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DATE: Tuesday, September 24, 2019

TIME: 1:30 p.m. - 5:27 p.m.

DOCKET NO: E-22, Sub 562 and E-22, Sub 566

BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter

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

And

Petition of Virginia Electric and Power Company,
d/b/a Dominion Energy North Carolina,
for an Accounting Order to Defer Certain Capital and
Operating Costs Associated with Greensville County
Combined Cycle Addition

VOLUME 6

Noteworthy
Reporting Services, LLC

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TABLE OF CONTENTS

EXAMINATIONS

E X H I B I T S

E X H I B I T S Cont'd.

P R O C E E D I N G S

CHAIR MITCHELL: Let's go back on the record. Public Staff, call your witnesses.

MS. FENNELL: Okay. We have one housekeeping matter to begin. Public Staff Witness Woolridge, the only time we had on cross was Nucor and Nucor has decided not to cross. So we would like to waive the appearance of our witness Woolridge.

CHAIR MITCHELL: Okay. And I'll entertain a motion to move his testimony in.

MS. FENNELL: Yes. We'll do all the testimony of the witnesses that were waived at the end, if that's okay --

CHAIR MITCHELL: Okay.

MS. FENNELL: -- or we can do that now. Okay.

CHAIR MITCHELL: Thanks, Ms. Fennell.

MS. FENNELL: All right. We call our witnesses Johnson and McLawhorn as a panel.

CHAIR MITCHELL: Let's get y'all sworn in, please.

SONJA R. JOHNSON and JAMES S. McLAWHORN,
having first been duly sworn, were examined
and testified as follows:

MS. HOLT: And if there's no objection, Chair Mitchell, I'd like to move in the direct testimony of Sonja Johnson first.

CHAIR MITCHELL: Hearing no objection, the motion will be allowed.

DIRECT EXAMINATION BY MS. HOLT:

Q. Ms. Johnson, please state your name, business address and position for the record.

A. (By Ms. Johnson) My name is Sonja R. Johnson. My business address is 430 North Salisbury Street, and my position is Public Staff Accountant.

Q. Thank you. And did you prepare and caused to be filed in this docket on September 23rd, 2019, testimony in question and answer form consisting of 31 pages, one appendix and one exhibit?

A. I did.

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

A. I do not.

Q. If you were asked the same questions today, would your answers be the same?

A. Yes.

MS. HOLT: Chair Mitchell, I request that the testimony of Ms. Johnson, consisting of 31 pages, be copied into the record as if given orally from the stand and that her appendix and exhibit be identified as premarked.

CHAIR MITCHELL: Motion is allowed.

(Johnson Exhibit 1 was premarked for identification.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

In the Matter of Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))))	TESTIMONY OF SONJA R. JOHNSON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

Q. **WILL YOU STATE FOR THE RECORD YOUR NAME, ADDRESS, AND PRESENT POSITION?**

A. My name is Sonja R. Johnson. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am an Accountant in the Public Staff – Accounting Division, and represent the using and consuming public in this proceeding.

Q. **HOW LONG HAVE YOU BEEN EMPLOYED BY THE PUBLIC STAFF?**

A. I have been employed by the Public Staff since January, 2006.

Q. **WHAT ARE YOUR DUTIES?**

A. I am responsible for analyzing testimony, exhibits, and other data presented by parties before this Commission. I have the further responsibility of performing the examinations of books and records of utilities involved in proceedings before the Commission, and summarizing the results into testimony and exhibits for presentation to the Commission.

Q. **PLEASE DISCUSS YOUR EDUCATION AND EXPERIENCE.**

A. A summary of my education and experience is attached as Appendix A.

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

A. The purpose of my testimony is to present the accounting and ratemaking adjustments I am recommending as a result of my investigation of the revenue, expenses, and rate base presented by Virginia Electric & Power Company, d/b/a Dominion Energy North Carolina Power (DENC or the Company), in support of its March 29, 2019, request for $26,958,000 in additional North Carolina retail revenue. On August 5, 2019, DENC filed supplemental testimony and exhibits that detailed a $2,079,000 reduction in its request for additional North Carolina retail revenue, for a revised total Company proposed increase of $24,879,000. My testimony and exhibits also set forth the Public Staff's overall recommendation regarding the revenue increase that DENC should be granted.

Q. WHAT REVENUE INCREASE ARE YOU PROPOSING?

A. Based on the level of rate base, revenue, and expenses annualized and normalized as of June 30, 2019, the Public Staff is recommending a decrease in annual base non-fuel operating revenue of ($8,112,000). The test year utilized in this proceeding is the twelve months ended December 31, 2018; however, the Company has updated rate base through June 30, 2019, and has made corresponding adjustments to update revenue and certain expenses through June 30, 2019.

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

A. My investigation included a review of the application, testimony, exhibits, and other data filed by the Company, an examination of the books and records for the test year, and a review of the Company's accounting, end-of-period, after-period, and other adjustments to test year revenue, expenses, and rate base. It also included a review of the Company's responses to the Public Staff's data requests.

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE ISSUES THAT THE COMMISSION WILL NEED TO DECIDE IN THIS CASE?

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

Q. WOULD YOU PLEASE PROVIDE A MORE DETAILED DESCRIPTION OF THE ORGANIZATION OF YOUR EXHIBITS?

A. Yes. Schedule 1 of Johnson Exhibit 1 presents a reconciliation of the difference between the Company's requested increase in base non-fuel revenues of $24,879,000, after supplemental adjustments, and the Public Staff's recommended decrease in base non-fuel revenues of ($8,112,000). Schedule 1-1 provides support for the revenue impact of adjustments that impact both rate base and net operating income. Schedule 1-2 shows the calculation of the gross revenue effect factors, which are used to determine the amounts presented on Schedule 1. Schedule 1-3 shows the calculation of the weighted state income tax rate recommended by the Public Staff for this proceeding.

Schedule 1 also sets forth the revenue requirement impact, based on annualized and normalized June 30, 2019 kilowatt-hour (kWh) sales, of the base fuel factor decrease recommended by Public Staff witness Floyd, subject to adjustment based on the outcome of the Company's currently ongoing fuel proceeding (Docket No. E-22, Sub 579). Because the Company did not include this revenue requirement change in its presentation in the general rate case proceeding, I have set it out separately from the impact of the Public Staff's base non-fuel revenue requirement adjustments.

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

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

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

Schedule 5 presents the calculation of the increase in operating revenue necessary to achieve the required net operating income. This is first shown in an amount that consolidates the base fuel and non-fuel components, but is then broken down into those two components, in the same manner and amounts as the presentation on Schedule 1.

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

A. I am recommending adjustments in the following areas:

1) Annual incentive plan (AIP)
2) Employee severance program costs
3) Operations and maintenance (O&M) Voluntary Retirement Program (VRP) Costs Backfill
4) Major storm restoration expense
5) Promotional advertising expense
6) Executive compensation and benefits
7) Coal combustion residual (CCR) costs
8) Non-fuel variable O&M expense displacement
9) Lobbying expense
10) Uncollectibles expense
11) Skiffes Creek
12) Chesterfield Units 3 & 4 Common Plant
13) Outside services
14) Amortization of Yorktown impairments costs
15) Mount Storm Fuel Flexibility Project
16) Non-utility generation (NUG) Contract Termination Expense Regulatory Asset
17) Impact on expenses of changes in usage and number of customers

18) Inflation adjustment
19) Cash working capital under present rates
20) Fuel revenues and expenses
21) Cash working capital effect of rate increase
22) Interest synchronization adjustment

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

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

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

2) The recommendations of Public Staff witness Maness regarding coal combustion residual costs.

3) The recommendations of Public Staff witness McCullar regarding depreciation.

4) The recommendation of Public Staff witness Williamson regarding Skiffes Creek.

5) The recommendation of Public Staff witness Boswell regarding excess deferred income taxes (EDIT).

6) The recommendation of Public Staff witness Thomas regarding the Mount Storm Fuel Flexibility Project.

7) The recommendation of Public Staff witness Lucas regarding Chesterfield Units 3 & 4 Common Plant.

Q. PLEASE DESCRIBE YOUR OWN RECOMMENDED ADJUSTMENTS.

A. My adjustments are described below.

ANNUAL INCENTIVE PLAN (AIP)

Q. PLEASE EXPLAIN HOW THE COMPANY ADJUSTED AIP IN THIS CASE.

A. The Company made an adjustment to AIP expenses in this case to reflect a 100% payout of AIP expense as opposed to the 120% payout that is reflected in test year expenses.

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

A. DENC offers two incentive plans to its employees: the Annual Incentive Plan (AIP) and the Long-Term Incentive Plan (LTIP). The AIP is offered to all non-union employees, including executives, who work 1,000 hours or more in a calendar year with acceptable performance. The LTIP is offered to employees at the executive level.

The AIP consists of goals set and approved by the Board of Directors (BOD) for a one-year term. In 2018, the test year in this case, the goals consisted of Consolidated Financials, Business Unit Financials, and Operating and Stewardship goals. The AIP is funded based on consolidated operating earnings per share (EPS) with a minimum funding threshold and maximum payout.

The LTIP goals consist of Performance Shares, which are further categorized between Return on Invested Capital (ROIC) and Total

Shareholder Return (TSR), and Restricted Stock Units (RSU). Both offerings are set and approved by the BOD for a three-year period.

The Company's payout of AIP is based on the achievement of targets from minimum up to maximum levels. During the test year, the Company included an adjustment to reduce the AIP from the 2018 payout level to the target level. I have adjusted the allowable costs of AIP to exclude the incentive amounts that were based on the financials metric, which is closely tied to the EPS, since the entire AIP is funded based upon a consolidated EPS. I have removed the amounts related to all executive-level employees, per the Company's BOD minutes, because these goals align with the shareholders' interests. It should be further noted that the Financials portion of the AIP accounts for 85% of the executive-level employees' accrual.

I have also adjusted the allowable LTIP costs to exclude the Performance Shares, which include the ROIC and TSR metrics. The Public Staff believes that the incentives related to ROIC and TSR should be excluded because they provide a direct benefit to shareholders rather than to ratepayers. These costs should be borne by shareholders.

EMPLOYEE SEVERANCE PROGRAM COSTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO EMPLOYEE SEVERANCE PROGRAM COSTS.

A. The Company included a normalized level of employee severance program costs based on the average costs for six programs that have occurred since 1994. The Company then normalized the average costs for the six programs over 4.17 years. The 4.17-year normalization period is the average period of time between employee severance programs over the 25-year period since 1994 (25 years divided by six programs equals 4.17 years).

I have removed employee severance program costs to reflect that these costs appear to be closely linked to the Dominion Energy Inc. (Dominion Energy) and SCANA Corporation (SCANA) merger that was approved by the Commission on November 19, 2018, in Docket Nos. E-22, Sub 551 and G-5, Sub 585 (Merger Order).

Q. HOW WERE EMPLOYEE SEVERANCE PROGRAM COSTS TREATED IN DENC'S LAST RATE CASE?

A. DENC's last general rate case was in 2016, in Docket No. E-22, Sub 532 (2016 Rate Case). By Order issued on December 22, 2016, the Commission approved an on-going level of severance program costs included in rates based on the actual costs of the Company's latest corporate-wide severance program at that time, which was its Organizational Design Initiative (ODI). Based on the historical frequency of corporate-wide severance programs at the time of that case, the 2016 severance costs were normalized over five years to derive a normalized level of those costs to recover through rates.

DENC's most recent employee severance program is its Voluntary Retirement Program (VRP), which was announced during the first quarter of 2019. The Company has reflected the workforce reductions under the VRP in its supplemental filing on August 5, 2019, resulting in reductions to salaries and wages, benefits, AIP, and payroll taxes.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED NORMALIZED EMPLOYEE SEVERANCE PROGRAM COSTS?

A. No, I do not. The Public Staff would typically include a normalized level of employee severance program costs, as it did in the Company's 2016 Rate Case, and utilize the actual costs of the Company's latest corporate-wide severance program, amortized over a reasonable period of time. However, the circumstances in this docket are distinguishable. In contrast to the severance program in the 2016 Rate Case, the VRP appears to be part of the integration of Dominion Energy Inc. and SCANA subsequent to its merger. Support for this contention is contained in the Company's response to a data request wherein DENC described the VRP as a program designed to support extensive transformational efforts already underway across Dominion Energy, and to successfully integrate the Southeast Energy Group (SEG). According to the Company in response to another data request, the SEG is a combination of four employing entities that merged with Dominion Energy on January 1, 2019, previously referred to as SCANA. The Company further stated that the four employing entities include South Carolina Electric and Gas (SCE&G), SCANA Energy Marketing, Inc. (SEMI), Public Service Company of North Carolina (PSNC), and Southeast Energy Services (previously SCANA Services, Inc.).

The Merger Order specifically precludes recovery of merger-related severance program costs. In decretal paragraph 5 of Merger Order, the Commission required DENC and PSNC to exclude the following expenses associated with the merger:

> DENC and PSNC shall exclude direct expenses associated with the Merger from their regulated expenses for Commission financial reporting and ratemaking purposes. Such expenses to be excluded include: acquisition premiums; change-in-control payments made to terminated executives; regulatory process costs; transaction costs such as investment banking, legal, accounting, securities issuances, and advisory fees; **integration costs such as costs related to the integration of financial, IT, human resources, billing, accounting, and telecommunications systems; and other transition costs such as severance payments,** changes to signage, transitioning employees to post-Merger employee benefit plans, and costs to terminate any duplicative leases, contracts and operations. [Emphasis added].

Q. WHAT AMOUNT OF ANNUAL SEVERANCE PROGRAM COSTS DO YOU RECOMMEND IN THIS PROCEEDING?

A. I have included a normalized level based on the amount that was calculated and approved in the 2016 Rate Case and is reflected in current rates. I recommend that the Company's additional annual normalized level of severance program costs be removed, due to the fact that these costs appear to be the result of the integration of SEG due to the merger of Dominion and SCANA. Pursuant to the Merger Order, transition costs related to severance payments should be excluded from Dominion's expenses.

O&M ASSOCIATED WITH VRP EMPLOYEE BACKFILL

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO O&M VRP EMPLOYEE BACKFILL.

A. In its supplemental filing, the Company made an adjustment to include 582 "planned" positions for both DENC and DES as a result of its most recent employee severance program, VRP. As of the time of the filing of my testimony, the Company had not hired any of these employees. Therefore, I have made an adjustment to remove the "planned" 582 employees from this case. However, should the Company hire any of these employees and provide documentation for the hiring of these employees, up to the close of the hearing in this docket, then I will update my testimony accordingly, after investigation and verification that the employees have been hired.

MAJOR STORM RESTORATION EXPENSE

Q. PLEASE PROVIDE AN EXPLANATION OF THE COMPANY'S ADJUSTMENT TO MAJOR STORM RESTORATION EXPENSES IN THIS PROCEEDING.

A. In this proceeding, the Company has made an adjustment to increase O&M expenses for North Carolina retail by $2,209,000 to reflect a normalized level of major storm restoration expenses, based on the average major storm expenses for the last nine years, including Hurricane Irene in 2011, which affected 1,323,856 customers and had a total O&M expense of $81,219,641; the June 2012 Derecho, which affected 1,055,306 customers and had a total O&M expense of $61,188,881; and Tropical Storm Michael in October of 2018, which affected 637,155 customers and had a total O&M expense of $31,403,814.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO THE COMPANY'S PROPOSED LEVEL OF NORMALIZED MAJOR STORM RESTORATION EXPENSES.

A. I have made an adjustment to the Company's normalized level of major storm restoration expenses by taking average storm costs for the last ten years, instead of the last nine years as done by the Company. Use of a ten-year average is consistent with the normalization of storm costs in the most recent rate cases for Duke

Energy Carolinas, LLC (DEC) in Docket No. E-7, Subs 989, 1026, and 1146, and for Duke Energy Progress, LLC (DEP) in Docket No. E-2, Sub 1142. In addition, due to the unpredictability of both the frequency and cost of major storms, a ten-year average is more appropriate for use in determining a normalized level.

This adjustment results in a decrease in the normalized level of major storm restoration expenses for North Carolina retail operations.

PROMOTIONAL ADVERTISING EXPENSE

Q. WHAT ADJUSTMENT HAVE YOU MADE TO PROMOTIONAL ADVERTISING EXPENSE?

A. The Company made an adjustment to eliminate some of the advertising expenses that were direct charged to DENC as well as those that were allocated from Dominion Energy Services (DES) in this case. Based on our review, the Company included instructional advertising that appears to be related to public notices specifically related to Virginia Jurisdictional Matters that I believe DENC ratepayers should not pay for. As a result, I have made an adjustment to eliminate those public notices that do not appear to relate to DENC ratepayers.

EXECUTIVE COMPENSATION AND BENEFITS

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

A. The Company made an adjustment to remove 50 percent of the compensation and benefits of the top three executive positions with the highest level of compensation allocated to DENC in the test period. Those three executives are (1) the Chairman President and Chief Executive Officer, (2) the Executive Vice President and President and Chief Operating Officer – Power Generation Group, and (3) the Executive Vice President, and Chief Financial Officer. My adjustment includes the removal of 50 percent of the compensation and benefits of an additional executive, the Executive Vice President and President & Chief Executive Officer – Power Delivery Group, The premise of including the compensation of the top four DENC executives is to reflect the fact that the executives' duties and compensation encompass a substantial amount of activities that are closely linked to shareholder interests. This adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers.

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

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

COAL COMBUSTION RESIDUAL (CCR) COSTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CCR COSTS.

A. As recommended by Public Staff witness Maness, I have amortized his recommended level of CCR costs for North Carolina retail operations over his recommended recovery period of 19 years, with the unamortized balance, net of accumulated deferred income taxes (ADIT), excluded from in rate base.

NON-FUEL VARIABLE O&M EXPENSE DISPLACEMENT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DISPLACE NON-FUEL VARIABLE O&M EXPENSES.

A. The Greensville County CC, a baseload generation unit, began commercial operation on December 8, 2018, at the very end of the test year in this proceeding. DENC made pro forma adjustments to include the full costs of this plant in the cost of service, including adding incremental non-fuel variable O&M expenses to reflect a full year of operation. With the addition of the Greensville County CC, other plants in DENC's fleet will operate less frequently, and thus incur fewer non-fuel variable O&M expenses. Therefore, I have adjusted non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses. Otherwise, operating revenue deductions would include both (1) a general annualized and normalized level of variable expenses and (2) the incremental variable expenses related to specific new generation facilities.

In its pro forma cost of service set forth in this proceeding, DENC made adjustments to sales revenues to reflect the effect of its proposed customer growth, usage, and weather normalization adjustments. However, the Company did not make a corresponding adjustment to non-fuel variable (energy-related) O&M expenses.

As discussed above, the Company also included in its pro forma cost of service specific incremental O&M expenses in its adjustment to fully reflect the Greensville County CC in the cost of service on an annualized basis. In my opinion, inclusion of both (1) an annualized level of energy-related non-fuel variable O&M expenses via the adjustment to reflect the annualized and normalized level of kilowatt-hour (kWh) sales after adjustments for changes in customer growth, usage, and weather normalization, and (2) annualized levels of incremental energy-related non-fuel variable O&M expenses specifically related to the Greensville County CC, would result in a total level of non-fuel energy-related O&M expense in this proceeding higher than the annual energy-related expense necessary to serve the end-of-period level of customers at the normalized level of generation.

I have, therefore, made an adjustment to reduce the general annualized level of non-fuel variable O&M expenses (excluding labor) by amounts proportionate to the estimated kWh generation underlying the Company's specific adjustment to annualize the Greensville County CC operations. The effect of this adjustment reduces North Carolina retail O&M expenses.

LOBBYING EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LOBBYING EXPENSES.

A. I have made an adjustment to remove internal and external lobbying expenses that were recorded above the line. In determining what costs should be removed, I reviewed the job descriptions of the employees identified as registered lobbyists and non-registered lobbyists that performed lobbying activities. I applied the "but for" test for reporting lobbying costs as used in a Formal Advisory Opinion of the State Ethics Commission dated February 12, 2010. The Commission recognized at pages 70-71 of its 2012 Dominion North Carolina Power Order in Docket No. E-22, Sub 479, that lobbying included not only employees' direct contact with legislators, but also other activities preparing for or surrounding lobbying that would not have been conducted but for the lobbying itself.

UNCOLLECTIBLES EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UNCOLLECTIBLES EXPENSE.

A. In its application, the Company made an adjustment to uncollectibles to reflect a five-year average. The uncollectibles expense on a total system level for each of the last five years is as follows:

2014	$49,412,000
2015	32,022,000
2016	19,820,000
2017	21,742,000
2018	22,748,000

In 2014, as reported in DENC's 2016 Rate Case, the Company changed its write-off and collection policies for customers with medical certifications. Prior to that time, although these customers existed, the Company did not include them in its determination of the reserve for uncollectibles. Due to its policy change, the Company recorded a $12.1 million credit accounting adjustment in 2014, on a total system level, to its reserve for uncollectibles account, with a charge to uncollectible expense, in order to establish an initial reserve for customers with medical certificates. The reserve for uncollectibles account is reflected on the Company's balance sheet as a contra account that reduces accounts receivable, so that the amount of accounts receivable, net of the uncollectibles reserve, is reflected on the Company's balance sheet at a level that is reasonably representative of the Company's expected level of collections from customers.

As calculated in the Company's last rate case, due to the change in policy, data from 2014 and prior years was not used to determine an ongoing level of uncollectibles. Therefore, I have calculated uncollectibles based on 2015 through 2018 data, which reflects the Company's current policy of establishing a reserve for customers with medical certificates. The uncollectibles ratio as a percentage of revenues that I have reflected in the current proceeding is 0.3285% as compared to the Company's 0.3963% ratio.

SKIFFES CREEK

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SKIFFES CREEK.

A. Based on the recommendation by Public Staff witness Williamson, I have removed the mitigation costs from rate base as they should not be borne by ratepayers.

CHESTERFIELD UNITS 3 & 4 COMMON PLANT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CHESTERFIELD UNITS 3 & 4 COMMON PLANT.

A. Based on the recommendation by Public Staff witness Lucas, I have removed the costs associated with the common plant related to Chesterfield Units 3 & 4.

OUTSIDE SERVICES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO OUTSIDE SERVICES.

A. The Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DENC by DES as well as those incurred by DENC directly. Our investigation revealed charges that were related to legal services for certain expenses that were allocated to DENC that should have been directly assigned to other jurisdictions. DENC ratepayers should be charged only the reasonable costs of providing electric service to North Carolina retail customers.

AMORTIZATION OF YORKTOWN IMPAIRMENT COSTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE AMORTIZATION OF YORKTOWN IMPAIRMENT COSTS.

A. In this case, the Company calculated a regulatory asset and annual amortization for impairment losses associated with Yorktown Power Station Units 1 & 2. In 2011, the Company recognized the impairment of Yorktown Units 1 & 2 for financial reporting purposes. In the 2012 rate case in Docket No. E-22, Sub 479, the Company requested to defer the costs associated with the impairments as a regulatory asset. The Commission deferred contemplation of the appropriate ratemaking treatment for Yorktown until the units were physically retired from service. The Company retired the units from service in March 2019. The Company is now requesting to defer the impairment loss as of March 31, 2019, as a regulatory asset to be recovered over a ten-year period on a levelized basis.

My adjustment is based on the Public Staff's recommended return and capital structure to its recommended rate base.

MOUNT STORM FUEL FLEXIBILITY PROJECT

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO THE MOUNT STORM FUEL FLEXIBILITY PROJECT.

A. Based on the testimony and recommendation of Public Staff witness Thomas, I have made an adjustment to remove certain costs associated with this project.

NUG CONTRACT TERMINATION EXPENSE REGULATORY ASSET

Q. PLEASE EXPLAIN THE NUG CONTRACT TERMINATION EXPENSE REGULATORY ASSET.

A. During the test year in this case the Company had a long-term power and capacity contract with a coal-fired NUG, with an approximate summer generation capacity of 218 MW. In May 2019, the Company entered into an agreement with the NUG and paid $135.0 million to terminate the contract, effective April 2019. The Company made an adjustment to amortize the termination fee over the original remaining term of the contract, which is 32 months (April 2019 through November 2021).

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE NUG CONTRACT TERMINATION EXPENSE REGULATORY ASSET.

A. I have made an adjustment to remove approximately $21.4 million from the NUG Contract Termination expense payment. Based on conversations with Company personnel, DENC did not reflect the capacity revenue that the Company would be receiving through 2022 or the estimated replacement power costs that would be incurred as a result of the termination of the NUG contract. My adjustment accounts for the "Net amount" of capacity revenue that the Company will be receiving from the PJM Capacity market, as well as the estimated replacement power costs that will be incurred as a result of the termination of the NUG contract.

Impact on Expenses of Changes in Usage and Number of Customers

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO EXPENSES FOR CHANGES IN USAGE AND THE NUMBER OF CUSTOMERS.

A. The Company adjusted revenues for the change in kWh sales and the number of customers due to customer growth, changes in usage, and weather normalization. The Company did not, however, make a corresponding adjustment to recognize the changes in the non-fuel variable O&M expenses, which are energy-related expenses that vary based on the level of kWh generation, due to the change in kWh sales. Neither did the Company make a corresponding adjustment to customer-related expenses to reflect the change in the number of customers.

I have adjusted these expenses to reflect the changes in kWh sales and the number of billings proposed by the Company in its customer growth, usage, and weather normalization adjustments. I have excluded from this adjustment those energy- and customer-related expenses, such as payroll, that have otherwise been adjusted to reflect the level of service at June 30, 2019.

INFLATION ADJUSTMENT

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

A. The Company has adjusted O&M expenses to reflect the effects of inflation on expenses not specifically adjusted elsewhere. I have made adjustments to reflect, in the calculation of the inflation adjustment, the Public Staff's adjustments to the O&M expenses subject to inflation.

NORMALIZATION OF REVENUES AND EXPENSES

Q. PLEASE EXPLAIN THE NORMALIZATION OF REVENUES AND EXPENSES.

A. In some instances, a revenue or expense item tends to fluctuate and the test year amount is not representative of a reasonable ongoing level. In those cases, it may be appropriate to make an adjustment to reflect a normalized level of the item. In determining whether a revenue or expense item should be normalized, the nature of the item, the amounts incurred in prior years, and the reasons for changes in the revenue and expense item over the years are often considered in determining whether an adjustment should be made to normalize the revenue or expense, and, if so, the appropriate level to include in rates. In this proceeding, the Company has proposed normalization adjustments for certain revenues and expenses, including nuclear refueling outage costs, storm costs, uncollectibles, employee severance program costs, and its annual incentive plan as discussed above.

<u>CASH WORKING CAPITAL UNDER PRESENT RATES</u>

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

A. The Company computed cash working capital using the lead-lag study method and then adjusted cash working capital to fully reflect the Company's proposed adjustments, before the amount of the proposed rate increase. I have made the following adjustments to the cash working capital under present rates:

(1) For presentation purposes, I have shown the working capital impact of revenues separate from expenses.

(2) Finally, I have adjusted cash working capital under present rates to reflect all of the Public Staff's adjustments, in accordance with the Commission's Order in Docket No. M-100, Sub 137. This cash working capital adjustment, which is reflected on Schedule 2-1(f), incorporates the effect on the

lead-lag study cash working capital of the Public Staff adjustments, before the rate increase.

FUEL REVENUES AND EXPENSES

Q. PLEASE DESCRIBE THE ADJUSTMENTS YOU ARE RECOMMENDING FOR FUEL CLAUSE REVENUE AND FUEL CLAUSE EXPENSE.

A. The Company made an adjustment to include the currently approved base fuel factor and Rider A (Docket No. E-22, Sub 558) to annualize fuel clause revenue by multiplying this rate by the annualized and normalized kWh sales in this case. In conjunction with the adjustment to fuel clause revenue, the Company made a corresponding adjustment to fuel clause expense to make the fuel clause expense equal to the fuel clause revenue, net of the regulatory fee.

I have adjusted fuel clause expense to reflect the base fuel rate and Rider A, set forth in the Second Supplemental Testimony of Company witness Haynes and recommended by Public Staff witness Floyd, subject to adjustment based on the outcome of the Company's currently ongoing fuel proceeding (Docket No. E-22, Sub 579).

The result of my adjustment is the inclusion of the impact of the Public Staff's recommended base fuel factor in the overall revenue requirement decrease set forth on Johnson Exhibit 1, Schedule 5. However, because the Company did not include the revenue requirement impact of the decrease in the base fuel factor in its presentation of net operating income in this proceeding, I have also set forth its revenue requirement impact, a reduction of ($2,155,000), separately on Johnson Exhibit 1, Schedules 1 and 5.

CASH WORKING CAPITAL EFFECT OF RATE INCREASE

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

A. The cash working capital lead-lag effect of the proposed revenue decrease as recommended by the Public Staff has been calculated on Johnson Exhibit 1, Schedule 2-1(g).

