020, cause to be prefiled in this docket, second settlement supporting testimony consisting of nine pages?

A. Yes.

Q. Do you have any changes or corrections to your prefiled partial or second settlement supporting testimony?

A. No.

Q. And if I asked you the same questions here today, would your answers be the same?

A. Yes.

Q. Mr. De May, did you prepare a witness summary for purposes of this hearing?

A. I did.

MR. ROBINSON: Chair Mitchell, at this time I would move that Mr. De May's prefiled testimony, as previously described, and Mr. De May's testimony summary be entered into the record as if given orally from the stand.

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

(Whereupon, the prefiled direct, rebuttal, partial settlement supporting, and second settlement supporting testimony, as well as prefiled testimony summary of Stephen G. De May were copied into the record as if given orally from the stand.)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Stephen G. De May, and my business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601. I am the North Carolina President for Duke Energy Carolinas ("DE Carolinas" or the "Company"), which is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy"), as well as Duke Energy Progress and Progress Energy, Inc., also wholly owned subsidiaries of Duke Energy.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have a Bachelor of Arts degree in Political Science from the University of North Carolina at Chapel Hill and a Master of Business Administration degree from the McColl School of Business at Queens University in Charlotte, North Carolina. In 2010, I completed the Advanced Management Program at the Wharton School of the University of Pennsylvania. I am a Certified Public Accountant ("CPA") in the state of North Carolina and I am a member of the American Institute of Certified Public Accountants and the North Carolina Association of Certified Public Accountants.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. My professional work experience began in 1986 with the public accounting firm of Price Waterhouse (now PricewaterhouseCoopers) and, subsequently, Deloitte, Haskins and Sells (now Deloitte & Touche), where my work focused on tax accounting and consulting for a variety of clients. In 1990, I joined Crescent Resources, Inc., a then wholly-owned real estate development subsidiary of Duke Power Company (a predecessor company to today's Duke Energy) where I was responsible for real estate accounting and finance. In 1994, I moved to the Treasury and Corporate Finance Department where I held, except for a two-year period, various finance-related positions of increasing responsibility. The two-year exception was for the majority of 2004 and 2005, during which time I had the lead responsibility for developing and managing Duke Energy's energy and regulatory policies. I was named Treasurer in 2007, a position I held until my current role. While Treasurer, I also served, at separate times, as Chief Risk Officer, head of Investor Relations and head of Tax. I assumed my current position as North Carolina President in November 2018.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I lead Duke Energy's regulated electric utility businesses in North Carolina, which include serving approximately 2 million DE Carolinas electric customers. I am responsible for the financial performance of the Company's electric utility in North Carolina and managing state and local regulatory and governmental relations, and community affairs. I also have responsibility for advancing the Company's legislative and regulatory initiatives related to its electric operations.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I testified before this Commission in the Company's 2009, 2011 and 2017 rate cases (Docket Nos. E-7, Sub 909; E-7, Sub 989, and E-7, Sub 1146 respectively). I also testified before this Commission in Duke Energy Progress' 2013 and 2017 rate cases (Docket No. E-2, Sub 1023 and E-2, Sub 1142). I have also filed testimony for Duke Energy in various proceedings before the South Carolina, Ohio, Indiana, and Kentucky commissions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide a brief overview of DE Carolinas' Application in this case. In my testimony, I note the key drivers of the Company's Application and how the requested rate increase will allow the Company to remain a financially strong utility that is well positioned in financial markets to the benefit of our customers. I also describe the three major elements of our Application, which are: (1) how we are making investments in a manner that improves service to our customers and improves the customer experience; (2) the steps we are taking to transition from our reliance on coal, including the responsible management and closure of coal ash basins; and (3) how we are exploring additional ways to better assist our customers most in need.

II. OVERVIEW AND CONTEXT OF THE COMPANY'S APPLICATION

Q. WHY DOES THE COMPANY BELIEVE THAT NOW IS THE TIME TO FILE THIS APPLICATION?

A. The conditions under which we operate continue to evolve since 2017, the year of DE Carolinas' last base rate proceeding, challenging our ability to continue to provide the type of electric service our customers expect. The Company is seeing and experiencing significant changes throughout many aspects of the electric industry, and the investments we have made and must continue to make are designed to keep pace with evolving customer needs and expectations. These investments are capital-intensive and the Company has incurred costs that are not otherwise reflected in current rates. Through testimony in this case, we clearly explain why a rate change is needed to support these drivers. We also describe how the Company has performed, and will continue to perform, through thoughtful planning and prudent investment to continue to provide safe, reliable and efficient electric service.

Q. PLEASE DESCRIBE THE MAJOR DRIVERS BEHIND THE COMPANY'S APPLICATION.

A. The energy sector is in a period of transformation and profound change driven by technological advancements, environmental mandates, storm activity and response, energy security and resiliency efforts, as well as changing customer expectations. We are taking steps to anticipate and keep pace with the changes occurring in our state, and this rate application reflects three general themes that demonstrate our attention to the needs of our North Carolina customers.

IMPROVING THE CUSTOMER EXPERIENCE AND RELIABILITY

Technology is transforming North Carolina, and changing the way customers use electricity and interact with their electric provider. Reliability remains essential as an increasingly connected population continues to expand, especially in urban areas of the state. Today, the need for consistent, reliable service isn't just the expectation of industry and manufacturing, but extends into every home and business—even at a time when that reliability is challenged by the increasing frequency of severe weather events and the threat of physical and cyber-attack. Customers today want a new and better experience, driven by information about how they consume energy and by tools that help them manage their consumption. From investments in cleaner, highly-efficient generation resources to plans to invest in our distribution grid, smart meters, and the tools we use to communicate with our customers, you will read and hear testimony from several witnesses in this case describing the steps the Company has taken to continuously improve the service our customers receive from, and the interactions they have with, DE Carolinas.

In this category, Witness Jay Oliver discusses the Company's Grid Improvement Plan and how that Plan works now and into the future to improve the customer experience and reliability, and Witness Donald Schneider discusses how our deployment of smart meters has worked and will continue to work well with our investments to modernize our grid. Witness Rufus Jackson details the challenges we faced with storms and severe weather in 2018 and how the Company was successfully able to restore power to over a million customers, quickly and efficiently. Witness James Henning describes the high-quality customer service provided by DE Carolinas and the efforts that the Company has taken to improve the customer experience when they interact with us, and Witness Marc Arnold discusses how our lighting programs continue to improve to meet the expectations and needs of our lighting customers.

MOVING PAST COAL

The Company is actively working towards achieving a lower carbon future by taking steps to close the final chapters on coal ash and reduce our reliance on coal-fired generation. We understand the need to protect the natural beauty and environment of North Carolina in a responsible manner while keeping prices as low as reasonably possible. Through testimony in this case, we describe steps we have taken to comply with environmental regulations for the disposal of coal combustion residuals, including the investments necessary to support ash basin closure activities, and investments we have made in generation resources like natural gas and solar. As part of our strategy to reduce our reliance on coal, we have taken a fresh look at the viability of several of our coal-fired plants and have concluded that making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now, while we continue to monitor the changing industry landscape and impacts of market forces.

In this area, Witness Jessica Bednarcik discusses investments necessary to support ash basin closure under federal and state regulatory requirements, and witness Steve Immel discusses our fossil/hydro fleet and how that fleet is becoming cleaner and more efficient as we make this transition. Witness John Spanos addresses the shortened depreciable lives for our coal-fired plants, and Witness Steven Capps explains how our high-performing nuclear fleet has and will continue to provide North Carolina carbon free generation now and into the future.

LOW-INCOME CUSTOMER SUPPORT

DE Carolinas is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship. The assistance programs that we offer, such as the Share the Warmth program, and our portfolio of demand-side management ("DSM") and energy efficiency ("EE") programs, including the Neighborhood Energy Saver Program, have helped many of our customers reduce energy costs, pay home energy bills, manage fluctuations in their monthly bill, and manage through the difficulty of paying their entire bill by the due date. We want to do even more for these customers, particularly those most in need, and are considering ways for the Company and our customer base to continue to be good stewards.

In this area, Witness Karl Newlin discusses how the Company has proposed a return on equity of 10.3% as a rate impact mitigation measure instead of the 10.5% that Witness Robert Hevert has offered. Witness Pirro discusses how the Company has not requested an increase in the Basic Facilities Charge ("BFC") for customers in this application, even though an increase is warranted, so that the Company and interested stakeholders can have the time and the opportunity to collaborate on ways to help low-income customers in our rate design. Witness Jane McManeus discusses proactive decreases that we have made in our filing (such as reductions to executive compensation) to give customers the benefit of reductions that the Company has agreed to in previous rate cases, and Witness Henning discusses our proposal to eliminate direct credit card fees for all our residential customers who pay their electric bills in that manner. Finally, as I will more fully discuss below, I propose other ways that we may be able to help our low-income customers.

Q. WHAT OTHER WAYS ARE YOU PROPOSING THAT THE COMPANY MAY CAN HELP MITIGATE PRICE IMPACTS ON CUSTOMERS WHO ARE MOST IN NEED?

A. DE Carolinas is convinced that more low-income energy assistance programs can be offered to aid customers in need of support and we have ideas for several low-income programs that we believe could help accomplish this goal. For example:

- Low-Income Bill Credit on the BFC: A fixed monthly bill credit off the BFC that would apply to qualifying customers' bills.
- Bill Round-Up Program: A voluntary program allowing customers to round-up bill payments to the next dollar and the difference would then be forwarded to an energy assistance foundation to help provide financial assistance with electric bills.
- Expansion and Retooling of the Supplemental Security Income (SSI) Price Discount: The Company currently has a discount program where certain customers receiving SSI are eligible to receive a discounted rate

for the first 350 kWh of use per month. The Company proposes to expand the eligibility for and increase the amount of the discount as well as extend the program to DE Progress customers.

Before seeking to implement these programs, the Company believes that stakeholder engagement is necessary to adequately consider these and other programs to develop an appropriate suite of effective options for the Commission to consider for approval. Accordingly, the Company requests that as part of its order in this case, the Commission direct the Company to host, and the Public Staff to participate in, a collaborative workshop with interested stakeholders to address the establishment of new low-income programs at DE Carolinas and require that the Company and/or the Public Staff file a final report with the Commission outlining the feedback and recommendations obtained in that workshop. The Company proposes to use the feedback and recommendations it receives from participants in such a workshop to form formal requests to the Commission for new, low-income programs.

Q. HAS THE COMPANY CONSIDERED ANY OTHER WAYS TO REDUCE THE IMPACT OF THIS REQUESTED RATE INCREASE TO ITS CUSTOMERS?

A. Yes. In this case, the Company is requesting a determination from the Commission that the storm costs submitted for recovery and supported in the testimony of Witness Jackson are reasonable and prudent. If the Commission issues a determination that the storm costs submitted are approved as reasonable and prudent for recovery in this case, the Company proposes to begin recovering those costs in current rates in the manner described by Witness McManeus in her testimony. 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.

Q. HAS THE IMPACT OF THE 2017 TAX CUTS AND JOBS ACT BEEN INCORPORATED INTO THE COMPANY'S REQUEST?

A. Yes. As explained by Witnesses John Panizza and McManeus, the proposed rates include a reduction from the corporate income tax rate from 35 percent to 21 percent. The Company also includes a proposal to return to customers, through a rider, excess federal and state deferred income taxes ("EDIT") and deferred revenue resulting from federal tax reform legislation (i.e., the 2017 Tax Cuts and Jobs Act) and reductions in the North Carolina corporate income tax rate.

III. IMPORTANCE OF A STRONG FINANCIAL POSITION

Q. WHY IS IT IMPORTANT TO MAINTAIN A STRONG FINANCIAL POSITION FROM THE STANDPOINT OF DE CAROLINAS' CUSTOMERS?

A. DE Carolinas is making and will continue to make important investments in our infrastructure to make it stronger, smarter, cleaner and more efficient. It is our responsibility to plan ahead and make these investments efficiently and prudently. To deliver on these promises, it is critical that we maintain a strong financial position and thereby ensure that the Company has the financial strength and flexibility to not only fund long term capital requirements, but to ensure the ability to meet short term funding needs as well. The single-most determinative factor of a healthy balance sheet and strong financial position is timely recovery of costs and the ability to generate cash flows sufficient to meet obligations as they become due, in all market conditions.

Q. PLEASE DISCUSS THE BENEFITS TO CUSTOMERS OF DE CAROLINAS MAINTAINING A STRONG FINANCIAL POSITION.

A. Witness Newlin describes these in greater detail, but I think it is important to emphasize the benefits that result from our overall request in this proceeding, particularly our request on return on equity, capital structure and timely recovery of costs. Historically, because of its financial position, the Company has had the financial strength and flexibility necessary to fund its long-term capital requirements, as well as to meet short-term liquidity needs, at an economical cost to customers. As such, DE Carolinas has been able to obtain cost-effective capital, something that has benefited customers and will continue to benefit customers as we continue to make the large investments required to provide a more robust, more efficient, smarter and cleaner electric delivery system. As important as low cost is, ready access to capital is critical to serving our customers. Access to capital is most assured for companies who have strong financial positions, strong investment-grade credit ratings and adequate cash flow generation to meet obligations as they become due. The financial flexibility that comes from the ability to access cost-effective capital in all market conditions, in such a capital-intensive industry, serves the best interests of our customers.

Q. PLEASE SUMMARIZE WHY DE CAROLINAS' REQUEST IN THIS PROCEEDING IS SO IMPORTANT FROM THE STANDPOINT OF THE INVESTMENT COMMUNITY.

A. Witness Newlin addresses this in detail, but I would like to make some general observations on this critical subject. DE Carolinas has enjoyed strong and cost-effective access to capital markets for years. This is a result of maintaining a strong balance sheet and constructive regulation that has recognized the need for an appropriate rate of return to Duke Energy's equity investors. Given our ongoing need for tremendous amounts of investor-supplied capital now and in the coming years, the Commission's decisions in this proceeding regarding the Company's return on equity, capital struture and the timely cash recovery of its costs will be critical.

IV. CONCLUSION

Q. WHAT IS THE KEY OBJECTIVE OF THE COMPANY'S REQUESTED GENERAL RATE ADJUSTMENT?

A. As I mentioned at the beginning of my testimony, the power business has entered a period of transformation and profound change driven by technological, environmental and operational forces, as well as changing customer expectations. Within this sea change, the Company recognizes that its most important objectives are to continue providing safe, reliable, affordable, and increasingly clean electricity to our customers with high quality customer service, both today and in the future. To achieve this, the Company must continue to invest in improving our grid; the transition from our reliance on coal, including our responsible management and closure of coal ash basins; investing in ways to make the energy we produce cleaner, more diverse, more reliable, and even more efficient for the benefit of our customers; and investing in new technologies to enhance the customer experience. Our Application is therefore made to support investments that benefit North Carolina and our customers while preserving the Company's financial position all while keeping prices as low as reasonably possible.

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

A. Yes.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.

A. My name is Stephen G. De May, and my business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601. I am the North Carolina President for Duke Energy Carolinas ("DE Carolinas" or the "Company"), which is a wholly owned subsidiary of Duke Energy Corporation ("Duke Energy"), as well as Duke Energy Progress and Progress Energy, Inc., also wholly owned subsidiaries of Duke Energy.

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this docket.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I introduce the Company's rebuttal case and witnesses, and address certain aspects of intervenors' proposals that, if accepted, would have a negative impact on the Company and, by extension, its customers.[1]

[1] The absence of specific rebuttal on the part of DE Carolinas to any policy concern, accounting adjustment or ratemaking issue proposed by an intervenor does not constitute acceptance of the recommendation made by the intervenor, nor does it reflect agreement with any calculations made by intervenors.

Q. ARE OTHER COMPANY WITNESSES PROVIDING REBUTTAL TESTIMONY?

A. Yes. All of our direct witnesses in this case are providing rebuttal testimony today with the exception of witnesses Kimberly McGee, Rufus Jackson, John Panizza, Teresa Reed, and Donald Schneider. The Company is also filing rebuttal testimony from DE Carolinas' witnesses Conitsha Barnes, David L. Doss Jr., Lon Huber, Renee Metzler, James Wells and Steven K. Young, and external expert witnesses Rudolph Bonaparte, Steven Fetter, Sean Riley, and Marcia Williams.

Q. IS THE COMPANY SUBMITTING TESTIMONY IN RESPONSE TO THE COMMISSION'S ORDER ISSUED ON JANUARY 22, 2020, DIRECTING THE PUBLIC STAFF TO FILE TESTIMONY ON FOUR TOPICS?

A. Yes. Witness Hager addresses the Public Staff's testimony concerning cost of service methodologies in her pre-filed rebuttal testimony and Witness Barnes addresses the Public Staff's testimony on the proposed stakeholder process to review affordability of electricity within the Company's service territory in her pre-filed rebuttal testimony. The depreciation and decommissioning of the Company's coal plants is addressed in the rebuttal testimony of Witness Spanos. Finally, Witness Bednarcik responds to the testimony of the Public Staff on coal combustion residual compliance costs in her rebuttal testimony.

III. KEY POINTS OF REBUTTAL CASE

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S VIEW OF THE PUBLIC STAFF AND INTERVENOR TESTIMONY FILED RECENTLY IN THIS CASE.

A. The State of North Carolina is at a crossroads in terms of its energy and regulatory policy. On one hand, the Governor has outlined aggressive goals to significantly reduce greenhouse gases, including carbon emissions by 2030. As the State's largest electric utility, these goals will require the Company to accelerate the move beyond coal and coal ash; safely and reliably facilitate thousands more megawatts ("MWs") of renewable energy resources such as solar, wind and energy storage; continue to improve the efficiency of its current generation fleet; continue (and seek to further extend) the operation of and investment in the Company's carbon-free nuclear fleet; and expand energy efficiency and demand-side management measures, all while consistently delivering electric service that is safe and reliable at low cost.

On the other hand, if accepted by this Commission, many of the recommendations set forth by the Public Staff and other intervenors would negatively affect the Company's financial ability to make these investments and help the State achieve its desired energy future. Regulatory outcomes that are contrary to well-established principles and that fail to strike the right balance between the Company and its customers would be detrimental to the State, just at a time when the State's policymakers are positioning North Carolina as a leader on climate policy and as one of the premier states in which to do business.

To transform our business and to meet the needs and desires of our customers and the State, DE Carolinas needs the consistent and timely recovery of its prudently-incurred costs and investments, as well as the continued ability to access capital at reasonable rates on favorable terms. The recommendations the intervenors make in this case materially challenges these core principles. DE Carolinas' requests to recover or defer costs for the *exact* types of investments that will transition the State to a lower carbon future and allow the Company to partner with the State to achieve its goals. These investments include: 1) the closure of the Company's coal ash basins in compliance with Federal and State laws and regulations, 2) accelerating the depreciable lives of some of the Company's coal-fired plants to foster more rapid plant closures, 3) investment in the Grid Improvement Plan, and 4) dual fuel conversions at some of the Company's plants for increased flexibility and lower fuel costs.

While there is a never a good time for a rate increase, the requests put forth by the Company in this case are needed to reflect in rates the prudent investments it made for the benefit of its customers. If the Commission were to accept the recommendations of the Public Staff and intervenors, it would reverse years of constructive regulation that has enabled DE Carolinas to perform at high levels while maintaining rates well below the national average. A significant change in the balance and constructiveness of the State's regulatory environment would reduce the Company's financial strength and flexibility, which would be to the detriment of customers now and in the long-term.

Q. HOW WOULD YOU RATE THE COMPANY'S QUALITY OF SERVICE?

A. The Company's performance by any measure has been outstanding for decades. The Company's rates for all classes of customers are well below the national average and have been for decades. The Company has been repeatedly recognized as a leader in the industry in storm restoration and over the last 3 years has been able to restore service to 95% of its customers within a few days over the course of hurricanes and a winter storm. The Company's nuclear fleet is recognized as being one of the best in the industry in terms of safety, reliability/availability and production costs. The Company's Fossil and Hydro operations have similar superior safety, reliability and production cost performance, while reducing carbon emissions by 39% from 2005 levels. The Company's transmission and distribution reliability has performed well, and we have continued to provide safe and reliable electric service; we have deployed new smart meters across our jurisdiction and are in the process of replacing the Company's outdated customer information system with a new, modern customer service platform that will transform how the Company serves customers by providing them with the easy, personalized experiences they expect from other service providers.. The Company's Economic Development organization – named one of the nation's leaders for the last 15 years – has brought more than two hundred businesses to the state, totaling $13 billion of capital invested in the State, 26,000 jobs and generated billions in tax revenues.

Many more examples are described by Company witness Hatcher in his direct testimony.

Notwithstanding the Company's responses to 7,955 data requests, providing 18,652 files consisting of 423,852 pages of documentation, not a single intervenor contests any of the aforementioned quality of service facts. As witness Hatcher states in his direct testimony, we are a well-run company and we believe that customers see and experience the benefits of our efforts every day. Nevertheless, in response to the Company's filing, intervenors propose that the Commission respond to the Company's performance with the following:

- Award the Company the lowest ROE in the nation for vertically integrated utilities and, at best, the national average – notwithstanding the performance and risk profile of the Company in the current regulatory environment;
- Reduce the Company's equity structure, which would further impair its financial health, earnings growth and balance sheet strength, and weaken its ability to earn a reasonable return;
- Disallow billions of dollars of costs associated with coal ash impoundment closure;
- Disallow any return – including even a debt return – on prudently incurred coal ash management costs over decades to come; essentially requiring the Company to borrow billions of dollars over the next 30 years without being able to recover the interest expense it incurs, receive the time value of the money borrowed, or receive an equity return;
- Limit the Company's ability to defer expenses necessary to modernize the electric grid and enable greater distributed energy resources; and
- Simultaneously require the Company to flow back hundreds of millions of dollars in excess deferred income taxes to customers immediately or in the very short term – and, in stark contrast to intervenors' position on recovery of coal ash costs, if over time then with interest at the Company's weighted average cost of capital.

Many of the intervenors' positions are antithetical to established regulatory rules and precedent, including precedent as recently as established as the Company's 2017 rate case in Docket No. E-7, Sub 1146. If adopted by this Commission, those measures would send a strong and clear signal to investors that the stable regulatory environment that has benefitted customers for the last 50 years with some of the lowest electric rates in the country has fundamentally shifted. The intervenors' positions, if adopted, would also send a clear message to rating agencies, which likely would result in an immediate downgrade of the Company's credit quality causing a further deterioration of the Company's balance sheet, increasing its cost of capital, and adversely affecting the terms on which the Company can borrow the billions of dollars of funds it needs to maintain a growing and changing system. Company witnesses Fetter, Hevert, Newlin, and Young will explain these potential ramifications in greater detail.

Q. PLEASE DESCRIBE THE ENERGY POLICY SIGNALS COMING FROM THE STATE OF NORTH CAROLINA AS THEY RELATE TO THE COSTS THE COMPANY SEEKS TO RECOVER IN THIS CASE.