INTEREST SYNCHRONIZATION ADJUSTMENT

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

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

ADDITIONAL COMMENTS

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS?

A. Yes, I do. First, during the course of our review, we have encountered the following constraints that have hindered the completion of our investigation: (1) some information requested from the Company was received immediately prior to the filing of our testimony in this case so that the Public Staff has not had adequate time to review it; and (2) although the Company has steadily responded to certain data requests on an on-going basis, some requested information is still outstanding. Specifically, the Public Staff is awaiting documentation pertaining to the Company's adjustment to reflect the DES Office building, and the Company has stated it will not have the specific information needed to complete our review until September. As stated in the testimony of Public Staff witness Lucas, certain information necessary for our analysis of the Company's depreciation expense is not available at this time. Additionally, due to the filing of the Company's Second Supplemental Testimony of Company witness Haynes on August 14, 2019, the Public Staff will need additional time to make any appropriate adjustments related to that filing. In light of the foregoing, the Public Staff will be filing supplemental testimony and/or adjustments to reflect the completion of our investigation of these areas.

Second, the Public Staff conducted an investigation of DES allocation factors to DENC. DES is the services company that provides services to various affiliated entities of DENC. The affiliated entities have a Cost Allocation Manual (CAM) that documents the guidelines and procedures for allocating costs between the entities to ensure that one entity does not subsidize another. During the test year, Dominion Energy, Inc. acquired SCANA Corporation, and the merger was approved by the Commission on November 19, 2018. This change has caused the DENC allocation factors to decrease on a going-forward basis. Based on our conversations with the Company, there have been some changes in allocation factors, but the Company has not done a full investigation to identify all the allocation factors that have changed. As a result, the Company is unable to quantify the savings to reflect the fact that O&M expenses allocated to DENC from DES will be less going forward. I recommend that DENC continue to work with the Public Staff to monitor the savings resulting from the allocation factor changes. I am bringing this to the Commission's attention because other regulated North Carolina companies have been able to quantify the savings related to allocation factor changes.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

SONJA R. JOHNSON

I am a graduate of North Carolina State University with a Bachelor of Science and Master of Science degree in Accounting. I was initially an employee of the Public Staff from December 2002 until May 2004, and rejoined the Public Staff in January 2006.

I am responsible for analyzing testimony, exhibits, and other data presented by parties before this Commission. I have the further responsibility of performing and supervising the examinations of books and records of utilities involved in proceedings before the Commission, and summarizing the results into testimony and exhibits for presentation to the Commission.

Since initially joining the Public Staff in December 2002, I have filed testimony or affidavits in several water and sewer general rate cases. I have also filed testimony in applications for certificates of public convenience and necessity to construct water and sewer systems and noncontiguous extension of existing systems. My experience also includes filing affidavits in several fuel clause rate cases and Renewable Energy and Energy Efficiency Portfolio Standard (REPS) cost recovery cases for the utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy

Progress, LLC, and Virginia Electric and Power Company d/b/a Dominion North Carolina Power.

While away from the Public Staff, I was employed by Clifton Gunderson, LLP. My duties included the performance of cost report audits of nursing homes, hospitals, federally qualified health centers, intermediate care facilities for the mentally retarded, residential treatment centers and health centers.

Q. Ms. Johnson, do you have a summary of your testimony?

A. (Sonja Johnson) I do.

Q. Could you please read it?

A. The purpose of my direct testimony is to present the accounting and ratemaking adjustments I recommend as a result of my investigation of the revenue, expenses and rate base presented by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, or DENC, in its application for additional North Carolina retail revenue filed on March 29th, 2019.

On August 5, 2019, DENC filed supplemental testimony and exhibits that reflected June 30th, 2019, updates and detailed a reduction in its request for additional North Carolina retail revenue. My testimony and exhibits set forth the Public Staff's overall recommendation regarding the revenue increase that DENC should be granted.

This concludes my summary.

Q. Thank you. And now I'll move on to the joint testimony.

Mr. McLawhorn, could you please state your name, business address and position for the record?

A. (James McLawhorn) My name is James S. McLawhorn. I'm the Director of the Public Staff's Electric Division, 430 North Salisbury Street, Raleigh.

Q. And, Mr. McLawhorn, speaking on behalf of the panel, did the panel prepare and cause to be filed in this docket on September 17th joint testimony in support of the Stipulation, consisting of five pages, one appendix and two exhibits?

A. We did.

Q. And did you also file on September 18 supporting schedules -- schedules in support of Exhibit 1 of the settlement exhibit, which was filed on 9/17/19?

A. Yes, we did.

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

A. I believe Ms. Johnson has one.

A. (Sonja Johnson) Yes, I do. If you would refer to Johnson Settlement Exhibit 1, Schedule 1, Line 42, in the Item column, this item pertains to the annual EDT -- EDIT rider. It reads currently five years. That should read two years, as opposed to the five that was filed on September the 17th and 18th of this year.

Q. Thank you.

COMMISSIONER GRAY: Ms. Johnson, would you repeat the location of that change? I'm sorry. I missed it.

MS. JOHNSON: Johnson Settlement Exhibit 1, Schedule 1, Line 42.

COMMISSIONER GRAY: Thank you.

MS. JOHNSON: You're welcome.

Q. If each of you are asked the same questions today, would your answers be the same?

A. (Sonja Johnson) Yes.

A. (James McLawhorn) Yes.

MS. HOLT: I move that the joint testimony of James McLawhorn and Sonja Johnson filed on September 17th, 2019, consisting of five pages, be copied into the record as if given orally from the stand, and that Appendix A, Johnson Settlement Exhibit 1, as revised, and Johnson Settlement Exhibit 2 be identified as premarked.

CHAIR MITCHELL: Motion is allowed.

(Johnson Settlement Exhibit 1 and Johnson Settlement Exhibit 2 were admitted into evidence.)

(Whereupon, the prefiled direct testimony of James McLawhorn and Sonja Johnson was copied into the record as if given orally from the stand.)

MS. HOLT: I also move that the supporting schedules filed on September 18 be identified as premarked.

CHAIR MITCHELL: They will be so identified.

(Supporting Schedules were admitted into evidence.)

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 562
DOCKET NO. E-22, SUB 566

PARTIAL SETTLEMENT JOINT TESTIMONY OF
JAMES S. MCLAWHORN AND SONJA R. JOHNSON
ON BEHALF OF THE PUBLIC STAFF-
NORTH CAROLINA UTILITIES COMMISSION

September 17, 2019

Q. MR. MCLAWHORN, PLEASE STATE FOR THE RECORD YOUR NAME, ADDRESS, AND PRESENT POSITION.

A. My name is James S. McLawhorn. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Public Staff – Electric Division.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are attached as Appendix A.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

Q. MS. JOHNSON, PLEASE STATE FOR THE RECORD YOUR NAME, ADDRESS, AND PRESENT POSITION.

A. My name is Sonja R. Johnson. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am an Accountant with the Public Staff – Accounting Division.

Q. DID YOU FILE DIRECT TESTIMONY ON AUGUST 23, 2019 IN THIS PROCEEDING?

A. Yes.

Q. MS. JOHNSON AND MR. MCLAWHORN, WHAT IS THE PURPOSE OF YOUR SETTLEMENT TESTIMONY IN THIS PROCEEDING?

A. The purpose of our testimony is to support the Agreement and Stipulation of Partial Settlement (Stipulation) between Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or Company) and the Public Staff (Stipulating Parties).

Q. PLEASE BRIEFLY DESCRIBE THE STIPULATION.

A. The Stipulation sets forth agreements between the Stipulating Parties in the following areas:

(1) Capital Structure
(2) Return on equity
(3) Uncollectibles
(4) Allocation of state accumulated deferred income taxes (ADIT) and certain ADIT balances
(5) Mount Storm impairment costs
(6) Non-utility generation (NUG) Contract Termination Expense
(7) Outside services
(8) Skiffes Creek mitigation costs
(9) Executive compensation
(10) Chesterfield Units 3&4 wet-to-dry conversion costs
(11) Federal unprotected excess deferred income taxes (EDIT)
(12) Lobbying
(13) Storm costs
(14) Employee severance program costs
(15) Advertising costs
(16) Incentive plan costs
(17) Employee Voluntary Retirement Program (VRP) Backfill costs
(18) Customer growth, usage, and weather normalization

(19) Variable Non-Fuel operations and maintenance (O&M) expense for Displacement
(20) Inflation
(21) Kilowatt-hour (kWh) Change in Revenue Annualization
(22) Dominion Energy Services (DES) Office Building

The Stipulation also sets forth agreement between the Stipulating Parties regarding the following non-revenue requirement area: (1) Revenue apportionment

Q. ARE THERE ANY UNRESOLVED ISSUES BETWEEN THE STIPULATING PARTIES?

A. Yes. The Stipulating Parties have not reached a compromise on the recovery of coal combustion residual (CCR) costs.

Q. WHAT BENEFITS DOES THE STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, the most important benefits provided by the Stipulation are as follows:

(a) A significant reduction of $13.517 million in the base non-fuel revenue increase from the $24.879 million increase requested in the Company's Supplemental Filing on August 5, 2019, resulting from the adjustments agreed to by the Stipulating Parties.

(b) The avoidance of protracted litigation between the Stipulating Parties before the Commission on the settled issues and possibly the appellate courts, and the associated increased accumulation of rate case expense recoverable from rate payers.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

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

A. Yes. The attached Johnson Settlement Exhibit 1 sets forth the accounting and ratemaking adjustments, and the resulting rate base, net operating income, return, and rate increase, to which DENC and the Public Staff have agreed plus the Public Staff's position on the unresolved CCR cost recovery issue. Johnson Settlement Exhibit 1, Schedule 1 is also attached to the filed Stipulation in this proceeding, as Settlement Exhibit I. Settlement Exhibit II is a calculation of the revenue requirement for the EDIT rider agreed to by the Stipulating Parties.

We would note that not until the Commission makes a determination regarding the yet unresolved issue of the CCR costs, can the accounting and ratemaking adjustments be finalized, and the resulting rate base, net operating income, return, and rate increase be calculated.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JAMES S. MCLAWHORN

I graduated with honors from North Carolina State University with the Bachelor of Science Degree in Industrial Engineering in May of 1984. I received the Master of Science Degree in Management with a finance concentration from North Carolina State University in December of 1991. While an undergraduate, I was selected for membership in both Tau Beta Pi and Alpha Pi Mu engineering honor societies.

I began my employment with the Public Staff Communications Division in June of 1984. While with the Communications Division, I testified before the Commission in general rate proceedings regarding matters of telephone quality of service.

In September of 1987, I was employed by GTE-South as an engineer in the Capital Recovery Department. I was responsible for analysis and recommendations to Company management regarding appropriate depreciation rates for recovery of the Company's capital investments.

I began my employment with the Electric Division of the Public Staff in November of 1988. I assumed my present position as Director of the Electric Division in October of 2006. It is my responsibility to supervise and make policy recommendations on all electric utility matters before the Commission.

I have testified previously before the Commission in numerous proceedings including Virginia Electric and Power Company Rate Cases Docket No. E-22, Subs 314, 333, 412, and 532; in Duke Energy Carolinas, LLC's Rate Cases Docket No. E-7, Subs 487, 909, 989, and 1146; in Duke Energy Progress, LLC's Rate Cases Docket No. E-2, Subs 1023 and 1142; in New River Light and Power Company Rate Cases Docket No. E-34, Subs 28 and 32; in Nantahala Power and Light Company Rate Case Docket No. E-13, Sub 157; in the Application of Dominion North Carolina Power to join PJM in Docket No. E-22, Sub 418; in Duke Power Company's request to merge with in Duke Power Company's request to merge with Cinergy Corporation in Docket No. E-7, Sub 795; in Dominion Energy, Inc.'s request to merge with SCANA Corporation in Docket No. E-22, Sub 551; in Duke Energy Carolinas, LLC's request for approval of its Save-A-Watt cost recovery model in Docket No. E-7, Sub 831; in Duke Energy Carolinas, LLC's solar distributed generation program in Docket No. E-7, Sub 856; and, in the Generic Investigation into Section 111 of the 1992 Energy Policy Act in Docket No. E-100, Sub 69.

Q. Do you have a summary of your joint testimony?

A. (James McLawhorn) Yes.

Q. Please read it.

A. The purpose of our partial settlement joint testimony is to support the Agreement and Stipulation of Partial Settlement, or Stipulation, between Dominion Energy North Carolina and the Public Staff.

The Stipulation, as filed on September 17th, 2019, sets forth agreements between Dominion and the Public Staff on a number of areas impacting the overall revenue requirement in this proceeding, as well as principles surrounding class revenue apportionment. There is one area that impacts the overall revenue requirement about which Dominion and the Public Staff have not reached agreement in this case, the recovery of coal combustion residual costs.

Johnson Settlement Exhibit 1 to our joint testimony sets forth the accounting and ratemaking adjustments and the resulting rate base, net operating income and rate increase to which Dominion and the Public Staff have agreed, plus the Public Staff's position on the unresolved CCR cost recovery issue.

Despite being only a partial settlement of issues in this case, the Stipulation still provides two important benefits for ratepayers: first, a reduction of almost $13 million in base non-fuel revenue increase from Dominion's requested increase of approximately $25 million as updated in its supplemental filing of August 5th, 2019; and, second, the avoidance of protracted litigation between Dominion and the Public Staff on the settled issues and resulting increased rate case expense that likely would be recoverable from ratepayers.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, we believe that the Stipulation is in the public interest and encourage the Commission to approve it.

This concludes our summary.

Q. Thank you. The witnesses are available for cross-examination.

MS. GRIGG: No questions.

MS. FORCE: I have a brief line of questions for Ms. Johnson, and I'll pass out an exhibit before we get started.

I'd ask that this be marked as AGO Johnson Cross-Examination Exhibit 1, please.

CHAIR MITCHELL: The exhibit will be so marked.

(AGO Johnson Cross-Examination Exhibit 1 marked for identification.)

CROSS-EXAMINATION BY MS. FORCE:

Q. Ms. Johnson, you -- just -- I think you just testified that you prepared the Settlement Schedule 1; is that correct?

A. (Sonja Johnson) That is correct.

Q. Now, if you look at Page 1 of this exhibit, would you agree that that is your Johnson Settlement Exhibit 1 with the correction that you just -- we need to make the correction that you just made to Line 42 to say two years instead of five years, right?

A. Correct.

Q. I wrote that on the court reporter's copy before I realized it was hers. So yours already reflects it.

So you were asked -- under that settlement, first of all, the rate of return on equity was agreed at 9.75 percent, correct?

A. Correct.

Q. And did you -- or somebody on the Public Staff respond to a discovery request from the Attorney General's Office asking to provide the settlement information again to reflect the impact it would have if instead of 9.75 percent, the rate of return on equity instead were 8.75 percent?

A. Yes, ma'am.

Q. And if you look at the next page -- just, first of all, for clarification, on Line 35 of your -- the first page, which is your schedule, it shows the total settled issues, the revenue impact, the reduction to the revenue requirement that's associated with what's been agreed to in settlement; is that right?

A. That is correct.

Q. And that's $13.517 million; is that right? Shown there in thousands, so the impact of the settlement that's been agreed to -- so it shows both for the Company and the Public Staff as three -- thirteen-point -- I'm sorry -- 13.517?

A. That is correct.

Q. Okay. If you turn to the next page of the exhibit, I submit to you that that is the data response that we received from the Public Staff showing if you were only to change the rate of return on equity from 9.75 percent to 8.75 percent how would that show up in the same schedule.

Did I summarize that correctly?

A. Yes, ma'am. But, again, just making clear that this is the impact of the settled issues and not the unsettled issue.

Q. Right. And so if we look at Line 35, the impact on the total settled issues would change that number to reduce the amount to $21,671,000; is that correct?

A. That is correct.

Q. Okay. That's if the only factor that's changed is the rate of return on equity and changing it to 8.75 percent?

A. That's correct.

Q. Okay. If you turn to the third page, this was not prepared by you, right?

A. No, ma'am.

Q. And would you agree, though -- and look -- you've seen this beforehand. Am I right?

A. Yes.

Q. And would you agree then that the basic method that was used there is to compare the calculation of the annual revenue reduction on the first page, which is your schedule that has $13,517,000 in Line 35 to the one that was prepared in the modified schedule for 8.75 percent rate of return on equity?

A. Yes.

Q. To show the difference in those two numbers, right?

A. That is correct. Yes.

Q. And the difference is $8,154,000?

A. Yes, ma'am.

Q. That's the effect of having that different rate of return on equity in the -- the total revenue requirement -- the reduction to the revenue requirement; is that right?

A. That is correct.

Q. Okay. And if you would turn then to the next page, you were also asked, were you not, to provide the same schedule using the number nine percent as the rate of return on equity? And this reflects the response that you gave for that; is that correct?

A. That is correct.

Q. And Line 35 then, compare -- the number -- if that were the only change made in the settlement numbers, it would come up with a reduction of 19,634,000?

A. Correct.

Q. And so if you look at the final page in the exhibit, as we did before, this was not on a schedule that you prepared, right?

A. No, ma'am.

Q. But it reflects the numbers for that Line 35 if you use the original schedule of 9.75 percent rate of return on equity to what it would be with nine percent rate of return on equity and shows a difference of 6,117,000; is that correct?

A. That is correct.

Q. Thank you. I don't have any other questions.

CHAIR MITCHELL: Any additional cross-examination for the witnesses?

MS. GRIGG: (Counsel nods negatively.)

MR. EASON: No.

CHAIR MITCHELL: Redirect?

MS. HOLT: No redirect.

CHAIR MITCHELL: Questions from Commissioners? I actually have one question, and this will go to Ms. Johnson.

EXAMINATION BY CHAIR MITCHELL:

Q. We have a question regarding the stipulated adjustment to the Mount Storm impairment.

A. (Sonja Johnson) Okay. That would be directed towards Mr. McLawhorn.

Q. Okay. Well -- all right. Well, I'll just address the panel. You guys can sort it out.

Okay. So it looks like to us that reading the Stipulation, the Stipulation is clear you've agreed to take out -- remove 50 percent of the Mount Storm impairment costs and amortize those over 2.75 years. I'm looking at Page 6 of the Stipulation just for your reference.

A. (James McLawhorn) Let me get that out.

Q. And then looking at the -- the exhibits on the Stipulation and the exhibits in direct testimony, the impairment adjustment consists of a rate base portion and an expense portion to arrive at the total revenue impact. The -- it does not appear that the -- the exhibits to the Stipulation reflect a rate base adjustment, and we want to make sure that it was the parties' intent to remove the rate base impact of the adjustment.

If it was not, could you please explain?

A. (Sonja Johnson) That was our intent.

Q. Okay. So the intent is to remove the rate base impact?

A. Yes, ma'am.

Q. Okay. All right. Thank you. I have nothing further.

CHAIR MITCHELL: Any additional questions? Questions on Commissioners' questions?

Okay. Well, I think you-all may step down. Thank you.

MS. FORCE: I'd like to move the admission of the exhibit AGO Johnson Cross Exhibit 1.

CHAIR MITCHELL: Hearing no objection, your motion will be allowed.

(AGO Johnson Cross-Examination Exhibit 1 was admitted into evidence.)

MS. HOLT: And I'd also like to move the

exhibits of -- of the direct testimony of Sonja Johnson, Exhibit 1 to her direct testimony, and Exhibits 1 as revised and Exhibit 2 of the settlement testimony.

CHAIR MITCHELL: Motion will be allowed. Thank you.

(Johnson Exhibit 1 and Johnson Settlement Exhibits 1 and 2 were admitted into evidence.)

CHAIR MITCHELL: Okay. Staff, you may call your next witness.

MS. FENNELL: The Public Staff calls Jack Floyd.

CHAIR MITCHELL: Good afternoon, Mr. Floyd.

JACK L. FLOYD,

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

DIRECT EXAMINATION BY MS. FENNELL:

Q. Good afternoon, Mr. Floyd. Could you please state your name, address and position for the record?

A. I'm Jack Floyd, Electric Engineer -- or Utility Engineer with the Electric Division, 430 North -- North Salisbury Street, Public Staff.

Q. Thank you. Did you prepare and cause to be filed in this docket on September 23rd, 2019, testimony consisting of 13 pages, one appendix and one exhibit marked as Floyd Exhibit 1?

A. Yes.

Q. Do you have any additions or corrections to your testimony?

A. I do not.

Q. If you were asked -- to be asked those same questions today, would your answers be the same?

A. They would.

MS. FENNELL: Okay. I request that the testimony of Mr. Floyd, consisting of 18 pages, be -- pages, be copied into the record as if given orally from the stand and that his appendix and exhibit be identified as premarked.

CHAIR MITCHELL: Motion is allowed.

(Public Staff Floyd Exhibit 1 was premarked for identification.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

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

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

A. My name is Jack Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Utilities Engineer with the Electric Division of the Public Staff, North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations concerning: (1) the methodology used by Dominion Energy North Carolina (DENC or the Company) in its cost-of-service study (COSS) filed in this case and the Company's adjustments to the COSS, (2) the class rates of return (ROR) on rate base under present revenues and the principles the Public Staff considers in evaluating proposed revenue assignment by customer class to be used in setting rates, (3) DENC's proposed modifications to certain rate schedules, and (4) DENC's proposed base fuel rates. The Public Staff's recommendations are based on a review of the application filed by DENC, the testimony and exhibits (direct and supplemental) of DENC's witnesses, and DENC's responses to numerous data requests.

METHODOLOGY OF AND ADJUSTMENT TO THE COSS

Q. WHAT IS THE PURPOSE OF THE COSS?

A. The purpose of a COSS is to determine the share of system revenues, expenses, and plant that should be allocated to jurisdictions and customer classes. The COSS determines the contribution of each jurisdiction and class to the Company's overall cost of service by examining the demand and energy consumption of the jurisdictions and customer classes, as well as Company resources used to provide utility service. Such determinations are then used to allocate both present and future revenue responsibilities.

Q. WHAT COST–OF–SERVICE METHODOLOGY DID DENC USE IN THIS PROCEEDING?

A. DENC used the summer/winter coincident peak and average (SWPA) methodology to determine both jurisdictional and customer class cost responsibility in this case.

Q. DOES THE PUBLIC STAFF AGREE WITH DENC'S USE OF THE SWPA COST-OF-SERVICE METHODOLOGY IN THIS PROCEEDING?

A. Yes. As explained below, the Public Staff believes that the SWPA cost-of-service methodology is the appropriate methodology because it appropriately allocates production plant costs in a way that most accurately reflects both the Company's generation planning and operation.

Q. HOW ARE PRODUCTION PLANT COSTS ALLOCATED UNDER THE SWPA METHODOLOGY?

A. Under the SWPA methodology, the fixed costs of production plant are allocated among jurisdictions and customer classes on the basis of a formula that contains two components. The first component, the "summer/winter peak" component, is based on the demand of the jurisdiction or customer class in question at the time of the utility's greatest summer and greatest winter system peak demands. The second component, the "average" component, is based on the average demand of the jurisdiction or customer class, i.e., total kilowatt-hour (kWh) sales for the year divided by the number of hours in a year. In other words, the first component is based on the peak demand at a particular time, and the second component is based on the average demand over an entire year. Unlike many other methodologies that allocate all of the production plant costs based on the single coincident peak or on a series of monthly peaks, the SWPA methodology recognizes that a portion of plant costs, particularly those incurred for base load generation, is incurred to meet annual energy requirements throughout the year and not solely to meet peak demand at a particular time.

Q. DID DENC MAKE ANY ADJUSTMENTS TO THE DATA USED TO CALCULATE THE SWPA ALLOCATION FACTORS?

A. Yes. DENC made two adjustments to its COSS. The first adjustment was made to recognize the impact of non-utility generators (NUGs) connected to its distribution system. The second adjustment was made to remove wholesale contracts that are expiring at the end of 2019. These adjustments impact both the jurisdictional COSS and the customer class COSS.

Q. PLEASE DESCRIBE THE NUG-RELATED ADJUSTMENT.

A. As described by Company witness Paul Haynes, the NUG adjustment was necessary because of the manner in which the Company measures demand for purposes of the COSS. The Company measures demand at the substation, while it measures energy sales at the customer meter. Thus, generation capacity that is connected to the distribution system is not recognized by the measurement of demand at the substation. In other words, the aggregate consumption at customer meters is not consistent with the demand observed at the substation, because the NUG generation interconnected at the distribution level serves part of that consumption. In order to reconcile this difference, DENC has adjusted the summer and winter peaks to recognize the NUG generation at the time of those peaks. This adjustment results in an increase of 450 MW to the measured system level summer peak, and 28 MW to the measured system level winter peak. No adjustment was necessary to the energy sales for either the jurisdictional or customer class COSS.

Q. HOW DOES THE NUG ADJUSTMENT IMPACT THIS RATE CASE?

A. The NUG adjustment impacts both the jurisdictional and customer class production allocation factors 1 and 2.[1] The differences are illustrated in Floyd Exhibit 1. With the NUG adjustment, the North Carolina retail jurisdiction is allocated a slightly greater percentage of production and transmission plant costs, which is then allocated to the residential and small general service customer classes as these classes are connected to DENC's grid at the system distribution level. This adjustment was made and accepted in the Company's 2016 general rate case, Docket No. E-22, Sub 532.

Q. PLEASE DESCRIBE THE WHOLESALE CONTRACT ADJUSTMENT.

A. As described by witness Haynes, this adjustment was made to remove the demand and energy requirements of wholesale contract customers that will no longer be served by DENC after 2019.

Q. DO YOU AGREE WITH DENC'S PROPOSED ADJUSTMENTS TO THE COSS?

[1] Factor 1 is the production plant allocator. Factor 2 is the transmission allocator.

A. Yes. The adjustments appropriately recognize the impact of the NUGs and the removal of wholesale contract load in 2020 on DENC's utility system.

CALCULATION OF CLASS RORS AND ASSIGNMENT OF REVENUES

Q. HOW ARE RORS USED IN DETERMINING REVENUE ASSIGNMENT?

A. RORs serve as an indicator of how the revenues produced by the various customer classes cover the costs to serve those classes, as well as informing how any additional revenues should be apportioned to the customer classes. Any ROR that is less than the overall system or jurisdictional ROR indicate that the revenues received from a specific jurisdiction or customer class do not fully cover its share of system costs. Conversely, an ROR that is greater than the overall system or jurisdictional ROR indicates that a jurisdiction's or class's revenues exceed the necessary cost coverage. While it is appropriate to address revenue cost recovery inequities as revealed through RORs, it is equally important to keep in mind that such an assignment is based on a snapshot in time of the Company's cost and load data. A different timeframe, test year period, or other perspective would very likely yield a different representation of cost causation and revenue assignment. This variability in RORs is why the Public Staff has historically targeted a ±10% "band of reasonableness" for class revenue assignment as discussed in more detail later in my testimony.

Q. HOW DID DENC ASSIGN ITS PROPOSED REVENUE REQUIREMENT TO THE CUSTOMER CLASSES?

A. In his direct testimony, Company witness Haynes explains in detail DENC's methodology for assigning the Company's proposed revenue requirement. In calculating the class RORs to be used in determining the apportionment of the class revenue assignment, the Company used base non-fuel revenues only. His testimony states, on page 21, that because fuel revenues and expenses do not impact the calculation of net operating income, any revenue deficiency in this case will need to be addressed through the apportionment of non-fuel base rates.

Q. DO YOU AGREE WITH THE COMPANY USING ONLY BASE NON-FUEL REVENUES TO CALCULATE CLASS RORS?

A. No. As the Commission determined in the Company's last general rate case, Docket No. E-22, Sub 532 (Sub 532),[2] both base fuel and base non-fuel revenues should be used in determining base revenue assignment. As discussed in the Commission's *ORDER APPROVING RATE INCREASE AND COST DEFERRALS AND*

[2] The Commission accepted the Agreement and Stipulation of Settlement in Sub 532 that stated both base fuel and base non-fuel revenues should be used in assigning base revenues and calculating RORs.

REVISING PJM REGULATORY CONDITIONS in Sub 532, DENC and the Public Staff settled this matter and used both base fuel and base non-fuel revenues, as described by witness Haynes in Sub 532 to apportion the revenue changes resulting from that case. Witness Haynes' testimony in this proceeding does not, however, take into account the impacts that base fuel revenues have on the total revenue picture. While I agree that base fuel revenues and expenses do not impact the calculations of RORs, base fuel revenues do impact the total revenues assigned to each customer class and the percentage change in revenues. Because the level of revenue increase has the ability to cause customer "rate shock", it is appropriate to consider both base fuel and base non-fuel revenues when considering how to apportion any revenue change resulting from this case.

Q. **WHY IS IT IMPORTANT TO ANALYZE THE CHANGES IN BOTH BASE NON-FUEL AND BASE FUEL REVENUES IN ASSIGNING THE REVENUE REQUIREMENT?**

A. It is important to look at changes to base non-fuel <u>and</u> base fuel revenues together because they are related to a baseline of costs that are anticipated to be incurred annually until the next general rate case.[3] The Commission said as much in its order in Docket No. E-22, Sub 479:

> General Statute 62-133(b)(3) is clear that the Commission must ascertain a utility's reasonable operating expenses in fixing rates. As conceded by the Company, fuel is a substantial operating expense in the overall cost of service. Therefore, a base fuel factor has to be established in a general rate case proceeding. This base fuel factor is designed to recover the appropriate level of fuel and fuel-related expenses. Once the base fuel factor is established, it does not change as a result of annual fuel charge adjustment proceedings filed pursuant to G.S. 62-133.2 and Commission rule R8-55. The Commission can, in an annual fuel proceeding, approve an adjustment to the base fuel factor. However, by adopting such an adjustment the Commission does not change the base fuel factor that was established in a general rate case. Accordingly, the Commission concludes that it is appropriate to calculate the rates of return for customer classes using the base fuel and base non-fuel revenues established in this case.[4]

Q. PLEASE DESCRIBE THE PRINCIPLES HISTORICALLY CONSIDERED BY THE PUBLIC STAFF WHEN ASSIGNING THE PROPOSED REVENUE REQUIREMENT

A. Consistent with our practice in past general rate cases, and consistent with the method approved by the Commission in past proceedings, I believe the principles outlined below should be taken

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[3] Base fuel revenues will be adjusted annually pursuant to .G.S. 62-133.2 and Commission Rule R8-55.

[4] *Order Granting General Rate Increase*, entered December 21, 2012, at 120.

into consideration to apportion any combined base fuel and base non-fuel revenues among the various customer classes.

These principles attempt to assign the revenue requirement to each customer class in an equitable and fair manner and to minimize rate shock to any individual class.

1. Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;

2. Maintain a ±10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;

3. Move each customer class toward parity with the overall jurisdictional ROR; and

4. Minimize subsidization of customer classes by other customer classes.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE ASSIGNMENT OF THE PUBLIC STAFF'S RECOMMENDED REVENUE REQUIREMENT TO THE CLASSES?

A. Public Staff witness Johnson provides the Public Staff's recommended jurisdictional revenue requirement for use in assigning the total base revenue requirement to the individual customer classes. In this case, the Public Staff is recommending a total revenue decrease. The principles outlined above are most appropriate when an overall revenue increase is recommended. When the recommendation is an overall revenue decrease, as in this case, it is appropriate to focus on addressing disparities in the class RORs when apportioning any such revenue decrease. However, any individual customer class revenue decreases should be limited so that no individual customer class sees an increase in its assigned revenue requirement. In other words, in the event of a revenue requirement decrease, no customer class should see an increase simply to bring the class ROR within 10% of the jurisdictional ROR.

RATE SCHEDULES

Q. DO YOU HAVE ANY COMMENTS OR RECOMMENDATIONS CONCERNING ANY OF THE COMPANY'S PROPOSED RATE SCHEDULES?

A. Other than the proposed rates in each rate schedule, the Company has only proposed one notable change to its rate schedules in this proceeding. This modification is associated with lighting services under Schedule 26. DENC is proposing to close availability of new high pressure sodium fixtures effective January 1, 2020. Customers seeking new lighting fixtures will need to select from a menu of light emitting diode fixtures. The Public Staff does not object to this modification.

Q. DO YOU HAVE ANY COMMENTS OR RECOMMENDATIONS CONCERNING THE BASIC CUSTOMER CHARGES IN THE COMPANY'S RESIDENTIAL RATE SCHEDULES?

A. Yes. DENC has proposed to increase the residential basic customer charge from $10.40 to $11.92 per month. I reviewed both the COSS and the unit cost data contained in Item 45e of Form E-1 of the Company's initial application and supplemental filings. In a COSS, costs are functionalized into one of three basic utility categories: customer account, demand, and energy. The unit cost data is calculated for each function by summing the costs of that function and dividing the sum by the number of units associated with that function delivered in the test year period. For example, "customer" costs are typically associated with functions such as customer account management, metering, billing, and account services. While the unit cost data in Item 45e is an approximation of the cost associated with each unit of service for a given utility function, it does provide an indicative benchmark to use when designing individual rate elements of various rate schedules.

Q. DOES THE PUBLIC STAFF HAVE GUIDELINES OR PRINCIPLES IT USES IN SETTING THE FIXED COMPONENT, OR BASIC CUSTOMER CHARGES IN A RATE CLASS?

Yes. On March 28, 2019, the Public Staff filed a report[5] with the Commission on the use of the minimum system method for the investor-owned utilities, including DENC, which provides a basis for establishing the portion of distribution system-related costs as "demand-related" and "customer-related." In that report the Public Staff concluded that fixed costs of electric service should be recovered from all customers, and that the minimum system method used to classify distribution plant, which serves as the basis for developing a basic customer charge, is a reasonable approach to developing the amount of the basic customer charge. In that report, the Public Staff also stated any increase in the fixed, or basic customer charge, for any customer class should not exceed an amount that would recover more than 25% of the revenue increase that was assigned to that customer class.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS RELATED TO THE COMPANY'S RATE SCHEDULES?

A. Yes. In reviewing Rider D (Tax Effect Recovery Rider) it was learned that the proposed factor of 1.6054 is incorrect. The correct factor should be 1.16054. The Company's Supplemental Filing did not address this issue. However, the Company has acknowledged this

[5] See "Public Staff Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities," dated March 28, 2019 and filed in Docket No. E-100 Sub 162.

correction and intends to correct this value of the Tax Effect Recovery Rider in its compliance filing in this proceeding.

BASE FUEL RATE

Q. PLEASE DESCRIBE HOW DENC HAS ADDRESSED THE BASE FUEL RATE IN THIS GENERAL RATE CASE.

A. In its application filed on March 29, 2019, DENC presented its proposed base fuel rate in the testimony of DENC witnesses Bruce Petrie and Paul Haynes. Haynes Schedule 3, Page 1 of 3, provides the calculations for DENC's placeholder base fuel rate of 2.142¢ per kWh, effective for usage on and after May 1, 2019. Haynes Schedule 4, page 1 of 5, provides the calculations for DENC's projected base fuel rate of 2.172¢ per kWh, to be effective on a temporary basis on November 1, 2019.

On August 14, 2019, DENC filed the Additional Supplemental Direct Testimony of Paul Haynes, which proposed a new base fuel rate of 2.092¢ per kWh to be effective beginning November 1, 2019, subject to refund as allowed by Gen. Stat. § 62-135.[6]

[6] DENC filed its annual application for fuel cost recovery in Docket No. E-22, Sub 579 (Sub 579), pursuant to Gen. Stat.§ 62-133.2, which included the same base fuel rate.

In its Sub 579 filing, DENC also proposes an EMF of 0.013¢ per kWh, based on a fuel expense under-recovery of $550,353 during the test period.

Q. PLEASE DESCRIBE DENC'S PROPOSED RIDER A1 IN THE FUEL CASE.

A. DENC believes that it is likely to over-recover fuel expenses in the second half of 2019. To mitigate this potential over-recovery, DENC proposes a decrement Rider A1 for the months of November 2019 through January 2020. This rider will equal the difference between the existing EMF and the EMF proposed to begin on February 1, 2020, which equates to (0.375¢) per kWh. The actual over- or under-recovery in the second half of 2019 will be trued-up in the EMF in next year's fuel case. DENC proposes that Rider A1 be allocated among the customer classes using voltage differentiation as it does with all other fuel riders.

Q. WHAT IS THE TOTAL FUEL RATE DENC PROPOSES TO BECOME EFFECTIVE ON AN INTERIM BASIS ON NOVEMBER 1, 2019?

A. As illustrated in Table 5 of witness Haynes' Additional Supplemental testimony, when proposed Rider A1 is combined with the proposed base fuel rate and the current EMF, the total fuel rate DENC proposes to become effective on an interim basis on November 1, 2019, is 2.105¢ per kWh.

Q. DOES THE PUBLIC STAFF HAVE ANY CONCERNS WITH THE COMPANY'S PROPOSED FUEL RATES IN THE GENERAL RATE CASE?

A. No. The Public Staff will address any concerns with fuel rates in Sub 579 and will propose that any necessary changes be incorporated into the final fuel rates that go into effect on February 1, 2020. The Public Staff also does not oppose the implementation of the proposed total fuel rate as part of the interim rates DENC proposes to become effective on November 1, 2019, as discussed in more detail above. However, prior to the time final rates go into effect, the Commission will need to establish a new base fuel rate in the general rate case.

In addition, Commission Rule R1-17(b)(9)(c) requires an applicant in a general rate case to provide an estimate of the net additional revenue that the proposed new rates will produce. This estimate is needed so that projected revenues can be compared with the proposed new revenue requirement.

The Public Staff does not oppose the Company's proposed Rider A1 because it returns over-collected ratepayer funds sooner than would otherwise occur.

Q. WHAT IS THE NET RESULT OF THE COMPOSITE BASE FUEL RATE AND FUEL RIDERS?

A. The net result of DENC's existing and proposed composite base fuel rate and fuel riders for each customer class is shown in Company Additional Supplemental Exhibit PBH-1, Schedule 3, (also Company Exhibit GGB-1, Schedule 4 in Sub 579).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JACK L. FLOYD

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Chemical Engineering. I am licensed in North Carolina as a Professional Engineer. I have more than 17 years of experience in the water and wastewater treatment field, nine of which have been with the Public Staff's Water Division. In addition, I have been with the Electric Division for almost 17 years.

Prior to my employment with the Public Staff, I was employed by the North Carolina Department of Natural Resources, Division of Water Quality as an Environmental Engineer. In that capacity, I performed various tasks associated with environmental regulation of water and wastewater systems, including the drafting of regulations and general statutes.

In my capacity with the Public Staff's Water Division, I investigated the operations of regulated water and sewer utility companies and prepared testimony and reports related to those investigations.

Currently, my duties with the Public Staff include evaluating the operation of regulated electric utilities, including rate design, cost-of-service, and demand side management and energy efficiency resources.

My duties also include assisting in the preparation of reports to the Commission; preparing testimony regarding my investigation activities; reviewing Integrated Resource Plans; and making recommendations to the Commission concerning the level of service for electric utilities.

Q. Do you have a summary of your testimony?

A. I do.

Q. Could you please present it now?

A. Yes. My testimony presents the Public Staff's analysis and recommendations regarding the cost of service methodology; class rates of return; revenue assignment; modifications to certain existing rate schedules; and the proposed base fuel rates.

With respect to the cost of service methodology, I concur with Dominion's use of the Summer-Winter Peak and Average methodology to assign production plant costs to the jurisdiction and rate classes.

I also concur with the adjustments Dominion made to its cost of service to recognize the effect of non-utility generators connected to its distribution system and the adjustment to remove the impacts of wholesale customer contracts that will terminate at the end of 2019.

My testimony also contains the Public Staff's recommendations regarding the assignment of base non-fuel and base fuel revenues to customer classes and Dominion's proposed rate schedules, including why it is appropriate to consider total base revenues when assigning revenue responsibility to the classes.

My testimony further describes the Public Staff's principles of revenue apportionment. The Public Staff has historically considered four principles when determining how to apportion revenues -- revenue increases resulting from general rate cases to customer classes. Those principles include limiting the increase to no more than two percentage points greater than the overall percentage increase; maintaining the returns on rate base within a plus or minus ten percent band of reasonableness compared to the overall jurisdictional return; moving all classes toward the overall jurisdictional return; and minimizing the subsidization among other -- or customer classes.

My testimony also concurs with the Company's proposals for rates and rate schedules. My testimony provides the Public Staff's position regarding the setting of the basic customer charge. That position reflects the belief that all customers should share in the recovery of fixed costs of electric service; that the minimum system method of classifying distribution plant, which Dominion used in this proceeding, is a reasonable approach to determining the basic customer charge; and, three, that any change in the basic customer charge should be limited to recover no more than 25 percent of the total revenue increase assigned to the class.

My testimony concludes by supporting the proposed fuel rates the Company proposed in its August 2019 supplemental filings. The Public Staff's interim support for these fuel rates is subject to our ongoing review and ultimate recommendations associated with the fuel proceeding in Docket E-22, Sub 579. And that completes my summary.

MS. FENNELL: Mr. Floyd is available for cross-examination.

MS. GRIGG: No questions.

MS. FORCE: No questions.

MR. EASON: No questions.

CROSS-EXAMINATION BY MS. HICKS:

Q. Good afternoon, Mr. Floyd.

A. Hey.

Q. My name is Warren Hicks. I represent CIGFUR. I wanted to ask you about a couple of exhibits that are already in evidence.

Do you have in front of you Company Stipulation Exhibit PBH-1, Schedule 1?

A. I do.

Q. All right. And do you have in front of you Company Stipulation Exhibit REM-1, Stipulation Schedule 4?

A. Yes.

Q. Okay. Were you in the room when I asked questions of Mr. Haynes earlier?

A. I was.

Q. All right. And looking at those two exhibits that we just pulled out, do you concur with Mr. Haynes's opinion that the rate increases being assigned to the LGS and 6VP rate classes are very small?

A. They are very small. I think we need to put some perspective on the numbers. Mr. Miller's exhibit and Mr. Haynes's exhibits are based on the Company's anticipated revenue outcome from this proceeding of eight and a half million increase.

The Public Staff doesn't agree with that and that's still subject to the resolution of these unresolved issues before the Commission. I think the Stipulation had a revenue requirement of 4.1 million, I think was the Public Staff's perspective of -- of the case. So that -- that needs to be kept in mind when reviewing these sets of exhibits.

Q. All right. Thank you. And do you also concur with Mr. Haynes's opinion that even though those increases that the Company is advocating for -- even though those increases are very small, nonetheless, they are above cost for rate class LGS and rate class 6VP?

A. Above cost in a literal sense, yes. Above cost in a figurative sense, maybe slightly. And I'll -- I'll --

I'll qualify that a little bit. This is a reason why the Public Staff has historically looked at a band of reasonableness around rate of return. You cannot pick a specific number and decide that that's the objective of any case, because as soon as the Commission sets rates in a proceeding, the next day, they're stale until the next rate case.

So we have to look at a band of reasonableness for the period of time that those base rates are going to be in effect. It could be one year. It could be three years, as we've seen with the past few Dominion cases. So that -- you need to keep in mind that band of reasonableness serves as a broader window than a specific number for us to consider appropriateness. And so within that band of reasonableness, we believe the rates are appropriate.

The classes that you highlight here, the 6VP is just outside of that window. So is large general service. So is the NS class and so is the small general service in terms of what the Company has proffered as their outcome from this proceeding.

Q. And when you say that those -- the rate of returns are just outside the range of reasonableness --

A. Right.

Q. -- what are you looking at when you're saying --

what are you basing that on?

A. Well, just taking the calculations as offered by Witness Miller with the Company, he has calculated based on the revenue increase of eight and a half million the -- the rates of return. And so I'm just taking him at his word on what he has filed in terms of these schedules.

Any change in that eight and a half million, depending on the unresolved issues in this case, could change this whole perspective. All of these schedules could be immaterial depending on what the Commission ultimately rules in the proceeding.

We did not offer any type of specific revenue apportionment in this case other than to articulate the principles that are in my direct testimony. I believe to the extent that Mr. Haynes and Mr. Miller could abide within those principles, they did, given the context of the Stipulation between the parties.

Q. All right. Thank you. And so just to be clear, are you saying that a Rate of Return Index that is 15 basis points above the band of -- above the band of reasonableness is just above the band?

A. Well, it would be .05 because for 6VP, it's 1.15 as calculated by the Company. So, again, it's -- it's a matter of perspective. It is -- it is literally slightly outside of that band, yes.

Q. I was asking about the LGS class.

A. Okay. The LGS is -- yes, you're -- you're right, 15 points -- 15 index points. I think that's what we were talking about earlier.

Q. Thank you.

A. Nucor is -- is 20 -- excuse me, ten. Ten.

Q. Nucor is --

A. Schedule NS is .8, and so to bring that up to .9 would be ten.

Q. So they're ten under --

A. Yes.

Q. -- as opposed to 15 over --

A. Yes.

Q. -- which is what the LGS class is?

A. Right. SGS is seven over. Residential is seven under.

Q. All right. And, Mr. Floyd, do you have a copy of DENC Haynes Redirect Exhibit Number 1 in front of you?

A. This should -- yes.

Q. It should --

A. It has the Sections H, I and J?

A. Yes. And it should say DENC Haynes Redirect --

A. Yes.

Q. -- Exhibit Number 1 up in the upper right-hand corner.

So I'll submit to you that this exhibit contains the same information as Company Stipulation Exhibit PBH-1, Schedule 1.

A. Right.

Q. And then it includes three -- three additional categories down at the bottom, H, I and J. And those categories demonstrate the impact of two riders that have been designed to refund a fuel overcollection that's occurring during the 2018 -- during this 2018 year period. Is that correct?

A. That's -- that's the way I interpret this, yes. It's fuel and EDIT.

Q. Okay. And is it your understanding that Combined Rider A-1 and proposed Rider B would be in effect for 15 months?

A. Rider A-1 is kind of a bridge rider until the permanent rates are -- likely take effect, at least at this point, February 1st, 2020. And then Rider B would take effect after that.

I think it's important to keep in mind that both Rider A-1 and B, which are roughly the same character rider -- they are EMF for fuel purposes. They're -- they're paying back what customers have already paid or overpaid. And then EDIT is a -- is a going forward to collect additional taxes, as I understand.

Q. So I think we're in agreement that -- I just want to make sure -- that Riders A-1 and Rider B would be -- or are repaying fuel amounts that have been overcollected for ratepayers.

A. That's my understanding, yes.

Q. Okay.

A. They -- they are -- they are related to the fuel experience modification factor.

Q. And they are temporary in nature?

A. They get check -- they get reset every year in a fuel proceeding.

Q. Correct. And would you also agree that the total base rate set in this case will be permanent until Dominion comes in for another base rate case?

A. Yes. And I think it's important to keep a -- the right perspective with these percent increases in revenues. The -- the Public Staff has historically looked at base revenues, fuel and non-fuel. The Commission has to set a base fuel rate in this proceeding, which -- which in the terms of the stipulations, the parties have agreed to a -- a particular number.

Outside of that, EMF and taxes are things that are -- have already occurred or are going to occur outside of the base rate revenue established in a proceeding. And so that's why when we look at the percentage -- two percentage points rule principle that we apply, we look at it and apply it only to the base rate revenues, fuel and non-fuel.

Q. All right. And in your opinion, is it equitable to rate classes LGS and 6VP who have rate of returns above the parity index to argue that Riders A-1 and B are offsets?

A. Offsets in terms of what?

Q. So is it fair to present those two riders, which if you look at the bottom of DENC Haynes Redirect Exhibit Number 1, Section J --

A. Uh-huh (yes).

Q. -- Line 45, you can see that there are rate decreases reflected on that line that are the result of netting the total base rate increase in this proceeding --

A. Right.

Q. -- the non -- excuse me, the -- the EDIT rider and then also -- the EDIT rider and then also those proposed fuel riders, those proposed fuel -- decrement fuel riders.

A. I -- I think it is a representation of the Company's position and hopeful outcome from the -- from the case. The EDIT is another issue that remains to be decided. I think fuel is -- will be decided or -- or fully resolved in the fuel proceeding which has yet to occur.

I -- I don't take issue with Sections H, I and J here as -- as they have been calculated. I don't think it is appropriate to look at those in terms of applying revenue apportionate -- apportionment principles, the two percent principle that I mentioned just a second ago. I think Section E of this, which was in his earlier exhibit, Exhibit 1 or Schedule 1, is more appropriate in terms of applying the Public Staff's revenue apportionment principle of -- of no more than two percent over the -- over the jurisdictional increase.

Q. So my question is is it fair to look at the fact that the LGS rate class and the 6VP rate class have rate of return and indexes that are outside of the range of reason -- reasonableness but say that is excusable under the circumstances because they are getting decreases as a result of proposed Riders A-1 and B?

A. Your characterization is somewhat nefarious and I'm not sure I agree with that, but I think -- I mean, in an -- in an ideal setting, yes, I would love to be able to say we could do -- achieve all four of the principles.

Unfortunately, that is -- is never -- we never have an ideal situation. I do think the Public Staff has -- has routinely looked at the percent increase to all classes and how those are impacted. The actual percent of base revenue increases takes a little bit of primacy over the rate of return principle. Not to say that it's any less of a principle, but in terms of when they start to conflict, we -- we need to look at what is going to happen to customers' bills.

And rates of return are -- are illustrative of the cases and how classes are impacted in terms of revenues and revenue apportionment. But at the end of the day, it's the customer, whether they're the Nucor on the system or whether they're my mother on the system, they're going to see what that bottom line is and -- and everybody's concerned about increases.

Unfortunately -- well, I -- I don't know. I wouldn't say unfortunately. More -- I'd say, fortunately, we've got a $24 million original increase that was requested down to at least eight and a half, 4.1 if the Commission agrees with the Public Staff's side of the unresolved cases. I think that's a pretty good outcome from this proceeding, given what we had.

We could do more to address the return issue in conjunction with the two percent principle if we were dealing with more of a -- a revenue increase. But we've whittled it down from 24, 25 to hopefully four -- 4.1 million. There could be a decrease in this proceeding, based on what the Commission finds on the unresolved issues.

So given that uncertainty, I think, in the scheme of things, everything has balanced out as well as it could.

Q. All right. Thank you. No further questions.

CROSS-EXAMINATION BY MS. FORCE:

Q. I do have one question.

A. Yes.

Q. It follows up with what you were just talking about. If there were a rate decrease, would that affect your percentages; that would mean no increase to the base charge for customers?

A. We would -- we would probably go that route. I would -- again, it depends. It's -- there's some degree, I think, that has to be kept in mind. If we're talking a couple of million dollars of increase -- a decrease, or are we talking $20 million dollar decrease? I don't know. I don't have that perspective, and so it's hard for me to say specifically.

If there's a decrease, I -- I do think it's safe to say the Public Staff's -- an unarticulated principle is -- has been that if there is an overall decrease that no class should see an increase for the sake of giving another class more of a decrease, again to go toward resolving some of these return issues.

It's -- it is a difficult place to be, but if I had to pick between the $24 million increase or a $4 million increase, I think the record is pretty straightforward with where I'd land.

Q. And -- and just to be more specific in terms of the base charge -- the basic monthly charge --

A. Uh-huh (yes).

Q. -- if there were a rate decrease, then, as I recall, in the past you've advocated no increase to the basic charge.

A. And that's likely the case here.

Q. Uh-huh (yes).

A. It's just, again, I need -- I need to keep my -- my ammo dry, so to speak.

Q. Okay. Thank you. I don't have any other questions.

REDIRECT EXAMINATION BY MS. FENNELL:

Q. Just one question, Mr. Floyd. Going back to DENC Haynes Redirect Exhibit, which we acknowledge is the same as Haynes Stipulation Exhibit, earlier you mentioned that what we, the Public Staff, tend to look at is Line E --

A. Right.

Q. -- which is the total base revenue, which includes base non-fuel and base fuel. And Ms. Hicks read these lines earlier in the exhibit, so I won't ask you to read these again.

But looking at the percentage change, if we were to agree to focus on parity in designing rates, rather than assigning an increase to each class, where would the -- the amounts that have been assigned to LGS and 6VP have to go to give them a decrease?

A. Well, it would likely go to the other classes, which would be residential, small general service and to some extent, contrary to Mr. Eason's client's position, it -- probably Nucor.

Q. Uh-huh (yes). Okay. Thank you. That's all.

CHAIR MITCHELL: Questions from Commissioners? Commissioner Clodfelter?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Okay. I have to do this. I'm sorry. Since you refer to it in your testimony, you are, of course, familiar with the March 28, 2019, report by the Public Staff on the use of the minimum system method.

A. Yes, sir.

Q. I have a hunch. Would I be right if my hunch were that you had a major role in preparing that report?

A. Yes.

Q. One of its primary authors perhaps?

A. I never take full custody of anything the Public Staff publishes, but, yes, I was -- I participated with it.

Q. You are familiar, are you, with Professor Bonbright's criticism of the minimum system methodology?

A. Yes, sir.

Q. He says it's absolutely incoherent.

A. And --

Q. Tell me why he is wrong.

A. I'm not saying he is wrong. What -- what I am saying is that -- and I think this is articulated to some degree in the report. Bonbright's treatise of ratemaking was done in the early '60s, if I recall, and there was update of that in the early '80s, I believe.

The system that he was familiar with at the time is not the system we have today, and the -- the potential for not recovering -- sufficiently recovering fixed costs puts us back into this room every three years. And as people continue to use the system in a different way, we need to come up with a means of looking at, analyzing and apportioning how fixed costs are recovered. And the minimum system approach, I think, is a reasonable way of looking at the distribution system that has, to a large extent, components of customer-related costs and demand-related costs.

Is it perfect? Absolutely not. You -- you will not hear me say it's -- it's -- it's a perfect way. I'm not even sure it's a good way, but it is a way. And I do think it provides a reasonable means to give us some -- some information about how to look at fixed cost.

It -- it does concern me that we have these debates about basic customer charges or -- or -- and fixed cost, because as I see the system changing, you know, we -- we are all concerned with low income customers and people of limited means, whether they're low income or not, to -- to pay bills. But for every dollar of cost we do not recover in one rate element in a tariff, it has to be recovered in another rate element. And in terms of the residential service, the basic schedule, Schedule 1 for Dominion, we have a basic customer charge and a energy charge. And so for every dollar of cost we throw into the energy charge to be recovered and the Company doesn't recover that, they're going to show up here again for another rate case.

But those costs are simply being shifted to people who are able to avoid buying kilowatt hours from Dominion, and that does trouble me, because long term, I think we are looking at lower basic customer charges, higher energy charges to produce the same revenues, and people with the means to avoid buying kilowatt hours are simply going to do so.

Q. They're going to conserve energy, in other words?

A. Well, conserve it, generate it themselves, but find some other way to not buy those kilowatt hours from the Company. And by extension, those fixed costs of utility service go unrecovered.

Q. Well, I -- I didn't really mean to get us off on this. I really was just going to have a little fun, but --

A. You hit a button with me.

Q. Well, you know, and --

A. Sorry.

Q. -- and I think you've sort of realized you hit a button with me because that's why I asked the question.

A. I know.

Q. So isn't -- isn't -- isn't it a fact that one of the things that's changed perhaps about the distribution system between Professor Bonbright's writing of his treatise and today is that we've now got -- which he didn't have to deal with, we've got third-party generators who are making use of the distribution grid and contributing nothing toward the fixed costs?

A. Your ten words to my thousand words say the same thing.

Q. And so when we use the minimum system methodology of allocating those distribution system costs on a per-customer basis, what we're really doing is letting those third-party users who are not contributing to fixed costs shift those costs to the residential customer base very largely. Isn't that what's happening?

A. I think you saw a little bit of that in -- in I think one of the Company's responses to your question. I can't remember which question it was, but it had to do with this basic customer method.

You saw that because there's this shift in total dollars toward the residential class as a result of the exercise that you requested.

Q. Well, this is the general rate case request by Dominion Energy and not an academic debate.

A. Right.

Q. So you and I will continue this on another day, but I just couldn't resist. Thank you.

A. Well --

Q. That's all I have.

A. I'll close with they complied with previous Commission orders in doing this.

CHAIR MITCHELL: Questions on Commissioner's questions?

All right. Mr. Floyd, you may step down. Thank you.

THE WITNESS: Thank you.

MS. FENNELL: I'd like to move the -- into evidence Jack's Exhibit -- or Mr. Floyd's Exhibit 1.

CHAIR MITCHELL: Motion is allowed.

MS. FENNELL: Thank you.

(Public Staff Floyd Exhibit 1 was admitted into evidence.)

CHAIR MITCHELL: And you may call your next witnesses.

MS. CUMMINGS: Public Staff calls Witness Maness and Lucas as a panel.

JAY LUCAS and MICHAEL C. MANESS,
having first been duly sworn, were examined
and testified as follows:

CHAIR MITCHELL: Hearing no objection, the motion will be allowed.

DIRECT EXAMINATION BY MS. CUMMINGS:

Q. We're handing out the summaries right now. While Mr. Drooz does that, I'll go ahead and get your testimony into the record.

Mr. Lucas, can you please state your name, business address and position for the record?

A. (Jay Lucas) My name is Jay Lucas. I'm an engineer with the Public Staff's Electric Division. My business address is 430 North Salisbury Street in Raleigh.

Q. Did you prepare and cause to be filed in this docket on August 23rd, 2019, testimony in question and answer form consisting of 93 pages, one appendix and 17 exhibits?

A. Yes.

Q. Do you have any additions or corrections to your testimony?

A. No.

Q. If I were to ask you those same questions today, would your answers be the same?

A. Yes.

MS. CUMMINGS: Chair Mitchell, I request that the testimony of Mr. Lucas, consisting of 93 pages, be copied into the record as if given orally from the stand and that his appendix and exhibits be identified as premarked.

CHAIR MITCHELL: Motion is allowed.