A. Around the same time the Company filed its Application in this Docket, the Department of Environmental Quality ("DEQ") presented to the Governor its Clean Energy Plan ("CEP") to meet North Carolina's goals to 1) "reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and obtain carbon neutrality by 2050, 2) foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes, and 3) accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state."[2] As DEQ notes, "[t]o successfully transition to a clean energy future, North Carolina must establish a 21st-century regulatory model that ***incentivizes business decisions that benefit both the utilities and the public in creating an energy system that is clean, affordable, reliable, and equitable***."[3] As part of the CEP, DEQ makes the following key recommendations it deems "critical to the transition":

> • Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.
>
> • Develop and implement policies and tools such as performance-based mechanisms, multiyear rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy.
>
> • Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.[4]

The Company's Application seeks to recover or defer costs for the very investments the CEP promotes: 1) the closure of our coal ash basins in compliance with Federal and State laws and regulations, 2) accelerating the depreciable lives of some of our coal-fired plants to foster more rapid plant closures, 3) investment in the Grid Improvement Plan, and 4) dual fuel optionality conversions. A fair capital structure and return on equity that will likewise recognize the Company's

[2] https://deq.nc.gov/energy-climate/climate-change/nc-climate-change-interagency-council/climate-change-clean-energy-16 (last visited February 27, 2020).
[3] *Id* (emphasis added).
[4] *Id.*

strong performance and allow it to continue to access the capital markets on favorable terms necessary to fund these investments is warranted.

In terms of the Company's proposal to accelerate the depreciable lives of some of its coal-fired units, the Company understands the Public Staff's position to stick with the status quo and not accelerate the retirement dates in the Company's Depreciation Study. Company witness Spanos addresses the Public Staff's position in his testimony; however, in line with the desires of the State, the Company anticipates ongoing pressure to meet aggressive carbon reduction and emissions goals and to adapt further climate change-related policymaking. The Company already faces calls for early retirement of its coal-fired generating units,[5] so it is seeking to take proactive steps in this case to position itself to meet these expectations. The Company believes the time to act on this highly foreseeable policy shift is now.

Q. HAVE THERE BEEN ANY OTHER NEW DEVELOPMENTS THAT SUPPORT THE COMPANY'S APPLICATION SINCE THE TIME OF THE FILING?

A. Yes. Another new development since the Company filed its Application in this Docket, is the passage of Senate Bill 559, an Act to Permit Financing for Certain Storm Recovery Costs ("SB 559"), by the North Carolina General Assembly which provides utilities an alternative to finance storm costs through securitization. The Company is pleased SB 559 passed and believes it will lead

[5] In fact, while the Company submits that a rate case proceeding is not the proper proceeding in which to address the economics of continued operation of its coal-fired units, both the Sierra Club and the Center for Biological Diversity & Appalachian Voices submitted testimony in this proceeding opposing recovery of the costs related to the continued operation of certain coal-fired units.

to savings for its customers. The Company looks forward to pursuing securitization at the appropriate time; however, these costs must remain a part of the Company's request in this proceeding until the Commission reaches the same determination of the Company and the Public Staff[6] that the costs were prudently incurred, and the Commission subsequently approves a financing petition. As I stated in my direct testimony:

> . . . . [T]he 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.* Accordingly, witness McManeus details the accounting adjustment needed to support the Company's position.[7]

Witness McManeus describes the removal of the Public Staff's proposed adjustment to remove the storm costs from the Company's requested revenue requirement.

Q. IN TERMS OF LOW-INCOME CUSTOMER SUPPORT, DO THE PUBLIC STAFF AND INTERVENORS GENERALLY SUPPORT THE COMPANY'S PROPOSED COLLABORATIVE STAKEHOLDER PROCESS?

A. Yes. We are pleased with the portions of the testimony of Public Staff Witness Floyd; North Carolina Justice Center, et. al. Witness Howat; and the Center for Biological Diversity & Appalachian Voices Witness McIlmoil supporting dialogue on ways the Company can mitigate electricity costs for its low-income

[6] *See* Testimony of Michelle M. Boswell Public Staff – North Carolina Utilities Commission, Docket No. E-7 Sub 1214 at 27-28 (February 18, 2020).
[7] De May Direct Testimony at 11 (*emphasis added*).

customers. The Company looks forward to the opportunity to engage with its interested stakeholders in a collaborative workshop to address this important issue for our customers.

IV. CONCLUSION

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

A. Yes.

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen G. De May, and my business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am the North Carolina President for Duke Energy Carolinas ("DE Carolinas" or the "Company"), which is a wholly owned subsidiary of Duke Energy Corporation, as well as Duke Energy Progress and Progress Energy Inc., also wholly owned subsidiaries of Duke Energy.

Q. DID YOU OFFER ANY DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this docket on September 30, 2019 and rebuttal testimony on March 4, 2020.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the Agreement and Stipulation of Partial Settlement the Company reached with the North Carolina Utilities Commission Public Staff ("Public Staff"), filed with the Commission on March _, 2020 in this docket (the "Partial Settlement"). The Company was able to reach a Partial Settlement with the Public Staff (together, the "Stipulating Parties") subsequent to the Company's filing of its pre-filed direct, rebuttal and supplemental testimony and exhibits and after extensive discovery conducted by the Public Staff and other intervenors. The Partial Settlement represents a balanced settlement for the parties on these issues, is in the public interest, and should be approved by the Commission. My direct and rebuttal testimony remain effective as applicable to the testimony of any non-settling Party, including the unresolved matters between the Company and Public Staff listed in the Partial Settlement.

III. THE PARTIAL SETTLEMENT

Q. PLEASE PROVIDE AN OVERVIEW OF THE MAJOR COMPONENTS OF THE PARTIAL SETTLEMENT.

A. The Partial Settlement resolves several of the revenue requirement issues between the Company and the Public Staff. Most notably, the Stipulating Parties came to a decision to remove the Company's deferred storm expenses, incurred to restore service to the approximately 1.3 million customers that were impacted by Hurricanes Florence and Michael and Winter Storm Diego in late 2018 (collectively, the "Storms"), from its requested increase in this rate case and permit the Company to proceed with filing a petition to securitize these storm costs as permitted by N.C.G.S. § 62-69. Over the last few years, North Carolina has been hit by several severe storms that left hundreds of thousands of people and businesses without power. In 2018, these Storms caused extraordinary damage and widespread outages across the DE Carolinas' distribution system and required a robust response from the Company. This response involved the activation and deployment of storm response teams internal to the Company, utilization of thousands of outside contractors, and the need to seek mutual aid from other electric utilities and allies in the industry. Despite the extraordinary damage to the Company's transmission and distribution systems because of these Storms, I am very proud of the Company's commitment to timely restoration efforts and a positive customer experience, which resulted in more than 83 percent of customers impacted by Hurricane Michael being restored within 72 hours, restoration within 48 hours for more than 90 percent of customers impacted by Hurricane Florence, and more than 95 percent of the customers impacted by Winter Storm Diego.

In 2019 North Carolina lawmakers put legislation in place to alternatively pay for major storm recovery, in a way that reduces costs for customers and allows the Company to recoup its storm-related expenditures to restore the system, harden it, and be better prepared for future storm activity. It is hard to imagine a better time to implement the cost-effective financing provided by the securitization statute than the catastrophic storms of 2018.

Specifically, once the Public Staff conducted its audit of the Company's storm expenses and concluded that such costs were prudently incurred[1], the Stipulating Parties agreed that the Company would remove from Commission consideration in this case its request for recovery of the deferred storm expenses and instead proceed with filing a financing petition within 120 days from the date of the Commission order addressing the prudency of the Company's storm costs in this proceeding. For purposes of settlement, the Stipulating Parties also agreed on the assumptions that will be used in the subsequent securitization

[1] Boswell Direct Testimony at 28.

docket to evaluate whether securitization provides quantifiable customer benefits when compared to traditional storm cost recovery. The Stipulating Parties further agreed that a storm cost recovery rider, initially set at $0, should be established in this rate case to provide the Company a mechanism to request recovery of its storm costs if the Company is unable to securitize its storm costs.

Further, as discussed in greater detail by Company witness Jane McManeus in her testimony, the Stipulating Parties agreed to revenue requirement adjustments for Aviation; Executive Compensation; Board of Directors; Lobbying; Sponsorships and Donations; Rate Case Expenses; Severance; Incentive Compensation; Retired Hydro O&M Expenses; Credit Card Fees; Advertising; Weather Normalization, Growth and Usage; and Protected Federal EDIT.

Q. DOES THE COMPANY AGREE WITH THE AGREED-UPON ADJUSTMENTS AS DESCRIBED IN THE SETTLEMENT AGREEMENT?

A. Yes.

Q. PLEASE ELABORATE ON HOW THE PARTIAL SETTLEMENT BALANCES THE COMPANY'S NEED FOR RATE RELIEF WITH THE IMPACT OF SUCH RATE RELIEF ON CUSTOMERS.

A. I attended public hearings held by the Commission in this matter and personally heard from dozens of our customers who are concerned about the impacts of any rate increase on their families and businesses. We are very mindful of these concerns. Although we are pleased that our rates are competitive and below the national average, and will remain so with this Partial Settlement, we know that providing safe, reliable, increasingly clean electricity at competitive rates is key to powering the State's economy and the lives of our customers. For these reasons, we look forward to using the storm securitization mechanism to help secure storm restoration cost savings for North Carolina energy customers. We also believe the concessions the Company has made in this Partial Settlement fairly balance the needs of our customers with the Company's need to recover investments made to continue to comply with regulatory requirements and safely provide high quality electric service to our customers.

Q. IN THE PARTIAL SETTLEMENT, DID THE COMPANY AND PUBLIC STAFF REACH AGREEMENT ON ALL ISSUES IN THIS DOCKET?

A. No. There are a number of issues that remain disputed between the Company and the Public Staff. Those issues are outlined in the Partial Settlement.

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

A. Yes.

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen G. De May, and my business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am the North Carolina President for Duke Energy Carolinas ("DE Carolinas" or the "Company"), which is a wholly owned subsidiary of Duke Energy Corporation, as well as Duke Energy Progress and Progress Energy Inc., also wholly owned subsidiaries of Duke Energy.

Q. DID YOU OFFER ANY DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony in this docket on September 30, 2019; rebuttal testimony on March 4, 2020; and partial settlement supporting testimony on March 25, 2020.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the Second Agreement and Stipulation of Partial Settlement the Company reached with the North Carolinas Utilities Commission Public Staff ("Public Staff") (together, the "Stipulating Parties"), filed with the Commission on July 31, 2020 in this docket (the "Second Partial Settlement"), and introduce several other witnesses that support the reasonableness of the Second Partial Settlement. The Company was able to reach a Second Partial

Settlement with the Public Staff subsequent to the Company's filing of its pre-filed direct, rebuttal and supplemental testimony and exhibits; extensive discovery conducted by the Public Staff and other intervenors; and prior settlements reached with the Public Staff, the Commercial Group, CIGFUR, Harris Teeter, Vote Solar, NCSEA, NCJC, NCHC, NRDC, and SACE in this proceeding. The Second Partial Settlement represents a balanced settlement for the Stipulating Parties on these issues, is in the public interest, and should be approved by the Commission. My direct and rebuttal testimony remain effective as applicable to the testimony of any non-settling party, including the unresolved matters between the Company and Public Staff listed in the Second Partial Settlement. Additionally, my settlement supporting testimony remains effective as applicable to the first partial settlement the Company entered into with the Public Staff.

III. THE PARTIAL SETTLEMENT

Q. PLEASE PROVIDE AN OVERVIEW OF THE MAJOR COMPONENTS OF THE SECOND PARTIAL SETTLEMENT.

A. Overall, the Second Partial Settlement resolves most, but not all, of the remaining revenue requirement issues between the Company and the Public Staff. I describe the Unresolved Issues later in my testimony.

As discussed by other Company witness testimony being filed today by Jane McManeus, Dylan D'Ascendis, and Karl Newlin, the agreement reached between the Stipulating Parties in the Second Partial Settlement can be summarized as follows:

Shareholder Contribution – The Company has agreed to make an annual $2.5 million shareholder contribution to the Share the Warmth Program in 2021 and 2022, for a total contribution of $5 million.

Cost of Capital – The Stipulating Parties have agreed to a return on equity of 9.6 percent, based upon a capital structure containing 52 percent equity and 48 percent debt as described by Witnesses D'Ascendis and Newlin. The Company's debt cost rate shall be set at 4.27 percent. The resulting weighted average rate of return is 7.04 percent.

EDIT – The Stipulating Parties have agreed to several terms in the Second Partial Settlement addressing the return of state and federal excess deferred income taxes ("EDIT") to customers. For example, the Company has agreed to return to customers the total unprotected federal EDIT amount over a five-year period and North Carolina EDIT over a two-year period. Additionally, if state or federal income tax rates happen to change again during the respective flowback periods, the Company may, under certain conditions, propose to reflect the effect of any future tax rate change on the remaining EDIT balance.

Grid Improvement Plan – The Public Staff has agreed to the Company's requested 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), Integrated Volt Var Control ("IVVC"), Integrated System and Operations Planning ("ISOP"), Transmission System Intelligence, Distribution Automation, Power Electronics, DER Dispatch Tool, and Cyber Security. For all other Grid Investment Plan ("GIP") investments proposed by the Company in this docket, the Company agrees that it will withdraw its request for deferral accounting. Further, the Company, in conjunction with the concurrent commitment of DE Progress, and the Public Staff will work together to develop biannual reporting requirements to track GIP expenditures that receive accounting deferral treatment.

<u>Cost of Service</u> – The Public Staff has accepted, for this case only and subject to agreement on certain conditions outlined in the Second Partial Settlement, the Company's proposal to calculate and allocate the Company's cost of service based on a 1CP Summer methodology.

<u>May Updates</u> - The Stipulating Parties have agreed to include the Company's updates to certain pro forma adjustments through May 31, 2020 ("May Updates"), pending and subject to the Public Staff's audit of the updates. In addition, the Stipulating Parties have agreed to limit the update to revenues to 75% of the difference between the May Updates and the Company's January update to recognize the uncertainty regarding the effects of COVID-19. The Stipulating Parties further agreed that the May Updates shall also include updates for benefits and executive compensation through May 2020.

Clemson CHP – The Company has agreed to a system disallowance of $19.1 million for the Clemson Combined Heat and Power Project.

Non-ARO Environmental Costs – The Stipulating Parties have agreed to amortize deferred non-asset retirement obligation ("non-ARO") environmental costs over an eight-year period.

Other Areas of Agreement – The Stipulating Parties have also agreed to terms governing the start date of the evidentiary hearings to allow time for the Public Staff to audit the May Updates; ongoing assessments of the cost effectiveness of GIP-related projects; clarification of GIP costs that are eligible for deferral; commitments to future cost of service studies; rate design issues; commitments to conduct audits and reporting obligations regarding plant and materials & supplies inventory.

Q. DOES THE COMPANY AGREE WITH THE CHARACTERIZATION OF THE AGREED-UPON ADJUSTMENTS AS DESCRIBED IN THE SETTLEMENT AGREEMENT?

A. Yes.

Q. PLEASE ELABORATE HOW THE PARTIAL SETTLEMENT BALANCES THE COMPANY'S NEED FOR RATE RELIEF WITH THE IMPACT OF SUCH RATE RELIEF ON CUSTOMERS.

A. I attended public hearings held by the Commission in this matter and personally heard from many of our customers who are concerned about the impacts of any rate increase on their families and businesses. I also followed the consumer statement positions filed in this Docket. We are very mindful of these concerns. Although we are pleased that our rates are competitive and below the national average, and will remain so with this Second Partial Settlement, we know that providing safe, reliable, increasingly clean electricity at competitive rates is key to powering the State's economy and the lives of our customers. Particularly in light of the current economic conditions of many of our customers due to the COVID-19 pandemic, we believe that the concessions the Company has made in this Partial Settlement fairly balance the needs of our customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to our customers. Our electric rates need to be adjusted to reflect these investments. Moreover, given the size of the necessary capital and compliance expenditures we are facing, it is essential that DE Carolinas maintain its financial strength and credit quality so that we will be in a position to finance these needs on reasonable terms for the benefit of our customers. In my opinion, we have been able to strike that balance with this Partial Settlement on the agreed upon items. However, we remain concerned about cost recovery for the Unresolved Items, as that is critical to the financial health of the Company.

Just a few of the ways we have struck this reasonable balance include: (1) the Company's willingness to settle for rates designed on the basis of a 9.6 percent return on equity and a 52 percent equity component of its capital structure, both of which will mitigate the impact of the rate increase on customers; (2) the Company's willingness to accept an overall lower revenue requirement will also mitigate the impact on customers; and (3) the Company's agreement to contribute $5 million to help many of our most vulnerable customers pay their electric bills.

Q. IN THE PARTIAL SETTLEMENT, DID THE COMPANY AND PUBLIC STAFF REACH AGREEMENT ON ALL ISSUES IN THIS DOCKET?

A. No. As I noted previously, a number of issues remain disputed between the Public Staff and the Company: (1) the Company's request to recover its deferred coal ash costs and its ongoing environmental compliance costs necessary to safely close the Company's coal ash basins; (2) the depreciation rates appropriate for use in this case, including whether the Company's proposal to shorten the lives of certain coal-fired generating facilities should be approved; (3) whether the Company's proposed amortization period of 7 years for the loss on the sale of certain hydroelectric facilities should be approved compared to the Public Staff's recommended 20 year amortization period; and (4) any other revenue requirement or non-revenue requirement issues other than those issues specifically addressed in the Stipulation or agreed upon in the testimony of the Stipulating Parties.

Q. IS THE COMPANY PRESENTING TESTIMONY OF OTHER WITNESSES IN SUPPORT OF THE AMENDED STIPULATION?

A. Yes. DE Carolinas' Witness McManeus supports the adjustments, rate making and accounting aspects of the Stipulation, while Witness Newlin supports the capital structure provided in the Stipulation. Finally, Witness D'Ascendis supports the overall return and capital structure provided in the Partial Settlement.

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

A. Yes.

My name is Stephen De May and I am the North Carolina President of Duke Energy Carolinas. Chair Mitchell and members of the Commission, I am pleased to appear before you today to put our rate application in perspective and provide insight into the Company's future priorities. Normally I would offer these remarks at the start of the hearing, but the restructured proceeding caused a change in our witness line up.

Rate cases are complex undertakings and they serve a vital role in the service to our electric customers in North Carolina. I would like to thank this Commission, the Public Staff, the intervenors in this proceeding, and the citizens who came to public hearings across our great state. We are aligned with all parties that this proceeding should strike a balanced outcome that benefits customers and ensures the Company's ongoing ability to serve them at the highest level. I would also like to thank my colleagues from Duke Energy. Those involved in putting this rate application together worked hard to put a serious, thoughtful and balanced case in front of this Commission. Their focus on our customers, and their efforts to build for this hearing a record of prudent utility management is matched *only* by the dedication of the thousands of others in our Company who come together every day to reliably power the lives and businesses of North Carolina.

Even before COVID-19, I would have said that we live in interesting times. But events since the pandemic began, including the tragic loss of life, the loss of jobs and businesses from the economic downturn, the upheaval to our way of life, and the rising focus on social and racial injustice, demonstrate that our country and our state are sailing through very rough seas right now, fraught with uncertainty. Duke Energy's role in all of this is clear: We must continue providing the essential service of electric power—deliver it reliably, affordably, with an eye on the conditions our customers are currently experiencing and with an eye on the future. The pandemic notwithstanding, our customers want cleaner energy, they want more convenience and control over their usage, and they want relief for those among us who are least able to afford their power bills. We want those same things too, and we plan, we invest, and we innovate to deliver them.

Three general themes define our request to adjust rates. They are: Improving the Customer Experience, Moving Past Coal, and Low-Income Support. I will take a moment to touch on each.

We continue to improve the experience our customers have in their relationship with Duke Energy, and to provide additional tools that increase convenience and control related to their usage. My fellow panelist Larry Hatcher provides great perspective on our customers' experience in his testimony. We are also seeking Commission approval to defer, for accounting purposes, investments in our grid improvement plan over a 3-year period. This plan, already described in great detail by Witness Jay Oliver, is foundational to our ability to continue bringing such benefits to our customers in a timely, cost-effective way, to supporting reliability and to transition to cleaner energy.

As the Company works diligently towards its goal of a low-carbon future, it is writing the final chapters on coal ash and coal-fired generation. We are responsibly managing the disposition of coal combustion residuals, simultaneously complying with federal CCR rules, state-level CAMA requirements, and a comprehensive settlement with North Carolina's Department of Environmental Quality, the Southern Environmental Law Center, and others. These actions are good for the state and our customers, and they position North Carolina as a leader in the resolution of an operational challenge facing utilities across the United States. The Company is seeking fair and equitable recovery of its coal ash mitigation costs, including a reasonable rate of return on investor capital needed to bring closure to the byproduct of burning coal.

Another important chapter closing on coal relates to our currently-operating coal generation facilities. Today, these facilities are critical to serving load and, in some cases, to system integrity and support. But the end of their useful lives is approaching, more quickly than anyone would have thought even just a couple of years ago. Expected retirement dates are accelerating, and we believe it is prudent to prepare for this by likewise accelerating the depreciation of our coal fleet. Few things are as foreseeable now as the end of coal-fired generation in North Carolina and we are asking the Commission to approve our proposal to continue to address it. No one will want to deal with the issue of unrecovered book values down the road while simultaneously constructing replacement generation, so let's deal with it now while there is still time.

Low-income support is prominent in this rate application, but it is also, importantly, a pillar of our future plans. Our original filing in this docket provides for no-change to the Basic Facilities Charge, a reduction to ROE, the elimination of direct fees assessed on credit or debit card payments, and a request of this Commission to direct the Company and the Public Staff to conduct a collaborative process, with other parties, to evaluate and develop new tools and measures to assist low-income customers with their electric bills. Our commitment to customer assistance then expanded through the many settlements we reached with intervening parties, including significant contributions of shareholder funds to low-income energy assistance programs—a total of $16 million over the next two years between Duke Energy Carolinas and Duke Energy Progress – as well as an agreement to explore an on-tariff financing pilot program.

I would be remiss if I didn't mention other steps we took to benefit our customers, including our plan to pull significant 2018 storm costs from this rate proceeding and proposing instead to securitize such costs under the provisions of recently enacted SB-559. This complex financing tool will deliver valuable savings for customers. Our customers will also benefit from an agreement to further reduce ROE and to flow back excess deferred income taxes on an accelerated timeline. These benefits are especially helpful to mitigating the challenging conditions brought on by the current pandemic.

As I close my remarks, let me end on a concept I opened with: Balance. Under the laws of this state, we have the obligation and privilege to serve our franchised customers, and to do so reliably and affordably. In return, as a regulated, investor-owned utility, we are allowed to recover our prudently-incurred costs, as well as a fair and reasonable return on investor capital. That compact sits at the intersection of customer interests and those of the Company and its investors. For the reasons articulated by Steve Young last week, we urge the Commission to consider the harm that certain intervenor positions would do to this compact and to this balance—for example, the Public Staff and the Attorney General's positions on coal ash are unprecedented, harmful to the financial integrity of the Company, and inconsistent with the law and the precedent this Commission set just two years ago.

The State of North Carolina is positioned to become a leader in energy and climate policy and is one of the premier states in which to live and do business. It is home to Duke Energy. We stand ready to deliver the energy future our customers expect and deserve, to respond to destructive storms quickly and safely, to help our customers in need, and to always act in our customers' best interests. The Company respectfully asks that balance and fairness guide the Commission's decisions.