(Public Staff Lucas Exhibits 1 through 14, 16 and 17; and Public Staff Lucas

Confidential Exhibit 15 were premarked for identification.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

In the Matter of Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF JAY LUCAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

Testimony of Jay Lucas

On Behalf of the Public Staff

North Carolina Utilities Commission

August 23, 2019

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

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

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Commission the Public Staff's position on whether Dominion Energy North Carolina (DENC or the Company), should be permitted to recover the full cost of disposing of coal ash or coal combustion residuals (CCR) created at its coal-fired generating facilities, as presented in the general rate case filed by DENC in Docket No. E-22, Sub 562, on March 29, 2019.

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. The Public Staff recommends that 40 percent of the costs for CCR remediation should be paid by the Company's shareholders and the remaining 60 percent be paid by the Company's customers.

The Company invested $124.2 million in converting Chesterfield Units 3 through 6 from wet ash handling to dry ash handling. The Public Staff recommends that 20.7 percent or $25.7 million of the Company's investment in converting Chesterfield Units 3 and 4 be removed from rate base on a system-wide basis.

Also, the Public Staff recommends that the Company's records on depreciation expenses be more transparent and readily available.

My testimony is organized as follows:

- History of CCR Management
- CCR State and Federal Regulatory Framework
- Legal Actions against DENC
- Site Visits by the Public Staff
- Past Knowledge about the Environmental Impacts of the Storage of Coal Ash
- Company Responsiveness to Public Staff
- DENC's Environmental Compliance History for CCR

- Cost Recovery Requested by DENC
- Chesterfield CCR Wet to Dry Ash Conversion Project
- Public Staff's Recommendations on CCR
  - Equitable Sharing
  - Specific Disallowances
  - Insurance Coverage
- Depreciation Expenses

HISTORY OF CCR MANAGEMENT

Q. WHAT IS THE HISTORY OF CCR MANAGEMENT IN THE UNITED STATES?

A. Coal has been used as a fuel in electric generating plants since the late nineteenth century and has been a dominant fuel for many decades. In the 1960s and 1970s nuclear generation began to compete with coal-fired generation and beginning in 2010, natural gas-fired generation began to compete directly with coal-fired generation.

In the eastern United States, the availability of fresh water allowed electric generators to sluice the ash remaining in the boiler fire boxes after combustion (bottom ash) into ash storage ponds. Most coal ash constituents would settle to the bottom of the storage ponds, and cleaner wastewater from the top of the ponds would be discharged into a nearby natural water body.

The enactment of the Clean Air Act and subsequent air quality rules in the 1970s required treatment of the emissions released by coal-fired generating facilities. Air pollution control equipment such as electrostatic precipitators and later flue gas desulfurization (FGD) created solid waste streams that were often placed in the ponds with bottom ash. Fly ash is a waste collected from air pollution control equipment.

CCR is a collective term that includes bottom ash and fly ash created by the burning of coal. Some CCRs can be recycled into raw materials for the concrete industry. CCR from FGD is known as synthetic gypsum and can be directly used by the drywall industry.

Groundwater contamination and accidental releases of CCR brought attention to the storage and disposal of CCR and ultimately led to the creation of the Environmental Protection Agency's CCR Rule, which is presented later in my testimony.

CCR STATE AND FEDERAL Regulatory FRAMEWORK

Q. WHAT IS THE SIGNIFICANCE OF ENVIRONMENTAL REGULATIONS THAT APPLY TO CCR?

A. The Public Staff recommends an equitable sharing of coal ash remediation costs. One of the reasons for our equitable sharing recommendation is that DENC has culpability for non-compliance with environmental regulations that are meant to protect groundwater and surface water from contamination by CCR constituents. Additionally, DENC's past management of coal ash has resulted in a risk of future contamination that EPA and the Virginia legislature have determined requires costly new management and closure requirements. This is explained more fully in the testimony of Public Staff witness Maness. I note that the equitable sharing recommendation is not based on the imprudence standard, which would result in a 100% disallowance, but instead is based in part on DENC's culpability for failure to comply in some instances with environmental regulations for protection of groundwater and surface water. Therefore, a summary of those environmental regulations is important to understand how DENC has been culpable.

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR CCR.

A. CCR surface impoundments contain certain elements, such as arsenic, boron, cadmium, sulfate, vanadium, and others that can, when present in sufficient concentrations, pollute surface water, groundwater, and drinking water. CCRs were originally considered for federal regulation under the Resource Conservation and Recovery Act (RCRA) of 1976, but were exempted by the 1980 Bevill Amendment as a category of special waste requiring further study and assessment.[1] In 1993, the EPA determined that regulation of coal combustion wastes as hazardous waste under Subtitle C

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[1] The Bevill Amendment, one of the 1980 Solid Waste Disposal Act Amendments, exempted fossil fuel combustion waste from regulation as a hazardous waste under Subtitle C of RCRA until further study and assessment of risk could be performed. 42 U.S.C. § 6921(b)(3)(A).

of RCRA was not warranted.[2] In 2000, the EPA determined that coal combustion wastes should instead be regulated as non-hazardous solid waste under Subtitle D of RCRA.[3]

The EPA first proposed specific regulations for the disposal of CCRs in 2010, and conducted a nationwide assessment of CCR surface impoundments, ranking the safety of the impoundments on the basis of dam design, safety, and integrity.[4] The EPA finalized the CCR Rule in April 2015, regulating for the first time the disposal of CCRs as a non-hazardous solid waste.[5] The CCR Rule became effective on October 19, 2015.

The regulatory framework in place prior to the CCR Rule, including the Clean Water Act and state groundwater regulations, as well as more recent requirements, are all relevant to the review of the Company's coal ash management and disposal in this case.

Q. WHAT DOES THE CCR RULE REQUIRE?

A. The CCR Rule establishes minimum criteria that must be met by owners and operators of CCR surface impoundments and CCR landfills. The

[2] Final Regulatory Determination on Four Large-Volume Wastes from the Combustion of Coal by Electric Utility Power Plants, 58 Fed. Reg. 42,466 (Aug. 9, 1993).

[3] Notice of Regulatory Determination on Wastes From the Combustion of Fossil Fuels, 65 Fed. Reg. 32,214 (May 22, 2000).

[4] CCR Impoundment Assessment Reports, available at: https://archive.epa.gov/epawaste/nonhaz/industrial/special/fossil/web/html/index-4.html.

[5] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities, 80 Fed. Reg. 21,301 (Apr. 17, 2015).

minimum criteria consist of location restrictions, design and operating requirements, groundwater monitoring and corrective action, closure of certain units, post-closure care, recordkeeping, and posting of information to the internet for public access.

The CCR Rule applies to new and existing CCR surface impoundments and landfills,[6] as well as lateral expansions of such units. The rule also applies to inactive CCR surface impoundments, defined as impoundments that no longer received CCR on or after October 19, 2015, and that still contained both CCR and liquids on or after that date.[7] The Rule does not apply to CCR landfills that ceased receiving CCR prior to October 19, 2015.

Q. HOW DOES THE CCR RULE APPLY TO CCR LANDFILLS AND IMPOUNDMENTS IN VIRGINIA AND WEST VIRGINIA?

A. As originally drafted, the CCR Rule was self-implementing, in that it had no associated federal permitting program or delegation of permitting authority to the states.[8] Facilities must comply with the CCR Rule regardless of

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[6] Existing surface impoundments and landfills are those that received CCR both before and after October 19, 2015, or for which construction commenced prior to October 19, 2015, and received CCR on or after October 19, 2015. 40 C.F.R. 257.53.

[7] The CCR Rule as it was originally adopted did not apply to inactive surface impoundments at inactive facilities. That exemption was vacated and remanded by the U.S. Court of Appeals for the D.C. Circuit on August 21, 2018. Utility Solid Waste Activities Group v. EPA (USWAG), 901 F.3d 414 (D.C. Cir. 2018).

[8] The Water Infrastructure for Improvements to the Nation Act was signed into law on December 16, 2016, and authorizes the states to create permitting programs to implement or act in lieu of the CCR Rule. For non-participating states, the Act directed the EPA to implement a permitting program "subject to the availability of appropriations . . . ." Pub. L. No. 114-322, 130 Stat. 1628, Section 2301 (2016). Neither Virginia nor West Virginia have submitted permitting programs to the EPA for approval.

whether they are directed to do so by a state regulatory agency, and enforcement can take place pursuant to the citizen suit provision of RCRA.

On December 28, 2015, Virginia revised its Solid Waste Management Regulations (SWMR) to incorporate by reference the CCR Rule.[9] CCR landfills must continue to meet the state requirements for industrial landfills in addition to the requirements in the CCR Rule,[10] and both CCR landfills and new and existing impoundments must comply with Virginia's general solid waste permitting requirements.[11] Inactive impoundments must obtain a solid waste permit for closure and post-closure, and are subject to all the requirements of an existing CCR impoundment.[12]

CCR units (ash pond impoundments and landfills) at each of the Company's coal-fired power plants in Virginia—Bremo Power Station, Chesapeake Energy Center, Chesterfield Power Station, Clover Power Station, Possum Point Power Station, Yorktown, and Virginia City Hybrid Energy Center—are subject to the CCR Rule. Based on my understanding, EPA's CCR Rule is not applicable to the Stage I & II landfill at Clover Power Station, the historic pond and landfill at Chesapeake Energy Center, or the Chisman Creek site disposal pits that received CCR from the Yorktown Power Station.

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[9] 32 Va. Regs. Reg. 1591; 9 VAC 20-81-800.

[10] 9 VAC 20-81-810(A).

[11] 9 VAC 20-81-810(C).

[12] 9 VAC 20-81-810(D).

West Virginia has not incorporated the CCR Rule into its state regulations. The Company operates one coal-fired power plant in West Virginia—the Mount Storm Power Station. Each of the Company's CCR units at the Mount Storm facility are subject to the CCR Rule.

Q. WHAT IS THE CURRENT STATUS OF THE CCR RULE?

A. On June 14, 2016, the United States Court of Appeals for the D.C. Circuit ordered the vacatur of the "early closure" provisions of the CCR Rule.[13] The early closure provisions allowed inactive impoundments to avoid the substantive requirements of the rule (e.g., location criteria, design and operating requirements, groundwater monitoring and corrective action, and closure and post-closure care) if they closed by April 17, 2018. In response to the Court's vacatur of the early closure provision, the EPA on August 5, 2016, issued a direct final rule extending the deadline by which inactive surface impoundments must come into compliance with the substantive requirements of the CCR Rule.[14] These revisions were incorporated into Virginia's SWMR in May 2017.[15]

The EPA proposed additional revisions to the CCR Rule in March 2018,[16]

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[13] Util. Solid Waste Activities Grp. v. EPA, 2016 U.S. App. LEXIS 24320.

[14] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Extension of Compliance Deadlines for Certain Inactive Surface Impoundments; Response to Partial Vacatur, 81 Fed. Reg. 51,802 (Aug. 5, 2016). The direct final rule took effect on October 4, 2016.

[15] 33 Va. Regs. Reg. 1920.

[16] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One); Proposed Rule, 83 Fed. Reg. 11,584 (Mar. 15, 2018).

and in July 2018 issued a rulemaking finalizing three of the proposed revisions.[17] This "Phase One, Part One" rulemaking adopted alternative performance standards where an authorized state or the EPA is acting as a permitting authority, set groundwater protection standards for four constituents that do not have maximum contaminant levels (MCLs), and provided certain units that are triggered into closure by the CCR Rule additional time to stop receiving waste and begin closure. In March 2019, however, the United States Court of Appeals for the D.C. Circuit remanded without vacatur at the EPA's request this "Phase One, Part One" rulemaking.[18] The compliance deadlines established by the remanded rule will remain in place until the EPA takes further action.

On August 21, 2018, the United States Court of Appeals for the D.C. Circuit vacated the portions of the CCR Rule that: allowed for continued operation of unlined impoundments; classified clay-lined impoundments as lined; and, exempted inactive impoundments at inactive facilities from regulation.[19] It also granted the EPA's request for voluntary remand without vacatur of provisions concerning coal residuals piles, beneficial reuse, and alternative groundwater protection standards.

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[17] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One), 83 Fed. Reg. 36,435 (July 30, 2018).

[18] Waterkeeper Alliance, Inc. v. EPA, 2019 U.S. App. LEXIS 7443.

[19] Utility Solid Waste Activities Group v. EPA (USWAG), 901 F.3d 414 (D.C. Cir. 2018).

Most recently, on August 14, 2019, the EPA published additional proposed revisions to the CCR Rule.[20] Its proposal would: (1) remove the 12,400-ton threshold for fill projects over which it requires that a user must make an environmental demonstration, instead requiring "specific location-based criteria"; (2) allow "temporary accumulations" of CCR without an enclosed structure; and (3) revise the requirements for annual groundwater monitoring reports to make those reports more transparent and establish a standardized format.

Q. HAS THE VIRGINIA LEGISLATURE PASSED ANY LAWS RELATED TO COAL ASH?

A. Yes. In April 2017, Senate Bill 1398 was signed into law.[21] The Act required owners or operators of CCR impoundments located within the Chesapeake Bay watershed (Bremo Power Station, Chesapeake Energy Center, Chesterfield Power Station, and Possum Point Power Station) to conduct an assessment of each unit, addressing items such as groundwater and surface water pollution, corrective measures to resolve such pollution, excavation, beneficial reuse, and the long-term safety of the impoundment. The law also delayed the issuance of any permit for the closure of a CCR unit until May 1, 2018, or a later date determined by the General

[20] Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Enhancing Public Access to Information; Reconsideration of Beneficial Use Criteria and Piles, 84 Fed. Reg. 40353 (Aug. 14, 2019).
[21] 2017 Va. Acts 817.

Assembly.[22]

The following year, in March 2018, Senate Bill 807 was signed into law.[23] The Act extended the moratorium on closure permits until July 1, 2019, for CCR units within the Chesapeake Bay watershed that no longer receive CCRs. The extended moratorium did not apply to any units where CCRs had already been moved to another impoundment on-site, were being removed from an impoundment, or were being processed for recycling or beneficial use. The Act also required the issuance of an RFP for the recycling and beneficial use of CCR at the Bremo, Chesapeake, Chesterfield, and Possum Point power stations, as well as the development of a business plan based on those submissions.

Lastly, in March 2019, Virginia Senate Bill 1355 (SB 1355 or CCR Excavation Act) was signed into law.[24]The legislation mandated closure by excavation of all CCR units at the Bremo, Chesapeake, Chesterfield, and Possum Point power stations that ceased accepting CCR prior to July 1, 2019. The owner or operator of each such unit must complete closure within 15 years of initiating the closure process at that unit. It also required beneficial reuse of a total of at least 6.8 million cubic yards of the excavated CCR from at least two of the sites. The owner or operator of each CCR unit required to close by excavation is also required to submit a report every two

[22] 2017 Va. Acts 817.
[23] 2018 Va. Acts 632.
[24] 2019 Va. Acts 651.

years beginning no later than October 1, 2022. The report must include closure plans and progress, as well as an analysis of any proposals received for beneficial reuse.

Q. PLEASE SUMMARIZE THE FEDERAL REGULATORY FRAMEWORK FOR SURFACE WATER.

A. The Clean Water Act (CWA) was enacted in 1972 to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters."[25] The CWA prohibits the discharge of pollutants from point sources[26] into a water of the United States, unless the discharge is authorized in accordance with a National Pollutant Discharge Elimination System (NPDES) permit.[27] In 1974, the EPA promulgated the Steam Electric Power Generating Effluent Guidelines and Standards (ELG Rule), which are incorporated into NPDES permits and set effluent limitations on wastewater discharges from power plants.[28] Under a facility's NPDES permit, wastewater from coal ash impoundments that is discharged must meet the conditions prescribed in the permit.

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[25] 33 U.S.C. § 1251(a).

[26] A point source is defined as "any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft, from which pollutants are or may be discharged." 33 USCS § 1362(14).

[27] 13 U.S.C. § 402.

[28] 40 C.F.R. Part 423.

Q. WHAT IS THE CURRENT STATUS OF THE ELG RULE?

A. On November 3, 2015, under the authority of the CWA, the EPA substantively amended the ELG Rule.[29] The amendments contained limitations and standards on various waste streams at steam electric power plants. The CCR Rule and the amendments to the ELG Rule are designed to coordinate compliance deadlines to allow utilities to make operational decisions taking into account the requirements of both rules. The ELG Rule had the potential to require cessation of certain operations due to requirements to utilize Best Available Technology Economically Achievable (BAT) for FGD wastewater and bottom ash wastewater transport. Compliance deadlines, however, have been delayed due to legal and administrative challenges to the rule.

In March and April of 2017, two administrative petitions were filed asking the EPA to reconsider the ELG Rule. The EPA granted the petitions to reconsider and, on September 18, 2017, published a notice postponing the earliest compliance deadlines for the BAT for bottom ash transport wastewater and FGD wastewater for two years (from November 2018 to November 2020). The postponement was "intended to preserve the status quo for FGD wastewater and bottom ash transport water until EPA

[29] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67,837 (Nov. 3, 2015).

completes its next rulemaking concerning those wastestreams."[30]

Most recently, on April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit vacated portions of the 2015 ELG Rule applicable to legacy wastewater[31] and leachate.[32] The Court found that the BAT set for legacy wastewater and leachate were outdated and inferior to other available technologies, and remanded those provisions back to the EPA.

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR SURFACE WATER IN VIRGINIA.

A. The Virginia Department of Environmental Quality (VDEQ) is authorized by the EPA to administer the NPDES program in Virginia, and issues Virginia Pollutant Discharge Elimination System (VPDES) permits under 9 VAC 25-31-10 et seq. VPDES permits contain conditions necessary to meet effluent limitations and standards promulgated under the CWA, as well as those necessary to achieve state water quality standards established under Chapter 260 of the Virginia Water Control Board's (VWCB's) regulations.[33] As discussed below, VPDES permits may also contain groundwater monitoring requirements.

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[30] Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 82 Fed. Reg. 43,494 (Sept. 18, 2017).

[31] Legacy wastewater refers to wastewater from five streams—FGD, fly ash, bottom ash, flue gas mercury control, and gasification wastewater—that is generated prior to the first compliance deadline (November 1, 2020).

[32] Southwestern Elec. Power Co. v. United States EPA, 920 F.3d 999 (Apr. 12, 2019).

[33] 9 VAC 25-31-220.

Virginia has also adopted an anti-degradation policy for surface waters. The policy provides that surface water quality must be maintained at a level that protects existing uses, with three tiers of protection: (1) "[a]s a minimum, existing uses and the level of water quality necessary to protect those uses must be maintained and protected"; (2) where water quality exceeds water quality standards, "that quality shall be maintained and protected" except where "necessary to accommodate important economic or social development"; and (3) where surface waters "provide exceptional environmental settings and exceptional aquatic communities or exceptional recreational opportunities," no new, additional, or increased pollution is allowed.[34]

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR SURFACE WATER IN WEST VIRGINIA.

A. The West Virginia Department of Environmental Protection (West Virginia DEP) is authorized by the EPA to administer the NPDES program in West Virginia, and issues NPDES permits under W. Va. CSR 47-10-1 et seq. NPDES permits contain conditions necessary to meet effluent limitations and standards promulgated under the CWA, as well as those necessary to achieve state water quality standards established under W. Va. CSR 47-2-1 et seq. As discussed below, NPDES permits also require facilities to develop a Groundwater Protection Plan.

[34] 9 VAC 25-260-30.

West Virginia has also adopted an anti-degradation policy for state waters. The policy provides that water quality must be maintained at a level that protects existing uses, with three tiers of protection: (1) maintenance and protection of existing uses and the conditions necessary to protect those uses; (2) maintenance and protection for "high quality" waters where water quality exceeds water quality standards, allowing degradation only where water quality will remain adequate to protect existing uses fully; and (3) for "outstanding national resource waters," prohibits "[a]ny new or expanded regulated activity that would degrade" those waters.[35]

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR GROUNDWATER IN VIRGINIA.

A. Virginia Code § 62.1-44.15(3a) directs the VWCB to establish water quality standards applicable to state waters.[36] The VWCB first adopted groundwater standards in 1977.[37] 9 VAC 25-280-10 et seq. contains groundwater standards that are applicable statewide,[38] as well as standards and criteria specific to each of four physiographic provinces with unique groundwater characteristics.[39]

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[35] W. Va. CSR 60-5-1 et seq.; W. Va. CSR 47-2-4.

[36] VA Code Ann. § 62.1-44.3 defines state waters as "all water, on the surface and under the ground, wholly or partially within or bordering the Commonwealth or within its jurisdiction . . . ."

[37] Guidance for VPDES and VPA Permit Ground Water Monitoring Plans (Sept. 30, 1998), *available at* https://www.deq.virginia.gov/Portals/0/DEQ/Water/Guidance/982010.pdf.

[38] 9 VAC 25-280-40.

[39] 9 VAC 25-280-50, 9 VAC 25-280-70.

Virginia also has an anti-degradation policy for groundwater, which provides that "natural quality shall be maintained" for constituents found at a level lower than the limit set by groundwater standards, as well as for those constituents that do not have applicable groundwater standards. Further, if the concentration of any constituent exceeds groundwater standards, "no addition of that constituent to the naturally occurring concentration shall be made." Variances are allowed in limited situations in which a change in natural quality is necessary for economic or social development.[40]

VDEQ may, in its discretion, include groundwater monitoring requirements in VPDES permits. In 1998, VDEQ issued a guidance document for determining when groundwater monitoring would be required in VPDES permits.[41] A chart depicting which of the Company's CCR units were subject to groundwater monitoring requirements under a VPDES permit from the years 2000 through 2018 is attached as **Lucas Exhibit 1**. Groundwater monitoring requirements and parameters contained within VPDES permits are site-specific. In general, upon detection of an increase over background levels for a given contaminant, the facility must enter into an extended monitoring phase. If, during this monitoring phase, any contaminant continues to exceed the background level, the facility must add additional monitoring wells and enter the assessment monitoring phase. Exceedances

[40] 9 VAC 25-280-30.
[41] Guidance for VPDES and VPA Permit Ground Water Monitoring Plans (Sept. 30, 1998).

during the assessment monitoring phase will require a Corrective Action Plan and Risk Assessment.

Virginia's SWMRs also require groundwater monitoring for solid waste landfills.[42] The regulations require facilities with solid waste permits to first determine background levels for detected constituents. The determination of background levels during this initial phase of monitoring is limited to the constituents shown in Table 3.1, Column A of the regulation. Subsequently, if there occurs a statistically significant increase[43] over the background level for any constituent, the facility must implement Phase II monitoring and establish Groundwater Protection Standards. During the Phase II monitoring program, the scope of monitoring is expanded to all detected Column B constituents. If, in later sampling, exceedances of these Groundwater Protection Standards are found, the facility must undertake corrective action.[44] For constituents for which an MCL has been adopted under the Safe Drinking Water Act,[45] the MCL for that constituent will be used as the Groundwater Protection Standard, except where the background level is greater than the MCL, in which case the background level can be substituted for use as the Groundwater Protection Standard.[46]

[42] 9 VAC 20-81-250(C). Groundwater monitoring is required for new and existing landfills, with the exception of landfills that were closed prior to December 21, 1988.

[43] 40 CFR 257.93(f) specifies the criteria for determining when a statistically significant increase has occurred.

[44] 9 VAC 20-81-260.

[45] 42 USC 300 (1974).

[46] 9 VAC 20-81-250(A)(6).

For constituents for which there is no MCL, either background levels or risk-based alternatives are used.

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR GROUNDWATER IN WEST VIRGINIA.

A. The West Virginia Groundwater Protection Act[47] went into effect in 1991 and authorizes the West Virginia DEP to establish water quality standards applicable to state waters. W. Va. CSR 47-12-1 et seq. contains the state's groundwater quality standards.[48]

NPDES permits issued by West Virginia DEP require facilities such as electric power generation stations to develop a Groundwater Protection Plan (GPP).[49] GPPs must provide for quarterly inspections and include an inventory of all operations that "may reasonably be expected to contaminate groundwater."[50] Existing impoundments must be evaluated for their potential to cause contamination, and action must be taken to eliminate, "to the degree practicable," that potential where it exists, and to address any contamination that has already occurred. New impoundments must be

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[47] W. Va. Code 22-12-1 et seq.

[48] With respect to certain steam electric generating facilities, the legislature may grant variances allowing exceedances of existing groundwater quality standards for ash disposal sites.[48] The regulation allowing for variances cites a study that concluded that nickel and selenium were consistently exceeding groundwater quality standards at ash disposal areas.[48] Therefore, the West Virginia regulations establish groundwater protection standards for variance-applicable areas for ash disposal sites at nine steam electric generating facilities within the state. W. Va. CSR 47-57A-1. Mount Storm is not eligible for such a variance, but can receive a variance allowing exceedances of existing groundwater quality standards for its coal storage site only. W. Va. CSR 47-57B-1.

[49] W. Va. CSR 47-58-1 et seq.

[50] W. Va. CSR 47-58-4.

designed to prevent groundwater contamination. Facilities may be required to install groundwater monitoring wells on a case-by-case basis. Where it is determined that contamination is occurring, the facility will work with West Virginia DEP to enter into a schedule of compliance.

West Virginia's solid waste regulations also address groundwater quality.[51] Specifically, permittees must install groundwater monitoring systems and conduct Phase I detection monitoring for the constituents listed in Appendix I or constituents prescribed by West Virginia DEP.[52] If samples indicate that there is an statistically significant increase (SSI) over background for one or more of the Appendix I constituents or prescribed constituents, the permittee must implement the Phase II Assessment Monitoring program. In assessment monitoring, the facility must include Appendix II constituents in its sampling and develop background levels and a groundwater protection standard (GPS) for all detected constituents. For constituents for which an MCL has been adopted under the Safe Drinking Water Act or a groundwater standard has been set in W. Va. CSR 47-12, that standard will be used as the GPS. Where the background level is greater than the MCL or state standard, or where there is no applicable MCL or state standard, the

[51] W. Va. CSR 33-1-1.

[52] "For coal combustion by-product facilities, the monitoring parameters must consist of some combination of the following: pH, temperature, alkalinity, hardness, total dissolved solids, total suspended solids, specific conductance, total organic carbon, calcium, magnesium, sodium, iron, manganese, aluminum, chloride, sulfate, arsenic, copper, nickel, selenium, zinc, barium, mercury, total and hexavalent chromium, lead, boron, molybdenum, cadmium, and vanadium." W. Va. CSR 33-1-4.

background level or a health-based level can be substituted for use as the GPS. If, during Phase II, any constituents are detected at statistically significant levels above the GPS, the facility must install additional monitoring wells and initiate an assessment of corrective measures.

Q. PLEASE SUMMARIZE THE REGULATORY FRAMEWORK FOR GROUNDWATER UNDER THE CCR RULE.

A. The CCR Rule is designed to address releases to groundwater from CCR waste disposal units. Pursuant to the CCR Rule, Groundwater Protection Monitoring must be performed at the waste boundary. The standards in the CCR Rule are based on national MCLs established by the EPA for drinking water quality pursuant to the Safe Drinking Water Act. Appendix III of the CCR Rule lists seven parameters — boron, calcium, chloride, fluoride, pH, sulfate, and total dissolved solids — that must be monitored semi-annually. These constituents are primary indicators of potential contamination from ash basins, and if discovered at certain levels, they trigger additional testing requirements for more constituents.

In particular, if it is determined that there has been a SSI over the established background level for any of the Appendix III parameters, then Groundwater Assessment Monitoring must begin within 90 days. The Assessment Monitoring shall include the Appendix III and Appendix IV substances and establish a groundwater protection standard for each Appendix IV constituent. Appendix IV of the CCR rule lists constituents including antimony, arsenic, barium, beryllium, cadmium, chromium, cobalt, fluoride, lead, lithium, mercury, molybdenum, selenium, thallium, and Radium 266-228 combined. The groundwater protection standard is to be the maximum contaminant level or background level, whichever is higher. If any Appendix IV constituents are determined to have an SSI in exceedance of the groundwater protection standard, then the nature and extent of the release must be characterized, additional monitoring wells must be installed, and assessment of corrective action must be started.

ENVIRONMENTAL LEGAL ACTIONS AGAINST THE COMPANY

PLEASE SUMMARIZE CCR-RELATED FEDERAL AND STATE LEGAL ACTIONS AGAINST THE COMPANY.

Sierra Club v. Virginia Electric and Power Company, US District Court for the Eastern District of Virginia, 2:15-CV-112 and US Court of Appeals for the Fourth Circuit, No. 17-1895

On March 19, 2015, the Southern Environmental Law Center filed a federal citizen suit on behalf of the Sierra Club for violations at the Chesapeake Energy Center. The complaint alleged that groundwater contamination from the coal ash basins and landfill was reaching navigable waters, rendering the ash basins and landfill "point sources" under the Clean Water Act and constituting an unpermitted discharge. The complaint also alleged violations by the Company of its NPDES permit based on groundwater contamination.