This concludes my testimony summary.

MR. ROBINSON: Thank you, Chair Mitchell. I will move on to Mr. Hatcher next.

Q. Mr. Hatcher, would you please state your name and business address for the record. You're on mute, Larry.

A. (Larry E. Hatcher) Sorry about that. So Larry Hatcher. My address is 400 South Tryon Street, Charlotte, North Carolina.

Q. And by whom are you employed and in what capacity?

A. I'm employed by Duke Energy, and I'm the senior vice president of customer services.

Q. Mr. Hatcher, on December 20, 2019, did you cause to be prefiled in Docket E-7, Sub 1214, direct testimony consisting of 32 pages?

A. Yes, sir.

Q. And did you on March 4, 2020, cause to be prefiled in that docket, rebuttal testimony consisting of three pages?

A. Yes, sir.

Q. Do you have any -- do you have any changes or corrections to your prefiled direct or rebuttal testimony?

A. No, sir.

Q. Mr. Hatcher, if I asked you the same questions here today, would your answers be the same?

A. Yes, sir.

Q. Did you prepare a witness summary for purposes of this hearing?

A. I did.

MR. ROBINSON: Chair Mitchell, I would move that Mr. Hatcher's prefiled direct and rebuttal testimony and testimony summary be entered into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, Mr. Robinson, your motion will be allowed.

(Whereupon, the prefiled direct and rebuttal testimony, as well as summary of Larry E. Hatcher were copied into the record as if given orally from the stand.)

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CAROLINAS, LLC.

A. My name is Larry E. Hatcher, and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202. I am the Senior Vice President of Customer Service for Duke Energy Corporation, including Duke Energy Carolinas ("DE Carolinas" or the "Company") and Duke Energy Progress ("DE Progress").

Q. BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Electrical Engineering from the University of South Alabama. Additionally, I have attended numerous industry and company-sponsored programs and courses.

Q. PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.

A. I have worked in the energy and chemical industries for 26 years. Before joining Duke Energy, I worked for Monsanto Company for nine years in a variety of engineering and leadership roles. Prior to working for Monsanto, I worked for the U.S. Navy as an electronics engineer for 5 years. In 2002, I joined Duke Energy at the Asheville station as an Operations Superintendent. I have held various leadership roles within the Fossil Hydro Organization ("FHO"), the Environmental, Safety and Health organization ("EH&S"), the Piedmont Natural Gas organization ("PNG") and the Customer Delivery organization ("CD"). Before assuming my current role, I served as Duke

Energy's Senior Vice President of Central Governance, Programs and Support in the customer delivery organization. My responsibilities included overseeing the safe and efficient operation of Duke Energy's distribution central services organization, including the control centers, emergency response, lighting, vegetation management, vehicle fleet and continuous improvement. I assumed my current position as Senior Vice President of Customer Services for Duke Energy in November 2019.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my role as Senior Vice President of Customer Services, I am responsible for customer contact operations, which includes Duke Energy's customer care centers and online customer interactions, revenue billing and receivables, and metering services for all our customers. My responsibilities also include managing the strategies to engage, interact and serve the Company's small and medium business customers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to highlight DE Carolinas' excellent service to our customers and how that translates to customer satisfaction. I also describe some of the steps the Company is taking to further improve the experience and satisfaction of our customers when they engage with us. Finally, I support

(1) the Company's proposal to establish a transaction fee-free payment program for credit, debit and electronic check/automated clearing house ("ACH") (hereinafter, "credit cards") methods for our residential customers; and (2) the Company's proposal to change when bills are considered past due and delinquent for our nonresidential customers.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. Hatcher Exhibit 1 is an audio file comparing the Company's current integrated voice response ("IVR") system to our new IVR, which contains enhanced functionality designed to improve our customers' experiences when they contact us. I provide details about our new IVR later in my testimony.

Q. WAS HATCHER EXHIBIT 1 PREPARED OR PROVIDED HEREIN BY YOU, UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. It was.

Q. HOW DOES THE COMPANY FOCUS ON DELIVERING EXCELLENT CUSTOMER SERVICE?

A. At Duke Energy, the customer is at the center of our purpose. Evolving customer expectations, emerging technologies and changing public policies all converge to create a dynamic environment for Duke Energy and the industry. As I describe in my testimony, Duke Energy works to build genuine connections with all customers by listening, anticipating their needs and offering solutions. The Company is using Customer Experience Monitor ("CX Monitor"), a proprietary survey, to measure Net Promoter Score ("NPS") by asking customers to rate 'How likely it is that they will recommend Duke Energy to a friend or colleague' on a '0-10' scale. NPS is the top metric used by companies across industries to measure customer advocacy. The NPS metric tracks customer loyalty and helps the Company get better insight into improving customer satisfaction. Using data and analytics, the Company is executing a long-term, customer-focused strategy designed to deliver greater value to our customers.

II. CUSTOMER SERVICE OVERVIEW

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S CUSTOMER SERVICE FUNCTIONS.

A. DE Carolinas' Customer Service Functions are comprised of multiple organizational departments responsible for developing and executing policies, processes and procedures to successfully interact with our customers via multiple communication channels. The primary channels our customers use to interact with DE Carolinas are phone; email; social media, inclusive of Facebook, Instagram, LinkedIn and Twitter; Duke Energy's website; and face-to-face interactions. Our organization includes customer care centers; customer service field operations, which is responsible for metering field services; and other activities, including complaint resolution, billing and payment processes and credit and collections activities.

A. Customer Care Centers

Q. PLEASE DESCRIBE THE OPERATION OF THE CUSTOMER CARE CENTERS.

A. Our customer care centers are designed (and continuously enhanced) using state-of-the-art technology with the objective to ensure that all customer inquiries are answered promptly and accurately. There are several locations and numerous remote agents that handle inbound and outbound calls, as well as emails, web inquiries, mailed letters, faxes and social media inquiries. There are over 500 Duke Energy representatives processing and supporting work in response to customer inquiries. Customer calls are either processed in the IVR, allowing customers to self-serve, or by a call center specialist. While we receive an ever-increasing number of inquiries via digital channels per year, we have not experienced a decrease in the number of phone calls that we receive from our customers. In fact, in 2018, DE Carolinas' customer care centers received an average of 1.7 million phone calls per month to the IVR system, of which 98 percent of the calls were handled by the IVR or an agent.

Q. DOES THE COMPANY RECOGNIZE THE DIVERSE NEEDS OF ITS CUSTOMER BASE WHEN PROVIDING CUSTOMER SERVICE?

A. Yes. In addition to its primary responsibility to provide safe and reliable electric service, the Company understands that its customer base has diverse service needs and we do our best to recognize them and accommodate where appropriate. For example, DE Carolinas assigns account managers to our large, complex customer accounts to answer questions, resolve issues and manage the customer relationship to enhance customer satisfaction. Another recent example is individuals from DE Carolinas' small and medium business organization met with builders in North Carolina to hear directly from them about ways we can improve their customer experience. Because of those discussions, the Company developed and launched a new Builder Portal App designed to improve the experience of builders and developers when submitting work orders, requesting status updates or seeking online support.

The Company also conducts ongoing evaluations of operational improvements and continuously looks for ways to improve the customer experience. For example, we offer a variety of billing and payment choices, including Paperless Billing, Pick Your Due Date and Equal Payment Plans to make paying your bill simple, secure and convenient. We share important information with our customers through monthly bill inserts, text or email and offer programs and tips to help protect our customers from high energy bills from extreme temperatures. DE Carolinas also offers a variety of energy efficiency programs and, for our low-income customers, energy assistance and bill management programs such as Share the Warmth and the Neighborhood Energy Saver Program. Additionally, we continue to enhance our customer service practices to address language, cultural and disability barriers. Among other accommodations, the Company's customer care center offers customer service and correspondence in Spanish, handles calls from TTY devices (text telephones), offers bills in Braille, and accepts pledges to pay from social service agencies. Moreover, our customer care centers provide 24/7 service for emergency and outage related requests.

B. Customer Service Field Operations

Q. PLEASE DESCRIBE HOW DE CAROLINAS PROVIDES SERVICE THROUGH ITS CUSTOMER SERVICE FIELD OPERATIONS GROUP.

A. DE Carolinas' field service employees complete service requests inclusive of new meter installations, service repair orders and start/stop service. Additionally, metering services is responsible for meter reading of non-smart meters, meter inventory management, acceptance testing and provisioning of meters for new installations, testing and refurbishment of meters removed from the field, installation and maintenance of transformer-rated meters, tamper and theft detection and investigation, and meter engineering and standards.

In addition to the work performed in normal operating conditions, these men and women support service restoration efforts due to extreme weather conditions. For example, in 2018, Hurricanes Michael and Florence and Winter Storm Diego severely impacted Duke Energy Carolinas' service territory. Members of the Company's field operations group led restoration efforts for impacted customers. As Company witness Rufus Jackson explains in his testimony, the Company's commitment to timely restoration efforts and a positive customer experience resulted in more than 83 percent of customers impacted by Hurricane Michael being restored within 72 hours, restoration within 48 hours for more than 90 percent of customers impacted by Hurricane Florence, and more than 95 percent of the customers impacted by Winter Storm Diego.

Q. HAS THE COMPANY RECEIVED RECENT RECOGNITION FOR EFFORTS BY THE FIELD SERVICE OPERATIONS GROUP?

A. Yes. Edison Electric Institute's ("EEI") recently recognized Duke Energy with the "Emergency Recovery Award".[1] The awards were in response to the Company's outstanding power restoration efforts after Hurricane Florence hit North Carolina and South Carolina in September 2018 and Winter Storm Diego that hit the Carolinas in December 2018. The Emergency Recovery Award is given to select EEI member companies to recognize their extraordinary efforts to restore power to customers after service disruptions caused by severe weather conditions or other natural events.

C. Digital Experience

Q. PLEASE DESCRIBE HOW DE CAROLINAS ENHANCES THE CUSTOMER EXPERIENCE THROUGH THE DIGITAL CHANNEL.

A. As I mentioned previously, the Company continues to experience an increased number of inquiries and service related requests received via the Company's website and social media sites. With the rapid transformation of technology, devices and new channels, customer expectations are increasing at an

[1] https://www.prnewswire.com/news-releases/duke-energy-earns-eeis-emergency-recovery-award-for-power-restoration-efforts-in-carolinas-after-hurricane-florence-300776958.html; https://www.prnewswire.com/news-releases/duke-energy-earns-eei-emergency-recovery-award-for-winter-storm-diego-power-restoration-efforts-300865411.html

accelerated rate, and we work to provide an easy-to-use, straightforward digital experience to meet their expectations.

The Company's digital transformation strategy began in 2015 to help deliver exceptional customer benefits, streamline previously manual processes and deliver long term efficiencies. The development of a customer mobile app, a major refresh of duke-energy.com and a suite of new and enhanced customer solutions, some in part enabled by the installation of smart meters as discussed by Company witness Schneider, are summarized in the table below:

Program/Product	**Description**	**Channels**
Proactive Outage Communications	A messaging program that alerts customers when there is an outage in their area	• Email • Text • Voice
Pick Your Due Date[2]	Enrolled customers select the billing due date that best aligns with their financial situation	• Online Web Form • Call Center Enrollment
Track My Service – Start and Stop Service	Eligible customers automatically receive order confirmations and reminders when they start, stop, and transfer service	• Email • Text • Voice
Usage Alerts[2]	Eligible customers automatically receive an email at the midpoint of their billing cycle with their current electricity cost broken down by appliance and projected cost and can opt to receive budget alerts	• Email • Text
Payment Confirmations	Eligible customers automatically receive an email or text message when their payment is received by Duke Energy	• Email • Text

Customers can now use duke-energy.com/home or the Customer Mobile App to complete most of the transactions available through the IVR, such as updating account information; making billing inquiries; reporting

[2] Smart meter enabled program or service.

power outages; checking the status of an outage; viewing bills; paying bills; and connecting, disconnecting or transferring service. Customers are also reporting a higher usage of digital methods to report outages and request service orders, with reported digital utilization up from 20 percent to 25 percent in 2018. Further, our customers reported satisfaction with our web offerings (with results for April 2019 reaching a record high), and reported higher levels of satisfaction with first contact resolution and ease of completing tasks.

Other examples of digital transformation efficiencies include a program called Ping It, which allows employees of the Company to remotely connect or check the status of a smart meter in lieu of sending a technician to the premise, saving time and travel costs. The Ping It program is especially useful during major storm events where the Company can use Ping It to determine which customers are out of power without the need for them to call and report an outage. The Company also proactively communicates outage updates to customers, via text and email, and provide updates on outage maps without the customer having to call.

Q. DESCRIBE HOW DE CAROLINAS' SOCIAL MEDIA PROGRAM HAS EVOLVED TO KEEP PACE WITH CUSTOMERS' CHANGING EXPECTATIONS.

A. With the rise in the use of social media in recent years, DE Carolinas has seen an increased number of its customers contacting us for account-related service through social media. Duke Energy has more than 550,000 followers on its

Facebook, Twitter, Instagram and LinkedIn pages. The Company uses these channels to inform customers about reliability updates in their area and changes that could impact their bill. Further, in the event of an emergency or major storm, DE Carolinas uses social media to proactively distribute (or "post") information so it reaches as many customers and stakeholders as possible, engage with customers who have questions, and analyze social media conversations to monitor how messages are being received. In advance of a major forecasted storm, the Company posts warning and safety preparedness messages. During a major storm, when large areas of customers are without power, Company employees respond to storm-related or outage-related customer service inquiries received via social media sites. Moreover, the Company may post updates from our meteorology team, videos detailing storm restoration progress, and photos of significant damage to infrastructure to show customers the scale of repairs underway.

III. <u>CUSTOMER SATISFACTION MEASURES</u>

Q. HOW DOES THE COMPANY MEASURE CUSTOMER SATISFACTION?

A. DE Carolinas recognizes that customer expectations continuously change and evolve and, to successfully enhance their experience, it is critical that we hear and understand the "voice of the customer" through several avenues, including direct customer feedback and industry benchmarking, to improve customer satisfaction ("CSAT"). The Company operates a robust CSAT program, which includes both national benchmarking studies and transaction and relationship CSAT studies. We then analyze results from these studies in vigorous monthly data review sessions, with findings driving improvements to processes, technology and behaviors – all to continuously improve the customer experience.

DE Carolinas also measures overall customer satisfaction and loyalty perceptions about the Company in an ecosystem of measurement tools intentionally designed to allow us to strategically identify opportunities to improve the customer experience. In 2018, the Company launched the CX Monitor survey, a randomized, census-based survey that measures customer loyalty and the ongoing perceptions of the customer experience via an email invitation with an embedded online survey link. The CX Monitor survey is sent to residential, small and medium business ("SMB") customers and large business customers for whom the Company has a valid email address. Customers are asked to rate 'How likely it is that they will recommend Duke Energy to a friend or colleague' on a '0-10' scale. In addition to measuring customer advocacy, the CX Monitor survey measures customer satisfaction using key experiences customers have had with us over the past 12 months. Examples of these experiences may be an outage experience or a payment experience. Customers rate their experience on a '0-10' scale and provide open-end verbatim comments detailing the primary reason(s) for their score. While the Company still utilizes J.D. Power as a relative benchmark against peer utilities, the value of the CX Monitor over other surveys is that it asks our own customers about their perception of an experience, which can then be compared against their actual experience.

Since the CX Monitor survey launched in 2018, the Company has collected responses from more than 410,000 residential electric customer surveys and over 25,000 SMB customer surveys enterprise-wide.[3] Since the survey launch in 2018, the Company has seen a significant increase in its NPS score. Further, some of DE Carolinas' top month over month NPS scores came at one of the most challenging periods for our Company, between the months of September and December of 2018 when the Company's service territory was severely impacted by storms. Customers responding to the CX Monitor survey during that period returned some of our highest NPS scores to date, all at a time when they, the Company and our neighbors were impacted by Hurricanes Florence, Michael, or both. During last year's hurricane season, the Company demonstrated exemplary performance in field operations and customer service. In a first for the Company, every employee who did not already have a primary storm role was assigned one.

In addition to our CX Monitor survey, Duke Energy uses "Fastrack 2.0", a proprietary, post-transaction measurement program. Fastrack 2.0 measures the quality of interactions customers have with the Company. Fastrack 2.0 was intentionally designed to complement the CX Monitor survey and provide greater insight into experiences that matter to our customers and near real time feedback to our front line, customer-facing

[3] The CX Monitor was launched to our large business customers in January 2019 and the Company is currently developing the baseline.

employees. The survey questions cover the customer's experience about completed field work such as requests to begin and end electric service, outdoor lighting repairs and new construction service requests. Analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. Through 2018, roughly 80 percent of DE Carolinas residential customers expressed high levels of satisfaction with these key service interactions (Start/Transfer Service (86 percent), Outage/Restoration (81 percent), and Street Light Repair (73 percent). The Company has also implemented 'Reflect', a post-contact survey that will gather customers' immediate feedback after contacting Duke Energy by web, text, call to automated system or live agent. As data is collected, this tool will provide critical feedback to improve all channels customers use to interact with Duke Energy.

Q. WHAT DO YOU ATTRIBUTE TO THE POSITIVE CSAT SCORES YOU JUST DESCRIBED?

A. At Duke Energy, our mission is to provide safe and reliable service, transform the customers' experience, modernize the energy grid, generate cleaner energy and be a good corporate citizen - all while keeping costs low. We are a well-run company and we believe that customers see and experience the benefits of our efforts every day. Here are just a few of the many recognitions Duke Energy has received in the past two years across the enterprise:

- For the 13th consecutive year, Duke Energy was named to the Dow Jones Sustainability Index for North America.

- Duke Energy was named to Fortune magazine's 2019 "World's Most Admired Companies" list for the second year in a row.

- Forbes magazine named Duke Energy as one of "America's Best Employers" – making the 2018 and 2019 list for U.S. electric utilities.

- The NAACP named Duke Energy an inaugural member of its Equity Inclusion and Empowerment Index, identifying Duke Energy as a corporate leader in fostering an equitable, just and inclusive workplace.

- For the 14th consecutive year, Duke Energy has been named to Site Selection magazine's annual list of "Top Utilities in Economic Development."

Further, I believe the robust team of customer care center representatives and customer field service personnel, our IVR options, and processes and procedures heavily influence our CSAT scores. I also believe the multiple options our customers have to communicate with and receive information from us, including through digital channels and social media, improves the customers' overall communication experience. The Company's ability to keep our customer's lights on reliably, efficiently and affordably all while being a good corporate citizen also contributes to positive CSAT scores. I provide just a few examples below:

Power Efficiency, Diversity and Reliability

Each day, we work to make our power system more efficient, more diverse and more reliable. In fact, over the years, DE Carolinas has become a leader in efficiency: for example, as witness Capps describes, the reliability and performance of our nuclear plants is among the best in the industry. In fact, in 2018 our nuclear fleet achieved a 95 percent capacity factor, marking the 19th consecutive year above 90 percent. Our fossil-fueled power plants continue to operate reliably and efficiently as well. As witness Immel explains, over the past five years, the percentage of time our fossil-fueled power plants are available to generate power, as measured by the Equivalent Availability Factor ("EAF"), is at or above the NERC average for comparable units. We are also working to make our system cleaner and more diverse. For example, we continue to expand our natural gas generation portfolio, including retrofitting two coal units at our Rogers Energy Complex to run on natural gas and coal – rather than coal only. Further, Duke Energy added 500 megawatts of solar in North Carolina during the year, which helped the state remain second in the nation for solar capacity. Duke Energy also outlined plans to deploy 300 megawatts of battery storage projects in the Carolinas over the next 15 years. Further, as witness Oliver details in his testimony, the reliability of our power delivery system has performed well, and we have continued to provide safe, reliable and affordable electric service. However, over the past ten years, we are seeing trends affecting our grid that lets us know that more must be done to improve the energy infrastructure to meet the needs of our customers. Our grid improvement plan, as explained by witness Oliver, was developed to deliver on customer expectations and address these trends. Overall, we are investing in making our infrastructure stronger, smarter, cleaner, more efficient and less reliant on any single fuel source, which leads to more reliable energy and a better experience for our customers.

Corporate Sustainability Goals

Duke Energy's approach to sustainability focuses on the issues that are most important to us and our stakeholders. We have mapped our priority issues to the United Nations Sustainable Development Goals ("SDGs"), which aim to "end poverty, protect the planet and ensure prosperity for all."[4] While we have alignment between our priorities and several of the SDGs, goals "Seven: Affordable and Clean Energy" and "Thirteen: Climate Action" are especially applicable to us. Our goals fall under four categories: Customers, Growth, Operations and Employees.

- Customers: Improve the lives of our customers and vitality of our communities (e.g., providing affordable energy, promoting energy efficiency – consumption and peak demand, charitable giving, community leadership and volunteerism, etc.)
- Growth: Grow and adapt the business, and achieve our financial objectives (e.g., stimulating economic development, promoting renewables, corporate governance, etc.).
- Operations: Excel in safety, operational performance and environmental stewardship (e.g., enhanced safety, reliable energy, reduced carbon emissions, etc.).

[4] The United Nations, *A/RES/70/1 - Transforming our World: The 2030 Agenda for Sustainable Development* (September 2015), *available at* https://sustainabledevelopment.un.org/content/documents/21252030%20Agenda%20for%20Sustainable%20Development%20web.pdf

- Employees: Develop and engage employees, and strengthen leadership (e.g., employee engagement, diversity and inclusion, etc.).

Generating Cleaner Energy

Duke Energy continues to advance its efforts to generate cleaner energy. Overall, we have lowered our carbon emissions by over 30 percent since 2005, consistent with Duke Energy's goal to reduce carbon emissions by at least 50 percent by 2030 and to net-zero by 2050. Additionally, we have plans to increase our reliance on renewable sources and invest in natural gas-fired power plants and battery storage projects.

Corporate Citizenship and Neighboring with Our Communities

Duke Energy has proudly served our communities through charitable giving and employee volunteerism for decades. During 2018, the Duke Energy Foundation contributed $31.6 million to our communities, and our employees and retirees volunteered 16,000 hours of community service across our jurisdictions. For DE Carolinas, we commit to helping our customers and communities with programs such as the Neighborhood Energy Saver Program to help our low-income customers become more energy efficient and our Share the Warm Program, an assistance program for our customers in need. And, as discussed by witness De May in his testimony, we look forward to doing more to help our low-income customers through the low-income energy assistance program collaborative we are requesting the Commission establish with participation from the North Carolina Public Staff and other key stakeholders.

Supplier Diversity

At Duke Energy, our supplier partners share our commitment to the local economies and communities we serve. As such, many of our suppliers are locally based and/or diverse. With the inclusion of local and diverse suppliers as one of the Company's priorities, Duke Energy was recently honored for having a Top Veteran-Friendly Supplier Diversity Program by the U.S. Veterans magazine. Our efforts to identify and recruit diverse suppliers are important to the Company's overall supply chain sourcing strategy. The relationships we have with state and community economic development organizations enables Duke to positively impact our communities while creating enhanced value for the Company.