The US District Court for the Eastern District of Virginia found that arsenic was leaching from the coal ash impoundments and landfill into the groundwater and then reaching surface waters, constituting an unpermitted discharge from point sources.[53] The Court found the Company liable for ongoing Clean Water Act violations, while ruling against Southern Environmental Law Center on the claims relating to the Company's NPDES permit.

On September 12, 2018, the Fourth Circuit affirmed the District Court's finding that arsenic was reaching surface waters via groundwater, and agreed with the District Court that the CWA regulates discharges into navigable waters via groundwater if there is a direct hydrological connection between the groundwater and navigable waters. The Court, however, concluded that the coal ash basins and landfill did not qualify as point sources, and therefore reversed the District Court's finding of Clean Water Act violations.[54] It also affirmed the District Court's holding that the Company was not in violation of its NPDES permit.

<u>James River Association, City of Richmond, VA Circuit Court (no case number)</u>

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[53] <u>Sierra Club v. Va. Elec. & Power Co.</u>, 247 F. Supp. 3d 753 (E.D. Va. 2017).

[54] <u>Sierra Club v. Va. Elec. & Power Co.</u>, 903 F.3d 403 (4th Cir. 2018). The Ninth Circuit in 2018 held that the conveyance of a pollutant from a point source to navigable waters by groundwater constituted a discharge under the Clean Water Act and required a NPDES permit. <u>Hawai'i Wildlife Fund v. Cty. of Maui</u>, 886 F.3d 737 (9th Cir. 2018). The Ninth Circuit's decision was appealed and is currently pending before the U.S. Supreme Court in <u>Cty. Of Maui v. Hawai'i Wildlife Fund</u>, Docket No. 18-260.

On February 9, 2016, the James River Association (JRA) filed a Notice of Appeal challenging the decision of the VWCB and VDEQ to issue a modified VPDES permit (Permit No. VA0004138) that would allow the discharge of wastewater from the Bremo Power Station. On March 7, 2016, the Company and JRA entered into a settlement agreement whereby JRA would not file its appeal, and the Company would submit an amended engineering report to VDEQ that establishes two levels of wastewater treatment: (1) a guaranteed minimum treatment that would apply to all coal ash wastewaters, and (2) an enhanced treatment that would apply to wastewaters that, after receiving the guaranteed minimum treatment, still exceed predefined pollutant concentrations. Sampling to determine whether treated wastewater requires enhanced treatment would be collected every four hours. The settlement also required the Company to limit its wastewater discharge rate to 1,500 gallons per minute, and to conduct regular fish tissue sampling in the James River until June 2018.

Prince William County Board of County Supervisors, City of Richmond, VA Circuit Court (no case number)

On February 11, 2016, the Prince William County Board of County Supervisors (PWC) filed a Notice of Appeal challenging the decision of the VWCB and VDEQ to issue a modified VPDES permit (Permit No. VA0002071) that would allow the discharge of wastewater from Pond D at the Possum Point Power Station. On March 8, 2016, the Company and

PWC entered into a settlement agreement whereby PWC would not file its appeal, and the Company would submit an amended engineering report to VDEQ that establishes two levels of wastewater treatment: (1) a guaranteed minimum treatment that would apply to all coal ash wastewaters, and (2) an enhanced treatment that would apply to wastewaters that, after receiving the guaranteed minimum treatment, still exceed predefined pollutant concentrations. Sampling to determine whether treated wastewater requires enhanced treatment would be collected every hour. The settlement also required the Company to retain independent contractors to perform the effluent compliance sampling required under the VPDES permit.

Potomac Riverkeeper Network v. State Water Control Board, City of Richmond, VA Circuit Court, CL 16-913

On February 26, 2016, the Potomac Riverkeeper Network filed an appeal challenging the decision of the VWCB and VDEQ to issue a modified VPDES permit (Permit No. VA0002071) that would allow the discharge of wastewater from Pond D at the Possum Point Power Station. The Potomac Riverkeeper alleged that: (1) the initial fact sheet accompanying the draft permit did not contain adequate information about the type and quantity of discharge, and erroneously stated that all wastewater at the facility had been transferred to Pond D and would be subject to the permit modifications, when the company had already discharged 30 million gallons of wastewater from Pond E into Quantico Creek; (2) the Board and VDEQ violated the CWA and state regulations when they failed to conduct a case-specific analysis to determine technology-based effluent limitations for the discharge from Pond D; (3) the modified permit would allow discharges that would contribute to an existing impairment in Quantico Creek; and (4) the modified permit would allow discharges that could potentially exceed water quality standards in Maryland waters. On November 2, 2016, the Circuit Court upheld the permit modifications and dismissed the appeal.

<u>State of Maryland v. State Water Control Board, City of Richmond, VA Circuit Court, CL 16-1241-3</u>

On March 14, 2016, the State of Maryland filed an appeal challenging the decision of the VWCB and VDEQ to issue a modified VPDES permit (Permit No. VA0002071) that would allow the discharge of wastewater from Pond D at the Possum Point Power Station. The State of Maryland alleged that the modified permit was not protective enough of water quality in the Potomac River watershed and could have a negative impact on human health and aquatic life. On June 16, 2016, after the Company agreed to stricter testing standards, the State of Maryland voluntarily withdrew its appeal.

<u>West, Brian v. Virginia Electric and Power Company, and Morrow, Daniel et al. v. Virginia Electric and Power Company, Prince William County, VA Circuit Court, CL17-003149 and CL17-003151</u>

On April 11, 2018, two complaints were filed in Prince William County Circuit Court on behalf of property owners living adjacent to the Company's Possum Point Power Station. The complaints contain claims for trespass, nuisance, and negligence, and allege that groundwater contamination from the plant's coal ash ponds contaminated the Plaintiffs' property and potable wells. The complaints allege that this groundwater contamination resulted in damages including diminution of property value, remediation costs, and costs associated with alternate water supplies. The Company filed responses on May 2, 2018. This litigation is ongoing.

SITE VISITS BY THE PUBLIC STAFF

Q. HAS THE PUBLIC STAFF HAD THE OPPORTUNITY TO VISIT AND TOUR THE DENC CCR BASIN SITES?

A. Yes. On May 14, 2019, the Public Staff visited the Bremo and Chesterfield sites. On June 6, 2019, the Public Staff visited the Possum Point site. These three sites, Bremo, Chesterfield, and Possum Point, plus Chesapeake are some of DENC's oldest coal-fired stations and are subject to the CCR Excavation Act. **Lucas Exhibit 2** shows photographs of each of the impoundments taken at the sites.

At each site, the Public Staff met with key plant personnel and DENC witness Jason Williams, Director of Environmental Services for Dominion Energy Services, Inc. Those employees gave site-specific overviews regarding the status of ash removal and activities to achieve CCR and

Virginia regulatory compliance and timelines going forward. The passage of the CCR Excavation Act created uncertainty as to the continuation of DENC's present closure activities and the future cost of compliance.

The Public Staff asked questions at each site's main office or meeting area and then toured the CCR areas. At all three sites, we observed CCR consolidation and/or temporary closure activities and associated infrastructure; this included dewatering and wastewater treatment systems, landfills, rail, and other transportation infrastructure.

The Bremo plant was converted to natural gas in 2014. The East Ash Pond and West Ash Pond are classified as "inactive CCR surface impoundments" under the CCR Rule and DENC began consolidation activities into the North Ash Pond on April 20, 2015. At the time of our site visit, the East Ash Pond and West Ash Pond were completely or nearly completely excavated and still required some additional dewatering and grading for stormwater management. A specialized wastewater treatment system was on-site by lease and operated by contractors to remove constituents from contact water from dewatering activities and manage stormwater prior to discharge under DENC's VPDES permit. VDEQ issued a solid waste facility Permit Number 618 on June 5, 2019, to govern the closure of the East Ash Pond and West Ash Pond. The North Ash Pond was being graded and temporarily capped with an impermeable cover.

The Chesterfield plant is an active coal-fired facility. In 2017, DENC made changes to transition from wet sluicing ash with storage in the Upper Ash Pond and Lower Ash Pond to dry ash handling, including completion of a bridge and an onsite lined landfill. At the time of our site visit, the Upper Ash Pond had the appearance of a capped landfill, mounded with vegetative growth, and the Lower Ash Pond was being graded and temporarily capped with an impermeable cover. DENC installed a specialized wastewater treatment system to remove potential pollutants from stormwater and wastewater from dewatering activities prior to discharge under DENC's VPDES permit.

The Possum Point facility was converted to natural gas in 2003. The Ponds A, B, C, and E are classified as "inactive CCR surface impoundments" under the CCR Rule and DENC began consolidation activities into Pond D in June 2015. At the time of our site visit, Ponds A, B, C, and E were completely or nearly completely excavated and still required some additional dewatering and/or grading for stormwater management. DENC leased a specialized wastewater treatment system and returned it to the vendor until greater certainty pertaining to closure of Pond D was established. Pond D was functioning as both an impoundment for CCR materials and contact water collected from the dewatering activities at Ponds A, B, C, and E. VDEQ issued a solid waste facility Permit Number 617 on June 13, 2019, to govern the closure of Ponds A, B, C, and E.

It is the Public Staff's understanding that the closure plans and solid waste permits for these three sites will have to be resubmitted and approved by

VDEQ to excavate the consolidated ponds in compliance with the CCR Excavation Act.

Q. WHAT IS THE STATUS OF CCR SITE REMEDIATION AT THE SITES NOT VISITED BY THE PUBLIC STAFF?

A. The Company is conducting groundwater monitoring at all of the sites described below.

The Chesapeake Power Station ceased operations of the coal-fired generation units on December 31, 2014, and the units have been decommissioned. The CCR storage areas consist of the Bottom Ash Pond and a landfill constructed on top of the historic ash pond. The Company has agreed to groundwater monitoring and closure for the three areas consistent with the CCR Rule standards in a Memorandum of Agreement with the Commonwealth of Virginia, dated November 13, 2018. Some CCR was removed from the Bottom Ash Pond for recycling between October 16, 2017, and March 9, 2018. The historic ash pond, landfill, and Bottom Ash Pond are to be excavated in compliance with the CCR Excavation Act.

The Clover Power Station began coal-fired generation in 1995 and has a dry ash handling system. There are two sedimentation basins, the FGD North and South Sludge Ponds, which are dredged periodically. The coal ash and FGD waste are disposed of in the Stage III Landfill and previously in the Stage I and II Landfill sections. Beginning in 2017, the Sludge Ponds were retrofitted with CCR Rule complaint liner systems.

The Mount Storm Power Station is an active coal-fired facility in West Virginia and has a dry ash handling system. The dry fly ash and bottom ash are disposed of in the onsite Phase B landfill. The Low Volume Waste Settling Ponds collect wastewater that may have come in contact with CCR. Beginning in 2016, each of the five ponds are either being retrofitted or dewatered, excavated, and closed. The FGD waste is either beneficially reused in mine reclamation projects or in manufacturing of Portland Cement, or disposed of in the Phase B Landfill.

Virginia City Hybrid Energy Center (VHEC) is an active coal-fired facility that was commissioned in 2012 with dry fly ash and bottom ash handling. The coal ash is disposed of in the Curley Hollow CCR Landfill, which has a synthetic liner and leachate collection and treatment system.

The Yorktown Power Station has a remaining active oil-fired unit, however, the remaining coal-fired generation was retired in 2017. A majority of the onsite landfill was capped and closed in 2017 and the remainder will be closed in 2019.

PAST KNOWLEDGE ABOUT THE ENVIRONMENTAL IMPACTS OF THE STORAGE OF COAL ASH

Q. ARE YOU SPONSORING ANY ADDITIONAL TESTIMONY OR EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. My testimony also incorporates by reference the Public Staff's Exhibits in the Direct Testimony of Public Staff Engineer Charles Junis, Exhibit Nos. 3, 4, and 6-10, filed in Docket No. E-7, Sub 1146, on January 24, 2018, which in combination with pages 34 through 53 of his testimony, address the history of known environmental impacts associated with the storage and management of coal ash in unlined surface impoundments.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF HISTORICAL DOCUMENTS ON CCR RISKS.

A. In general, the exhibits are historic academic, industry, and regulatory documents that show a growing awareness of environmental issues, and, more specifically, research, development, and promulgation of new environmental regulations with direct impacts on the electric power generating utility industry, including the Clean Air Act of 1970, Clean Water Act of 1972, Dam Safety Act of 1972, Safe Drinking Water Act of 1974, and Resource Conservation and Recovery Act of 1976. The documents are not a comprehensive review of the state of scientific and engineering knowledge about the risks of groundwater and surface water contamination from ash basins; it is a selection of documents that the Public Staff believes demonstrates an evolving body of scientific knowledge over more than 50 years concerning and acknowledging the risks of environmental contamination resulting from storing coal ash in unlined impoundments and the feasibility of alternative methods of coal ash management.

These documents demonstrate that, by the early 1980s, the electric generating industry knew or should have known that the wet storage of CCR in unlined surface impoundments was detrimental to the quality of surrounding groundwater and surface water. This knowledge was evident in the 1979 report entitled "Health and Environmental Impacts of Increased Generation of Coal Ash and FGD Sludges" written by a research group from Arthur D. Little, Inc., and the Industrial Environmental Research Laboratory of the EPA. The report stated that FGD sludge and coal ash waste stored in "[w]et impoundments have the potential for contributing directly to groundwater contamination" (Docket No. E-7, Sub 1146, Testimony of Charles Junis Exhibit No. 7, NEP Study, p 153). It further concluded that "areas using lined impoundments would tend to minimize the potential effects on ground and surface waters" (Id. at p 155).

This important realization was reinforced by the 1982 "Manual for Upgrading Existing Disposal Facilities" published by the Electric Power Research Institute (EPRI). The manual states "[b]ecause ponds by design maintain a hydraulic head of standing water above the settled waste, there is little that can be done to eliminate leachate generation and migration" and "[f]or this reason, ponding has fallen into disfavor with EPA as a permanent method of waste disposal." (Docket No. E-7, Sub 1146, Testimony of Charles Junis Exhibit No. 8, pp 8-2 and 8-3). "While groundwater can be protected and leachate generation can be minimized with sound engineering design and site operation, monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of a safe disposal practice." (Id. at p 4-19) The earliest monitoring by the Company began in December 1983.

The 1988 Report to Congress by the EPA (1988 EPA Report) [55] was an extensive review of the quantities, physical and chemical characteristics, and collection and storage methods of waste products from coal-fired electric generation. The report describes coal combustion waste disposal and re-use methods and technological advancements, and assesses the use of each across the industry. At the time of the report, regulations on impoundments or ponds were becoming more restrictive, which was increasing the cost and decreasing the use of impoundments. The use of liners, leachate collection systems, and groundwater monitoring had increased in the years leading up to the publication of the 1988 EPA Report. The report states the following in the Executive Summary:

> Only about 25 percent of all facilities have liners to reduce off-site migration of leachate, although 40 percent of the generating units built since 1975 have liners. Additionally, only about 15 percent have leachate collection systems; about one-third of all facilities have ground-water monitoring systems to detect potential leachate problems. Both leachate collection and ground-water monitoring systems are more common at newer facilities.

1988 EPA Report, p ES-3.

Exhibits 2-7 (Id. at 2-17) and 4-4 (Id. at 4-19) of the report are a 1985 map of EPA regions with a pie chart of electricity generation by fuel type and a 1985 table of CCR waste management facilities by EPA region. It is worth

[55] *Available at* https://www.epa.gov/sites/production/files/2015-08/documents/coal-rtc.pdf (last visited August 15, 2019).

noting that EPA Region 4, at nearly a 4:1 ratio, was the only region to use more surface impoundments than landfills.[56] Region 3, contiguous to the north and including Virginia and West Virginia, was nearly the opposite with a ratio greater than 3:1 of landfills to surface impoundments. However, in 1985, DENC owned and/or operated 10 ash ponds and 2 landfills. Exhibit 4-6 is a table of the quantity of liners installed for leachate control at utility waste management facilities by EPA region. (Id. at p 4-31).

It is the Public Staff's opinion that industry leaders, prior to the recent nationwide trend towards development, strengthening, and enforcement of regulations for storage and disposal of CCR, were at least partly responsible for setting the "industry standard" for waste disposal, which they cite for past decisions regarding coal ash management. DENC (as part of Dominion Energy), Duke Energy, and their predecessors in North Carolina, Virginia, and West Virginia, were industry leaders that failed to improve and modernize their practices despite the available knowledge described in my testimony above. In particular, as publications from 1979 and later warned of the risks of CCR constituents leaching into groundwater from unlined storage ponds, DENC and other utilities should have installed comprehensive groundwater monitoring well networks to determine if the risk was materializing at their ash ponds.

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[56] Duke Energy Carolinas' 17 ash basins, all of which were constructed no later than 1980, and Duke Energy Progress 19 ash basins, are located in Region 4.

Q. WHAT EVALUATIONS AND CONCLUSIONS HAS DENC HISTORICALLY MADE PERTAINING TO POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH THE STORAGE AND MANAGEMENT OF CCR AT POSSUM POINT?

A. The VWCB issued an NPDES permit to Virginia Power for its Possum Point facility effective April 26, 1985. It is my understanding that according to this NPDES permit, which was not produced in discovery, Virginia Power was required to conduct groundwater monitoring in the vicinity of Possum Point Ponds D and E. According to a Special Order, dated April 14, 1987 **(Lucas Exhibit 3)**, "[t]he initial groundwater monitoring data indicate[d] violations of groundwater standards" and the "Board orders and Virginia Power agrees to study the groundwater in order to define the extent and nature of the contamination and to evaluate the remediation alternatives." (Id. at p 1) Around this time, DENC was also considering expanding and reactivating Pond D at Possum Point. In combination, the Company and its consultants performed a number of studies summarized below:

August 1986 Groundwater Study

The purpose of the report was to present "the results of a groundwater study performed for the proposed expansion of the ash disposal facility at the Possum Point Power Station." (p 1-1) With the expansion of Pond D, the Company planned for ash to be "periodically (approximately every 7 years) dredged from Ash Pond E and placed in Ash Pond D." (p 1-1) The consultant, Dames & Moore, evaluated the groundwater quality effects from the existing Pond E by reviewing effluent data and groundwater monitoring data from five downgradient wells. It was observed that "the groundwater exceeded the [National Primary Drinking Water Standards] for cadmium, chromium, and lead" and "Ash Pond E effluent exceeded the National Primary Drinking Water Standards for selenium." (p 4-5)

The consultant concluded that the "groundwater quality effects due to the Ash Pond D expansion will be considerably less than the effect Ash Pond E presently has on the groundwater quality. . .[h]owever, in its final stages, Ash Pond D will affect the quality of groundwater in an area larger than that currently affected." (p 7-1) The continuation of groundwater monitoring was recommended, and "[a] detailed groundwater monitoring plan and a contingency plan for groundwater protection" was being prepared. (p 7-1)

<u>May 1987 Site Investigation</u>

The purpose of the investigation was to determine the composition of the ash to be placed in Pond D and the predicted effectiveness of proposed groundwater protection measures. Pond D had been filled to capacity and "been out of service since approximately 1971." (p 1) At the time of the investigation, "[f]ly ash and bottom ash generated at the station are currently slurried with water from the Potomac River and transported by gravity to Ash Pond E." (p 5) Based on American Society for Testing Materials ("ASTM") leach test results, the report states that "the chemical data indicates a significant reduction in extractable ion concentrations between coal ash produced at the plant and ash placed in the ponds." (p 8) This may be explained by the constituents, which were present in the ash when it was originally placed in the pond, settling in the ash pond and leaching into the underlying soils and groundwater.

The consultant, GAI Consultants, Inc. (GAI), concluded and recommended that the low permeability of the existing Stratum E, silty clay, in the western portion of the pond in combination with a one-foot thick clay liner and slurry wall would create a containment system. (p 1-2) The consultant also recommended a groundwater monitoring network of eleven wells be installed and sampled quarterly. (p 27-28)

<u>December 1987 Preliminary Analysis Report</u>

"The purpose of this report [was] to provide VEPCO with a preliminary evaluation of ground-water quality around ash Pond E prior to the completion of six months of monitoring." (p 1) The report briefly describes initial findings, including elevated concentrations of sulfate and total dissolved solids, from the first three months of sampling data and provides a scope of work to be completed by GAI Consultants, Inc. in 1988. The completed work is presented in detail in the July 1988 Ground-Water Study, with November 1988 Addendum, and the October 1988 Site Assessment.

July 1988 Ground-Water Study

The purpose of the study was to address the four key aspects of the VWCB's Special Order, dated April 14, 1987: 1) "collect monthly ground-water quality data", 2) "prepare a report which evaluated the data", 3) "define the nature and extent of ground-water impacts", and 4) "evaluate alternatives for remediation, including a cost estimate." (p 1) At the time of the report, construction was underway at Pond D to increase the height of the embankment/dam by 100 feet, line the permeable portions of the impoundment with a 12-inch thick layer of clay, and install a slurry wall along portions of the perimeter. (p 2) From July through December of 1987, "monthly samples from 27 wells [were] collected by Virginia Power." (p 3). The consultant, GAI, averaged the contaminant concentration levels from the 6 months of sampling and compared the values to the EPA primary drinking water standards and the VWCB groundwater standards. It was observed that the groundwater from the well located near the oil ash[57] and pyrite[58] disposal area exceeded "the EPA primary drinking water standard [for cadmium] of 0.01 ppm" and there were many exceedances of the groundwater standards, including some in the upgradient wells. (p 5-6)

In addition, the consultants identified constituent sources and the extent of

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[57] Oil ash is the byproduct generated from the combustion of oil. In the past, the Company used oil as fuel and/or an additive.

[58] Pyrite is a mineral made of iron disulfide that naturally occurs in coal and is too hard to be crushed in the coal crushing process.

groundwater impacts. It was determined through leach testing that "the leachate from the oil ash contains more types and higher concentrations of elements than the effluent derived from the metals cleaning pond sludge, dry coal ash, or ash already present in Ponds D and E." (p 8) The remainder of the report describes potential remedial techniques and the possibility of a variance from the Virginia ground water standards.

<u>Addendum Report to July 1988 Ground-Water Study</u>

The purpose of the Addendum Report, dated November 1988, was to provide additional information requested by the VWCB including: 1) a description of the ammonia, cadmium, nitrate, pH, and zinc plume migration and risk assessment to human health and aquatic organisms; 2) detailed analysis of the alternative remediation options; and 3) a description of the recommended corrective action plan. (p 1) GAI concluded in its risk assessment that: 1) there are "no significant human health risks" as a result of groundwater contamination, 2) "there has been no adverse impact or effect to the aquatic biota in Quantico Creek", and 3) "acute toxicity is not occurring in the mixing zone since there is no acute toxicity in the effluent." (p 3-13) These conclusions were greatly impacted by the facts described in this and earlier studies that Virginia Power owns the impacted lands (August 1988 Report, p 7-1), the distance and direction of the nearest private well user, and the significant difference in flow magnitude between the groundwater discharge and the Quantico Creek. (p 11)

The remediation assessment section describes five remediation techniques that are incorporated and assembled into six alternative action plans. Based on its evaluation, GAI recommended Alternative 3 that consisted of: 1) "installation of a slurry wall and lining Pond D," 2) "lining of the metals cleaning pond," and 3) "construction of a lined, dry site for disposal of oil ash and pyrites from Pond E and generated from the station." (p 68) Alternative 3 was recommended for the following reasons (p 69):

> 1. removal and proper disposal of identified sources of contamination;
> 2. leachate generation will be minimized by lining the dry site and covering with a synthetic membrane and soil cap. Leachate will be treated at the metals cleaning pond;
> 3. elimination of need for off-site waste disposal at a hazardous waste disposal facility; and
> 4. it is the most cost-effective alternative for site remediation, since it incurs substantially lower costs than Alternatives 5 and 6 ($3.5 million vs. $7.3 million and $5.6 million, respectively).

For context, Alternative 5 was a "combination of Alternative 3 [construction of a dry site for disposal of oil ash and pyrites] and lining Pond E." (p 38) Alternative 6 was a "combination of Alternative 3 [construction of a dry site for disposal of oil ash and pyrites] with groundwater collection and treatment." (p 39) Table 6, on page 67, shows a comparison of key decision factors between the alternatives.

Another Report entitled "Conceptual Design Report – Dry Waste Disposal Site and Metals Cleaning Pond Rehabilitation" describes in further detail the engineering of Alternative 3 and the selection of technology. Furthermore, the groundwater monitoring plan was recommended to utilize a network of seven wells sampled "at the beginning of each calendar quarter for the first 5 years and annually thereafter at the beginning of the third calendar quarter." (p 71) This monitoring plan was in addition to the quarterly monitoring prescribed in the NPDES permit.

<u>October 1988 Site Assessment</u>

The purpose of the report was to address the first three aspects of the VWCB's Special Order, dated April 14, 1987: 1) "collect monthly ground-water quality data", 2) "prepare a report which evaluated the data" and, 3) "define the nature and extent of ground-water impacts." (p 1) The report discusses these three topics in greater detail than the July 1988 Report. A plume of water quality impacts in the proximity of Pond E and Quantico Creek has migrated and is "centered around well PP-1." (p 7) "The pH at PP-1 averages 4.03 units (about 1.9 units below background [more acidic]), sulfate averages 224.5 mg/l (49 times above background), and TDS [total dissolved solids] averages 917 mg/l (10 times above background)". (p 7) "Other wells to the east and west of PP-1 show similar ash impacts but to a progressively lesser degree with distance." (p 7) The consultants found through trilinear diagram analyses that "the coal and oil ash individually contribute contaminants to ground water and that oil ash may have been intermittently deposited (either by sluicing action or direct dumping) at or near both the southeastern and southwestern corners of Pond E." (p 11)

The off-site impacts were limited because the "[g]round water generally flows from north to south through the site with ultimate discharge into Quantico Creek, indicating that few, if any, residential wells north and west of the site are likely to be impacted by Pond E." (p 13) However, two shallow monitoring wells in the area of a domestic well had characteristics of the Pond E supernatant and Potomac River water and "[t]his evidence, along with the shallow depth of these wells, indicates that some water from Pond E has migrated to the vicinity of these wells.' (p 14) "Higher-than-background concentrations of TDS, sodium, sulfate, iron and chloride (Appendix A) are present in the two shallow wells. . .and no exceedances of the health-based primary drinking water standards [had] been observed in the well cluster." (p 14)

"As previously noted, the GAI site investigation detected a plume of contaminated ground water moving toward Quantico Creek from the southeastern corner of Pond E." (p 15) As to the impact on the Quantico Creek, the consultant concluded that "the volume of contaminated ground water entering the creek [was] practically negligible compared to the typical flow volume in the creek" and this was confirmed by a mass-balance analysis. (p 17-18) Lastly, the consultant describes the determination of site-specific ground water standards (SSGWS) incorporating background exceedances; however, there is no evidence that the consultant performed a comparison analysis of the monitoring data to the SSGWS. (pp 31-36)

1989 Special Order

Shortly after the fulfillment of the April 1987 Special Order conditions, including the studies described above, the VWCB issued another Special Order, dated September 12, 1989, that stated "[t]he results of the study indicate that groundwater monitoring and remediation is required at the Site" and that the "Board orders Virginia Power and Virginia Power agrees to implement the groundwater remediation and monitoring plan contained in Appendix A." (**Lucas Exhibit 4**, p 1) Appendix A states that Virginia Power shall "[r]emediate the Site in accordance with the Final Conceptual Design Report for Dry Waste Disposal Site and Metals Pond Rehabilitation and Corrective Action Plan . . . prepared by GAI Consultants, Inc., dated November, 1988." The referenced document is summarized below.

November 1988 Corrective Action Plan . . . The purpose of the report was to present the conceptual design of the remedial action recommended in previous reports including the following:

- A dry waste disposal site, with a low-permeability liner, for the placement of oil ash and pyrites to be removed from Pond E and adjacent areas, and for future oil ash and pyrites generated at the power station.
- Installation of a low-permeability liner in the existing metals cleaning pond near Pond E.

The report describes a life-cycle cost analysis utilizing a six percent inflation rate and a ten percent discount rate that estimated the present worth cost of the dry waste handling to be $2.7 million. (Id. at p 17) The report estimated the construction cost of the metals ponds rehabilitation to be "approximately $450,000." (Id. at p 18) The summary section, pages 19 through 21, of the report details key design features of the recommended remedial action.

The Public Staff requested additional reports submitted in compliance with the 1989 Special Order. The Company was unable to identify any other related documents in response to DR 164-4.

The Company's decision to not construct the dry waste disposal site appears not to be in compliance with the 1989 Special Order and, without additional documentation, appears to be unreasonable. The Company hired and paid consultants to conduct studies, evaluate alternatives, perform design, and draft at least seven reports but did not complete the resulting recommended remedial action that the VWCB and the Company agreed upon.

September 2004 Groundwater Site Characterization Report

The purpose of the report was to present "the results of groundwater investigations conducted for Ash Pond D and Ash Pond E located at the Company's Generation's Possum Point Power Station . . . pursuant to the requirements of Section F.4a of the Facility's [VPDES] Permit." (p 1-1)

"Prior to conversion of the Facility's two coal fire units to natural gas in March 2003, Ash Pond E received coal ash via hydraulic sluicing." (p 1-1) At the time of the report, Pond E was receiving discharges from the Metals Cleaning Pond and the Oily Waste Pond, Pond D decant water, untreated Potomac River water, and stormwater. (p 1-1) Figure 1-2 of the Report is an aerial map on which the waste facilities, including Ponds D and E, the metals cleaning treatment basins, oil waste basin, and former oil ash storage area, are identified. Pond E was an unlined settling basin that was dredged approximately every five years and the dredged materials were disposed of in Pond D. (p 2-3)

In accordance with the VPDES permit, the Company monitored fifteen wells and submitted annual reports of the sampling results and an evaluation of the water quality compared to background, state standards, and past data. (pp 2-4 and 2-6) The cluster of groundwater monitoring wells west of Ash Pond E and proximate to the closest private residential well were "abandoned in the early 1990s" so "[o]n March 8, 2004, URS installed new monitoring wells ED-22R and ED-23R." (pp 2-5) The groundwater flow velocity from Ash Pond E to Quantico Creek was calculated to be 84 feet per year. (p 3-8) "The closest residential [groundwater] user is located at 18411 Possum Point Road approximately 800 ft west of Ash Pond E; the domestic well at this residence is 30 ft deep and draws water from the Middle Potomac aquifer." (p 3-11) The nearby residential properties were mapped on Figure 3-7.

The 2003 groundwater data indicated 49 statistically significant exceedances of background levels including the dissolved constituents of barium, cadmium, copper, iron, manganese, nickel, phenols, potassium, sodium, and zinc. (p 4-3 and 4-4) Furthermore, the report identified constituents, including barium, cadmium, copper, iron, manganese, nickel, vanadium, and zinc, of potential concern based on a comparison to the USEPA Region 3 tap water risk-based concentration ("T-RBC"). (p 4-5) Detected constituents, including barium, cadmium, phenols, sodium, and zinc, exceeded the applicable Virginia groundwater standards. (p 4-5 and 4-6) The groundwater data was then compared to the USEPA MCLs and the VDEQ groundwater protection standard, which resulted in exceedances of cadmium and nickel. (p 4-6) The report states the data "suggests that historical activities in the area of [Ash Pond D and Ash Pond E] have degraded groundwater quality compared to background levels." (p 4-13)

As to a risk assessment of the groundwater, the consultant concluded that (pp 5-3 and 5-4):

> Since Dominion controls the land use, it is unlikely that the industrial nature of the Site will change in the near future. Due to this, no completed pathway exists from groundwater to drinking water. The findings of this risk assessment indicate:
>
> - It is appropriate to continue monitoring onsite groundwater;
> - There should be no immediate requirement to install additional onsite or offsite groundwater monitoring wells; and
> - **Downgradient groundwater is not suitable as a drinking water source.** (emphasis added)

The site characterization report concluded that the "groundwater conditions at the Facility do not currently pose risk to identified offsite human health and ecological receptors." (p 8-5) URS identified a preferred corrective measures alternative consisting of "the following three elements: 1) institutional controls (recording groundwater use restrictions in the property deed to ensure that no exposure to groundwater would occur at the Site), 2) long-term groundwater monitoring, and 3) establishment of site-specific, risk-based groundwater MCLs [or alternative concentration levels] for protection of offsite human health and ecological receptors associated with Quantico Creek." (pp 8-5 and 8-6)

Q. DID YOU REVIEW SIMILAR HISTORICAL DOCUMENTS FOR OTHER COMPANY GENERATING STATIONS?

A. Yes. However, there were significantly fewer documents produced by DENC during the discovery process for the other generating stations. It is unclear if additional regulatory communications, evaluations, and studies never existed for the other generating stations, or if they existed in the past but were not retained by DENC. Three additional reports are summarized below, one each for Chesapeake, Chesterfield, and Yorktown.

<u>June 2003 Chesapeake Assessment of Corrective Measures Report</u>

The executive summary to the report states that the report "was prepared in support of the Company's adherence to the requirements of Solid Waste Permit No. 440 (Chesapeake Energy Center; CEC), and those promulgated in the Virginia Solid Waste Management Regulations (VSWMR 9 VAC 20-80-270 and 310)" and that "[a]rsenic concentrations were reported in the uppermost aquifer underlying the facility at concentrations that statistically exceed its GPS during the 2002 second semi-annual sampling event (September 17, 2002)." (p ES-i) URS further states in the Executive Summary(p ES-v):

> The results of the Nature and Extent Study, specifically, identification of a source mass other than the landfill (buried sedimentation basin), the duration of the release [50+ years], and hydrogeologic limitations to aquifer remediation (including complex sedimentary deposits, low permeability, and high temporal variation), indicate that restoration of the aquifer (i.e., remediation down to GPSs) is likely technically impractical.

In the 1950's, "[t]wo settling basins were present to south of the developed area (north of the current landfill's footprint) and were used for the settling-out of CCB [coal combustion byproducts] that was sluiced into the basins." (p 4-2) The site developed as "[d]ata from the 1960s and 1970s indicate as many as three settling basins for CCB and associated berms and roads located on the peninsula" and "[i]n the early 1980's these ponds covered the entire peninsula area on which the landfill is constructed." (pp 4-3 and 4-4) As the ponds neared full capacity, they were converted to a dry ash landfill. The landfill construction was described as follows (p 4-5):

> In 1985 a dry ash landfill was constructed on top of the sedimentation basin. **As noted on preconstruction drawings, wet, loose, soft, CCB from the bottom of the sedimentation basin was not removed prior to landfill construction (Figure 4-6).** [emphasis added] The wet ash on

> which the landfill was constructed had a surface elevation of approximately 16 to 18 ft msl.

In addition to the landfill, there are a sedimentation basin, metals cleaning pond, and oily waste pond located on the site.

Based on the comprehensive statistical assessment of the groundwater monitoring data, arsenic was identified as a Constituent of Potential Concern (COPC) while antimony, barium, beryllium, cobalt, copper, nickel, and selenium were identified as Constituents of Interest (COI).[59] (p 4-14)

The human health assessment section concluded (p 8-3):

> The groundwater pathway at the Site is incomplete. Groundwater is not used at the Site and there are no known users of groundwater in the area. Consequently, exposure to groundwater cannot be reasonably expected to be significant.

URS presents an evaluation of a number of corrective measures technologies and recommends that "Institutional Controls and Long-Term Monitoring should be strongly considered as the appropriate remedy for the site." (p 13-6)

<u>February 2007 Chesterfield Groundwater Quality and Risk Assessment Report</u>

[59] Constituents of Interest (COIs) are defined as those constituents that are present in sampled media above at least one screening criteria (e.g., background, GPSs, MCLs, etc.). A COI *cannot* be considered a COPC unless a rigorous screening has been conducted and the comparison indicates an exceedance (e.g., a step-wise comparison to background and other fixed criteria using valid statistical procedures).

The introduction to the report states that it was prepared in accordance with Special Condition 1.B.7.b of the VPDES permit and a request by VDEQ for a "corrective action plan and schedule addressing contamination of groundwater attributed to the Old Ash Pond"; however, the purpose was to characterize the groundwater quality and assess risk to human health and the environment to determine the appropriate corrective action, if any was required. (p 1) The Old Ash Pond is the CCR unit referred to as the Lower Ash Pond in the testimony of Company witness Jason Williams. At the time of the report, the Lower Ash Pond treated wastewaters by settling from the following sources (p 1-2): fly ash and bottom ash sluice water associated with generating units 3 through 6; the metals Cleaning Waste Treatment Basin; drainage from the Coal Pile Runoff Pond; the oil Retention Basin; the Master Sump Pond; and stormwater.

The report states that "[t]he facility has monitored groundwater at the Site since 1986 [and] [q]uarterly groundwater monitoring has been conducted since 1995." (p 2) The statistical analysis of third quarter 2006 groundwater data indicated 21 statistically significant exceedances of background levels including the following constituents: ammonia, arsenic, barium, chloride, iron, manganese, molybdenum, and pH. (p 9 and Table 7) Furthermore, the report identified constituents, including ammonia, arsenic, iron, and vanadium, of potential concern based on a comparison to the USEPA Region 3 tap water risk-based concentration ("T-RBC") and the USEPA

MCLs. (p 10) The report states ammonia and arsenic contamination is "most likely associated' with the Old (Lower) Ash Pond. (p 12)

As to a risk assessment of the groundwater, the consultant concluded that (p 17):

> Since Dominion controls the land use, it is unlikely that the industrial nature of the Site will change in the near future. As a result, no completed pathway exists from groundwater to drinking water. The findings of this risk assessment indicate:
>
> - It is appropriate to continue monitoring onsite groundwater;
> - There should be no immediate requirement to install additional onsite or offsite groundwater monitoring wells;
> - Action to remediate groundwater in the area of the Old Ash Pond is not warranted based on the findings of the risk assessment; and,
> - **A groundwater restriction may be warranted for the site for potable use of groundwater.** (emphasis added)

The report concluded that the "risk screening did not indicate a current potential risk to human or ecological receptors from discharges of Site groundwater to surface water." (p 20) URS recommended the following actions to prevent a "future threat to receptors" (p 20):

> - Institutional controls – groundwater from this Site is not/will not be used as a drinking water source;
> - Continuance of long-term groundwater monitoring in accordance with the Permit;
>
> . . .
>
> - Periodic surface water sampling in the waters surrounding the Old Ash Pond to ensure groundwater contamination is not affecting surface water quality.

September 2011 Yorktown Chloroform Investigation Report

The purpose of the report was to present the findings of a site investigation and identify the source of "chloroform detections in upgradient groundwater monitoring wells 09 and 02-B during one or more monitoring events since 2008." (p 2) URS concluded the following (p 9):

> Based on the data presented in this investigation report, the chloroform detections in facility background wells are the result of current or historical activities upgradient of the land and facility wells.

Q. DID YOU REVIEW ANY HISTORICAL DOCUMENTS PERTAINING TO THE CHISMAN CREEK SITE?

A. Yes. The Chisman Creek Site was not mentioned in Company witness Williams' testimony or in discovery responses pertaining to the CCR disposal and/or storage sites, despite falling clearly within the Public Staff's Data Request 3 from March 2019. I have briefly summarized the earliest available report below.

1990 Superfund Site Interim Closeout Report[60]

"Between 1957 and 1974, Virginia Power, a Potentially Responsible Party (PRP), employed a private contractor to haul the fly ash from the Yorktown Power Generating Station" and "[l]arge quantities of the fly ash were deposited in four abandoned sand and gravel borrow pits" on the property

[60] *Available at* https://semspub.epa.gov/work/03/463592.pdf (last viewed on August 20, 2019)

owned by Virginia Power. (p 2) In 1980, a domestic well owner reported discolored water and the State Water Control Board began sampling and found elevated levels of trace metals in groundwater, surface water, and soils. The Chisman Creek site has "approximately 500 to 1000" people living within one mile and the property in the "immediate vicinity of the site is mainly residential." (p 1) Records of Decision were signed by the EPA Regional Administrator in September 1986 and March 1988 with objectives for remediation. Subsequently, there have been Five Year Review Reports, with the most recent being dated December 2016.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THESE EVALUATIONS AND CONCLUSIONS.

A. On repeated occasions, site investigations and/or regularly scheduled monitoring events have shown evidence of degradation of the natural groundwater quality as a result of the Company's coal ash disposal practices. The Company has produced a limited number of pre-2000s site characterization, investigative, and/or corrective measure reports through discovery; these are mostly applicable to the Possum Point site. The Company has not provided, and the Public Staff has therefore not had the opportunity to review, such reports for the other coal-fired facilities for the years prior to 2000. Unanswered questions remain about what the Company knew or did not know regarding CCR contamination at the time it made key decisions pertaining to coal ash storage. For example, the

Company took a variety of CCR disposal approaches as illustrated in the table below:

Lucas Table No. 1

Station	Impoundment	First Year of Operation	Liner	Amount of CCR Stored (Cubic Yards)
Bremo	North Pond	1983	No	4,295,472
Chesapeake	Bottom Ash Pond	1985	No	60,000
Chesapeake	Landfill	1985	Yes[61]	975,000
Chesterfield	Upper Ash Pond	1985	No	11,300,000
Mount Storm	Phase A&B Landfill	1986	Yes	19,305,000
Possum Point	Pond D	1986	Yes[62]	2,312,287
Yorktown	Landfill	1985	Yes	1,500,000

The data presented in Lucas Table No. 1 was compiled from public information on the Dominion Energy website and a response to Public Staff Data Request 3-1(b). (**Lucas Exhibit 5**) Within a four year period from 1983 through 1986, the Company opened seven coal ash storage units ranging in protectiveness of groundwater from an unlined pond presently containing over 10,000,000 cubic yards to a lined landfill presently containing 1,500,000 cubic yards. It would be reasonable to expect that there were

[61] The lined landfill was constructed on top of the historic unlined pond.

[62] The one-foot thick clay liner was not constructed with a liner meeting the requirements of CCR Rule § 257.71(a)(1).

proposals, cost-benefit analyses, budgets, environmental studies, engineering plans, permit applications, and/or other planning documents produced leading up to and supporting the decisions to construct new and/or modify existing CCR storage units. Those records would help make it clearer what the Company knew at the time and why they made the decisions they did. The Company is not able to demonstrate, with the records it has available, that it fully accounted for and mitigated the risks of CCR contamination in prior decades of CCR disposal and management.

In addition, the characteristics of the CCR disposed of in the impoundments changed over time. The enactment of the Clean Air Act and subsequent air quality rules in the 1970s required treatment of the emissions released by coal-fired generating facilities. Often constituents previously emitted into the air became part of the waste stream into the impoundments and/or landfills. **Lucas Exhibit 6** is a table of when the Company implemented specific environmental controls, per the response to DR 162-1.

Q. WHERE CCR RECORDS CANNOT BE FOUND OR DO NOT EXIST, ARE THERE OTHER POTENTIAL SOURCES FOR THIS HISTORICAL INFORMATION?

A. Yes. The first possibility would be for testimony from the Company's witness on the subject of CCR management and environmental compliance. However, Company witness Jason E. Williams, Director, Environmental Services for Dominion Energy Services, Inc., "assumed his coal ash environmental compliance role when he joined the company in August 2015." (**Lucas Exhibit 7**, p 2) He would not have firsthand knowledge of historic events and decision-making beyond discussions with colleagues and the documents produced in discovery.

The Public Staff obtained Company organizational charts from 1995, 1997, and 2001, and management charts from 2005 through 2019. Based on the charts and written discovery responses, Cathy Taylor, from approximately 2002-2015, and Judson White, from at least 1995-2002, preceded Jason Williams in similar roles at the Director level. (Id. at p 1) These individuals reported to the Vice President of Environmental Services position held by Pamela Faggert and A.W. Howard over this period. These persons and their predecessors may have firsthand knowledge beyond that of witness Williams, but are no longer Company employees.

In an effort to obtain more records that would provide information on historic events and decision-making, the Public Staff requested records or other information in the possession of A.W. Howard and Pamela Faggert and their direct reports that had not already been produced in discovery, pertaining to historical coal ash management decisions and practices. The Company responded that any records retained by those individuals would have been included in the files searched in response to previous discovery requests.

On page 3 of Commissioner Clodfelter's partial concurrence and dissent in the June 22, 2018, Order in Docket No. E-7, Sub 1146, (the most recent

Duke Energy Carolinas rate case), he noted the lack of historical knowledge held by witness Jon F. Kerin.

> The Company's primary witness on these matters, witness Kerin, only first assumed responsibility for the Company's response to coal ash issues in 2014, without any pertinent prior experience concerning the subject. . . . Although he testified that he had reviewed various historical documents and Company records as part of his introduction to his new duties, on a number of occasions during the evidentiary hearing, he was confronted with significant historical Company or industry documentation which was altogether unfamiliar to him or which he could not recall well enough to discuss. . . . His conclusory testimony that the Company had complied with all pertinent laws and regulations, and had conformed to industry standards prior to 2014, simply cannot be afforded any substantial weight. . . . The Company provided no witness who could testify concerning the Company's budgeting for, accounting for, or recovery of costs associated with the handling of coal ash wastes prior to 2014.

Witness Williams appears to be knowledgeable about the Company's CCR Rule compliance decisions and current operations, but relies "upon information and belief, knowledge of the Company's history of monitoring and discussions with other employees" to answer discovery questions concerning past decisions to monitor and remediate coal ash sites. Anticipating a similar issue in this case, the Public Staff has, as described above, attempted without great success to obtain from the Company all available sources of historical information.

COMPANY RESPONSIVENESS TO THE PUBLIC STAFF

Q. HAS THE PUBLIC STAFF HAD DIFFICULTY OBTAINING INFORMATION FROM THE COMPANY?[63]

A. Yes. On March 29, 2019, the Public Staff sent the Company Data Request No. 3, Item 11 (DR 3-11), which requested that the Company provide groundwater monitoring data in spreadsheet format for each coal-fired generating facility showing exceedances, by constituent, of applicable groundwater quality standards from the date that groundwater monitoring first began (obligated or voluntary) at each facility to the present. The Company responded by providing what it called "readily available" groundwater monitoring reports and "readily available" groundwater monitoring plans for those facilities. The Company did not provide a spreadsheet as requested, nor did it provide groundwater monitoring reports and groundwater monitoring plans for all applicable years at each facility.

Likewise, Data Request 3 items 18 and 19 (DR 3-18 and DR 3-19) requested: (1) a spreadsheet with groundwater monitoring data taken at or beyond the site boundary as well as information on exceedances; and (2) a spreadsheet with groundwater monitoring data taken inside the site boundary as well as information on exceedances. The Company again

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[63] Excerpts from data request and responses described in this section are shown in **Lucas Exhibit 8.**

responded by directing the Public Staff to its "readily available" groundwater monitoring reports. The Company did not provide spreadsheets as requested, nor did it provide all groundwater monitoring reports.

Data Request 3 item 14 (DR 3-14) requested information on how many groundwater monitoring wells the Company had in place at each of its coal-fired generating stations prior to 1990, 2000, 2010, 2013, 2014, 2015, 2016, 2017, and 2018, and how many are in place today. The Company was only able to confirm the number of wells back to the year 2000.

Lastly, Data Request 3 item 16 (DR 3-16) requested copies of all current and historic NPDES permits by plant site. The Company was unable to produce all historic NPDES permits, as summarized below.

The Public Staff made repeated attempts to obtain the records and data requested in Data Request No. 3. Follow-up data requests were sent on May 7, 2019 (DR 41), May 28, 2019 (DR 61), June 5, 2019 (DR 81), and June 24, 2019 (DR 100). In addition, the Public Staff attempted to obtain the requested information in a series of conference calls and meetings with the Company. These calls and meetings took place on May 20, 2019, June 5, 2019, June 17, 2019, July 1, 2019, and July 8, 2019.

In response to Data Request 61, received on June 7, 2019, and as a follow-up to the call on May 20, 2019, the Public Staff received a set of static spreadsheets with groundwater quality data for its facilities. These spreadsheets, however, only represented certain years and do not provide a complete set of data. Specifically, they contain only raw data, without additional information such as applicable background levels.

In sum, after all responses to the data requests excerpted in **Lucas Exhibit 8** had been received, records that the Company has been unable to locate and provide to the Public Staff include:

Groundwater monitoring reports for the following years:

- All facilities – prior to the year 1999
- Bremo – 1999, 2001-2005, 2007 - 2014
- Chesapeake – 1999, 2015
- Chesterfield – 1999 - 2002
- Clover – 1999 - 2004
- Mt. Storm – 1999 – 2001, 2003
- Possum Point – 2003, 2018
- Virginia City Hybrid Energy Center – all located
- Yorktown – 2003, 2018

VPDES permits for the following years:

- Bremo – anything prior to 2005
- Chesapeake – 1982 – 1995, 2000 - 2007
- Chesterfield – anything prior to 2004, 2009 - 2016
- Clover – anything prior to 2011
- Mt. Storm – anything prior to 2014
- Possum Point – anything prior to 2001
- Virginia City Hybrid Energy Center – all located
- Yorktown – anything prior to 2007

The Company has acknowledged that it has not been able to locate some historical NPDES/VPDES permits and related documents. Furthermore, the records that were provided are not in a useful format. The Company's groundwater monitoring information is a disorganized mass of data numbering thousands of pages. Multiple consultants were used at various times at the plants with no standard formatting or presentation of data. It is not possible given the state of the Company's records as provided to the Public Staff to organize the data into a format that would allow for a full review of the history of groundwater exceedances. Prior to the CCR Rule groundwater monitoring and reporting requirements, it appears that the Company has never compiled any of the groundwater data in a centralized format for its own use. The Public Staff believes the Company would have difficulty making decisions that require comparing plants to each other or determining any trends in the data.

Of note to the Public Staff's investigation, it is not possible to identify all groundwater exceedances caused by CCR over the life of the Company's CCR units, because it is not feasible to reconstruct a complete history of exceedances from the Company's existing records. The Company's position, as shown in **Lucas Exhibit 8** at pp 27-28, is that it has provided what data it has, and that it is the Public Staff's obligation to piece together the information into a spreadsheet showing groundwater exceedances.

The Public Staff asked about the Company's records retention policy and the Company indicated that it had complied with all applicable laws and regulations on records retention. The Public Staff also asked in DR 61 for a copy of the Company's record retention policies. The Company's 2014 record retention policy requires that it keep groundwater monitoring reports permanently, and that it keep NPDES/VPDES permits for the life of the facility. The Company's 2005 record retention policy required it to keep both groundwater monitoring reports and NPDES/VPDES permits for the operating life of the facility. The Company was not aware of a record retention policy prior to 2005.

The Public Staff contemplated filing a motion to compel with regard to our discovery requests on groundwater monitoring and exceedances. Rather than embroil the Commission in a discovery dispute, we worked for months to establish a good faith understanding with the Company as to the basis for its incomplete responses. The result is that the Company's inability to provide historic records pertaining to groundwater for its coal-fired generating facilities, as discussed above, is acknowledged in a stipulation between the Company and the Public Staff, provided here in **Lucas Exhibit 9**.

Q. ARE THERE OTHER CONCERNS WITH THE COMPANY'S RESPONSES TO PUBLIC STAFF DISCOVERY REQUESTS?[64]

A. Yes. The Company's response to several questions in DR 3 should have included information and records pertaining to Chisman Creek, discussed above, which was an open pit for CCR from the Yorktown plant that contaminated drinking water and was designated as a Superfund site by the EPA. DR 3 asked for this type of information but the Company did not provide it.

[64] Excerpts from data request and responses described in this section are shown in **Lucas Exhibit 8.**

Also, DR 3-5 asked for "a list of all administrative or regulatory findings of environmental noncompliance . . . ." The Company's response to DR 3-5 did not have any information on the Chesterfield, Mecklenburg, and VCHEC plants. The Public Staff sent a second data request asking why those plants were not included (DR 60-1). In response to DR 60-1, DENC reiterated that all documents in the Company's possession had been provided. However, through a records request to VDEQ, the Public Staff later found that VDEQ had made regulatory findings against the Company for environmental problems at the Chesterfield power plant from 2009 through 2017. These findings are shown in **Lucas Exhibit 10**. The Company did not produce these documents during discovery.

Additionally, in DR 3-15, the Public Staff asked the Company to provide information on any unpermitted seeps at the Company's CCR sites. The Company responded that it did not have any seeps. The Public Staff followed up with an additional DR 41-6 for the Company to identify any "engineered or non-engineered discharges, including all locations in which a pollutant is conveyed, in any manner from an impoundment to waters of the United States or a water of the State." The Company stated that it "is not aware of any unauthorized or unpermitted discharges from its basins." Both requests included that the Company identify all seeps and also any seeps that had previously been eliminated.

In response to a request to the VDEQ, the Public Staff received documents indicating the Company did self-report a seep at Chesterfield and submitted a seep mitigation plan to the VDEQ in August of 2018. These documents are signed by witness Williams and provided in **Lucas Exhibit 11.**

It also appears the Company did not respond fully to the Public Staff in the Company's previous rate case in 2016 (Docket No. E-22, Sub 532). In the 2016 rate case, the Public Staff sent DR 68-5, which asked for any findings or violations by the VDEQ as follows:

> Have there been any findings, violations, assessments, fines, or penalties by the Virginia DEQ regarding VEPCO's CCR facilities or CCR closure activities? If so, please provide a detailed explanation of each such circumstance, as well as all applicable documents published or transmitted to DNCP by the Virginia DEQ. Please list the dollar amounts and dates paid for any payments made by VEPCO in connection with resolution of alleged violations of law or regulations.

The Company responded that it had only received a warning letter regarding the Possum Point plant as follows:

> On November 18, 2015, Virginia DEQ issued a warning letter to the Possum Point Power Station for an overflow of a temporary tank associated with water being removed from a CCR pond. Corrective actions were put in place and no fine or penalty was assessed by the agency…

Some of the regulatory actions shown in **Lucas Exhibit 10** should have been provided by the Company in the previous rate case. These omissions cast doubt on what information the Company has but will not provide.

ENVIRONMENTAL COMPLIANCE

Q. WHEN DID DENC BEGIN CONDUCTING GROUNDWATER MONITORING?

A. DENC installed groundwater wells and began monitoring the groundwater quality on different dates for different sites. Unlike Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), DENC did not voluntarily install monitoring wells. Instead, the DENC monitoring wells were installed in response to VDEQ requirements as part of DENC's NPDES and/or solid waste permit conditions. These requirements began as early as the mid-1980's at certain impoundments. See **Lucas Exhibit 1**.

DENC states the initial requirement to monitor groundwater didn't begin until as late as 2016 for its historic Possum Point Ponds A, B, and C. Despite the 1977 adoption of the Virginia groundwater regulations and the 1982 EPRI Manual stating that the "monitoring of groundwater and leachate, is nevertheless necessary to provide convincing proof of a safe disposal practice" (Docket No. E-7, Sub 1146, Charles Junis Exhibit No. 8, p 4-19), DENC did not start monitoring groundwater quality at some of its sites until three decades later. Furthermore, DENC did not engage in comprehensive groundwater monitoring until even later, as quantitatively described by the table in **Lucas Exhibit 1**.

Q. WHAT IS THE STATUS OF COMPLIANCE WITH STATE GROUNDWATER STANDARDS FOR DENC'S VIRGINIA SURFACE IMPOUNDMENTS?

A. The Company is required by its VPDES and/or solid waste permits to monitor for exceedances of groundwater standards at its CCR storage sites. In general, VPDES permits with groundwater monitoring requirements provide that, upon detection of an increase over background levels for a given contaminant, the facility must enter into an extended monitoring phase. If, during this monitoring phase, any contaminant continues to exceed the background level, the facility must add additional monitoring wells and enter the assessment monitoring phase. Exceedances during the assessment monitoring phase will require a Corrective Action Plan and Risk Assessment. The Company provided Corrective Action Plans for the Bremo (2015) and Chesapeake (2011) sites.

Virginia's Solid Waste Management Regulations (SWMR) also require groundwater monitoring.[65] Facilities with solid waste permits must first determine background levels for detected constituents. The determination of background levels during this initial phase of monitoring is limited to the constituents shown in Table 3.1, Column A of the solid waste regulation. Subsequently, if there occurs a statistically significant increase over the background level for any constituent, the facility must implement Phase II

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[65] 9 VAC 20-81-250(C).

monitoring and establish Groundwater Protection Standards. During the Phase II monitoring program, the scope of monitoring is expanded to all detected Column B constituents. If, in later sampling, exceedances of these Groundwater Protection Standards are found, the facility must undertake corrective action.[66]

Based on the 2017 and 2018 annual groundwater reports required by the Virginia SWMR, the Public Staff has compiled a table quantifying the number of testing results from groundwater downgradient of the Industrial Landfill at Chesapeake that have exceeded the groundwater protection standards. In addition, the Public Staff has visually illustrated the constituents that exceed these measures at the site. Please see **Lucas Exhibit 12** for the table and map.

Q. **WHAT IS THE STATUS OF COMPLIANCE WITH FEDERAL CCR RULE GROUNDWATER STANDARDS FOR DENC'S VIRGINIA AND WEST VIRGINIA SURFACE IMPOUNDMENTS?**

A. The Company is required by the CCR Rule to monitor groundwater at the waste boundary for constituents regulated by EPA. More specifically, DENC is required to perform baseline/background sampling and then detection monitoring for Appendix III parameters. If a statistically significant increase over background levels is detected for one or more constituents, then assessment monitoring is required for Appendix IV parameters. If the testing

[66] 9 VAC 20-81-260.

results exceed the groundwater protection standards, the facility owner must characterize the nature and extent and initiate an assessment of corrective action. For some of its sites, including Bremo, Chesterfield, and Possum Point, DENC has been required to submit an assessment of corrective measures as a result of exceedances of the background levels and groundwater protection standards. With conformational or additional sampling events, other DENC sites may also be required to submit assessments of corrective measures. Under the CCR Rule, DENC is required to file annual groundwater monitoring reports summarizing the detection and, if applicable, assessment monitoring activities and data. Based on those reports and notifications,[67] the Public Staff has compiled a table quantifying the number of testing results from groundwater downgradient of the ash impoundments that have either exceeded the natural background levels or the groundwater protection standards. **Lucas Exhibit 13**. In addition, the Public Staff has visually illustrated the constituents that exceed these measures at each monitoring well on a map of each site. **Lucas Exhibit 14**.