Price

While one might assume that such performance would result in higher costs to customers, our achievements have been accomplished while maintaining rates that compare very well nationally and in fact are below the national average even with the full projected increase. The latest survey from the EEI reflects national average cents per kWh price for typical residential, commercial and industrial customers. The national average for residential customers is 13.16¢ per kWh, for commercial customers is $10.77¢ per kWh, and for industrial customers is 7.01¢ per kWh. The average for the South Atlantic Region for residential customers is 11.37¢ per kWh, for commercial customers is 8.81¢ per kWh, and for industrial customers is 6.45¢ per kWh. DE Carolinas' projected price of currently 10.92¢ per kWh for residential customers, 7.88¢ per kWh for commercial customers, and 6.33¢ per kWh for industrial customers are all well below the national average and below the South Atlantic Regional average.

IV. <u>CUSTOMER SATISFACTION MEASURES</u>

Q. IS THE COMPANY WORKING TO FURTHER IMPROVE THE LEVEL OF CUSTOMER SERVICE?

A. Yes. Duke Energy is working hard across the business to further improve the customer experience. In my organization, we are doing our part to transform the customer experience by making strategic, value-based investments for the benefit of our customers.

Q. PLEASE PROVIDE EXAMPLES OF WAYS YOUR ORGANIZATION IS HELPING TO TRANSFORM THE CUSTOMER EXPERIENCE.

A. Two key examples are enhancements to our integrated voice response ("IVR") system and the deployment of Customer Connect.

Integrated Voice Response

In 2016, the Company launched an effort to replace the existing IVR system with advanced technology focused on transforming the caller's experience. The new IVR design reflects learnings from customer feedback and industry best practices that led to several key areas of focus, which included: 1) proactively identifying the customers and why they are calling the Company, 2) a tailored customer experience like what they receive from other consumer product companies and 3) less menu options to complete their request in the IVR. Options available after the deployment of the new IVR include call prediction, easy self-serve options, customer call back and a post-call survey. The call prediction functionality predicts the reason the customer is calling the Company. For example, “I see you have a pending service order scheduled for tomorrow. Is this why you are calling?” The Company recognizes customers want the ability to self-serve while navigating seamlessly through the IVR. Existing self-service functionality such as requesting a payment arrangement and reporting a power outage will be improved via voice activated prompts which will help provide a more positive customer experience. New self-serve options include texting a link to local payment locations, allowing customers the ability to update their phone number in the IVR and requesting their account number through the IVR. An audio comparison of the existing IVR and new IVR is provided as Hatcher Exhibit 1.

An increased number of calls during a specified timeframe may result in longer than usual hold times to speak with a specialist. The new IVR will also allow customers the option to continue holding until a specialist is available, or have their place in line reserved for them allowing for us to return their call at the number of their choice. The Company’s ongoing focus to understand “the voice of the customer” has been expanded to the new IVR with the implementation of the post-call survey. The post-call survey offers customers the option to provide immediate feedback on their experience. The Company plans to launch the new IVR in the third quarter of 2019.

Customer Connect

In 2017, the Company began the conversion of its old customer information system ("CIS") into a modern customer service platform, known as Customer Connect. Through this conversion, the Company will be able to deliver a customer experience that will simplify, strengthen and advance our ability to serve our customers. The platform will be leveraged to provide real-time insights to enhance the customer experience. One example of this is how the Company can leverage these insights to enhance operations during significant storm events. With this new platform, data can be visualized in new ways to uncover insights into experiences customers are having across the Company's phone, web and social media channels. The Company can also leverage the automated, targeted marketing capabilities to increase effectiveness of communication campaigns during major storm events and for other operational needs.

In June 2018, the Company successfully deployed the first of several deliverables under the Customer Connect Program, which provides the capabilities to start gathering, storing and analyzing customer insights to better understand our customers so we can better serve them to their personal level of satisfaction, and this deliverable is the first step in doing that. Specifically, the Company began gathering relevant touchpoints that customers are having with Duke Energy in real time such as web visits, phone calls, power outages, outbound communications, and product and service participation. The Company also delivered enhanced communication capabilities which provide more personalized service with automated and targeted campaigns. These capabilities automate processes, increase effectiveness and provide metrics to gauge success.

The integrated analytics platform will be used to provide real-time learnings to enhance the customer experience. One example of this is how the Company can use this newly available information to enhance operations during significant storm events. With this new platform, data can be visualized in new ways to uncover insights into experiences customers are having across the Company's phone, web and social media channels. The Company can also use the automated, targeted marketing campaigns to increase effectiveness of communication campaigns during major storm events and for other operational needs.

In February 2019, leveraging insights from the holistic customer profile, the Company began using the new platform to predict the intent of customers when they call. Additionally, the Company has been making this information more readily available to our customer care agents, who are now using it for insight into why a customer may be calling, which is allowing for more informed and productive conversations with our customers. In May 2019, the Program implemented a new capability to better communicate with customers during major storms. The Company is now able to create targeted customer communication lists by leveraging attributes that are particularly relevant during major storms, such as the substation or operations center a customer is served by, or whether the customer or nearby customers are experience an outage. These lists will be used to send more specific communications about the specific storm-related circumstances near the customer's home or business. Additionally, later this year, these capabilities will be expanded to include the ability to automate these email campaigns from Customer Connect and allow them to be configured in advance and quickly executed in desired circumstances.

V. ENHANCEMENTS TO CUSTOMER OFFERINGS

Q. HAS THE COMPANY IDENTIFIED ADDITIONAL PROGRAMS THAT IT MAY OFFER TO IMPROVE CUSTOMER SATISFACTION?

A. Yes. The Company is seeking approval in its Application to implement is to eliminate convenience fees for credit and debit card payments made by our residential customers. The requirement to pay a convenience fee when making a payment is one of the largest frustrations our residential customers experience. Customers have grown accustomed to paying for other products and services with a credit card or debit card without a separate, additional fee. Eliminating these fees for our residential customers would provide additional, convenient options for residential customers to pay their bills, which would ultimately increase customer satisfaction. Additionally, the Company is seeking approval to change the bill payment due date for non-residential customers from fifteen days to twenty-five days after the bill date. The

Company's proposal is in response to feedback received from its non-residential customers.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL FOR A FEE-FREE CREDIT/DEBIT CARD PROGRAM.

Currently, customer payments made by mailing a check, paying with cash or check at a free pay station, using bank draft or paperless billing, are free of charge. The costs for the Company to offer these methods are paid for by all customers and not recovered exclusively by those specific customers that use that method of payment. However, residential customers using a credit or debit card through any payment channel are subject to a $1.50 convenience fee per transaction. The convenience fee is collected from the customer by the Company's third-party vendor, Speedpay. The Company receives no portion of this fee.

Q. WHY IS THE COMPANY PROPOSING THIS PROGRAM NOW?

A. As customer expectations change and more payments are processed electronically, utility companies are beginning to offer fee-free payment programs for their residential customers for all methods of payment.[5] Customers are increasingly making more payments today by credit or debit card. The number of payments made by credit and debit cards continues to grow as a preferred method of payment by many consumers.[6] In fact, Duke

[5] According to J.D. Power and Associates, as of 2016, about 28 percent of surveyed electric utilities provide a fee-free card payment option. *See* J.D. Power Catalog. J.D. Power and Associates, 2016 Electric Utility Residential Customer Satisfaction Study.

[6] According to the Federal Reserve Payments Study: 2018 Annual Supplement. The number of payments made by credit, non-prepaid debit, and prepaid debit cards grew more rapidly than the number of payments made by any other payment type in the 2012 to 2015 and 2016 to 2017 periods.

Energy Corporation has seen 14 percent average year over year growth in credit/debit card transactions over the past several years, and with this change we expect the growth rate to double – so 28 percent more transactions in 2019 than in 2018.

A recent study by Fiserv (a leader in financial services) also discusses the trends by customers moving toward card transactions and away from checks: "Checks are on a continual downward trajectory in the United States as consumers shift away from checks and toward card payments, a market dynamic that billers should not overlook. The Company believes it is reasonable to offer a fee-free payment program for these payment methods to its residential customers, and recover the costs associated with that program from all customers through cost of service. Eliminating these fees for the Company's residential customers would provide additional options for residential customers to pay their bills. Consumer advocate groups have also suggested that convenience fees for paying utility bills can be burdensome to customers.[7]

We also know that our customers want this option. The Company's Customer Service department routinely receives inquiries about no-cost electronic payment methods. In the Company's Monthly Residential Transaction Surveys, residential customers noted some of the following when asked what they liked least about Duke Energy:

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[7] Nat'l Ass'n of State Util. Consumer Advocates, *Urging Utilities to Eliminate "Convenience" Fees for Paying Utility Bills with Debit and Credit Cards and Urging Appropriate State Regulatory Oversight* (Nov. 13, 2012), *available at* https://nasuca.org/2012-07-urging-utilities-to-eliminate-convenience-fees-forpaying-utility-bills-withdebit-and-credit-cards-and-urging-appropriate-state-regulatory-oversight/.

> *"I refuse to pay a convenience fee. No one else charges this for their products…"*

> *"I like everything except the processing fee of $1.50 by doing it over the phone. I pay all my bills this way with zero fees."*

> *"Shouldn't charge me a fee to pay you."*

> *"It's ridiculous to pay an extra fee to pay off my monthly statement."*

> *Í think it is stupid that there is a $1.50 charge to pay online or over the phone. Duke is the only company that I deal with that does that."*

We think our customers will appreciate being able to use credit cards with the Company the same way they can with other companies.

Q. HOW EXACTLY WOULD COST FREE ALTERNATIVE PAYMENT METHODS BENEFIT THE COMPANY'S CUSTOMERS?

A. Eliminating these fees for the Company's residential customers would provide additional fee-free options for residential customers to pay their bills. In addition, the option of a fee-free payment when using a credit card, debit card or electronic check would lead to greater satisfaction for all customers who primarily pay for goods and services with these payment methods. There are many reasons why customers prefer to use their credit or debit card, which may include: (1) customers feel safer using a debit or credit card that includes security protections from their bank, (2) using a prepaid card, (3) receiving loyalty rewards for credit cards, (4) using a fast payment method to prevent a pending disconnection for non-pay, or (5) having a lack of a checking account (some customers have salaries or social security funds provided on prepaid debit cards and do not have a bank account). Regardless of the reason a customer may have, they would be more satisfied with the ability to pay by the method of their choice without incurring additional fees.

Q. HOW DOES THE COMPANY PROPOSE TO PAY FOR THE FEES THE PROGRAM WOULD ELIMINATE?

A. The Company proposes to recover the costs associated with the fee-free payment program—the elimination of the convenience fees—from all customers through an adjustment to the cost of service as explained by witness McManeus. This would eliminate the $1.50 convenience fee currently directly charged by Speedpay to these residential customers paying by credit, debit or electronic check.

Q. WILL DE CAROLINAS STILL OWE SPEEDPAY THE CREDIT CARD TRANSACTION FEES?

A. Yes. We have worked with Speedpay throughout the Duke Energy enterprise to obtain a low cost for card and electronic check payments of $1.50 per transaction for residential customers. DE Carolinas will pay the per transaction fees to Speedpay.

Q. WHY IT IS REASONABLE FOR THE COMPANY TO INCLUDE THE COST OF FEE FREE PAYMENT IN ITS COST OF SERVICE THAT IS PAID BY ALL RESIDENTIAL CUSTOMERS?

A. The more convenient the Company can make the bill paying process for customers to pay bills, the more all customers will benefit. Customers who self-serve, pay on time, and are satisfied with the options available to them are the least expensive to serve, which is a benefit to all customers. Customers who do not pay on time and enter the credit collections cycle drive increased costs, which are ultimately borne by all customers. Lastly, customers who are not satisfied tend to call Customer Care Centers more often. Every call into the call center results in increased costs for all customers. This means that every call that can be avoided leads to savings for all customers. Giving customers options to pay by the method of their choice without incurring additional fees will lead to more satisfied customers and, ultimately, savings.

Q. CAN YOU SUMMARIZE THE ADOPTION RATE THAT THE COMPANY ANTICIPATES IF THIS PROGRAM WERE IMPLEMENTED?

A. Yes. Based on market research, analytics and industry trends, the Company anticipates that the average percentage increase in adoption once the fee-free program is implemented is a 100%-200% increase in transaction volume within the first 12 months. This expectation is aligned with what vendors have experienced with other utilities that make the switch from a convenience fee model to a fee-free payment model.

Q. IS THE COMPANY PROPOSING A FEE-FREE PROGRAM FOR ITS COMMERCIAL AND INDUSTRIAL CUSTOMERS AT THIS TIME?

A. Not now. Cost-effective payment methods are generally available to commercial and industrial customers because the average payment amounts for these customers are significantly higher than residential (which leads to higher processing costs). As such, the Company is not proposing a fee-free program for commercial and industrial customers at this time.

Q. HAS THE COMPANY ADOPTED THIS PROGRAM IN ANY OF ITS OTHER JURISDICTIONS?

A. Yes. The Company requested and received approval to implement the transaction fee-free program in its most recent rate case proceeding in South Carolina in Docket No. 2018-319-E. The program went into effect in South Carolina on June 1, 2019.

Q. PLEASE DESCRIBE THE PROPOSED CHANGE TO THE NON-RESIDENTIAL RATE SCHEDULES RELATED TO BILL PAYMENT DUE DATE.

A. In response to requests from nonresidential customers for additional time to process electric invoices, the Company is proposing to change when bills are past due and delinquent from fifteen days to twenty-five days to match the current requirement for residential customers.

Q. WHY IS THE COMPANY PROPOSING THIS NOW?

A. The Company has received feedback from its non-residential customers of their desire for additional time to make their payments to the Company. Not only will this extension align our remittance period with the number of days the Company offers residential customers, but it will better align with the payment terms of net thirty days non-residential customers have with other vendors. Further, by the time a bill is rendered and delivered by the United States Posta Service, our non-residential customers are often left with only a few days to process and remit their payments. Changing the remittance period will help extend the number of days for them to process and remit their payments in a timely manner. Accordingly, the Company believes this change will be positively received by the Company's non-residential customers and may help mitigate the challenges our current remittance period places on them.

VI. CONCLUSION

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

A. Yes.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CAROLINAS, LLC.

A. My name is Larry E. Hatcher, and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202. I am the Senior Vice President of Customer Service for Duke Energy Corporation, including Duke Energy Carolinas ("DE Carolinas" or the "Company") and Duke Energy Progress ("DE Progress").

Q. ARE YOU THE SAME LARRY E. HATCHER WHOSE TESTIOMONY AND EXHIBITS WRE FILED IN THIS DOCKET?

A. Yes, I filed adopted direct testimony and an exhibit in this docket on December 20, 2019.

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

A. The purpose of my rebuttal testimony is to 1) discuss no intervenors have contested the Fee-Free Program and 2) respond to Public Staff witness Michelle Boswell's recommendation for the Company to track the impact, of the Fee-Free Program that no longer have a separate fee associated with the payment, on the late payment and uncollectible accounts, and report the quantitative impact in testimony in the Company's next general rate case.

Q. BASED ON REVIEW OF INTERVENOR TESTIMONY, HAS ANYONE CONTESTED THE FEE-FREE PROGRAM?

A. No.

IV. RESPONSE TO PS WITNESS BOSWELL

Q. PLEASE RESPOND TO WITNESS BOSWELL'S RECOMMENDATION THAT BOSWELL'S RECOMMENDATION THAT THE COMPANY TRACK THE IMPACT OF THE FEE-FREE PROGRAM, ON THE LATE PAYMENT AND UNCOLLECTIBLE ACCOUNTS, AND REPORT THE QUANTITATIVE IMPACT IN TESTIMONY IN THE COMPANY'S NEXT GENERAL RATE CASE.

A. The Company does not track the payment method with the customer's delinquency status at the time the payment is received. The Company blends all costs incurred for bill payment-related expenses, which is reflected in the cost of service. Any quantitative impact would be reflected in the future cost of service.

Q. WHAT PAYMENT RELATED INFORMATION COULD THE COMPANY REPORT IN ITS NEXT GENERARL RATE CASE?

A. The Company proposes to track and report the number of payments made by channel per year in the next general rate case.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

I am the Senior Vice President of Customer Service for Duke Energy Carolinas, LLC. In my direct testimony, I highlight our customer service efforts and how that translates to customer satisfaction. I also describe several steps the Company has taken to further improve the experience and satisfaction of our customers when they engage with us, including enhancements to our integrated voice response system and proposals in this rate case to implement a fee-free payment program for residential customers using credit and debit cards, and to change when bills are considered past due and delinquent for our nonresidential customers.

As a leader in our customer service organization at Duke Energy, I am proud of our continued mission to provide safe and reliable service, transform the customers' experience, modernize the energy grid, generate cleaner energy and be a good corporate citizen - all while keeping costs low. As examples, the Company's nuclear fleet is recognized as being one of the best in the industry in terms of safety, reliability, availability and production costs. The Company's Fossil and Hydro operations have similar superior safety, reliability and production cost performance, while reducing carbon emissions by 39% from 2005 levels. The Company's transmission and distribution systems have also performed well notwithstanding the need for modernization as described by witness Oliver. We have deployed new smart meters across our jurisdiction and are in the process of replacing the Company's outdated customer information system with a new, modern customer service platform that will transform how the Company serves customers by providing them with the easy, personalized experiences they expect from other service providers.

At Duke Energy, the customer is at the center of our purpose. Evolving customer expectations, emerging technologies and changing public policies all converge to create a dynamic environment for Duke Energy and the industry. As I describe in my testimony, Duke Energy works to build genuine connections with all customers by listening, anticipating their needs, and offering solutions. Our response to the ongoing COVID-19 Pandemic is evidence of this, as Mr. De May just highlighted. Another example is our consistent storm response. The Company has been repeatedly recognized as a leader in the industry in storm restoration and over the last several years have been able to restore service to 95% of its customers within just a few days over the course of hurricanes and winter storms. We have been repeatedly recognized for our efforts by organizations including the Dow Jones, Forbes, Edison Electric Institute, the U.S. Department of Labor, the NAACP, and the Ethisphere Institute to name a few.

My rebuttal testimony responds to Public Staff witness Michelle Boswell's recommendation for the Company to track the impact of the Fee-Free Program, that will no longer have a separate fee associated with the payment, on the late payment and uncollectible accounts and report the quantitative impact in testimony in the Company's next general rate case. The Company does not currently practice this and, therefore, the Company agrees to track and report the number of payment made by channel per year in the next general rate case. Additionally, I would like to note no intervenors have contested the Fee-Free Program.

This concludes the summary of my direct and rebuttal testimony.

MR. ROBINSON: Thank you, Chair Mitchell. The panel is now available for cross examination.

CHAIR MITCHELL: All right. My notes indicate that we will begin with the Attorney General's Office.

MS. TOWNSEND: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. TOWNSEND:

Q. Good morning, gentlemen. My name is Teresa Townsend. I am with the Attorney General's Office. Most of my questions will be -- all of my questions will be for Mr. De May; and Ms. Force will direct questions to Mr. Hatcher when I am done.

Mr. De May, on page 3 of your direct testimony, you listed several responsibilities of your position as North Carolina president for Duke Energy since you took that position in November of 2018, correct?

A. (Stephen G. De May) Correct.

Q. In that list, you don't mention any responsibility regarding litigation either brought on behalf of the Company or against the Company.

Would you describe your role in any

litigations brought against the Company or when the Company brings litigation against the third party?

A. My role is limited when it comes to litigation, Ms. Townsend. I, of course, am responsible for the performance and issues that arise, and the regulatory incremental affairs, success of our two utilities here in North Carolina. When litigation is entered into or we are receiving litigation, I am made aware of that litigation, generally, when it rises to the level of materiality. And I will be updated on that periodically when there are updates -- material updates to be made. But that would be the extent of it.

If decisions have to be made, either settlement decisions or any other decisions related to the litigation, I will be involved in those discussions.

Q. Thank you. At the moment, there is litigation -- active litigation going on and/or that has recently been settled; is that correct?

A. Are you able to rephrase? There's a lot of litigation. Are you speaking with regard to coal ash?

Q. Yes, sir.

A. Okay. That is correct.

Q. Okay. If I may go through the lawsuits of which I'm aware, and if you could provide us an update or a status report on that litigation as best you know. I understand you don't know -- I'm not asking for the weeds. I'm just asking in general what the status of those lawsuits are.

A. If you're referring to the litigation where Duke is suing a group of insurance companies -- are you referring to that?

Q. We will get there, yes. Let me go through the list starting with --

A. Okay.

Q. -- the 2013 action that was brought against Duke by DEQ, and that was about unpermitted discharges of wastewater, VSP breach, plus the 2L groundwater exceedances at the DEC plant, correct?

A. I'm not aware of that litigation.

Q. Okay. I'm sorry, I didn't mean to interrupt.

Is that not part of the 12/31/19 settlement agreement, that action, to your knowledge?

A. I don't know.

Q. All right. We'll get there. The second lawsuit was brought in February of 2017 by a Dr. Nigel and Donna Beust (phonetic spelling) alleging a lost sale of their property and property diminution due to the alleged stigma of the Dan River coal ash spill in February of 2014.

Do you know anything about that litigation?

A. Not specifically.

Q. But that was brought to a head, and it was settled, correct?

A. Ms. Townsend, I'm not familiar with these lawsuits that you're naming.

Q. Okay. Let me try the next one for you. In February again in 2017, there was a suit brought against DEC by individuals owning property in varied proximity the Dan River plant for private nuisance, trespass, negligence, gross negligence, and willful misconduct, and violations of the North Carolina Oil Pollution and Hazardous Substances Control Act related to the coal ash spill from the Dan River plant.

Are you familiar with that lawsuit?

A. I am vaguely familiar with that lawsuit because I recall that it occurred, but I don't have any updates for you.

Q. Okay. So you don't know if it was settled?

A. I don't.

CHAIR MITCHELL: Ms. Townsend, I

apologize, I'm going to interrupt you. Mr. De May, would you please adjust the volume of your mic or move it closer to you, if that's possible. Your volume is just -- is low, and I want to make sure that the court reporter and the parties can hear you.

THE WITNESS: I'm going to try earbuds to see if that improves it.

(Pause.)

Q. Okay. Try them out.

CHAIR MITCHELL: All right. Mr. De May, let's see if that's an improved situation. Can you -- let's just hear from you for a test.

MS. TOWNSEND: You're on mute, Mr. De May.

THE WITNESS: Can you hear me now? Is this any better?

CHAIR MITCHELL: It may be better. Let's go ahead and proceed. Please proceed, Ms. Townsend.

MS. TOWNSEND: Thank you.

Q. In talking about the lawsuit you mentioned came in March 2017 when DEC filed suit for recovery under -- I believe there were 38 excess level third-party liability insurance policies issued between 1971 and '86 alleging breach of contract for denying coverage related to DCR cleanup and -- at 15 power plants in North Carolina and South Carolina arising out of CAMA, and the federal CCR rule and South Carolina laws seeking recovery of dollars already spent as well as dollars to be spent in the future.

Is that the case that you are referring to?

A. Yes, it is.

Q. Okay. And going on, in August of 2017, there was a class action suit in Wake County by Amy Brown against both DEC and DEP on behalf of property owners living near nine coal ash impoundments at Allen, Asheville, Belews Creek, Buck, Cliffside, Lee, Marshall, Mayo, and Roxboro for groundwater contamination.