The picture of DENC's groundwater compliance is far from complete. The inactive CCR surface impoundments that were previously eligible for the early closure provisions[68] of the final CCR Rule are no longer exempt after

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[67] *Available at* https://www.dominionenergy.com/company/community/environment/reports-and-performance/ccr-rule-compliance-data-and-information.

[68] 40 CFR 257.100(b).

the vacatur by the United States Court of Appeals for the D.C. Circuit. The EPA has granted a 547-day extension of the applicable deadlines that affect the East and West Ponds at Bremo, the Bottom Ash Pond at Chesapeake, and Ponds A, B, C, and E at Possum Point. This means that there will be more groundwater monitoring data collected in compliance with the CCR Rule and likely additional exceedances.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPLIANCE STATUS OF DENC'S SURFACE IMPOUNDMENTS DURING THE LIFETIME OF THE STRUCTURES.

A. The lifetime compliance record for the Company's CCR impoundments is incomplete due in part to the lack of data retained by DENC. As stated earlier, the groundwater data that was provided was in a form that makes it practically impossible to reconstruct a complete history of groundwater exceedances. The Public Staff believes that the Company has had exceedances at its impoundments over a long period of time.

In general, groundwater flow is slow and affected by gravity and permeability. The migration of CCR contaminants can be even slower due to chemical absorption/adsorption in process water, groundwater, and soils. For the unlined impoundments, the CCR, which is the source of the regulated constituents, is and has been cumulatively leaching contaminants into the groundwater over many years. The groundwater is slowly transporting those contaminants out of the impoundment area as detected in waste boundary and in many cases surrounding groundwater monitoring wells. It is reasonable to assume that concentration levels will vary minimally during the time between exceedances.

Q. HAS THE CHISMAN CREEK SUPERFUND SITE THAT RECEIVED CCR FROM THE YORKTOWN PLANT HAD ANY GROUNDWATER EXCEEDENCES?

A. Yes. The Fifth Five-Year Review Report for Chisman Creek Superfund Site,[69] dated December 2, 2016, provides a summary of the site background, response action, progress since the last review, technical assessment, and issues/recommendations. Groundwater samples are taken semi-annually at 10 monitoring wells. On page 11, the report states that the groundwater had exceeded the MCLs for arsenic and the Regional Screening Value for vanadium. A surface water sample from Pond A indicated an exceedance of the Region 3 ecological screening level for vanadium. The technical assessment section states the following on page 16:

> Groundwater and soil investigations in 2010, 2011 and 2013 found vanadium groundwater contamination and fly ash west of Area C, across Wolf Trap Road. These investigations revealed that although most of the components of the remedy are functioning as intended there are other components that are not currently operating and functioning as designed.
>
> Extending the water lines to Wolf Trap and Allens Mill Roads to serve homes in the area of the Site is preventing human exposure to the contaminated groundwater.

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[69] *Available at* https://semspub.epa.gov/work/03/2240450.pdf

The issues/recommendations section on pages 18 and 19 included "fully delineate the extent of all contamination in soil and groundwater" and "[r]echeck all properties in the groundwater impact area to determine if any private wells are present and if so, if they are in use."

COSTS OF CCR-RELATED ENVIRONMENTAL IMPACTS AND RATEMAKING OPTIONS FOR THOSE COSTS

Q. FOR CCR MANAGEMENT, HAS DENC INCURRED COSTS RELATED TO GROUNDWATER CONTAMINATION AND ENVIRONMENTAL DEGRADATION?

A. Yes. Since DENC began monitoring groundwater near its CCR impoundments at the direction of environmental regulators, there has been evidence of degradation of the natural groundwater quality. Beginning as early as the 1980s, the Special Orders at Possum Point presented in the "Past Knowledge about the Environmental Impacts of the Storage of Coal Ash" section above demonstrate that the Company had specific knowledge of groundwater contamination from CCR. This finding of degradation is further supported by the continued groundwater monitoring and annual reports required by VDEQ, and more recently, the monitoring required by the CCR Rule.

The Company will incur substantial costs to remedy CCR-related environmental impacts and prevent risks of continued and worsening degradation, whether the remedies are required by citizen action lawsuits, regulatory enforcement, or the CCR Rule and the CCR Excavation Act. The closure requirements that are in the CCR Rule and the CCR Excavation Act were enacted in response to environmental contamination caused by CCR surface impoundments.

Costs of corrective action related to environmental impacts are included in the rate request to the extent corrective action under the CCR Rule is required to address environmental impacts, including the dewatering and excavation of CCR surface impoundments. While the Company calls these "compliance" costs to meet the requirements of the CCR Rule, corrective action is only needed where CCR constituents have contaminated the water to a degree in excess of environmental standards.

The costs to comply with the CCR Rule and the Virginia solid waste regulations, which incorporate by reference the CCR Rule, that DENC witness Williams states "are driving the Company's coal ash expenditures" (Williams Direct Testimony, p 1), are designed specifically to remediate ash basin environmental impacts that arose before the enactment of the CCR rule.

It is likely that the state environmental regulators in Virginia and West Virginia,70 even in the absence of the CCR Rule, would not allow groundwater exceedances to remain indefinitely in violation of pre-existing

[70] There is also the possibility that environmental organizations would have brought legal actions if not satisfied with the oversight of environmental regulators.

state groundwater regulations, and groundwater exceedances and other non-compliance events like seeps and discharges would have remained a liability for the Company if not mitigated. A major issue in this rate case is determining the appropriate regulatory treatment of the costs to remediate and restore water quality standards degraded due to the Company's past CCR storage and disposal practices. Likewise, the costs to remediate CCR disposal sites even to the extent there is no current contamination reflects a judgment by the EPA and the Virginia legislature that the risks posed by the Company's initial disposal practices is too great to allow for continued operation or less expensive closure options.

Q. WHAT REGULATORY OPTIONS HAS THE PUBLIC STAFF CONSIDERED WITH RESPECT TO CCR-RELATED COSTS?

A. The option advocated by DENC is to treat its CCR-related costs as required for compliance with new state laws and the CCR Rule and, therefore, as reasonable to recover in rates. DENC witness Williams states "[t]he Company's ash handling practices have included a combination of management options over time, which have been consistent with industry standard and regulatory requirements." (Williams Direct Testimony, p 9) In other words, DENC's view is that costs to remediate groundwater impacts, including exceedances of state and federal protection standards, should not be excluded from recovery because corrective action to remediate those impacts is required to achieve compliance with new laws and regulations, such as the CCR Rule.

Another option is to conclude that the CCR Rule and Virginia legislation are a direct consequence of environmental impacts caused by the CCR management practices of DENC, such as the Chisman Creek and Battlefield disposal sites,[71] and other electric utilities, and therefore DENC shareholders should bear responsibility for the full costs.

A third option is to share costs between DENC's customers and DENC's shareholders. This is the same approach taken by the Public Staff in the DEP and DEC rate cases, except the recommended sharing ratio is different based on factors explained later in my testimony.

Q. WHY DOES THE PUBLIC STAFF ADVOCATE THE THIRD APPROACH, AN EQUITABLE SHARING?

A. The Public Staff believes the issue of cost responsibility for environmental impacts is complex, and needs to account for the following factors: (1) some impacts are not clearly imprudent or reasonable; (2) estimating historic costs to remediate environmental impacts would be speculative; and (3) the incomplete records of DENC and the challenge of reconstructing all the Company's decision-making on CCR management make it difficult, if not

[71] For example, Chisman Creek and Battlefield are specifically identified in the preamble of the CCR Rule. 80 Fed. Reg. 21,302. "These proven damage cases include eight cases where the utility was directed by the state to provide an alternative water supply (. . . VEPCO Chisman Creek . . .) . . ." Id. at 21,457. "The second case is the Battlefield Golf Course in Chesapeake, Virginia where 1.5 million yards of fly ash were used as fill and to contour a golf course. Groundwater contamination above MCLs has been found at the edges and corners of the golf course, but not in residential wells. An EPA study in April 2010, established that residential wells near the site were not impacted by the fly ash and, therefore, EPA does not consider this site to be a proven damage case. However, due to the onsite groundwater contamination, EPA considers this site to be a potential damage case." Id. at 21,328.

impossible, to conduct a prudence review.

Notwithstanding the difficulty of conducting a prudence review on CCR management, it is clear that DENC had a duty to avoid contamination of surface waters and groundwater under both federal and state environmental regulations and laws.

Specifically, DENC had a duty to comply with state groundwater standards without regard to whether it followed accepted industry practices. Furthermore, in the context of "accepted industry practices," it should be noted that Dominion is an industry leader with the ability to influence what those practices were at the time. Virginia groundwater regulations were enacted in the 1970s and have an "anti-degradation policy" to protect state water quality. West Virginia groundwater regulations were enacted in the 1990s and also have an "anti-degradation policy" to protect state water quality. Finally, and most importantly, DENC created the risk of coal ash contamination, their original disposal of CCR has led to actual environmental contamination in several instances, their original disposal of CCR poses an ongoing contamination risk that requires expensive remediation in the judgment of the EPA and the Virginia legislature, and ratepayers will not receive any additional electric service for this costly remediation. As described more fully by Public Staff witness Maness, some degree of equitable sharing is appropriate in this circumstance, and equitable sharing has been ruled lawful.

Q. PLEASE SUMMARIZE THE EVIDENCE OF ACTUAL CONTAMINATION THAT HAS OCCURRED AT DENC DISPOSAL SITES FOR CCR.

A. DENC incurred numerous groundwater exceedances and did not engage in comprehensive groundwater monitoring and remediation until enactment of the CCR Rule. See the groundwater exceedances shown in **Lucas Exhibit 12 and 13,** the number of groundwater monitoring wells installed by year in **Lucas Exhibit 1**.

The groundwater exceedances currently reported to VDEQ from DENC monitoring wells are further indication of the breadth of environmental impacts. The 548 groundwater exceedances listed in **Lucas Exhibits 12 and 13**, showing statistically significantly exceedances over natural background levels, MCLs, and/or groundwater protection standards, are attributable to migration of contaminants from DENC's ash disposal sites.

In these circumstances, it would be unreasonable to charge ratepayers for all the CCR compliance costs. Due to its environmental degradation, DENC has a great deal of culpability for compliance costs related to CCR impoundment closures, whereas ratepayers are not culpable at all for those costs.

For the foregoing reasons, the Public Staff believes the equitable sharing of CCR management costs, as recommended in the testimony of Public Staff witness Maness, is reasonable.

Q. DO YOU BELIEVE THAT THE COMMISSION SHOULD TREAT DENC IN THIS CASE THE SAME AS IT TREATED DENC IN ITS 2016 RATE CASE?

A. No. The Public Staff has vastly more information regarding the Company's CCR management and groundwater contamination than it did in 2016, despite the incomplete discovery responses from the Company. The documented environmental problems produced in Docket No. E-22, Sub 532 (2016 Rate Case) were very small by comparison; as noted above, the Company represented that it had received only a warning letter from the VDEQ in 2015 regarding a minor spill.

Furthermore, as is discussed by witness Maness, the costs in the 2016 Rate Case were much less in magnitude than in the present case, and that is a factor that witness Maness uses in his recommendations on equitable sharing.

It is also important to note that the resolution of CCR remediation costs in the 2016 rate case was the result of an agreement and stipulation of settlement between the Public Staff and the Company. The settlement, accepted by the Commission, clearly stated that it was not to have precedential value. If a decision based on that negotiated settlement in a prior case were to affect the decision in the present case, where different facts and circumstances exist, the incentive to enter settlement agreements in the future would be greatly diminished.

Q. DOES THE PUBLIC STAFF RECOMMEND A DIFFERENT SHARING IN THIS CASE THAN WHAT IT RECOMMENDED IN THE DEP AND DEC RATE CASES?

A. Yes. In this case, the Public Staff recommends that 40 percent of the costs for CCR remediation should be paid by the Company's shareholders and the remaining 60 percent be paid by the Company's customers. In the DEP rate case, E-2, Sub 1142, the Public Staff recommended a 50-50 percent sharing of costs between shareholders and ratepayers. Similarly, in the DEC rate case, E-7, Sub 1146, the Public Staff recommended a 49-51 percent sharing of the coal ash costs between shareholders and ratepayers.

Q. WHY DOES THE PUBLIC STAFF RECOMMEND A LESSER SHARING IN THIS CASE THAN THE DEP AND DEC RATE CASES?

A. As explained by witness Maness, the Public Staff's recommendation regarding the percentage of sharing in this case is appropriate given the significant magnitude and nature of the cost that fails to enhance reliable service, produce electricity, or otherwise benefit current ratepayers.

An additional component that guides the determination of the Public Staff's recommendation for sharing is the degree of culpability the Company has for the coal ash costs. While the Public Staff believes that DENC failed to properly manage its coal ash over time, we recommend that less than a 50-50 percent sharing is appropriate in this case due to several factors, including: (1) DENC has not been found guilty of criminal negligence for its environmental impacts; (2) DENC has not had significant state regulatory enforcement actions taken against it; and (3) while there are widespread environmental impacts, especially groundwater contamination, there is less evidence, at this point, of the extent of the impacts than was present in the DEP and DEC rate cases. This may change in the future when more data is available as a result of the groundwater monitoring requirements in the CCR Rule; however, our recommendation regarding equitable sharing in the present case must rest on what evidence is presently available. If we have more data on exceedances and environmental impacts in the future, we may recommend a different equitable sharing ratio for the costs in future cases.

SPECIFIC IMPRUDENCE DISALLOWANCES

Q. YOU EARLIER STATED THE PRACTICAL OBSTACLES TO CONDUCTING A GENERAL PRUDENCE REVIEW OF CCR MANAGEMENT. DID YOU DETERMINE IF THERE WERE ANY NARROWER PRUDENCE ISSUES RELATED TO COAL ASH?

A. Yes. In 2015, the Company began making investments in a series of capital projects to comply with the CCR Rule and the ELG Rule, referred to by the Company as the Chesterfield Integrated Ash (CHIA) project, which included the wet to dry conversion of Units 3 through 6, construction of a new landfill, haul road and access bridge, and a new low volume wastewater treatment system.

On June 15, 2015, the Company executed an agreement with a contractor to design and build dry ash handling facilities for the Chesterfield Units 3, 4, 5, and 6. The dry ash handling facilities were intended to replace wet handling (the sluicing of ash to storage ponds). These facilities were completed at a cost of $124.2 million. The generating capacities of these units are as follows:

Lucas Table No. 2

Chesterfield Unit	Winter capacity, MW
3	102
4	168
5	342
6	690
TOTAL	1302

Q. DO YOU BELIEVE THAT DENC SHOULD RECOVER THE FULL COST OF THE CHESTERFIELD WET TO DRY CONVERSION?

A. No. In its 2015 Integrated Resource Plan, the Company indicated that Chesterfield Units 3 and 4 would be retired in 2020 and these units were retired in March 2018. The Public Staff believes that the Company should not have made this long-term investment for Units 3 and 4 if they were to remain in service for less than five years. The combined capacities of Units

3 and 4 are 270 MW or 20.7 percent of the four-unit total. Therefore, the Public Staff recommends that 20.7 percent of the $124.2 million investment, or $25.7 million, be removed from rate base on a system-wide basis. The Virginia State Corporation Commission (SCC) had a similar finding, although it calculated the amount of disallowance differently.

Q. DID THE VIRGINIA STATE CORPORATION COMMISSION DENY COST RECOVERY OF CHESTERFIELD 3 AND 4?

A. Yes. The SCC found that the Company made the investment in the June 2015 timeframe when the Company's own analysis showed those units were expected to be either retired or retrofitted to burn natural gas by 2020. In its *Final Order*,[72] dated August 5, 2019, the Virginia State Corporation Commission found:

> [T]he Wet-to-Dry Conversion for Units 3 and 4 is not being used to serve customers. Pursuant to Code § 56-585.1 D, the Commission finds that Dominion has not established that the "cost incurred" for this project was reasonable and prudent at the time such cost was incurred. The Company likewise has not established that such cost was "necessary" under Code § 56-585.1 A 5 e. Accordingly, the Wet-to-Dry Conversion for Units 3 and 4 shall not be reflected in the revenue requirement for Rider E.

Final Order, at 9.

The SCC further found that the Wet-to-Dry Conversion for Units 5 and 6, the Landfill, and the Waste Water Treatment System should be recovered

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[72] Case No. PUR-2018-00195, Final Order, *available at* http://www.scc.virginia.gov/docketsearch /DOCS/4%243v01!.PDF.

as they continue to serve native load customers. In distinguishing the disallowance, the SCC stated:

> Unlike the Wet-to-Dry Conversion for Units 3 and 4, the Commission finds that Dominion reasonably and prudently incurred these specific environmental costs at the time such cost was incurred. In contrast to Units 3 and 4 at that time, Units 5 and 6:
>
> (i) were newer, larger, and more efficient facilities;
>
> (ii) were not expected to transition to intermediate or peaking status;
>
> (iii) were not recommended for operation only in the "short term";
>
> (iv) were not avoiding major capital investments; and
>
> (v) were not slated for retirement by 2020 under Cpp-compliant plans in the 2015 IRP.

Id. at 10-11.

Q. DID THE STAFF TO THE SCC HAVE ANY DIFFICULTY DETERMINING THE COST OF THE CHESTERFIELD 3 AND 4 PROJECT?

A. Yes. In testimony in the Virginia Rider E Docket, Carol Myers (Exhibit No. 21), Staff to the SCC, testified that the Staff asked the Company for a breakdown of the project by unit and the Company initially objected to the request to the extent it would require original work.[73] Ms. Meyers stated "[t]hrough subsequent discussion with the Company . . . a detailed cost breakdown by unit does not appear to exist" because all construction costs were treated as common plant. Ms. Meyers testified that this treatment of costs was unreasonable and costs should have been directly assigned to

[73] Case No. PUR-2018-00195, Testimony of Carol Myers, Exhibit No. 21, at 4, *available at* http://www.scc.virginia.gov/docketsearch/DOCS/4h7l01!.PDF.

the individual generating units.

However, the SCC Staff was able to develop a rough estimate of the costs of the construction work done at Units 3 and 4.

> The Company developed a rough estimate of the capital cost of the Chesterfield 3 and 4 Wet-to-Dry Conversions of $18 million by comparing two Engineering, Procurement, and Construction contract bids it obtained for Chesterfield Power Station - one for work to be completed at Units 3, 4, 5, and 6 and one for work to be completed only at Units 5 and 6.

Exhibit No. 21 at Summary.

Q. DID THE INTERVENORS MAKE DIFFERENT RECOMMENDATIONS IN THE VIRGINIA PROCEEDING?

A. Yes. The Virginia Attorney General's Division of Consumer Counsel witness Chris Norwood[74] (Exhibit No. 15) recommended that all the costs of the CHIA project be disallowed including Units 5 and 6, the landfill, and the bridge to the landfill. In his summary Mr. Norwood stated:

> My review indicates a number of serious deficiencies in Dominion's decision-making related to the CHIA Project. These deficiencies included: 1) failing to evaluate alternatives before initially proceeding with the Project in June of 2015; 2) failing to maintain documentation to confirm the reasonableness of the evaluations that were conducted to support initiating and continuing the CHIA Project; and 3) failing to adequately consider the significant economic and environmental risks to continued operation of the Chesterfield coal units that existed at the time the Company's decisions were made to proceed with the CHIA Project, and thereafter when PJM market prices continued to fall. As a result of these multiple decision-making failures, the Company's $247 million

[74] PUR-2019-00195, Direct Testimony of Scott Norwood on Behalf of The Office of the Attorney General, Division of Consumer Counsel, filed on April 23, 2019, available at http://www.scc.virginia.gov/docketsearch/DOCS/4h7501!.PDF.

> CHIA Project will likely provide little or no value to customers since the Company has recently announced the planned retirements of Chesterfield Units 3 and 4 in 2020, and because it appears that Chesterfield Units 5 and 6 may also be retired by 2023.

Exhibit No. 15 at Summary.

Mr. Norwood also stated that "[i]t is highly unusual and not good practice for a utility to fail to maintain detailed documentation" to support its decision making on the CHIA project when there was good reason for the Company to expect it would be closely scrutinized by the SCC and its customers. Id. at 15.

The Sierra Club also recommended that the SCC disallow recovery of wet-to-dry component of the capital costs spent to keep Units 3 through 6 operational as well as the associated landfill and Reymet Road costs because neither are reasonable or prudent. In Exhibit No. 8, Sierra Club witness Devi Glick,[75] testified that evaluating the compliance deadline for both CCR and ELG rule, October 31, 2020 was the final compliance deadline. Exhibit No. 8 at 14. Witness Glick stated that the Company could have pursued alternative such as the retirement of the units and the entire CHIA project was not required on the timeline or the scale on which the Company proceeded. Id. at 15.

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[75] PUR-2019-00195, Direct Testimony of Devi Glick on behalf of Sierra Club, Exhibit 8, filed on June 11, 2109, at 9, available at http://www.scc.virginia.gov/docketsearch/DOCS/4h6v01!.PDF.

Q. DO YOU AGREE WITH DENC WITNESS JASON WILLIAMS' STATEMENT THAT EPA'S 2015 EFFLUENT LIMITATIONS GUIDELINES FORCED DENC TO CONVERT ITS COAL PLANTS TO DRY ASH HANDLING?

A. No. On page 4, lines 16 through 21, DENC witness Jason Williams states the following:

> On September 30, 2015, EPA finalized the Effluent Limitation Guidelines ("ELG") rules revising the regulations for the Steam Electric Power Generating category (40 CFR Part 423). The rule set new federal limits on multiple metals found in wastewater that can be discharged from power stations including a prohibition on discharges associated with bottom ash management systems.

In September 2017, the EPA postponed the earliest compliance date for the new effluent limitations and pretreatment standards for FGD wastewater and bottom ash transport water for two years, from November 1, 2018, until November 1, 2020. However, the final compliance date (the "no later than" compliance date) of December 31, 2023, for this portion of the ELG rule has not changed. EPA projected that it would take approximately three years to propose and finalize a new rule, and it is unclear whether the new rule will place the same limitations on fly ash transport water and bottom ash transport water.

INSURANCE COVERAGE FOR ENVIRONMENTAL LIABILITY

Q. HAS DENC RECEIVED OR RECOVERED ANY INSURANCE PROCEEDS FOR ENVIRONMENTAL DAMAGES?

A. No. The Public Staff investigated whether the Company has environmental or general liability insurance coverage that would provide coverage for mitigation and remediation costs associated with CCR sites.

The Company states that it holds policies issued by:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Specifically, in DR 81-1, the Public Staff asked the Company to provide all notices, claims and related documents sent by the Company to insurers that relate to CCR. In response, the Company provided **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** See DR 157, **Lucas Exhibit 15** (Confidential).

Q. DOES THE PUBLIC STAFF HAVE A RECOMMENDATION REGARDING MONITORING DENC'S INSURANCE NOTICE OF CLAIMS FOR INSURANCE COVERAGE?

A. The Public Staff recommends that the Commission monitor the existing and potential insurance claims, as similarly discussed in the DEP and DEC rate case orders. If any insurance proceeds are ultimately received or recovered, the Commission should require that DENC place all insurance proceeds received or recovered in a regulatory liability account to be disbursed back to ratepayers or to offset the costs to ratepayers of the Company's coal ash costs.

DEPRECIATION EXPENSE

Q. DID THE COMPANY REQUEST AN ADJUSTMENT TO DEPRECIATION EXPENSE IN ITS INITIAL RATE CASE FILING IN MARCH 2019?

A. Yes. The Company's requested adjustment is shown in E-1, Item 10, Adjustments NC-37, NC-75, and NC-82 (March filing), which is shown as **Lucas Exhibit 16**. Page 1 of the March filing shows a projected gross plant balance of $42,957,794,000 and a composite depreciation rate of 2.94%. Page 2 of the March filing is a narrative explaining the adjustment.

Q. DID THE COMPANY MAKE A FILING REGARDING ITS DEPRECIATION EXPENSE IN ITS SUPPLEMENTAL FILING IN AUGUST 2019?

A. Yes. The Company made its supplemental filing on August 5, 2019 (August filing) as shown in **Lucas Exhibit 17**.

Q. HOW DID THE MARCH FILING AND AUGUST FILING DIFFER?

A. The August filing utilized an entirely new method of calculating the depreciation expense adjustment. The two filings do not have any common information, spreadsheets, or calculations. They both contain a narrative on Page 2 but the narratives are completely different. The first sentence of the narrative for the method used in the August filing states: "The first step in determining the increase in Depreciation Expense is to calculate the amount of North Carolina Jurisdiction Depreciation Expense at the end of the test period (line 2)."

The Public Staff disagrees with this statement. Like most of the other adjustments in a general rate case, the first step is determining system-wide expenses. With depreciation, this first step starts with determining the system depreciable rate base and then determining depreciation rates for the various components of rate base, typically by FERC account. Allocation of expenses between states is one of the last steps, not the first.

Q. DID THE COMPANY HAVE DIFFICULTY PROVIDING THE BASIS FOR THE AMOUNTS IN ITS AUGUST FILING?

A. Yes. After it was requested by the Public Staff, it took the Company two business days to retrieve from its system the depreciable rate base and depreciation rates for solar, transmission, and distribution plant. The Company used this information in the calculation of the updated depreciation expense for North Carolina of $56,400,000 (August filing, Page 1, Line 2). Company staff stated that this process would take even longer if required for other depreciable rate base components such as production plant and general plant. Therefore, the Company was unable to retrieve the depreciable rate base and depreciation rates by FERC account for use by the Public Staff's depreciation witness Roxie McCullar, or by the Public Staff's accounting staff, in order to calculate the June 2019 depreciation expense for North Carolina of $59,572,000 (August filing, Page 1, Line 1).

Q. DO YOU BELIEVE THE COMPANY SHOULD HAVE THIS INFORMATION READILY AVAILABLE?

A. Yes. The Company is a regulated utility and its records should be transparent and readily available, especially during a general rate case. The Public Staff is unable to verify the effect of the Company's updated information on its requested adjustment in the August filing.

Q. ARE YOU RECOMMENDING ANY CHANGES TO THE AMOUNTS IN THE AUGUST FILING?

A. Not at this time. However, if the Company provides additional information regarding depreciation expenses, the Public Staff may supplement its testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Jay B. Lucas

I graduated from the Virginia Military Institute in 1985, earning a Bachelor of Science Degree in Civil Engineering. Afterwards, I served for four years as an engineer in the Air Force performing many civil and environmental engineering tasks. I left the Air Force in 1989 and attended the Virginia Polytechnic Institute and State University (Virginia Tech), earning a Master of Science degree in Environmental Engineering. After completing my graduate degree, I worked for an engineering consulting firm and worked for the North Carolina Department of Environmental Quality in its water quality programs. Since joining the Public Staff in January 2000, I have worked on utility cost recovery, renewable energy program management, customer complaints, and other aspects of utility regulation. I am a licensed Professional Engineer in North Carolina.

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

A. (Jay Lucas) Yes, I do.

Q. Can you please give that at this time?

A. Yes. The purpose of my testimony is to make recommendations to the Commission on the Public Staff's position in DENC's general rate case regarding whether the Company should be permitted to recover the full costs of coal combustion -- coal combustion residuals, or CCR, disposal.

I have reviewed the state and federal regulatory framework for CCR and the Company's compliance record. I have developed a summary of environmental legal actions against the Company and the industry knowledge of CCR management as it evolved over time. I have also developed a summary of CCR studies and reports that are specific to the Company's facilities.

The Company was unable to produce all groundwater monitoring data and discharge permits that the Public Staff requested, which resulted in a stipulation between the Company and the Public Staff. Also, the Company did not produce documents that should be in its possession regarding its CCR management and disposal practices.

I reviewed the Company's compliance status with state groundwater standards and EPA's CCR Rule and found evidence of degradation of the natural groundwater quality beginning as early as the 1980s. The Company has incurred significant costs to remediate its CCR sites and will incur significant costs in the future.

The incomplete records of the Company and the speculative nature of determining what other actions the Company could have taken over several decades make it difficult, if not impossible, to do a prudence review. The Public Staff recommends an equitable sharing of coal ash costs because DENC has culpability for non-compliance with environmental regulations and its past management of coal ash has resulted in a risk of future contamination that requires costly new management and closure requirements.