Are you familiar with that one?

A. No, I'm not.

Q. All right. And then on December of 2017, SEOC filed a citizen suit on behalf of Appalachian Voices, the North Carolina State Conference of the NAACP, and Stokes County branch of NAACP against DEC alleging violations of the Clean Water Act related to alleged unpermitted discharges to surface water and groundwater violations as Belews Creek steam station.

Do you know the -- do you know about that?

A. I vaguely recall that lawsuit because of the parties involved, but I do not have any update on it.

Q. All right. And just two others. On December 15, 2017, Cindy Braswell, a plant Allen neighbor, filed a pro se complaint against DEC for alleged well contamination on two parcels of that land -- of her land.

Do you know anything about that lawsuit?

A. No.

Q. Okay. And last, on April 21, 2019, DEQ ordered Duke Energy to excavate coal ash at six remaining sites in North Carolina. That was Allen, Belews Creek, Cliffside, Marshall, Mayo, and Roxboro. Duke Energy filed petitions for contested cases in the Office of Administrative Hearings to appeal that order.

You are familiar with that action, correct?

A. Yes.

Q. All right. We mentioned the insurance lawsuit brought by Duke against -- of its insurance carriers, correct?

A. Yes.

Q. All right. Now, if I may refer to AGO Cross

Exhibit 13.

A. I'm ready.

Q. All right.

MS. TOWNSEND: Chair Mitchell, we would like to identify that and have it marked as De May AGO Direct Exhibit 1 [sic].

CHAIR MITCHELL: All right. Ms. Townsend, the document shall be marked De May AGO Direct Exhibit Number 1[sic].

MS. TOWNSEND: Thank you.

(AGO De May Cross Exhibit 1 was marked for identification.)

Q. And this is the March 2017 complaint of Duke Energy versus the insurance companies, correct, Mr. De May?

A. Yes.

Q. All right. And on page 3 there is a section entitled "Nature of the Action."

Can you please read for us the paragraphs 1 and 2 related to that section?

A. Paragraph 1:

"This is a civil action seeking insurance coverage under certain third-party liability insurance policies, the policies, sold to Duke by the defendant insurance companies. Each of the policies provides coverage for liability for property damage caused by an occurrence.

Paragraph 2:

"In particular, Duke seeks damages for breach of contract and an order declaring the present and future rights, duties, and liabilities of the parties under the policies and directing the defendant insurers to identify -- indemnify Duke for damages suffered by Duke for certain environmental claims, known as the environmental claims, asserted against Duke arising out of coal combustion residuals, CCRs, at 14 Duke power plants in North Carolina and one Duke power plant in South Carolina."

Q. Thank you, sir. The only power plant not included was the W.S. Lee plant in South Carolina; is that correct? Is that your memory?

A. Not included in what?

Q. In the complaint asking for relief.

A. Yes, I believe that may be true.

Q. Thank you. The complaint provides some background on the environmental claims starting on page 9 of the document. In paragraph 40 -- are you there?

A. I am.

Q. All right. Paragraph 40 explains that power plants generating electricity through the combustion of coal create a number of waste byproducts, one of which is CCR or coal combustion residual, or more simply coal ash, yes?

A. Yes.

Q. All right. Would you please read for the record how the Company's complaint described coal ash in paragraph 40? It's on page 10 if you want to start with the words "coal ash," second sentence.

A. Are you asking me to read to the end of that paragraph?

Q. Yes, please.

A. "Coal ash contains various heavy metals and potentially hazardous constituents including arsenic, barium, cadmium, chromium, lead, manganese, mercury, nitrates, sulfates, selenium, and thallium. Coal ash has not been defined, itself, as a hazardous substance or hazardous waste under federal law, although some constituents of coal ash may be hazardous in sufficient quantities or concentrations."

Q. Thank you, Mr. De May. And if you would, turn to paragraph 44 on page 11.

A. Okay. I'm there.
Q. All right. It says:
"It's alleged, without regard to historical awareness of harm, that coal ash constituents from coal ash basins and other areas have been infiltrating into groundwater over a long period of time. State environmental regulators have alleged there have been environmental impacts or potential impacts to groundwater beneath each of Duke's North Carolina and South Carolina coal-fired power plants that are part of this claim."
Have I read that correctly?
A. Yes, you did.
Q. All right. And if we could move to paragraph 22 of the complaint, which is on -- I mean 52 of the complaint, which is on page 14.
A. I'm there.
Q. All right. Starting with paragraph 52, it provides that the North Carolina power plants in which Duke faces liability on account of alleged environmental property damage allegedly caused by CRR are as follows, correct?
A. Yes.
Q. All right. And then they list Allen,

Asheville, Belews Creek, Cape Fear, Rogers, Dan River, H.F. Lee, Marshall, Mayo, River Bend, Roxboro, L.V. Sutton, Weatherspoon, and H.B. Robinson in South Carolina, correct?

A. Yes.

Q. All right. For each power plant listed, one of the paragraphs -- like paragraph 55 states that Duke has incurred substantial cost on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Allen plant for which Duke makes a claim under the policies issued to Duke Power. Duke is incurring substantial additional cost on an ongoing basis and will continue to incur substantial additional cost in the future, correct?

A. You read that correctly.

Q. Thank you. Do you know what the current status of this insurance litigation is, Mr. De May?

A. I do. They are in various phases of discovery. I understand that that will conclude this year. Hearings will begin in 2020 -- 2020, and a trial is expected in the beginning of 2021.

Q. Thank you. Have -- there have been some settlements, but those are confidential, correct?

A. You broke up, I'm sorry. There have been some settlements?

Q. Right. But those are confidential; we will not get into those, correct?

A. Confidential but limited -- limited in nature and scope.

Q. Thank you. Now, if I may refer you to an exhibit that's already in play, it is Public Staff Junis Direct Exhibit 1. That is the DEQ settlement agreement dated December 31, 2019.

(Reporter interruption due to sound failure.)

Q. Okay. Mr. De May, I believe you said that you were aware of the settlement agreement; is that correct?

A. Yes, I am aware of the settlement agreement. I don't have it in front of me.

Q. I'm sorry, you broke up. I missed you there.

A. I do not have it in front of me.

Q. Oh, you don't have Junis --

A. Junis --

Q. -- the direct -- the Exhibit 1?

A. I'm going to try and pull the -- to correct my audio. Just give me one minute, please.

(Pause.)

THE WITNESS: Ms. Townsend, would you please repeat the exhibit name? I apologize.

Q. No problem. It is the 12/31/19 settlement agreement, and it has been filed under Public Staff Junis Direct Exhibit 1.

A. Okay. Coming.

Q. Thank you.

(Pause.)

THE WITNESS: Okay. I have it.

Q. Great.

A. Sorry for that.

Q. No problem. What role, if any, did you have in negotiating this settlement, Mr. De May?

A. I was involved along the way.

Q. Okay. Were any other staff members involved in the negotiation?

A. There were quite a number, and there were very technical details involved in the settlement that I had very little input on it.

Q. Understood.

A. And a limited understanding of it.

Q. Okay. And this settlement is not only with DEQ, is it; it's with -- deals with some of the other lawsuits or disputes that we talked about earlier, correct?

A. Yes.

Q. Okay. If we look at paragraph 9 -- I'm sorry, 5 on page 2, it talks about the litigation that is involved in this settlement, and that's quite a list. I believe that entails most of the ones that we talked about, correct?

A. I will accept that, yes.

Q. Thank you. It looks like it was the two-state law enforcement actions brought by DEQ. In fact, they talk about it in 6. It says it desires to resolve and settle any disputes between them in connection with the OAH proceedings. And that would be those 4/1/19 closure determinations, correct?

A. It would, yes.

Q. All right. The state enforcement action, those would be the ones brought in 2013 and thereafter. The Federal Clean Water Act (sound failure). And then there are evidently some --

(Reporter interruption due to sound failure.)

Q. So just go back to paragraph 6, we dealt with the fact that they were the OAH proceedings, the state enforcement actions, the Federal Clean Water Act lawsuit, and PJRs, which are petitions for judicial review.

In order to ensure that the impoundments are excavated on an expedited basis and to remove the uncertainty associated with litigation; is that what the paragraph tells us?

A. Yes, I see that.

Q. All right. And then on paragraph 7, this talks about the actual impoundments at the facilities regulated under CAMA. And it deals with -- A says it's about Allen, and it says Allen has two CCR impoundments, a retired ash basin, and an active ash basin, and that it's approximately 123 acres, correct?

A. That's what it says, yes.

Q. All right. And then B was the Belews Creek steam station, C is the Cliffside steam station, and D is the Marshall steam station, correct?

A. Yes.

Q. And then we have E and F being the Mayo and the Roxboro, correct?

A. That's correct.

Q. DEP, correct?

A. Correct.

Q. All right. And if we'll go to paragraph 50, this is on page 24, it states that DEQ is the only state entity that is bound by this agreement and consent order, correct?

A. Yes.

Q. All right. And if you go to paragraph 53, it has some stipulations -- I'm sorry, it's on page 25. Are you there?

A. I am.

Q. All right. It talks about stipulations between only the parties to this agreement regarding their rate recovery proceedings, correct?

A. Yes.

Q. All right. And it says on page 26, under the first full sentence:

"For example, and without limitation, the agreement in this subparagraph does not extend nor shall it be construed to apply to the issues of; one, whether Duke Energy acted prudently and reasonably in the past; or two, whether Duke Energy prudently and reasonably performs its obligations under this agreement."

Is that correct?

A. It does say that. But it is saying that, if we do perform these actions, that those are deemed prudent unless we imprudently execute on that.

Q. By the parties to this agreement only, though, correct?

A. Yes.

Q. All right. And that is all the questions I have, Mr. De May, thank you for your patience and for your answers.

A. Thank you, Ms. Townsend.

Q. And Ms. Force, as I said, has questions for Mr. Hatcher.

CROSS EXAMINATION BY MS. FORCE:

Q. Good morning, Mr. Hatcher.

A. (Larry E. Hatcher) Good morning.

Q. Are you okay?

A. Yes, ma'am.

Q. Let me know if I need to turn my monitor off, I'm hearing a little feedback.

CHAIR MITCHELL: I'm hearing it too, Ms. Force, so I would ask that you-all keep your lines on mute until the moment you need to speak, please. Thank you.

MS. FORCE: Okay.

Q. Mr. Hatcher, my name is Margaret Force. I'm with the Attorney General's Office. And in looking at your testimony, I see that your responsibilities include customer care, online customer interactions, billing and metering services, and you also address some of the new features of the Customer Connect system; is that right?

A. Yes, ma'am.

Q. I think I only heard part of your answer, but it was a "yes, ma'am," right?

A. Correct.

Q. I have some questions about the technology that Duke is using with Customer Connect to help customers take advantage of emerging programs or apps that make use of the detailed data that Duke is collecting from customers' smart meters, the advanced meter infrastructure, to monitor and conserve energy. And it looks like the questions are appropriate for you and for Mr. Schneider both, so I plan to start with you. But if you think that I need to ask another witness, just let me know who to ask, please. Okay?

A. Okay.

Q. Okay. I see, on page 4 of your direct testimony, starting on line 16, that you stated that the customer is at the center of Duke's purpose and that evolving customer expectations, emerging technologies, and change in public policies all converge to create a dynamic environment for Duke. And you also say that Duke works to build genuine connections with customers by listening, anticipating their needs, and offering solutions.

Is that a fair restatement of your testimony at that point?

A. Yes, ma'am.

Q. In the -- excuse me -- in the last Duke Carolinas rate case, there were some parties who questioned Duke's investment in Customer Connect and in AMI meters, and their position was that customers should be able to access their own very detailed data that Duke is collecting from AMI meters. I'm sorry, did that last part not come through?

CHAIR MITCHELL: Ms. Force, just for purposes of the record, restate the whole question, please, ma'am.

MS. FORCE: Okay.

Q. In the last Duke Carolinas rate case, there were some parties who questioned Duke's investment in Customer Connect and AMI, and posited that customers should be able to access their own very detailed data that Duke is collecting from AMI meters.

Are you familiar with that testimony and position that was made in the last case, Mr. Hatcher?

A. Are you referring to the Retha Hunsicker testimony?

Q. One of the testimonies from Duke was from Ms. Hunsicker -- I'm sorry about the pronunciation of the name -- and there was also testimony from Mr. Schneider, but also there were other witnesses -- other parties who addressed that issue in their briefs, namely the EDF, the Environmental Defense Fund; and North Carolina Stainable Energy Association; and others.

Does that -- are you familiar with that?

A. So I'm familiar with Mrs. Hunsicker's testimony. Some of the others that you mentioned, I understand that they did provide testimony in that hearing, but I personally have not reviewed it.

Q. Okay. One of the things that was posited in that case was that customers should be able to use their own already available -- their own customer data through already available and used national standard protocol that's called the Green Button Collect My Data standard; are you familiar with that?

A. Yes, ma'am.

Q. So would you disagree that Green Button Collect was identified as an important feature for customers to benefit from the implementation of Customer Connect and the rollout of AMI meters?

A. I would agree that that was the testimony; yes, ma'am.

MS. FORCE: I'd like to ask the Commission to take judicial notice of its order in the Sub 1146 rate case, which was the last Duke rate case, and I refer that that is available through AGO Exhibit 44. I don't believe it's been taken -- it could be that it's already in the record, but I'm not sure.

CHAIR MITCHELL: Just for purposes of the record, Ms. Force, can you -- will you please indicate the date of the Commission's order that you were referencing? And we'll take judicial notice, hearing no objection to your request. I just want to make sure you specify the date of the order.

MS. FORCE: The date of the Commission's order, as I have it, appears on page 334 of that order, and it was issued on June 22nd of 2018.

CHAIR MITCHELL: In docket number?

MS. FORCE: And the main docket number in that case was Docket Number E-7, Sub 1146. And also, in addition to the 334 pages in the majority order, there were also dissenting opinions that appear after that.

CHAIR MITCHELL: All right. Hearing no objection, Ms. Force, to your motion, we will take -- the Commission will take judicial notice of its order. Thank you.

MS. FORCE: Thank you. I appreciate that. And I do not propose to put that into an exhibit, and I'm not going to rehash what appears in the order in this hearing. We can take that up in our brief. But as I understand it, the Commission has indicated that it intends to take judicial notice of at least some of the issues from the other case, so I want to make sure this is available to our -- for our use. Okay.

Q. Mr. Hatcher, the Commission has a pending rulemaking about access to the detailed customer data that Duke is collecting using the new AMI meters and related customer privacy issues, and that's in Docket Number E-100, Sub 161.

Are you familiar with that docket?

A. Is that referred to as the data access docket?

Q. That's right.

A. I am familiar with that docket as taken. I don't personally have any details as to what's being discussed in that.

CHAIR MITCHELL: Ms. Force, you're on mute, so you'll need to start your question over.

MS. FORCE: I'm sorry.

Q. And can you tell me, is there another witness that you'd suggest that would have more familiarity with that docket?

A. I would refer you to Don Schneider. What I'm aware of, Ms. Force, in terms of Green Button, is I know we're currently not part of that alliance. I do know that we do make and allow energy consumption data available to our customers if they request it. They are free to use that data however they see fit. So if there's an app out there that they feel like they could use that data to plug into and get better information on how to manage their energy usage or whether they think they should pursue solar installations at their home, they're certainly welcome to that data, and we can and do provide that to our customers.

The data access docket I know has taken up some of these issues, and, you know, we do look forward to the outcome of that docket. But beyond that, really the technical issues associated with Green Button I will refer to Mr. Schneider.

Q. And for clarification, it's my understanding that some of those issues -- well, let me put it this way. That the Customer Connect works in tandem with the AMI meters. So I want to be clear that I will be able to ask my questions and get them answered if it overlaps in the Customer Connect and how that's being rolled out; is that correct, then?

A. It does overlap, so it's kind of one of the key components to the overall customer information system that we put in with Customer Connect. So the information coming off the meters goes into the billing system is where I pick up on it in my organization, and then we also did maintenance of those meters after they were installed. So, in terms of the information that would be coming in, it would be coming in through billing databases, and then, you know, we could run queries or be able to provide that information back to the customer if they request it.

Also, you know, we have a smart meter app that the customers can use to be able to extract that energy usage data pretty much on a realtime basis if they want to, you know, enroll with that app and be able to get that information.

Q. I do have some more --

CHAIR MITCHELL: I'm sorry, Ms. Force, I'm going to interrupt you. Mr. Hatcher, you are trailing off. We're having a hard time hearing you, particularly when you get to the end of your sentences. So if you could just be cognizant of that. We can hear you when you start your sentences, but then you trail off. So just try to moderate your vol- -- the volume of your voice to make sure that we hear, and that everybody can hear your responses to the questions.

All right. Ms. Force, I interrupted you, so you may proceed. Ms. Force, you're on mute.

MS. FORCE: I apologize.

Q. Mr. Hatcher, it looks like you're familiar with some of the issues that go to customer access to the data. And so I'd ask you to turn to AGO Exhibit 46, please.

A. Okay. Just a moment, please.

Q. Sure.

(Pause.)

Q. Let me know when you're there.

(Pause.)

THE WITNESS: Give me just a moment. We're pulling that up.

(Pause.)

Q. Mr. Hatcher, while you're bringing that up, I'm going to have some questions about some of the other exhibits that appear nearby there that the AGO has put -- provided ahead of time. If you have that folder, that would be helpful.

A. Okay. We'll work to get that information.

(Pause.)

CHAIR MITCHELL: Ms. Force, are you -- where are you in your cross examination of the witness?

MS. FORCE: I have another 15 minutes or so.

CHAIR MITCHELL: Okay. So, Mr. Robinson, at this point, are we waiting to get documents in front of the witness?

THE WITNESS: Yes, ma'am.

CHAIR MITCHELL: Okay.

MR. ROBINSON: Chair Mitchell, if we could just have five minutes to ensure that Mr. Hatcher has what he needs.

CHAIR MITCHELL: All right. Mr. Robinson, I'll give you your five minutes. And let's also check the volume with Mr. Hatcher's system. We're having a hard time hearing him. He's trailing off, and then there is sort of a hum that also occurs when he speaks. So if you could have someone look into the system just to ensure that you-all have it functioning optimally, that would be appreciated. All right. Let's go off the record. We'll go back on at 10:10.

(At this time, a recess was taken from 10:04 a.m. to 10:10 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please.

MS. FORCE: Shall I begin?

CHAIR MITCHELL: All right. Mr. Hatcher, would you please confirm that you have the documents in front of you?

THE WITNESS: Yes, ma'am, I do.

CHAIR MITCHELL: All right. And I would

remind you to just be cognizant of the volume level of your voice so that we can hear your complete sentences. All right. Ms. Force, you may proceed.

MS. FORCE: Thank you.

Q. Mr. Hatcher, you have what was AGO Exhibit 46 before you. That was what was prefiled before.

Do you recognize -- would you agree with me that that is on Duke letterhead, and it's a February 10, 2020, filing in that docket we were talking about, the rulemaking concerning customer data that was made by Duke?

A. Yes, ma'am, I do.

MS. FORCE: I would ask to mark this as AGO Hatcher Cross Exhibit 1, please.

(Pause.)

MS. FORCE: I'm sorry, can you hear me? I'd ask to mark this as AGO Hatcher Cross Exhibit 1, please, for the record.

CHAIR MITCHELL: All right. Ms. Force, the document shall be marked as AGO Hatcher Cross Exhibit Number 1.

(AGO Hatcher Cross Exhibit Number 1 was marked for identification.)

MS. FORCE: Thank you.

Q. Would you please turn to page 4, Mr. Hatcher. And I'm looking just partway down the page, there's a date shown there, and these are -- this is Duke copying in what has been proposed in a Public Staff proposed rule change that would be effective January 1, 2022.

And can you agree with me that Duke opposes this requirement that would say that customer data must be maintained and made available to customers and customer-authorized third parties in electronic machine readable format that conforms to the NAESB standard described there or another Commission-approved electronic machine readable format that conforms to national recognized standards and best practices?

MR. ROBINSON: Chair Mitchell, if I may, the Company objects. This has to do with a completely different docket. There has been no Green Button testimony that has been filed or prefiled in this case. I'm not sure as to why Ms. Force is asking Mr. Hatcher these questions.

CHAIR MITCHELL: All right. Ms. Force, how do you respond?

MS. FORCE: I would explain that, in the last rate case, there was quite a bit of discussion, not only about Customer Connect, but about the cost recovery for AMI meters and whether the benefits to customers are sufficient to justify cost recovery. And, in this case, that question comes up again where the Company has gone forward and implemented its program without embracing some of the very important pieces of it that were put in the record last time and were to be taken up subsequently.

CHAIR MITCHELL: All right. Ms. Force and Mr. Robinson, I'm going to overrule the objection. The Commission historically and typically allows open cross, but, Ms. Force, I would ask that you just move through this as quickly as you can in the interest of making the most efficient use of our hearing time. Thank you.

MS. FORCE: Okay.

Q. Now, I don't remember that you answered the question, Mr. Hatcher.

Would you agree that Duke opposes the proposal that has been put forward in that rule and gives some reasons for that? That's what I wanted to talk to you about. And just to elaborate, this is a Green Button Connect-type standard in my understanding. Is that your understanding too?

A. Yes, Ms. Force. So I agree that what you've read is in this document that I'm looking at. You know, we didn't --

(Reporter interruption due to sound failure.)

CHAIR MITCHELL: All right. We are having significant issues with the audio in the -- on Mr. Hatcher's setup. So here's what we're going to do. We are going to take a 15-minute recess. Duke, I'm going to ask that you provide a different setup for Mr. Hatcher and for anyone that was to testify using the audio/visual setup you have in that room. So let's go off the record. We will go back on at 10:30.

MR. ROBINSON: Yes, Chair Mitchell.

(At this time, a recess was taken from 10:15 a.m. to 10:30 a.m.)

CHAIR MITCHELL: All right. Mr. Hatcher, have we remedied the situation with your audio?

THE WITNESS: I think so, yes, ma'am.

CHAIR MITCHELL: Okay. All right. Let's go back on the record, please.

Ms. Force, you may proceed.

Q. Mr. Hatcher, okay, I didn't see you back on the screen. You've moved in my windows, I'm sorry.

We were talking about the --

CHAIR MITCHELL: Ms. Force, I'm sorry, let me interrupt you just one moment.

Mr. Hatcher is now sitting behind Alison Williams' system, just so persons participating on the video conference are clear who's testifying. Mr. Hatcher is behind Alison Williams.

MR. ROBINSON: Yes. And, Chair Mitchell, if I may, I just want to apologize. There was an issue with Mr. Hatcher's actual computer, so we're using Ms. Williams' computer for him to be able to testify, I hope the audio is much better on this one.

CHAIR MITCHELL: Thank you, Mr. Robinson.

All right, Ms. Force, you may proceed.

Q. Mr. Hatcher, looking at that exhibit that we were discussing before the break, there is a rule that's set out there, and Duke has indicated about the proposal to incorporate a Green Button Connect-like standard. And I gather that one of the reasons is that, even though the requirement would not kick in until January of 2022, Duke says that, if the standard is required, then Duke will have difficulty implementing its Customer Connect program fully by April 2021 as is now planned. Do you agree?

A. Yes, ma'am, I do.

Q. And you mentioned earlier that, instead of using the Green Button Connect, that Duke offers its customers what's called My Duke Data Download, correct?

A. Yes, ma'am; that's correct.

Q. I'm having a little trouble hearing you, but I'll try to listen up.

A. Yes, ma'am, that is correct.

Q. That was much better. Okay.

My Duke Data Download is not a national standard, is it? Isn't that something that's Duke's own version that's based on the older technology called Green Button Download My Data?

A. You probably know more about that than I do, from a technical perspective. If I may, the reason that we were having concerns about the January date, the Customer Connect platform is really not just designed to deal with the Green Button issue. It's really designed -- it's a whole new customer information system for our entire enterprise.

So it's designed to give kind of a state-of-the-art interaction for customers to interact with us, just like they would other large retail-type customers. It's designed to be able to take advantage of the advanced meter infrastructure that's been installed in the field so the customers do have a lot more of that information available to them and have more control. But it's also designed to give us a more personal experience with the customer versus kind of a more global experience with the customer.

So all of that is really built into this tool. So it's a lot bigger than just what you're talking about with the Green Button.

The reason we said that the date was going to be a challenge, the deployment of Customer Connect goes into DEC in April of next year, and then you're looking at a three- to four-month, you know, checkout period, a deployment period to make sure everything is good and that we're solid. And then we're going to do DEP in November of next year. So to be able to get through that, get the project implemented across the Carolinas, that January date was of concern.

And to do something with our legacy systems when we're trying to implement this new customer information system just didn't feel prudent from that perspective.

Q. Okay. I'd ask you to please turn to AGO Exhibit 45 now.

A. Okay. Just a moment, please.

Q. Sure.

(Pause.)

THE WITNESS: Okay.

CHAIR MITCHELL: Ms. Force, you're on mute.

MS. FORCE: I'm sorry. I got that backwards.

Q. Mr. Hatcher, I'd submit that this is a response to a data request by Duke to the Public Staff; do you see that? Are we on the same page?

A. Yes, ma'am.

Q. All right.

MS. FORCE: And I'd ask to mark this AGO Hatcher Cross Exhibit 2, please.

CHAIR MITCHELL: The document will be so marked.

(AGO Hatcher Cross Exhibit 2 was marked for identification.)

CHAIR MITCHELL: Ms. Force, you are on mute again.

MS. FORCE: I apologize.

Q. Mr. Hatcher, I submit to you that these -- this is a description by Duke on the difference between the My Duke Data Download program and the Green Button Connect program. And it looks to me like there's a difference in functionality that, in the one case, the information would also be available automatically for approved third parties under the Green Button Connect program, but not under Duke's. At least that's one of the differences; do you agree?

A. Let me read this, and I will let you know. Just a moment.

(Witness peruses document.)

Yes, ma'am, I agree.

Q. So if you go back to the comments that Duke filed that we were looking at in that Cross Exhibit 1, on pages 4 through 5, would you agree with me, then, that Duke gives a couple of reasons for not adopting the Green Button Connect approach? One of those being that Duke has surveyed its customers and found that customer demand for that technology was not out -- did not outweigh the project costs implemented; do you see that comment?

A. Yes, ma'am.

Q. Do you agree?

A. Yes, ma'am.

Q. And Duke would require Commission to vet potential third-party involvement, right?

A. Yes, ma'am.

Q. Okay. Taking that first reason, that Duke has not found customers are interested, I'd ask you to please turn to AGO Exhibit 48.

A. Exhibit 48. Okay. Just a moment, please.

Q. Sure.

A. 48.

(Pause.)

Q. Do you have that?

A. I'm getting it, yes, ma'am.

Q. Okay.

A. Okay. It's in front of me. Okay. I have it, Ms. Force.

Q. And at the top of that, does it say on your copy, "Duke Energy Green Button position and cost-benefits analysis dated 4/12/2019"?

A. Yes, ma'am.

Q. Is this something that you recognize,

Mr. Hatcher? I almost called you Mr. Williams.
Mr. Hatcher.
A. I have not reviewed this.
Q. Okay.
MS. FORCE: Well, first, I'd ask that this be marked as AGO Hatcher Cross Exhibit 3, please.
CHAIR MITCHELL: The document will be so marked.
(AGO Hatcher Cross Exhibit 3 was marked for identification.)
Q. And I submit to you, Mr. Hatcher, that this was a document that was part of a discovery response to another party in the rulemaking proceeding. And it describes Duke's survey of its customers and cost-benefit analysis. Can you just look at it briefly and see if that appears to be the case to you? If you can look on page 2 in particular, I'm going to have a question there.
A. Okay. Yes, ma'am.
Q. So on page 2 there are some projected costs of using the Green Button Connect standard. The analysis here shows total cost for five years including integration, setup, O&M, et cetera, about $1.7 million,

right?

A. Yes, ma'am.

Q. And then there's an analysis of how many customers might make use of their data using the Green Button Connect standard; do you see that?

A. I do.

Q. And Duke indicates, as I understand it, that they've looked at how many users have shown an interest by looking at how many sessions have occurred where customers have gone on to the Duke portal to look at their data and taken a percentage of that. Do you agree with me there?

A. I believe that's correct; yes, ma'am.

MR. ROBINSON: Chair Mitchell -- Chair Mitchel, I'm sorry, this is Camal. If I may, renewing my objection, Chair Mitchell. It's -- obviously, it's one thing to evaluate the benefits of AMI and Customer Connect, but these cost analyses that Ms. Force is going into, I question whether this witness should be the one receiving these questions.

CHAIR MITCHELL: All right. Ms. Force, how do you respond?

MS. FORCE: This document is a Duke

document, and it speaks for itself. I'd like to just get it into evidence, and we can move along. I don't have too many more questions for the witness.

CHAIR MITCHELL: All right. I'll overrule the objection and ask Ms. Force that you please move along.

Q. I do want to ask you, this indicates a cost of $1.7 million, but putting that into perspective, it's my understanding from the last rate case that Duke has invested $73.9 million in AMI meters in 2016.

Is that better asked to a different witness, then?

A. Mr. Schneider; yes, ma'am.

Q. Okay. I'll save that. My understanding of the investment in Customer Connect as of the last rate case was, if I have this right, $123.1 million is the North Carolina retail share. Does that sound right to you?

A. Give me a moment, and I'll let you know.

Q. Okay. Thanks.

(Pause.)

THE WITNESS: Can you repeat that amount, please?

Q. In the last rate case, I saw that the North Carolina retail share of actual and estimated costs of the implementation was then $123.1 million.

A. I believe that is correct.

Q. Okay. Thank you. And I think we talked about this a little bit, but you don't disagree with me that, in the last rate case, there were advocates for consumers, including the Public Staff -- and in the customer data access proceeding -- including the Public Staff and the AGO, North Carolina Sustainable Energy Association, and EDF, all recommending that Duke be required to offer access using the Green Button Connect standard or some similar standard that would make it more flexible for customers to be able to use third-party applications and programs, not just Duke's. Would you disagree with that?

A. I would agree the way you stated it; yes, ma'am.

Q. Okay. I am going to ask -- and I'm not going to ask questions on that. I can do the text. But would you please look at AGO Exhibit 47? I'll try to make it quick.

A. Okay. Just a moment.

(Pause.)

THE WITNESS: Okay.

Q. Would you agree with me that these appear to be reply comments from Duke in that same rulemaking proceeding and they're dated July 17, 2020?

A. Yes, ma'am.

Q. All right.

MS. FORCE: I'd ask that this exhibit be marked as AGO Hatcher Cross Exhibit 4, please.

CHAIR MITCHELL: All right. The document shall be so marked.

(AGO Hatcher Cross Exhibit 4 was marked for identification.)

Q. And just -- Mr. Hatcher, turning to page 18, would you agree with me that the comments there say that, if the Commission approves the Public Staff's proposed rule, the Companies note that they could not begin such a project until late 2022 or early 2023 after full implementation and stabilization of Customer Connect?

A. Yes, ma'am.

Q. All right. So the distinction being that customers would be able to use, as you've pointed out, the programs that Duke has offered, but will not have the same options for working with third parties in order to use third-party programs through some -- an automatic -- a more flexible process that allows them to do that; that's available as a standard; would you agree?

A. Well, the customer can get their data if they want to obtain their data, and they're welcome to go to any third party to use their data.

Q. And the way it's established under the protocol that Duke has used, then, if the customer does that, they would need to download the data and provide it to that third party each time they want to take a look with the application that they're using; is that right?

A. Yes, ma'am, currently.

Q. Okay. I have -- I already talked about the Commission's order in the last case. I'd ask one more thing, and that there's a transcript that's included and -- I am trying to find the number. AGO Exhibit 30. It's the transcript from the rate case.

A. Okay.

Q. Volume 18 in this docket, 1146 case; do you have that?

A. Yes, ma'am.

Q. Pages 250 to the end address these same issues, would you agree, Ms. Hunsicker's testimony and Mr. Schneider's from the last rate case?

A. Let me find the page.

(Witness peruses document.)

You said 250?

Q. Yes. I may be mistaken. I believe that the Commissioners provided a copy that has page 1 of that volume and then it starts again on 250 to the end. Anyway.

MS. FORCE: I'd ask that this volume be marked as AGO Hatcher Cross Exhibit 5.

THE WITNESS: Okay. I have it in front of me. Could you repeat your question, please?

Q. Would you agree with me --

CHAIR MITCHELL: All right. Give me an opportunity to --

MS. FORCE: I'm sorry.

CHAIR MITCHELL: -- identify the document. It will be marked as AGO Hatcher Cross Examination Number 5.

(AGO Hatcher Cross Exhibit 5 was marked for identification.)

CHAIR MITCHELL: All right. Ms. Force, proceed with your question.

MS. FORCE: Thank you.

Q. Mr. Hatcher, would you agree that this is the transcript of testimonies from witness Hunsicker on the Customer Connect project and cost, followed by testimony on witness Schneider on AMI meter rollout in the last -- dated 2018 in that transcript?

A. Yes, ma'am.

MS. FORCE: Okay. I don't plan to take up hearing time going through the transcript, but I would ask that the transcript be admitted into evidence and available.

CHAIR MITCHELL: Ms. Force, just so I'm clear, are you moving that AGO Hatcher Cross Examination 5 be admitted into evidence?

MS. FORCE: So that the testimony in that transcript is available in this case as evidence as well; that's right.

CHAIR MITCHELL: All right. Please restate your motion, Ms. Force, just for purposes of clarity in the record. I want to make sure I understand what you're asking.

MS. FORCE: Sure. I'd ask that these pages from the transcript of the testimony from witnesses Hunsicker on Customer Connect, and witness Schneider on AMI meter rollout, that were addressed in the last rate case, be admitted in this case for use in this case.

CHAIR MITCHELL: All right. And --

MR. ROBINSON: Chair Mitchell, if I may. The Company just notes for the record that it objects again, as I indicated before, as it pertains to this transcript being levied into testimony in the prior case, and it really has no bearing on this particular case, in terms of the cost or AMI or Customer Connect investments in general.

CHAIR MITCHELL: All right. I'm going to overrule the objection, Mr. Robinson, and Commission will give the evidence the weight it's due.

And, Ms. Force, just again, your motion that AGO Hatcher Cross Examination Exhibit Number 5 be admitted into evidence is allowed.

(AGO Hatcher Cross Exhibit 5 was admitted into evidence.)

MS. FORCE: Thank you. And with that, I don't have any other questions for this witness.

CHAIR MITCHELL: All right. Mr. Page,

you're up.

MR. PAGE: Thank you, Madam Chair. My technology is great when it worked. I couldn't get my mouse to put on the camera or the auditory portion of this.

CHAIR MITCHELL: Just goes with the morning we're having so far, Mr. Page. All, right. Please proceed, sir.

MR. PAGE: It goes right along with it. Is it Monday? It feels like a Monday.

CROSS EXAMINATION BY MR. PAGE:

Q. In any event, let me address the panel for just a second. Mr. Hatcher, I'm sorry to tell you, I don't have any questions for you this morning.

A. (Larry E. Hatcher) That's okay. That's certainly fine, thank you.

Q. And, Mr. De May, some of the questions that I had intended to ask you have already been covered by the Attorney General, so I'm not going to go over that again. But I do have a couple of lines of questions that I wanted to ask you, that I understand you have another witnesses to testify in these areas, but the questions that I have are not, kind of, down-in-the-weeds-type questions or very high granular questions, they're broad-overview types of questions. But if I should have to ask you something where you don't know the answer, you can just simply say, "I'm sorry, I don't know," and I will accept that; is that okay with you this morning?

A. (Stephen G. De May) Sounds good. Thank you.

Q. All right. Would I be correct in saying, Mr. De May, that, other than directives that come down to you from the parent corporation, Duke Energy, as president, you are pretty well where the buck stops for Duke Energy Carolinas in North and South Carolina?

A. Yes, I would agree with the way you worded that.

Q. And as you discussed with Ms. Townsend -- my first series of questions have to do with coal ash.

So you discussed with Ms. Townsend, did you not, Duke's present engagement in what is a somewhat extensive and somewhat expensive process and program for cleaning up the remaining coal ash ponds and repositories; is that correct?

A. Well, I wouldn't call it much of a discussion. We talked about the numerous lawsuits that are pending related to that matter.

Q. All right . Then would you agree with the statement I just made, that, currently, Duke is engaged, as a result of litigation and settlements and that sort of thing, in a fairly complex and expensive program to clean up those coal ash basins?

A. Yes. We are undertaking the kind of program you just described, but it's to comply with federal, state -- federal and state requirements. We are also operating under a settlement agreement with DEQ and the Southern Environmental Law Center.

Q. And that's the 2019 settlement that you and Ms. Townsend did talk about a little bit?

A. Yes.

Q. And so your settlement with DEQ, would I be correct in saying that, among other things, DEQ was following the mandates of the North Carolina Coal Ash Management Act?

A. In what regard are you asking whether they were following?

Q. Well, as a state regulatory agency, they've got to have statutory authority to do what they do --

A. They did have statutory -- yes, thank you. They do have statutory authority, and they have great discretion, actually, as the environmental regulator, both as a regulator, but also by virtue what the statute gave them.

Q. And that agreement, the 2019 agreement, is what is driving the timing of the cleanup of the remaining basins, and to a certain extent the cost of the cleanup; is that correct?

A. I would say that some of the timing, certainly, a large degree of the costs were determined by CAMA and the federal CCR rules. I would say that there were a number of coal ash basins that were previously classified as low risk that DEQ have discretion on. They exercised their discretion and issued an order on April 1st directing the -- of 2019, directing the Company to fully excavate all those remaining basins.

And the settlement is the result of a collaborative process between the Company and the DEQ and other parties to arrive at a -- what I would say, a more middling position.

Q. It was the DEQ action in requiring the cleanup of even the low-risk basins, which, if my memory serves correctly, increased the estimated cost of cleanup from somewhere in or around the $5 billion area to somewhere in or around the 8- to $9 billion area; is that -- do you recall the same thing?

A. Yeah. Although, you know, my numbers are a little different. It took the figure to about $10 billion, their full excavation order. The settlement actually reduced that total estimated cost by about a billion and a half dollars. The settlement, in our opinion, brought benefits for our customers to the tune of about a billion and a half dollars.

Q. Thank you for that clarification.

Duke Energy Carolinas operates in both North and South Carolina; do they not?

A. We do.

Q. To your knowledge, does South Carolina have any sort of statute that is functionally the equivalent to the North Carolina Coal Ash Management Act?

A. South Carolina is effectively conforming, at this point in time, with the federal CCR rules; and so we operate as one system, as you know, across borders, and the generation system is not separated by a border, it is a shared system. And so South Carolina does have coal ash remediation costs in its current rates for the North Carolina facilities. So they are covering their CRR -- federal CRR costs.

Q. In your last general rate case in South Carolina, would I be correct in saying that the

South Carolina Public Service Commission stated, among other things with regard to coal ash cleanup, that it simply did not consider itself bound by the North Carolina Coal Ash Management Act?

A. To the extent that the Coal Ash Management Act did require a mitigation plan that resulted in a higher cost, South Carolina did say that; that's correct. We are currently appealing that.

Q. And as a result of their making that decision, they -- they basically disallowed some of the coal ash cleanup costs that you had asked to be able to collect from South Carolina consumers; is that correct?

A. That is correct. Again, the subject of ongoing challenge.

Q. I understand that that is under appeal.

Do you know whether or not there is anything approximately equivalent or similar to the North Carolina Coal Ash Management Act that impacts Duke's operations in Florida?

A. Are you asking if Florida has a CAMA equivalent?

Q. Yes.

A. I do not believe they do.

Q. How about the same question as to Duke's operations in Ohio?

A. Well, I see where you're going with this. I don't believe there is legislation like CAMA in the other states that we are operating in. That is not -- that is my understanding. However, each state is dealing with compliance with the CCR rules in their own individual way.

Q. All right. So this is really my last question on this particular point.

So the same -- your answer would be the same if I were to ask you about Indiana and Kentucky?

A. Yes.

Q. All right. Well, let's leave coal ash in the rearview mirror, then, and move on to another topic.

I am correct in saying, am I not, that Duke serves a number of industrial and manufacturing customers in North Carolina?

A. Yes, you are.

Q. Are those customers and their loads important to Duke's operations and finances in North Carolina?

A. Of course they are. The -- in the Carolinas, the commercial and industrial sector is -- or the industrial sector is about a third of our load.

Q. Can you list any other reasons why these types of high-load-factor customers are important to Duke's operations? For example, don't customers like that buy an awful lot of energy from Duke and a lot of it off peak?

A. Well, yes. And I would say, among the reasons our industrial customers are important to us is they are efficient users of power; and they are, of course, a really great source of economic development for our state, which is -- you know, has those kind of follow-on impacts for the electric utility that serves this state.

Q. And they don't usually fail to pay their bills or pay those bills late; would that be a true statement?

A. It's not 100 percent true, but it is generally true.

Q. All right. And those industrial and manufacturing customers provide relatively good-paying jobs which help to support laundries, and grocery stores, and automobile dealers, and other service industries; do they not?

A. They do. And Duke is quite active in helping attract more industrial customers to the state.

Q. As opposed to, say, 20 years ago, 2000, does

Duke have more or fewer manufacturing and industrial customers than it did 20 years ago?

A. I don't know the answer as terms -- in terms of numbers of customers, but I imagine our entire system has grown significantly. And I imagine the industrial load has grown significantly as well. In terms of numbers of customers, I can't say.

Q. All right. Do you know how Duke's sales to manufacturing and industrial customers today compares to the level of such sales 20 years ago?

A. Not in any, you know, specific sense, no.

Q. All right. Were you the Duke president at the time of the last Duke general rate case about two years ago?

A. I was not.

Q. Did you participate in that rate case?

A. I did, as a witness for treasury-related issues, cost of capital, credit quality, et cetera.

CHAIR MITCHELL: Mr. Page, I apologize. I have to interrupt you. I need to inquire as to whether Commissioner Clodfelter is still on the line. I no longer see him.

Commissioner Clodfelter, are you on the line?

COMMISSIONER CLODFELTER: Yes, I am. Sorry, I forgot to turn the video back on after the break, but I'm here and have been here consistently since 10:30.

CHAIR MITCHELL: Okay. Thank you, sir. Mr. Page, I apologize, you may proceed.

MR. PAGE: That's quite all right, Chairman Mitchell. Commissioner Clodfelter, I see that your blinds haven't gotten any younger than they were earlier this morning.

COMMISSIONER CLODFELTER: They have not.

Q. So, Mr. De May, again, the question for you is, do you know whether or not Duke's sales to manufacturing and industrial customers are more or less in 2020 than they were in 2000?

A. And my answer is I don't have those statistics; but I would guess that it is higher than it was in 20 -- than it was.

Q. Do you recall, in the last rate case, reading Mr. O'Donnell's testimony?

A. From the 2017 rate case?

Q. Yes, sir.

A. I recall having read it, but I don't recall what I read.

Q. Would you accept, subject to check, that he presented evidence showing that, in the 20-year period from 2000 or 1997 to 2017, Duke had lost an awful lot of its industrial and manufacturing load? Would you accept that subject to check?

A. Yes.

Q. Have you had a chance to review Mr. O'Donnell's testimony in this case?

A. I did.

Q. And he offers some evidence, does he not, tending to show that recently the trend of Duke's retail rates has been to move closer to the regional and national averages than it was, say, five years ago?

A. I will accept that he said that, if that's your question.

Q. Yes. Do you have any reason to disagree with that conclusion?

A. Well, I don't know whether to agree or disagree with the conclusion. I'll agree that he said it. I don't have those specific facts available to me.

Q. Will you agree that --

A. I would just say, sometimes when people see us increasing rates, they assume that the average is staying stag, but that other companies, utility companies, are not increasing their rates, which isn't true.

Q. All right. Did you review the tables and charts that Mr. O'Donnell included in his testimony to illustrate that point?

A. I reviewed Mr. O'Donnell's testimony at a cursory level, but I did look at it; and I have not committed those tables or the information you're describing to memory.

Q. All right, sir. Will you agree that the types of customers we're talking about, the high-load-factor manufacturing and industrial customers, that they operate in a highly competitive environment compared to the regulatory environment in which Duke operates?

A. That's comparing an apple and an orange. They are in competitive businesses, and Duke Energy is a regulated utility. Two different things.

Q. Yeah. I wasn't trying to --

A. But I would agree they operate in competitive environments.

Q. Thank you, sir. Since they operate in a competitive environment, would you agree that manufacturers are always looking for ways to put their production in the areas where their costs of production are the lowest?

A. Well, there are a lot of reasons that go into the siting of a facility, and I think their location to their markets is one. You know, maybe of proximity to commodities that are used in and their processes and so on. I agree that their cost structure is very important, and an industry that uses a lot of electric power does look for -- to that index when they decide where to settle.

Q. Yeah. If I misled you with the question, I apologize. I didn't mean to imply that manufacturers base decisions solely on the cost of electricity, but --

A. You didn't.

Q. Okay. I'm glad that I didn't.

Let's say that you have a hypothetical manufacturing customer in North Carolina which either shuts down operations in North Carolina or reduces its level of production in North Carolina. Would that have a positive or negative impact on Duke's earnings and finances?

A. Of course it would have a negative impact if we lost any of our industrial.

Q. All right. To an extent, Duke can offset such a hypothetical customer's variable revenues against the variable costs that they impose, but what about the fixed costs; what happens to them if that hypothetical customer goes away or ceases production?

A. I didn't follow the question. Do you mind repeating it?

Q. Don't mind a bit.

Each of the industrial and manufacturing customers that you have imposes both fixed and variable costs on Duke's system; is that correct?

A. All customers do.

Q. All right. So I'm not interested here in following the variable costs, I'm interested in following the fixed costs. If a customer on whom Duke has relied through the rate-setting process to pay certain fixed costs goes away, then those fixed costs don't go away, do they?

A. No, they don't.

Q. And those fixed costs are ultimately going to have to find a place to land so that, in fact, they are recovered by Duke, will they not?

A. That's correct.

Q. And in the hypothetical we're discussing, that landing spot could be with another customer or another class of customers; would you agree with that?

A. Yes, I would.

Q. Thank you very much, sir, that's all the questions I have.

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

Mr. Neal, you are up.

MR. NEAL: Good morning. Thank you, Chair Mitchell. No questions.

CHAIR MITCHELL: All right. Mr. Quinn, you're up.

MR. QUINN: No questions for NC WARN at this time. Thank you.

CHAIR MITCHELL: All right. Ms. Lee on behalf of the Sierra Club.

MS. LEE: Yes. Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. LEE:

Q. Good morning, Mr. De May and Mr. Hatcher. My name is Bridget Lee. I represent the Sierra Club in these proceedings, and all of my questions will be for Mr. De May.

A. (Stephen G. De May) Good morning.

Q. Mr. De May, you've testified that the Company took a fresh look at the viability of several of its coal fired plants; is that right?

A. At the viability of our coal plants?

Q. Yeah. I'm looking at page 7 of your direct, line 15.

A. All right.

(Witness peruses document.)

I see it.

Q. Can you let me know, which of the plants did the Company give that fresh look?

A. Well, we are evaluating our fleet continuously. Witness Steve Immel, who is in this part of our Company, will be taking the stand in the not-too-distant future, and he can definitely give you some details around which part of the fleet, you know, measures up against what metrics. But I will tell you that we are consistently and continuously evaluating our fleet for efficiency, for economic effectiveness, and what place it plays in the portfolio both in the near term and the long term.

Q. Okay. So just to be to be clear about your testimony here, when you mentioned that the Company has taken a fresh look, are you referring to that ongoing evaluation of the fleet, or are you referring to something else?

A. I'm referring to the ongoing look.

Q. Okay. Great. I have a number of questions about this. They might be better suited for witness Immel, so I'm going to go ahead and ask a couple, but you can push them to him if that will be more appropriate.

A. And I will try, and it may not be Steve in every case.

Q. Okay. So if you could just -- you mentioned this -- the ongoing look which included an evaluation of the economic viability of coal units.

Could you describe that in a little bit more detail?

A. You know, probably not in the detail that you're looking for. But you may know that we recently filed on September 1st, just a couple of days ago, a new IRP for both DEC and DEP. In advance of that, we did any evaluation of our coal fleet. And we do that routinely, so it's not the first time we've ever done such a look. But we recently did, or took that fresh look at the place that they serve in our generation portfolio. So I don't have details on the operational results of that review.

I can tell you, though, between their economic effectiveness and efficiency as a generating source is declining, climate policies, both at the state level and our own climate policies as a Company, are also pushing this fleet to an earlier retirement than we believed even just a couple of years ago.

Q. Thank you. So just to be crystal clear on this, the fresh look at the viability that's mentioned in your direct, there are you also referring to the analysis that the Company connected per the Commission's 2018 IRP order calling for a more robust look at coal-fired unit economics?

A. You know, the words in my testimony are really just referring to an ongoing review of our portfolio; and we have taken fresh looks at that. And if we're having this conversation a year from now, we will probably have another fresh look at it. So I'm really just referring to something that's ongoing.

And the state of play, the place that those assets serve in our portfolio is shifting for the reasons I described. There are economic reasons they are shifting, and there are climate and clean energy goals as reasons why they are shifting.

Q. Okay. Thanks. When the Company identifies capital expenditures that it needs to conduct at a plant, whether to comply with a regulatory requirement or just to keep an older plant up and running, how does it decide whether those capital expenditures are a reasonable choice to make?

A. Well, generally, we evaluate options. And the investments that we've made in our coal fleet since the last rate case are a good case study for the question you're asking. We made investments in that fleet because those investments -- because we need those assets to be available to serve load. Those assets, in order to be available, have requirements, regulatory requirements placed upon them that we have to meet to be able to run them.

And so we look at alternatives. Before we make an investment, we look at alternatives, and nobody has suggested that we -- there was a lower-cost alternative to replace that generation. And so we do that analysis routinely. It's just part of what we do in decision-making at the Company. And those were made because they were the least-costly option for maintaining that generating capacity.

Q. Okay. And maybe we could just talk about one

plant as an example of what you've just described. I'm thinking of the Allen plant. And I believe, in the Company's application in this case, the Company has requested recovery of costs somewhere in the ballpark of $100 million for upgrades at the Allen plant.
Does that sound about right?
A. I will accept that.
Q. Okay. And would you also accept, subject to check, and ballpark for sure is fine, that a large part of those costs were incurred to convert the bottom ash handling system from wet handling to dry handling, maybe about $70 million?
A. Specifically in the case of Allen?
Q. Correct.
A. Okay. I don't know that.
Q. Okay.
A. You know, subject to check, I think that's fine.
Q. Sure. Okay.
A. I would suggest that those investments were made to keep out the Allen plant running because we needed it.
Q. Okay. And the Company is required to close units 1, 2, and 3 at the Allen plant by 2024 per court

order; is that right?

A. I don't know. Steven can tell you that.

Q. Okay. You mentioned the 2020 integrated resource plan that was filed earlier this week. I believe that indicated that the most economic retirement year for Allen units 2, 3, and 4 was 2022; does that sound right?

A. So I'm not sure if it's 2 and 3 or 2, 3, and 4. So I don't know. But we did move two units up to the end of -- or to 2022, and the other units are still, I think, 2024. And that's for really voltage support and giving us time to replace them.

Q. Okay. And would you accept, subject to check, that on page 175 of the 2020 IRP, it was indicated that Allen units 2, 3, and 4 could be retired by 2022 without any additional transmission or any additional generation being built?

A. Yes.

Q. Okay. And you mentioned the other units there, units 1 and 5, I believe the new most economic retirement year indicated in the IRP is now 2024 for those units. In prior IRPs I think unit 5 had a 2028 retirement date; does that sound about right?

A. That's right. And you have the unit numbers correct, thank you.

Q. Okay. Of course. So is it the Company's position, then, that the investment in upgrades that will only be utilized at Allen units 2, 3, and 4 for five years at most is prudent?

A. I'm saying that we needed those units. We continue to need those units. We did not have a less-costly way of replacing that generation, and we will continue to make that kind of analysis on this fleet. I would also point out Public Staff, who takes a great interest in the same questions you're asking, has recommended -- recommended no disallowance on these coal investments.

Q. So I guess my question may be a little bit different. For the -- in particular, let's talk about this -- the conversion of bottom ash handling from wet to dry.

The Company undertook that in compliance with CAMA; is that correct?

A. I know that it took those steps in compliance with, whether it's CAMA or CCR.

Q. Okay. And is it your understanding that CAMA allows for variances in any of its deadlines?

A. I don't know those kind of details.

Q. Okay.

A. Suggestion is we had an alternative; and I'm proposing to you that we chose the best alternatives in making the investments we made. And Steven Immel can definitely give you more details on the question you just asked.

Q. Okay. Great. And just to close out that run of questioning, and maybe this is for Mr. Immel.

Do you know if the Company attempted to seek a variance from any of the CAMA deadlines with respect to the Allen plant?

A. Steven.

Q. Okay. Switching gears a little bit. In support of its application in this case, the only direct testimony relating to coal ash cleanup activities was that of Jessica Bednarcik; is that correct?

A. She is our coal ash compliance witness, correct.

Q. Okay. And Ms. Bednarcik's direct testimony didn't present any information regarding the Company's waste management policies, decision-making, or operating practices prior to 2014, did it?

A. How much prior to 2014? Do you mean anytime prior to 2014?

Q. Anytime.

A. If you are saying that, then I will accept that.

Q. Okay. Subject to check. I didn't see any mention of that in her direct.

A. Okay. I don't know if there is.

Q. Okay. And, Mr. De May, when you were speaking earlier this morning with Mr. Page, you mentioned that you had participated in the Company's prior rate case; is that right?

A. Yes.

Q. Okay. So are you familiar with the testimony of Jon Kerin in that case?

A. I don't -- I read some of Jon Kerin's testimony in the order, itself, but I don't recall hearing his testimony live.

Q. Okay. But is it right to say that you are aware that Mr. Kerin was the Company's primary witness for coal ash issues in that case?

A. Yes.

Q. Okay. And is Jon Kerin still the vice president of coal combustion products for the Company?

A. I don't know.

Q. Okay. Who might know the answer to that?

A. Well, I'm certain he's not, because I knew the head of coal combustion products until he moved to a different job just recently.

Q. Okay.

A. (Larry E. Hatcher) So this is Larry. I can answer that. He's not currently in that role, and Jessica is in that role.

Q. Oh, thank you so much. And does -- and, Larry, if you know this better, please jump in, but the question was for Mr. De May, so I'll put it to him first.

Does Ms. Bednarcik have more firsthand knowledge about the Company's coal ash management practices than Mr. Kerin had?

A. (Stephen G. De May) I think that's a question you should ask the Jessica Bednarcik.

Q. Okay. Does the Company consider its pre-2014 actions with respect to coal ash management relevant to this application?

A. Not especially. And, you know, the pre-2014 actions were litigated, I think, quite significantly in the last rate case. Part of the order of the Commission on this matter said as much, that they dealt with issues like management penalty and moving forward. The question was, are your expenditures going forward prudent; and when a determination of prudency is made, then we will be able to recover our costs. So that would be my answer to that question.

Q. Okay. And subject to check, would you agree with me that Mr. Kerin's direct testimony in the prior rate case, Docket, E-7, Sub 1146, included conclusions about the Company's pre-2014 actions with respect to coal ash management?

A. Are you going to be more specific or just --

Q. Sure. Yeah. I can -- I didn't have the testimony handy for you, but subject to check I'll just read you one line. This is page 12 of John Kerin's direct, lines 14:

"At each step of the environmental regulatory evolution process, DE Carolinas was in line with industry standards, and reasonably and prudently managed CCRs and coal ash basins."

A. I remember that line. Your question is? I'm sorry.

Q. Just the question is, so in the prior case, the Company did put forth direct testimony regarding conclusions about the Company's position on whether it had handled coal ash reasonably in the past.

A. Yes. Because that question was relevant in that case.

Q. Okay.

A. You asked me if I thought it was relevant in this one, and I'm saying no.

Q. Okay. So -- but isn't it true that some of the rebuttal testimony in this case gets at the Company's conclusions on pre-2014 coal ash management?

A. You asked me what the Company's position is. You asked me what my position was. And my position is those issues are not as relevant in this case as they were in 2018 or 2017.

Q. Okay. Similar question, but just to put a little bit of a finer point on it.

Does the Company consider the history of design, construction, operation, maintenance of its coal ash ponds relevant to the question of whether the costs for which it now seeks recovery could have been lower had the Company acted differently in the past?

MR. ROBINSON: Chair Mitchell, if I may, I may object. That calls for a legal conclusion.

CHAIR MITCHELL: All right. Ms. Lee, what's your response?

MS. LEE: If Mr. De May has a -- he's just spoken to the Company's position with respect to the relevance of conclusions, so this is along the same lines, if he's able to answer.

CHAIR MITCHELL: All right. I'll allow the question, recognizing that the witness is not an attorney.

THE WITNESS: Would you repeat the question, Ms. Lee?

Q. Of course. Does the Company consider the history of design, construction, operation, and maintenance of its coal ash ponds relevant to the question of whether the costs for which it now seeks recovery could have been lower had the Company acted differently in the past?

A. Well, I will say -- and it might even have been Mr. Kerin who said it first -- that it's the Company's position that no decision, action, or lack of action historically on the management of our coal ash basins is causing any unjustified cost today. And so I don't know if that answers your question of relevance, but I feel like our past actions, how we got from the very first coal ash basin to the coal ash management enacted CCR were dealt with from the last rate case.

And there are residual and lingering issues, and things like the litigation with insurance companies and so on; but in terms of the regulatory questions that are in play in this rate case, we believe it's whether or not the expenditures we have made are prudent, whether we are effectively and responsibly closing the ash basins in compliance with the state, federal and -- state and federal law, but I would also say in compliance with direction from the environmental regulator.

And so the question is, are we doing that and are we doing that well. That's a legitimate question. And there may be people who think not all of our costs are legitimate. That is not our position. I would say that there is also a matter of cost recovery that has just been evident in all of the testimony so far. But I think those are the issues at stake here.

Q. Okay. Thank you for that answer.

Mr. De May, would you agree with me that, when the Company elects to file an application requesting a rate increase, the burden of proof rests with the Company alone?

MR. ROBINSON: Chair Mitchell, I object again. That calls for a legal conclusion as well.

CHAIR MITCHELL: I'll allow the question. I recognize -- we recognize Mr. De May is not an attorney, but I'll allow the question to stand.

THE WITNESS: The burden of proof for prudency is ours. However, if a party challenges that assertion of prudency, that party needs to establish it in no uncertain terms in a quantifiable way. And then we must rebut that, effectively, in order to ultimately prevail in a prudency decision. But I think the initial burden of proof, and I guess ultimate burden of proof, is ours.

Q. Okay. And for that initial burden of proof for the evidence necessary to substantiate the Company's prima facie case, you would agree with me that it's not required of either the Commission, or the Public Staff, or any intervening parties to fill in the gaps of lacking evidence, and that that does rest with the Company?

MR. ROBINSON: Chair Mitchell, I'm just going to continue my objection.

THE WITNESS: Yeah. On that, I don't have an answer.

Q. Okay.

A. Subject to legal.

Q. Sure.

CHAIR MITCHELL: For purposes of the record, let me rule on Mr. Robinson's objection. I'm going to overrule it. Ms. Lee, please ask the question one more time, and I will ask the witness to respond.

MS. LEE: Thank you, Chair Mitchell.

Q. Mr. De May, would you agree with me that it is not required of, nor would it be appropriate for the Commission, the Public Staff, or any intervening parties to fill in the gaps of any lacking evidence which may be necessary to substantiate the Company's prima facie case?

A. I don't know the answer to your question, because if there is no such evidence, or evidence doesn't exist, or -- you know, I just don't know. I'm sorry.

Q. Okay. No problem. I believe you mentioned earlier, perhaps when you were talking with Mr. Page, that you had read the Commission's orders in the prior rate cases; is that correct?

A. (No audible response.)

Q. Okay. Are you familiar with certain commissioners --

(Reporter interruption due to no audible response.)

THE WITNESS: Yes, I'm sorry. I think I was on mute. Yes was my answer.

Q. Thank you. And are you familiar with certain Commissioners' dissents in those cases calling into question the sufficiently of the evidence introduced by the Company at those hearings regarding the reasonableness and prudence of the Company's coal ash expenses or the proper ratemaking treatment for those expenses?

A. I am aware of that, yes.

Q. Okay. And just finally, would you consider the Company's evidentiary presentation in those cases satisfactory?

MR. ROBINSON: Chair Mitchell, I would just ask for a continuing objection to this line of questioning, please.

CHAIR MITCHELL: And the objection is overruled. The question may stand. Mr. De May, you may answer.

THE WITNESS: I do think it was

satisfactory and reasonable in a Commission decision.

Q. Okay. And final question. I'm just looking at your rebuttal testimony on page 5, line 14. You mentioned that there is never a good time for a rate increase.

Mr. De May, do you think that during the middle of a global pandemic and a national recession a rate increase is appropriate?

A. Well, I will answer that question in this way. I do think rate increases are hard anytime, and there are a significant number of our customers who struggle with their bills today. We only come in for a rate increase when rates no longer reflect the costs and the investments that we have incurred that benefit our customers.

And we have done a lot in this rate case to mitigate the impact on our customers, especially those who are hardest hit. And we started off this rate case with our initial filing. Net of EDIT -- net of a return of EDIT that we had proposed, at a 6 percent customer rate, retail average rate increase, and under the terms of the settlement, making certain assumptions around coal ash, et cetera, the rate increase is

2.1 percent.

So, you know, we have done a lot of things to mitigate the impact for customers. You may have read just recently that, because of a -- kind of an innovative approach to our fuel filing, we rolled forward the period of time for the fuel cost adjustment in DEC from year end 2019 to the end of the first quarter; and we were able to deliver an average retail rate decrease of more than 2.1 percent. And so we are doing things -- and I can go into the whole COVID thing of what we've done for our customers. We recognize rate increases are hard, especially for a certain segment of our customer base; but we have to reflect the investments we've made in rates, and we have to be able to achieve our targeted rate of return.

Q. Thank you, Mr. De May, for your time. I have no more questions.

A. Thank you, Ms. Lee.

CHAIR MITCHELL: All right.

Mr. Trathen, you're up.

MR. TRATHEN: Thank you, Chair Mitchell, just a few.

CROSS EXAMINATION BY MR. TRATHEN:

Q. Mr. De May, just piggy-backing on the last question, you referenced the 2.1 percent average proposed increase. That's an after EDIT number, correct?

A. (Stephen G. De May) It is.

Q. And what is the average rate increase that DEC is seeking pre-EDIT?

A. That number is -- I have that number right here. Pre-EDIT is 8.5 percent down from 9.2 percent.

Q. Okay. And would you agree that the Commission, in connection with its review of this rate case, is obligated to consider changing economic conditions, among other things?

A. I would agree with that, yes.

Q. And would you agree that that would include the pandemic?

A. I would definitely agree with that in the economic impact of the pandemic, but I would also point out the Company has also factored those very same conditions into its rate application and through its settlements.

Q. Mr. De May, do you have the Tech Customers Potential Cross Exhibit Number 50 nearby?

A. Yes, I do. I have it right now.

Q. Excellent.

MR. TRATHEN: Chair Mitchell, if I could go ahead and identify this as Tech -- as De May Tech Customers Cross Exhibit Number 1.

CHAIR MITCHELL: All right. The document shall be so marked.

(De May Tech Customers Cross Exhibit Number 1 was marked for identification.)

Q. Mr. De May, does this appear to be a transcript of a Duke Energy Corporations earnings call from May 12, 2020?

A. Yes.

Q. Did you -- did you listen in on this call?

A. Yes.

Q. Would you turn to page 4, please? On my copy, it's -- the top of the page is turning to slide 7. Are you there, sir?

A. Yes.

Q. Could you just look at the last full paragraph, and I would refer you to the reference to the $56 billion plan; do you see that?

A. Did you say in the last paragraph on that page?

Q. Yes. It's the next-to-the-last sentence.

A. Yes.

Q. Do you see where it says:

"In our 5-year $56 billion plan to invest in cleaner energy, grid improvements, and other infrastructures critical to customers in communities we serve will create meaningful shareholder value for many years to come."

With respect to the $56 billion plan that's referenced here, do you know what you that number might be for DEC?

A. Oops, sorry, I pushed the wrong button. The capital plan for DEC, I don't know what the DEC equivalent over that five-year period is. I know that North Carolina, as a jurisdiction, is roughly half of our jurisdictional totals; and so if I gave a number, it would be speculative, so I don't know.

Q. Okay. And do you know whether this figure includes the proposed GIP grid investments?

A. It does.

Q. Okay. That's all the questions I have for you, Mr. De May.

A. Thank you, Mr. Trathen.

CHAIR MITCHELL: All right. Thank you Mr. Trathen.

Any additional cross examination for the witness?

(No response.)

CHAIR MITCHELL: All right. Hearing none, Mr. Robinson, redirect, please, if any.

MR. ROBINSON: Yes, Chair Mitchell, I do have a few.

REDIRECT EXAMINATION BY MR. ROBINSON:

Q. So I'll start with Mr. Hatcher first, and then I'll just transition over to Mr. De May.

So, Mr. Hatcher, do you recall questions from the Attorney General's Office counsel regarding the Green Button standard?

A. (Larry E. Hatcher) Yes, sir.

Q. Do you recall that Ms. Force, in particular, stated in response to my objection that her questions pertain to the prudence of a Company's investments in Customer Connect and AMI?

A. Yes, sir.

Q. Mr. Hatcher, are you aware of some of the benefits that AMI currently provides to customers?

A. I am. So the AMI technology really gives the customer a little bit more insight and control over their energy usage. So they have the ability to run reports that gives them information up to the almost minute level of their energy usage throughout the day; and then they can use that information with other apps or the third-party applications to determine if there's opportunities for them to be more efficient.

In addition to that, it provides capabilities for the customer to pick their own due date for their bill; it has the capability that they can get usage alerts if they want to be able to set that up so that it would give them notification that their energy usage is getting to a certain point in a billing cycle.

There's other applications where they can, if it's a start/stop service, they can get status updates on the start/stop service based on the year being activated or stopped. Those types of applications, yes.

Q. Thank you, Mr. Hatcher. Are there any benefits to AMI with regards to storm response, for example?

A. Absolutely. In terms of storm response, gives us a better indication as to whether the electricity is still on in a customer's residence. We can ping that meter and know if there's power at the meter or not. It also gives us the ability to better communicate with the customers on a more personal basis. So instead of kind of having a zoned electrical outage and put that information out there with an estimated time of recovery for that customer, really it gets more localized so that individual customer has a bread idea of when the power will be restored.

Q. Mr. Hatcher, is there anyone else this case that could speak to additional benefits of AMI?

A. Mr. Schneider; yes, sir.

Q. Thank you. Mr. Hatcher, questions with regard to the Customer Connect.

Are you aware of the benefits -- or any of the benefits that Customer Connect will be able to provide?

A. Yes, sir. So, you know, if you look at Customer Connect, we've already implemented some of those benefits. So if you look at the -- being able to get the data loaded and being able to see how the customers are interacting with us on a routine basis. So are they interested in certain products or services; are they having questions about their bill; are they looking for certain information on our web page; we can be able to see that now so we give a more personal experience to that customer when they interact with us digitally or to call the call center for information.

And additionally, we talked about the AMI meters and how that interfaces with the Customer Connect, so I won't repeat those benefits. But it really gives the customer more a customized experience with Duke Energy versus the way we've had to operate with the legacy systems in the past.

Q. Thank you, Mr. Hatcher. And to speak on the synergy between Customer Connect and AMI for a brief second, is it true -- or are you aware of whether the foundational investments of AMI and Customer Connect are needed for innovate rate designs?

A. That's my understanding; yes, sir.

Q. Thank you, Mr. Hatcher. I have some questions now for Mr. De May.

So first off, Mr. De May, just for the benefit of the record, as you may not have heard Mr. Bob Page's first question. You are the North Carolina president for Duke Energy Carolinas; isn't that correct?

A. (Stephen G. De May) Yes.

Q. Thank you. Mr. De May, in addition, do you recall questions from the Sierra Club and the Tech Customers regarding the Company's rate case in the context of the current pandemic?

A. Yes.

Q. And, Mr. De May, I know you gave some of the things that the Company has done when it filed its case.

Do you recall, Mr. De May, when the Company actually filed these rate cases?

A. The DEC rate case was filed almost a year ago, September 30th of 2019.

Q. And -- thank you. And do you recall what the test year was, Mr. De May?

A. 2018.

Q. Mr. De May, so the majority of the costs that are included in this case is reflected in cost of service. When did they actually occur?

A. In 2018.

Q. But --

A. Perhaps I didn't understand your question. I'm sorry.

Q. No, you answered the question, Mr. De May.

A. Okay.

Q. Okay. Mr. De May, since the Company postponed its rate case, can you describe some of the additional steps the Company has taken to try to mitigate the rate increase for customers?

A. Well, I think we -- to start, we have entered into some very constructive settlement agreements. In particular, the agreement with Public Staff that culminated in May. 9.6 percent ROE, a return of excess deferred income taxes over the five-year period of time are examples of some mitigation -- mitigations towards the rate increase for our customers.

In the intervening time between when this rate case was filed and today, of course, we've been dealing with the COVID situation. And we have really done a lot of great things for our customers in that regard. I acknowledge that that's not part and parcel of this rate case, but it is at least an illustration of the Company's ongoing efforts to help our customers when we can.

Q. Thank you, Mr. De May. One other line of questions.

So do you recall questions from the Sierra Club counsel on the Company's investment in its coal units?

A. I do.

Q. Mr. De May, are the Company's investments in its coal units, or its generation fleet in general, based on information available to the Company at the time those decisions are made?

A. Well, that's -- when we make a decision, we're making it with all the material information known to us at the time, and we evaluate all the alternatives to -- seeking a solution to the problem at hand.

Q. Okay.

A. Yes. You know, we made the decision in the moment with the best information we had under the circumstances.

Q. Thank you, Mr. De May. And in addition, as it pertains to the Company's coal plant investments in this case, were many of the investments needed to maintain compliance with environmental laws such as CAMA?

A. They all were. You know, they were all compliance related. Or, you know, they included the dry ash handling, wastewater and stormwater systems, lined retention ponds, et cetera. So quite a bit of required investments just to keep those plants running.

Q. Mr. De May, are remaining coal plants currently important to serve load at this time through the obligations?

A. Well, they're critical to serving load. And in the cases as we discussed in Allen, couple of those units are necessary for transmission support. And so until that support can be replaced with something else, we'll need to keep those around a little longer.

Q. Thank you. And before you used Allen as an example.

Mr. De May, can you elaborate on how important Allen was during this summer's heat wave?

A. Well, you know, our coal fleet isn't always the first to dispatch, and I think we all know that at this point, but those plants ran a healthy amount. I don't have the specifics here, but we were running our coal fleet during the heat wave.

Q. Thank you. No further questions.

CHAIR MITCHELL: All right. Thank you, Mr. Robinson. We'll proceed to questions from Commissioners.

Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: I don't have any questions.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes, thank you.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. De May, I think we're still good morning, yes, looking at the clock. Good morning.

A. (Stephen G. De May) Good morning.

Q. I have a few questions, and they're a bit scattered, but I'm filling in some gaps here.

I'm curious, Ms. Lee asked you about the current assignments with responsibility for coal combustion residuals, and you discussed with her the transition, I think, from Mr. Kerin to Bednarcik; do you recall that?

A. I wasn't very smooth in that, but I was focusing on titles, and I -- rather than the role.

Q. Well, did I misunderstand the roles?

A. No.

Q. Okay. Well, thank you. I want to ask you about another name, and actually, if Mr. Hatcher knows the answer to this, too, that will be fine.

In the record in the 2018 rate case, which, by the way, the Commission has taken judicial notice of that record, one name that consistently appears over and over again with respect to such things as long-range planning for waste coal ash, strategic planning for waste coal ash, and identification of options for disposal of coal ash is an individual name, and apologies for pronunciation, Issa Zarzar. Do you know that name?

A. (Larry E. Hatcher) So this is Larry. Yes, sir, I'm familiar with that name.

Q. Did I get it close to being right?

A. Yes, sir.

Q. Is Mr. Zarzar still employed by the Company?

A. My understanding, he is. Mr. Immel could confirm that for you for sure.

Q. Is he employed by Duke Carolinas or by Duke Progress?

A. That, I do not know.

Q. Do you know what Mr. Zarzar's current title and scope of responsibilities are?

A. No, sir, I do not.

Q. Do you know when Mr. Zarzar last had assignments related to coal combustion residuals?

A. No, sir, I don't. Again, I think Mr. Immel or Ms. Bednarcik would have a better handle on that.

Q. Thank you, sir. I'll leave you alone on that. Thank you.

Mr. De May, back to you. Are you still with me?

A. (Stephen G. De May) Yes, sir.

Q. I asked a question of Mr. Newlin, and, unfortunately for you, he tagged you as possibly a person who might know something about this. But I asked Mr. Newlin what he knew about the regulatory agreement in Florida in 2017 with respect to Duke's Florida affiliate whereby the Commission in Florida directed or permitted -- I'm not sure whether it was a direction or a permission -- Duke Florida to redeploy -- my word, not theirs -- redeploy some of the EDIT in order to accomplish other objectives, cost recovery objectives. I think they -- my understanding is they may have related to early retirement of the Crystal River plant. Are you familiar with that?

A. I am.

Q. Can you just give me a more detailed description of it, put some boxes around it and give me some corners and things like that?

A. Yes, I can. When tax reform occurred, or the Jobs Cut and Tax Act occurred, whenever tax reduction occurs, our customers, all utility customers, generally benefit in two ways. One is from the lower tax rate lowering cost of service as a -- you know, on an ongoing basis; the other is converting accumulated deferred income taxes into excess deferred income taxes, which at some point and in some way, customers will ultimately benefit from.

The way the Florida Utilities Commission and our Duke Energy Florida utility dealt with it was actually more of a kind of an agreement. You know, I don't know who came up with the ideas first. But let me just give you orders of magnitude, rough orders of magnitude. The lower tax rate delivered about $130 million a year in lower tax expense for Duke Florida's customers. The excess deferred income tax benefit was about $70 million a year, and that was both protected and unprotected.

And the $70 million was an ARAM flow back for the protected, and a five-year flow back for the unprotected. So you do that math, and it was about $70 million a year for quite a number of years.

And what they chose to do with those funds, the $200 million -- 130 from the tax rate, 70 from the EDIT -- was to apply $50 million of that benefit to the accelerated depreciation of Crystal River's units 4 and 5, which was a nonoperating coal plant that had remaining book value on it. The $150 million was used to recover storm costs from Hurricanes Irma and Michael. And they had significant balances there. I think the combination of those two was about $750 million, give or take.

And that $150 million a year went to return -- or to recover those storm costs and replenish the utility's storm reserve, which I think -- this one I can't remember, but it was about $125 million. So that's how they did that.

And let me just add that the storm flow back or recovery piece will end in mid-2022. The accelerated depreciation component will continue until their next general rate case, at which time it will be revisited through depreciation studies and in the ordinary course. And that rate case, I think, is a '22 rate case.

Q. Thank you for that. What I'm curious about is, in the absence of that agreement with the regulators, would I be correct to think that Duke Florida would have been seeking to recoup those costs, the excess book value and the storm costs, by seeking recovery through rates?

A. Well, I do know that Florida has a storm securitization law, so I don't know whether --

Q. I apologize for interrupting you, but let me focus really on just the piece, then, that related to the Crystal River early retirement and the depreciation that was still on the books that needed to be taken.

Am I correct that the Company, if it hadn't reached that agreement with the use of the EDIT, would have instead been asking to recover that book value in rates?

A. Yes. But they are effectively recovering it in rates still. And they're -- you know, so the accelerated depreciation -- I mean, it's -- it's a netting of sorts. It's a -- it's -- you know, these revenues and expenses are fungible. So they could have given the customer the benefit of the EDIT and then increased rates for the accelerated depreciation.

This was an opportunity for the state to achieve two policy -- really priorities. One was an interest in accelerating the depreciation of their coal fleet; and also to pay for the destructive storm damage. But -- and tax reform allowed them to do it without affecting customer rates.

Q. Thank you for that explanation. And I understand the netting concept. That's exactly what I was really focused on. And you could probably guess my interest in the subjects. We'll leave it at that for now. Let me move to a different topic.

A. Sure.

Q. On pages 9 and 10 of your direct testimony, you discuss some ideas the Company has investigated. You don't need to have this in front of you, but if you want to get it, I'll give you a moment.

A. No, I have it.

Q. Great. You discuss some of the ideas the Company's been exploring to bring forward programs that might be of assistance to lower income customers. And I appreciate that testimony, and I thank you for that testimony. I'm just curious about why the Company chose not to bring any of those forward to the Commission in this rate case for consideration and evaluation, possible either piloting or for implementation. Why not bring them forward in this rate case to -- at least for a good look-see?

A. Well, I have an answer for that, and the answer is this: We have learned, and sometimes the hard way, that to do really hard complicated things requires a thoughtful, deliberate, and robust stakeholder process. The numbers of stakeholders that are interested in anything that we do is, as you can just imagine, is great. When you start thinking about low-income programs and the like, whatever is -- does spring from that effort, other customers are going to have to carry. And we thought that what this process needed that Power Forward didn't do, and that frankly, Commissioner Clodfelter, Senate Bill 559 didn't do enough of, was stakeholder support.

We didn't build it in those efforts, and we were effectively unsuccessful, at least in the multiyear rate plan part and in Power Forward, because our stakeholders want to be involved in those kinds of major decisions. And so the whole idea of collaboratives around low income was for the Commission to put their imprimatur on this effort. Because I think everybody thinks this is important.

You asked a question the other day, why now, and why didn't it happen earlier. And there's not a good answer for that. But it doesn't mean because Duke didn't give, you know, a second thought to its customers who were struggling, and it's not because Public Staff didn't or the Commission didn't, we just didn't -- just like why is the country just now wrestling with systemic racism and social injustice.

Sometimes it just -- you just have to get there.

And I am suggesting that the Company is serious about its interest in doing structural changes to benefit our low-income customers. We are very -- we are very generous in our contributions to things like Share the Warmth, the Energy Neighbor Fund, the Helping Home Fund. You know, I have statistics of all the millions of dollars we've given to those programs over time. But I think now is the time to think about structural change to ratemaking, and rate design, and just those kinds of things to help our customers in a much more structural, enduring, lasting way.

Q. I want to say that I really appreciate the seriousness of the sincerity of your answer in my question. I appreciate it. And it takes me to what may be my final question, really, because I believe what you said; I agree with what you said about the time being right and the time being now. And so I need from you some comfort on one point.

So I'm being asked to have confidence that this stakeholder process is being proposed -- have confidence in that process going forward. And where I struggle a bit is I then look at the fact that the Company has, through various settlements, partial settlement agreements, has made certain commitments to support a particular proposal, or to oppose a particular proposal, or not to put forward a certain proposal. All of those actually really deal with cost of service, but as we all know, cost of service issues often are strong drivers of what happens in rates.

And so I look at those and say the Company's tying its hands already in these settlements. What am I to do with that, in terms of the integrity and the confidence level I have in the stakeholder process? I don't know if you want to respond to that question. It may just be that I should leave that out there rhetorically.

A. I'd like to, if I can. So, first of all, we believe that our settlement agreements are constructive, and we support them. We were careful, I guess, in coming to some of the terms of those settlement agreements to leave open and preserve the true potential of this collaborative. The fact is a number of the parties that we entered into these agreements on will be important parties at that collaborative table. So whether they brought those ideas to us in the form of a settlement or whether they brought them to us at this collaborative table, I think all these ideas are worth exploring.

I -- you -- it was just a number of days ago when there were a lot of discussion around this. And you could hear a different sound out of the industrial group, and you could hear a different sound out of the low-income advocates. And so you can only imagine how challenging this will be, which is why we didn't -- which is why we came to the Commission.

If we had just been silent about this and decided to roll out a stakeholder process ourselves, I think a number of parties would have looked at it like they look at anything our Company does, with a jaundiced eye; which is unfair but it's a fact. And -- but like I said, putting the Commission's seal of approval on this with expectations, and I think -- I hope that I am part of delivering back to the Commission something that exceeds your expectations. But more importantly, does something positive and lasting to solve an issue that has been around way too long.

Q. That's helpful. Thank you. And let me ask you my final question, really.

Recognizing the pressure that the Company is under, and for that matter the Commission as well, from various interest groups, each of whom has their own special view about how things should work to their advantage, what would the Company think if -- and I have not vetted this with any of my colleagues, this is just me speaking as one Commissioner -- but what would the Company think if the Commission were to suggest or propose, perhaps, that the process could be assisted if we had a third party involved as well? Some independent expertise to assist in making sure that no voice got to be the overriding dominant voice in the discussions. Would the Company think that that was helpful?

A. I commit to you now, the Company would support that proposal. And I can tell you from my own personal experience that the stakeholder processes that have gone the best that we've been involved in have all been professionally mediated, and structured, and run by people who do that kind of thing. You look at the clean energy plan process. You look at our own grid improvement plan process. You know, Jay Oliver spoke a lot about what we did leading up to this proposal. We did a lot, but we didn't do it by ourselves, and I think it would have been hard.

Q. Okay. Mr. De May, I appreciate your time this morning. Thank you.

A. Thank you, Commissioner.

CHAIR MITCHELL: All right. Commissioner Duffley?

COMMISSIONER CLODFELTER: That's all I have.

CHAIR MITCHELL: Commissioner Duffley?

COMMISSIONER DUFFLEY: Yes. I have a few questions.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good afternoon, gentlemen. Most of my questions will be -- or all of my questions will be for Mr. De May.

So you testified about many factors that is causing upward pressure on rates. You have coal ash expenditures, grid modernization, costs to meet your carbon reduction goals, and you also attended the public witness hearings and have committed to this stakeholder process to discuss the issue of affordability. And I think that I heard probably some of the answer to my question, but I just want to make sure if you have anything to add to this question.

Has the Company thought about, or is the Company concerned about rate case fatigue? And what is the Company actively doing to address that concern?

A. (Stephen G. De May) Yeah. You know, I will just say something that I think anybody involved in this process already knows. Rate cases are really hard. They're very costly. They just sap organizations of resources. And, you know, I think rate case fatigue is a real issue.

We -- we made -- let me say it this way. We supported legislation in 2019 that would have provided a multiyear rate plan. And one of the virtues of multiyear rate plan is the ability to put programs in certain kind of identifiable and observable plans and expenditures and so on, on the table, do a little bit of the hard work of vetting it, and then letting it go for a while.

And, you know, there's been a great deal of resistance to that idea here in North Carolina. I chalk up at least 50 percent of that resistance to the way we rolled it out. But I can -- or I can just tell you, though, that we are supportive of mechanisms that diminish the need for frequent rate activity. But I also want to add, though, that the level of investments that are required to improve, to maintain, and to expand our infrastructure are not decreasing. And so there has to be some ability to bring these investments into rates, and then -- in an easier fashion, and in perhaps a more, you know, moderated fashion over time. And so we continue to explore ideas that would get us to that kind of place.

So I don't have the solution for you. If it's worth anything to you, we agree with your view on how hard these rate cases are. We have responded to 8,000 data requests in this rate case. We have 29 witnesses. Even with settlement agreements with 10 different parties, every issue is being litigated by somebody. And, you know, I think some reform would be great, I just haven't cracked that nut yet.

Q. Okay. Thank you. And I'd like to give a caveat to the next set of questions that I'm about to ask you. No one should read anything into this, these questions, or if I'm leaning one way or the other. I'm just trying to obtain additional data points, and really, as a new Commissioner, have some education on the issues that I'm about to ask you about.

So in the last rate case in E-7, Sub 1146, DEC put forth two proposals to the Commission in an effort to assist with cash flow and credit metrics. The first is what I call the run rate, other

Commissioners call it something different, but it was approximately -- it was to add approximately $200 million to the revenue requirement in that case.

And then the second proposal was to increase the revenue requirement by $200 million as a cash flow mitigation measure in response to the Company's requirement to flow back the EDIT. So it was a total of $400 million.

Did I generally capture DEC's proposal in the last rate case?

A. Yeah. I wasn't sure about the EDIT number, but I totally accept your version of that.

Q. Okay. Thank you. And in the last rate case in your post-hearing brief, and that was filed in April of 2018, and specifically on page 42, the Company suggested that, although the written proposal in De May's Rebuttal Exhibit 5 did not identify specific use of the $200 million relating to the cash flow mitigation measure, the brief suggested that the EDIT flow back and the coal ash costs -- I think it was in that case -- the ongoing coal ash costs, could offset each other.

Did I accurately summarize the portion of DEC's post-hearing brief?

A. Yes.

Q. Okay. And I am aware of the testimony by both DEC and the Public Staff regarding their respective positions on the return of the unprotected federal EDIT totaling approximately $982 million. But -- so I'm aware that the parties had different positions, right.

But in the end, in the second agreement and stipulation of partial settlement, you and the Public Staff have agreed to flow back the unprotected federal EDIT over a five-year amortization period with a return. Do I have that correct?

A. You do.

Q. Okay. And the deferred coal ash costs through January of 2020 in this case is approximately 491 million. The Commission has not yet received the audited revenue requirement reconciliation from the Public Staff, but I'm assuming that those numbers have been updated through May of 2020, or not?

A. Coal ash has only been updated through the end of January for DEC.

Q. Okay. Thank you for that. And so it's -- and DEC's position related to the deferred coal ash case through January of 2020 is to recover the cost over a five-year amortization period with a return; am I correct in that DEC position?

A. You are. You are correct.

Q. So both the unprotected federal EDIT and the deferred coal ash expenditures have a five-year amortization period under what you're currently presenting to the Commission; is that accurate with the settlement agreement with Public Staff?

A. That is a true statement, yes.

Q. So again -- I'm finally getting to my question that I did caveat earlier.

Is the -- so, did the Company think about requesting in this case what it requested in the post-hearing brief in the last case, about doing a full offset of the deferred coal ash expenditures with the unprotected federal EDIT within the context of this rate case? I mean, I just need a little education why -- if there's some type of benefit to extending it over five years, if it has to do with the revenue requirement. Could you speak to me a little bit about that issue?

A. Yeah. You know, I think our experience back in 2018 where we made that proposal, and for very good reasons the Commission said let's deal with this in the next rate case. As I remember, we were compressed on time from when the hearings were held, to when the tax act became law, to when we had to deal with rate reduction. And to get an order out, it just seemed like that was a complicated way to resolve EDIT.

And -- but to answer your question did we consider doing that in this case, yes, because we think about all kinds of scenarios; but we chose to do it just to keep the parts separate. In part, because the impact to customer bills are -- is kind of the same. Whether you just offset them or whether you are, you know, letting each one kind of amortize over a different period.

I guess what I'm trying to say is that we knew EDIT was a powerful rate mitigation tool for our customers. I mentioned before that it's taking our original ask of net 6 percent down to net 2.1 percent. That's the power of such a large EDIT balance. The knowing, however, that EDIT -- you know, we thought edit should be -- you know, let me say that there's a school of thought that says EDIT should flow back at a different rate than five years; that it should flow like ARAM does. But we knew it to be also a tool and a lever, and came to a very constructive settlement with the Public Staff on that.

And so maybe I didn't answer the question directly, but we considered it, we just didn't choose to apply for a rate adjustment that way.

Q. Okay. Thank you for that.

A. I could have gotten there in less time, sorry.

Q. Well, it took me a while to get to my initial question, so we're even there. So -- but -- and I did read your testimony, and part of your initial testimony was with respect to the EDIT, the sense of gradualism, and I'm just wondering, I mean, whether you handled it the way you have with the Public Staff settlement versus doing a full offset in this case. I mean, if -- either way would not necessarily be addressing the tax issue in a haphazard manner, in your opinion, or do you have -- do you have concerns that it would -- that there could somehow be rate volatility and harm to the customers or to the utility?

A. I'm going to rely on my colleague, Jane McManeus, to clean up the answer I'm about to give you. So if you are flowing back EDIT over a five-year period and proposing to collect a like number on coal ash expenditures, for instance, over that same five-year period, there is no -- there is no difference between that and just netting the two. In fact, in a way that's kind of what you're doing.

I believe what Florida did was outside of a general rate case. So what -- the situation we have here is we have a general rate case with dozens and dozens of moving pieces. You know, we would love to collect our coal ash expenditures over a five-year period of time. Steve Young was very clear about the importance of cash flow generation to the Company. We support the settlement of the five-year flow back of EDIT to the customers.

I think, in a general rate case, the Commission has the ability to change periods and arrive at a targeted outcome, if you will. And so I think that's kind of the beauty of doing these things in a general rate case. And I don't know if that was responsive to your question, but I don't -- I don't -- I am just not seeing the difference between dealing with all these issues at the same time in the same general rate case. I just think it's all happening. This netting is happening.

Q. Okay. Thank you for that. And so now I'm going to get to my additional data point that I would like to see, and if I could have a late-filed exhibit on this. What I'd like to see is a revenue requirement reconciliation, like a Boswell Exhibit 1.

COMMISSIONER DUFFLEY: And, Ms. Downey, it might be more appropriate for Public Staff to do this, but I'm going to ask Mr. De May.

And it sets forth this hypothetical where the total amount of the deferred coal ash expenditures is fully offset by a portion of the unprotected federal EDIT, so that I can see any type of revenue requirement impacts and the effects to the EDIT rider that the Public Staff and the Company have agreed to in their second stipulation of partial settlement.

Which one of you would like to volunteer for that late-filed exhibit?

MS. DOWNEY: Commissioner Duffley -- if I may, Chair Mitchell, respond to that?

CHAIR MITCHELL: You may, Ms. Downey.

MS. DOWNEY: Commissioner Duffley, Ms. Boswell will be filing full sets of schedules with our update testimony, assuming the Commission allows us to file it on September 8th, and we would be glad to include such a reconciliation at that time if that would be okay.

COMMISSIONER DUFFLEY: That is acceptable to me. Thank you very much, Ms. Downey. And I have no further questions.

THE WITNESS: Thank you, Commissioner.

COMMISSIONER DUFFLEY: Thank you.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: No questions at this time. Thank you.

CHAIR MITCHELL: Okay. And Commissioner McKissick?

COMMISSIONER McKISSICK: Thank you, Madam Chair, I do have a couple of questions.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. And I guess first I'd like to address them to Mr. De May. And it's going to touch upon some of the concerns that Commissioner Clodfelter spoke of when he was discussing the policies that could be implemented to impact affordability and issues of that sort.

I remember reading back in your -- I think it was your direct testimony about programs such as a low-income bill credit that would apply to your basic facilities charges and as well as, you know, looking at expansion and retooling of the supplemental security income.

Are those types of initiatives already taking place outside of North Carolina where Duke operates today?

A. (Stephen G. De May) I don't know the answer to that question. I don't know what low-income assistance measures are in the rate structures the other states we do business in. I'm sorry.

Q. Okay. But you are committed to working diligently to try to see what we could do to facilitate the consideration of various programs as expeditiously as possible, rather than -- I know you talked about pulling together groups of stakeholders to work through things, but what is it that you're able to commit to today, so that I understand that?

A. Well, we would like to undertake this collaborative with Public Staff over the course of a period of about a year and provide frequent updates to the Commission as to our progress; and all along the way, give the Commission an indication of where things look promising, where we're hitting roadblocks with stakeholders, et cetera.

We propose this collaborative in a very

thoughtful, serious way, Commissioner McKissick, and by bringing it to the Commission for its seal of approval and its imprimatur, I -- you know, if we wanted to just be just all showy about it and not real substance, we would've have done that. And so we want all stakeholders to be held to the fire on this.

Q. Okay. And --

CHAIR MITCHELL: Commissioner McKissick, I apologize, I've got to interrupt you. We've come to our lunch break, so we will go off the record now. We will go back on at 1:30, and we will resume with questions from Commissioner McKissick.

(The hearing was adjourned at 12:30 p.m. and set to reconvene at 1:30 p.m. on Thursday, September 3, 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 7th day of September, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112