The Company crated the risk of future contamination by CCR and is responsible for actual groundwater contamination. The Company, not its customers, is responsible for its actions and its decisions that have led to the need for corrective action to remediate the groundwater. Therefore, the Public Staff recommends that 40 percent of the costs of CCR remediation should be paid by the Company's shareholders.

With regard to the Company's insurance coverage for environmental damages, the Public Staff recommends that the Commission monitor claim proceeds and require the Company to disburse any recovered proceeds to the ratepayers.

This completes my summary.

Q. Thank you, Mr. Lucas. And, Mr. Maness, can you state your name, business address and position for the record?

A. (Michael Maness) Yes. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Raleigh, North Carolina. And my position is Director of the Accounting Division with the Public Staff.

Q. Did you prepare and cause to be filed in this docket on August 23rd, 2019, testimony in question and answer form, consisting of 34 pages, one appendix and one exhibit?

A. Yes.

Q. Do you have any additions or corrections to your testimony?

A. No, I do not.

Q. If I were to ask you those same questions today, would your answers be the same?

A. Yes.

MS. CUMMINGS: Chair Mitchell, I request that the testimony of Mr. Maness, consisting of 34 pages, be copied into the record as if given orally from the stand, and that his appendix and exhibit be identified as premarked.

CHAIR MITCHELL: Motion will be allowed.

(Maness Exhibit 1 was premarked for identification.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

In the Matter of Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. **BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.**

A. A summary of my qualifications and duties is set forth in Appendix A to this testimony.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to present certain accounting and ratemaking adjustments that I am recommending be adopted by the North Carolina Utilities Commission (Commission) for purposes of determining the revenue requirement to be approved for Virginia Electric & Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company) in this proceeding.

Q. **HOW ARE YOUR RECOMMENDED ADJUSTMENTS BEING INCORPORATED INTO THE PUBLIC STAFF'S RECOMMENDED RATE INCREASE?**

A. I have provided the aggregate impact of all the adjustments I am recommending to Public Staff witness Sonja R. Johnson for inclusion in her Exhibit 1, in which she calculates the overall decrease in the Company's base non-fuel revenue requirement recommended by the Public Staff, which is then used to determine the recommended base non-fuel rate increase.

Q. IN WHAT AREA ARE YOU RECOMMENDING ADJUSTMENTS?

A. I am recommending an adjustment to the amount of amortization expense and rate base treatment proposed by the Company for the coal combustion residual (CCR) expenditures that it incurred between July 1, 2016, and June 30, 2019.

GENERAL INFORMATION REGARDING COAL COMBUSTION RESIDUALS

Q. WHAT ARE "COAL COMBUSTION RESIDUALS"?

A. Coal combustion residuals, or CCRs, including coal ash, are the by-products left over once combustion in a coal-fired power plant is completed. It can include fly ash, bottom ash, and other coal-derived and emissions control-related materials generated from burning coal for the purpose of generating electricity. Historically, electric utilities such as DENC have disposed of this ash by depositing it in nearby facilities such as ash landfills or ash ponds (where the ash is commingled with liquids).

Q. PLEASE BRIEFLY DESCRIBE THE BACKGROUND OF DENC'S COAL ASH MANAGEMENT ACTIVITIES.

A. The background related to these activities is described in the testimony of Public Staff witness Lucas. Briefly, as discussed in detail in his testimony, DENC's CCR management activities are today being conducted pursuant to several federal and state statutes and regulations, including, but not limited to the Environmental Protection Agency's (EPA) CCR Rule (CCR Rule), the federal Clean Water Act and the related EPA Steam Electric Power Generating Effluent Guidelines and Standards (ELG Rule), and several Virginia and West Virginia state laws and regulations.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED ADJUSTMENTS RELATED TO CCR EXPENDITURES.

A. The Company has made adjustments intended to result in the recording of a regulatory asset to reflect expenditures it has incurred to date to comply with the above-described federal and state governmental requirements imposed to provide for the safe disposal of CCRs. These adjustments include (1) the elimination of the CCR-related accounting entries made to the Company's books and records during 2018 or before for financial accounting purposes, (2) a pro forma adjustment to increase rate base to defer as a regulatory asset the CCR expenditures incurred between July 1, 2016, and June 30, 2019 (the Deferral Period), and (3) a pro forma adjustment to increase operations and maintenance (O&M) expenses to reflect a three-year amortization of those costs.

FINANCIAL AND REGULATORY ACCOUNTING FOR DENC'S CCR COSTS

Q. WHAT FINANCIAL OBLIGATIONS HAVE THE STATE AND FEDERAL STATUTES AND REGULATIONS PLACED UPON THE COMPANY?

A. As noted in the Company's exhibits filed in the Company's previous general rate case, Docket No. E-22, Sub 532 (Sub 532), between January 1, 2015, and June 30, 2016, the Company incurred $84,421,000 (on a total system basis) of CCR costs. The ratemaking treatment of this amount was addressed and resolved in the Sub 532 case. Per its supplemental exhibits and workpapers filed in the current proceeding, during the Deferral Period the Company incurred an additional $376,693,000 (on a total system basis), for a total of $461,114,000.

Q. HOW HAS THE COMPANY TREATED THESE OBLIGATIONS FOR FINANCIAL ACCOUNTING PURPOSES?

A. For financial accounting purposes, the Company has recorded the current fair value of its entire projected level of CCR expenditures, with adjustments for market influences and probability-weighted cash flows, as an Asset Retirement Obligation (ARO) liability, based on the requirements of Topic 410 (Asset Retirement and Environmental Obligations) of the Accounting Standards Codification (ASC 410) promulgated and maintained by the Financial Accounting Standards Board (FASB).

Upon initial establishment, the ARO liability is offset in the financial statements by one or both of two separate amounts. The first is a balance sheet asset, the Asset Retirement Cost (ARC), which represents amounts related to the future useful life of still operating assets; the ARC is depreciated over those remaining useful lives. The second is an immediate write-off to expense of ARO amounts that are related to assets that have already been retired or are no longer reflected in the financial statements (such as those written off as financially impaired).[1]

Q. **FOR RATEMAKING PURPOSES IN THIS PROCEEDING, IS THE COMPANY PROPOSING TO UTILIZE ARO ACCOUNTING AS PRESCRIBED BY THE FASB?**

A. No. In this proceeding, the Company has reversed all of the entries made on its books in association with the establishment of the FASB-

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[1] The FERC has adopted a similar method of accounting for use in accordance with its Uniform System of Accounts (USOA); however, both the FERC and this Commission provide for departures from the USOA for purposes of state jurisdictional accounting and ratemaking purposes (through the use of regulatory assets and liabilities). CFR Title 18, Chapter I, Subchapter C Part 101 - Accounts 182.3 and 254; Rules and Regulations of the North Carolina Utilities Commission – Rule R8-27.

mandated CCR ARO liability, and is instead proposing the deferral and amortization of actual expenditures during the Deferral Period. (A similar procedure was followed in the Sub 532 case for the expenditures made between January 1, 2015, and June 30, 2016.) The reversals include amounts initially recorded in plant in service (for the ARC), and O&M expenses (for the expense write-off).

The Company bases its proposal not to adopt ARO treatment for North Carolina retail ratemaking purposes on a 2004 Commission Order in Docket No. E-22, Sub 420, which focused on the relationship between the Commission's long-standing treatment of nuclear decommissioning costs and the FASB's required treatment of AROs pursuant to Statement of Financial Accounting Standards No. 143 (SFAS 143), now codified within ASC 410. This Order essentially allowed DENC to replace ASC 410 accounting treatment of a legal retirement obligation with a treatment that has been approved by the Commission. In this case, as in the Sub 532 rate case, the Company is asking the Commission to replace ASC 410 treatment with its own proposed ratemaking treatment.

Q. HOW IS THE COMPANY PROPOSING TO TREAT CCR EXPENDITURES AND OBLIGATIONS FOR RATEMAKING PURPOSES?

A. As noted previously, the Company proposes to establish a regulatory asset for actual CCR expenditures made during the Deferral Period, and to amortize that regulatory asset over a three-year period beginning with the effective date of the rates approved in this proceeding. This is fundamentally different from the FASB's ARO approach, in that it focuses on the recording and future recovery of actual costs spent, rather than the determination of a liability for future expenditures and the assignment of that liability to both past and future accounting periods for earnings recognition purposes.

Q. DOES THE PUBLIC STAFF AGREE WITH THIS APPROACH?

A. The Public Staff agrees with the concept proposed by the Company of deferring the costs incurred during the period in question and amortizing them over some multi-year period (but does not agree with the amortization period proposed by the Company in this case, as will be discussed later). The use of the Company's deferral approach results in a more straightforward tracking of the monies expended and awaiting future recovery than does the FASB's ARO approach, although it starts from a presumption that all of the costs should be eligible for consideration of recovery, not rejected simply because they are related to service in prior years. In this particular instance, I believe that the presumption is reasonable in this case, although it certainly is not so in all instances. The reason deferrals are not always appropriate is because North Carolina is a historical test year jurisdiction: retroactive ratemaking is generally unlawful, so deferral of past costs for purposes of future rate recovery should be a strictly limited exception to the retroactive ratemaking prohibition.

With regard to deferral, the Agreement and Stipulation of Settlement entered into in Sub 532 by the Company, the Public Staff, and Carolina Industrial Group for Fair Utility Rates I (CIGFUR I) (Stipulation) stated that:

> By virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR expenditures incurred through June 30, 2016, the Company has authority pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, to defer additional CCR expenditures, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a rate case or other appropriate proceeding.

The Commission, in Sub 532, approved this provision of the Stipulation; furthermore, the Public Staff believes that given the magnitude of the costs involved in the current proceeding, continued deferral has been reasonable. Therefore, the Public Staff has no objection to the deferral of expenditures made during the Deferral Period.

Q. WHAT IS THE EFFECTIVE RESULT OF THE COMPANY'S APPROACH?

A. The effective result of the Company's approach is to replace, for ratemaking purposes, the ARO approach required by the FASB for financial accounting purposes with the Company's proposed approach of deferring actual cash expenditures and then recovering them through amortization. On the Company's books, the regulatory asset and liability entries effectuating its approach take the form of overlaying the financial accounting entries; however, their effect, when added to the financial accounting entries, is to replace, for jurisdictional accounting and ratemaking purposes, the FASB's financial accounting approach with the accounting approach that has been previously approved by the Commission and that is proposed by the Company for purposes of this proceeding (and which is guided by the Commission's specific directives regarding cost recovery).

PUBLIC STAFF RECOMMENDED ADJUSTMENTS

Q. IN GENERAL, WHAT ADJUSTMENTS HAVE YOU MADE TO THE COMPANY'S COSTS OF COAL ASH MANAGEMENT?

A. I have made the following adjustments:

1. Calculation of the return between July 1, 2016, and June 30, 2019, using annual compounding, rather than monthly compounding;

2. Amortization of the balance of deferred coal ash expenditures as of June 30, 2019, over a 19-year period, rather than the 3-year period proposed by the Company; and

3. Reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base. This reversal, in conjunction with the 19-year amortization period, produces an equitable and reasonable sharing of the burden of coal ash expenditures between the Company's ratepayers and its shareholders.

RETURN COMPOUNDING ADJUSTMENT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE COMPOUNDING OF THE RETURN ON DEFERRED CCR COSTS.

A. The Company has included a return on the accumulated expenditures made during the Deferral Period in the calculation of total deferred costs to be amortized, using the weighted overall rate of return approved by the Commission in Sub 532. This overall return has been appropriately adjusted to a net-of-tax level using the combined income tax rate utilized elsewhere in this proceeding (which incorporates both the weighted state income tax rate and the 21% federal rate). However, the Company has employed monthly compounding in the calculation, instead of annual compounding.

The use of monthly compounding produces an annual dollar return amount that is greater than the amount that would be produced by simply multiplying any given principal amount outstanding for a year by the annual rate of return; thus, in my opinion the annual dollar return in the Company's calculation is overstated.[2] I have instead utilized the method approved by the Commission in the recent general rate cases of Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (Docket Nos. E-7, Sub 1146 and E-2, Sub 1142, respectively), which utilized annual, instead of monthly, compounding. Using this approach prevents the dollar return for each year from being overstated.

EQUITABLE SHARING ADJUSTMENT MADE TO AMORTIZATION EXPENSE AND RATE BASE

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO AMORTIZE THE DEFERRED BALANCE OF JULY 2016 THROUGH JUNE 2019 CCR COSTS OVER 19 YEARS, AND TO REVERSE THE

[2] As an example, if one were to assume that the target annual rate of return was 12.00%, under annual compounding the amount of return accrued for the first year on a \$100 investment would be \$12.00 (\$100 x 1.00% x 12 months), exactly the target annual return, and the balance at the end of the first year would be \$112.00. The interest for the second year would be based on that \$112.00, and so forth. However, under monthly compounding, the interest accrued for the year would be calculated by the formula [(\$100 x 1.01^{12}) - \$100], and the balance at the end of the first year would be \$112.68. The dollar return of \$12.68 would be greater than what would be appropriate given the annual target of 12.00%.

COMPANY'S INCLUSION OF THE UNAMORTIZED COSTS IN RATE BASE.

A. The Company has recommended that the costs of coal ash management be amortized over three years for ratemaking purposes in this proceeding. In my opinion, that is simply too short an amortization period for costs of the magnitude and nature of these. Instead, the Public Staff has been guided in its choice of amortization period for these costs in this proceeding by its belief that it is most reasonable and appropriate for these CCR costs to be shared equitably between the ratepayers and the Company's shareholders.

Q. **WHY DOES THE PUBLIC STAFF BELIEVE THAT THE CCR COSTS ACCUMULATED DURING THE DEFERRAL PERIOD SHOULD BE EQUITABLY SHARED BETWEEN THE RATEPAYERS AND SHAREHOLDERS?**

A. There are two general reasons why the equitable sharing of DENC's Deferral Period CCR costs is reasonable and appropriate for ratemaking purposes. First, Public Staff witness Lucas is testifying in this proceeding that the Company had a duty to avoid contamination of surface waters and groundwater, and that overall it both created the risk of environmental contamination related to its coal ash disposal and originally engaged in coal ash disposal practices that led to actual contamination. Furthermore, he testifies that DENC's original disposal practices pose an ongoing contamination risk that requires expensive remediation without any additional electric service benefit to its ratepayers. However, Mr. Lucas also testifies that it is very difficult at this date to determine which specific Company actions might have been imprudent or unreasonable, or to quantify the remediation costs for such actions, particularly in light of the incomplete records of the Company. Therefore, he is of the opinion that some degree of equitable sharing is appropriate in this circumstance.

Second, there is a history of approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. Such sharing between ratepayers and shareholders has been approved for costs of abandoned nuclear construction and in at least one case for environmental cleanup of manufactured gas plant facilities. Even if the reasons for equitable sharing set forth by Mr. Lucas were not present, the Public Staff still believes that some level of sharing, comparable to that previously used for abandonment losses on cancelled nuclear generation facilities, would be appropriate and reasonable for DENC's CCR costs.

Q. IS THE TYPE OF EQUITABLE SHARING YOU AND MR. LUCAS DESCRIBE APPROPRIATE EVEN FOR COSTS FOR WHICH

THERE HAVE BEEN NO SPECIFIC IMPRUDENCE OR UNREASONABLENESS FINDINGS?

A. Yes. Whether or not some specific disallowances of imprudently incurred or otherwise unreasonable costs are made in a specific case, it is still appropriate to consider whether equitable sharing is appropriate for the remainder of a particular body of costs not specifically found to be imprudent or unreasonable. Accordingly, the lack of any finding of specific imprudence or unreasonableness does not invalidate consideration of whether or not a sharing adjustment is appropriate and reasonable. There may well be reasons, such as the ones discussed in this testimony, that make equitable sharing appropriate and reasonable independent of prudence conclusions.

Q. **WHY DO YOU BELIEVE THAT THE MAGNITUDE AND GENERAL NATURE OF THE CCR COSTS PRESENTED FOR AMORTIZATION IN THIS PROCEEDING MAKES IT APPROPRIATE TO IMPLEMENT EQUITABLE SHARING?**

A. First, the total amount of costs incurred during the Deferral Period ($376,693,000, on a system basis) is quite large. The N.C. retail amount presented for amortization ($21,841,000, including the return adjusted as recommended earlier in my testimony) amounts to an average of approximately $179 per N.C. retail customer, using the 121,777 customers utilized by Public Staff witness Johnson in her customer growth expense adjustment. Requiring the N.C. retail customers to bear the cost of a three-year amortization period for these costs would burden them to the tune of almost $60 per year, on average, even before considering the impact of including the unamortized amount in rate base. (In fact, even without the removal of the unamortized amount from rate base that enables an equitable sharing adjustment, I believe that a three-year amortization period would be much too short for an expense of this magnitude.) Second, it must be remembered that DENC will be incurring significant additional costs in the future; in fact, the Company testified to the Virginia legislature in December 2018 that compliance with SB 1355 (or the CCR Excavation Act), which applies to sites in the Chesapeake area, may cost between $2.4 billion and $5.7 billion.[3] Therefore, the costs of approximately $461 million incurred before and during the Deferral Period do not come close to the total CCR costs the Company expected to incur as of the end of 2018. Third, much like the sharings that have been approved by the Commission with regard to plant abandonments over the years, the incurrence of these costs will not provide any benefits to customers in terms of additional electric service or improvements in service. Fourth, unlike

[3] Available at https://www.roanoke.com/news/virginia/coal-ash-excavation-could-cost-dominion-ratepayers-an-extra-per/article_f031a4b3-3c8d-578d-a8e8-b859589609bc.html (last visited August 23, 2019).

some situations in recent years in which plants have been retired early due to economic reasons, the incurrence of CCR costs has not been the result of an economic analysis that pointed toward an action that would be economically advantageous to ratepayers. Instead, the incurrence of CCR costs has been the result of actions needed to comply with laws and regulations, actions that, as testified to by witness Lucas, resulted at least in part from risks of contamination created by DENC and actual contamination resulting from DENC's own original disposal procedures. Finally, the Commission has implemented equitable sharing in several past circumstances involving incurred costs that did not provide any future benefits to retail customers, as is further discussed later in my testimony.

Q. HOW DOES THE PUBLIC STAFF ACHIEVE AN EQUITABLE SHARING OF COSTS SUCH AS CCR COSTS?

A. The first step in achieving an equitable sharing in a situation such as this is to exclude the unamortized amount of the deferred expenses from rate base. As a result of taking this step, the Company will not be allowed to earn a return from the ratepayers on the unamortized balance while the deferred costs are being amortized. The second step is to choose an amortization period that will result in a reasonable and appropriate sharing of the costs.

Q. IS EXCLUDING DEFERRED EXPENSES OR LOSSES FROM RATE BASE LEGAL UNDER THE NORTH CAROLINA GENERAL STATUTES?

A. Yes, according to advice of Public Staff counsel. Pursuant to N.C. Gen. Stat. § 62-133(b)(1), the only costs that the Commission is required to include in rate base are (1) the "reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period . . . ," and (2) in some circumstances, the costs of construction work in progress. I am advised by counsel that beyond those requirements, what is and what is not allowed in rate base is within the legal discretion of the Commission to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers. Moreover, N.C. Gen. Stat. § 62-133(d) requires the Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates." According to counsel, N.C. Gen. Stat. § 62-133(d) operates separately from N.C. Gen. Stat. § 62-133(b), and provides the Commission with discretion to authorize equitable sharing of utility costs, where appropriate to achieve reasonable and just rates.

The Commission has taken this approach several times in past cases, most often in the cases of nuclear and coal plants abandoned prior to commencing commercial operation, including, specifically for DENC, the abandonment losses related to Surry Unit 3, Surry Unit 4, North Anna Unit 3, and North Anna Unit 4. In DENC's 1983 general rate case, Docket No. E-22, Sub 273, the Commission outlined its policy regarding the treatment of plant abandonment losses:

> The proper rate-making treatment of abandonment losses related to electric generating plants has been before the Commission in several cases and will continue to arise in future cases. The Commission has, therefore, undertaken to re-examine this important issue in order to develop a more consistent and equitable approach to it. The Commission's ultimate responsibility with respect to ratemaking is to fix rates for the service provided which are fair and reasonable both to the utility and to the consumer. G.S. 62-133(a); State ex rel. Utilities Commission v. Morgan, 277 N.C. 255, 177 S.E. 2d 405 (1970); State ex rel. Utilities Commission v. Area Development, Inc., 257 N.C. 560, 126 S.E. 2d 325 (1962).
>
> Although the parties to this proceeding may disagree as to the proper amortization period to be utilized with regard to plant abandonment losses, they generally agree that Vepco should be allowed to recover the prudently invested cost of its abandonment losses through amortization over some period of time. The Commission, based upon the evidence presented, must determine what is a fair amortization period in order to fairly allocate the loss between the utility and the consumer. Thus, the Commission finds no appropriate basis for requiring an amortization period greater than 10 years for North Anna Unit 3. This Commission in Docket No. E-22, Sub 224, approved a 10-year amortization of Surry Units 3 and 4; in Docket E-22, Sub 257, the Commission continued the 10-year write-off of Surry Units 3 and 4 and approved the write-off of North Anna Unit 4 over a 10-year period; in

> Docket No. E-22, Sub 265, the Commission continued to allow Vepco a 10-year write-off for all three of said units. This Commission has consistently used a write-off period of 10 or fewer years for all major plant cancellations.
>
> Based upon a careful consideration of the evidence of record in this case, the Commission finds and concludes that a 10-year period is a reasonable period and should be used for the amortization of the North Anna Unit 3 cancellation costs. Furthermore, the Commission concludes that amortization of the losses resulting from Vepco's cancellation of its Surry Units 3 and 4 and North Anna Unit 4 should be continued over 10 years as previously ordered by the Commission. Utilization of a 10-year amortization period is proper and fair in this proceeding for the reason that such an amortization period, particularly when considered in conjunction with the Commission's decision as subsequently discussed, to allow Vepco no return on the unamortized balance, will serve to more reasonably and equitably share the burden of such plant cancellations between the Company's shareholders and its present and future ratepayers.
>
> Pursuant to the Commission's reexamination of the proper rate-making treatment of abandonment losses, the Commission has determined that it is neither fair nor reasonable to include any portion of the unamortized balance of such investments in rate base and, furthermore, that no adjustment should be allowed which would in fact have the effect of allowing the Company to earn a return on the unamortized balance. The Commission has concluded that this treatment provides the most equitable allocation of the loss between the utility and the consumer.

<u>Seventy-Third Report of the North Carolina Utilities Commission</u>, pp 354-55.

The policy of exclusion from rate base was applied consistently from 1983 forward during the rash of nuclear plant cancellations by the large electric utilities of this State.

This specific issue has also come before the North Carolina courts. While I am not an attorney, it is my understanding that equitable sharing of prudently incurred utility costs has been ruled to be lawful in past cases. A memorandum from Public Staff counsel addressed this question in the last Duke Energy Carolinas rate case, Docket No. E-7, Sub 1146. That memorandum was attached to my testimony in that docket as Appendix B, and was allowed by the Commission since it was the foundation underlying my recommendation on equitable sharing. Any recommendation the Public Staff makes on equitable sharing will depend on the facts and circumstances of each case, but the legal foundation is the same. Therefore, in response to this question I incorporate by reference the memorandum labeled as Appendix B to my testimony in Docket No. E-7, Sub 1146.

As discussed in that memorandum, in 1989 the North Carolina Supreme Court affirmed the Commission's decision that reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs. In State ex rel. Utilities Com. v. Thornburg, 325 N.C. 463 (1989), the Attorney General had sought exclusion of all abandonment costs related to the Harris Nuclear

Plant. However, the Commission allowed amortization of the abandonment costs, with no return on the unamortized balance. The Court ruled that the Commission was acting within its discretion:

> [T]he Commission's order does not err as a matter of law in authorizing CP&L to continue to recover a portion of the cancellation costs of the abandoned Harris Plant as operating expenses through amortization. The Commission's determination was supported by several findings and conclusions. First, the Commission found that although "[t]his case must of course be decided on the basis of North Carolina statutes" the "majority of courts and commissions that have dealt with this issue have allowed ratemaking treatment of abandonment losses, usually as operating expenses." Second, the Commission concluded "that a liberal interpretation of the operating expense element of ratemaking so as to include the Harris abandonment losses is appropriate herein." Last, the Commission found further support for its conclusion was provided by N.C.G.S. § 62-133(d), which allows the Commission to consider all material facts in the record in determining rates.
>
> . . . .
>
> Last, we disagree with the Attorney General's contention "that strong policy considerations support the disallowance of [cancellation] expenses." We note that jurisdictions have generally dealt with the allocation of cancelled plant costs in one of the following three ways:
>
> (1) recovery of all of the costs from ratepayers, by allowing amortization of the investment plus a return on the unamortized balance;
>
> (2) recovery of all costs from shareholders through a total disallowance of recovery in rates, instead requiring the utility to write off the entire amount in a single year; or
>
> (3) recovery from ratepayers and shareholders through amortization of costs in rates over a period of years, with no return on the unamortized balance.

> . . . Strong policy considerations support the Commission and commentators who have concluded that method three is the best of the three alternatives in that it promotes "an equitable sharing of the loss between ratepayers and the utility stockholders."
>
> . . . .
>
> On this record, the Commission's continued use of method three is within the Commission's discretion, and this Court will not disturb that decision.

Similarly, an equitable sharing of costs was approved in the Commission's October 7, 1994, *Order Granting a Partial Rate Increase* in Docket No. G-5, Sub 327 (1994 Order). In that case, Public Service Company of North Carolina (PSNC) owned several sites that were previously operated as manufactured gas plants (MGPs). The MGPs had ceased operations in the early 1950s. At the time of the rate case, the MGP sites were the subject of "investigations under environmental laws." 1994 Order at 6. In its Order, the Commission concluded that deferral and amortization of MGP clean-up costs in a general rate case, rather than through a tracker, would result in more stable rates than otherwise. Furthermore, the Commission concluded that the unamortized balance of MGP costs should not be included in rate base, resulting in a sharing of clean-up costs between ratepayers and shareholders that would provide PSNC with motivation to minimize its costs or seek contributions from others.

Q. ARE THE CCR COSTS THAT DENC IS SEEKING TO RECOVER IN THIS CASE "USED AND USEFUL," THUS IMPLYING THAT THEY MUST BE INCLUDED IN RATE BASE?

A. No. In North Carolina utility regulation, the term "used and useful" only applies to the public utility's property (including true working capital, as discussed below), not the expenses it incurs in the operation, maintenance, or disposal of that property. Some might claim that since the costs deferred for coal ash clean-up are associated with property that is or once was used and useful, the costs themselves should be considered "used and useful," and therefore should be included in rate base, to the extent they remain unamortized, pursuant to N.C. Gen. Stat. § 62-133(b)(1). In my opinion as a regulatory accountant, and in the opinion of Public Staff counsel, this argument is incorrect and is an inappropriate application of the term "used and useful." It is appropriate to state that the actual costs capitalized by a utility as the costs of used and useful property itself may be included in rate base and thereby earn a return, as long as those costs are reasonable and prudently incurred, and are intended to provide utility service in the present or in the future; however, the expenses of operating and maintaining that property in the present or in the future do not get capitalized as part of the cost of the property. Instead, they are allowed to be recovered from the ratepayers on an ongoing basis as operating expenses, if they themselves are determined by the Commission to be reasonable and prudently incurred. This recovery is provided for under N.C. Gen. Stat. § 62-133(b)(3), an entirely different portion of the statute. If, however, there are expenses that were incurred in the past, but for some reason the Commission decides that they can be deferred for recovery in the future, the Commission can approve a regulatory asset to capture such expenses, and even provide for a return on them due to the deferral of their recovery (by including them in rate base or otherwise providing for carrying costs). This treatment is within the discretion of the Commission, but it does not transform the Commission-created regulatory asset into capitalized property cost, such as the cost of a generating plant. The two types of costs are fundamentally different from one another; one is the actual cost of property intended to provide service in the present or future; the other is a past expense deferred for future recovery. The first, if reasonable and prudently incurred, may be required to be included in rate base; the second carries no such requirement.

Q. IN WHICH CATEGORY DO THE DEFERRED COSTS PROPOSED IN THIS CASE BY DEC FOR AMORTIZATION FALL?

A. I believe that the costs should fall into the category of a deferred expense for the following reasons:

(1) In data responses to the Public Staff, the Company has stated that the vast majority of the CCR expenditures made from January 2015 through June 2019 would be charged to expense if the FASB and FERC USOA ARO accounting requirements did not exist.

(2) Even for those items that might be capitalized costs of property in the absence of the FASB and FERC USOA ARO accounting requirements, the Company has itself chosen to request a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past. Although the Company could have chosen to propose following a different method, whereby it might specifically identify capital costs separately and include them in rate base, depreciating them over their useful lives, while accounting for other expenses on an ongoing basis, it did not. Instead, the Company has proposed to utilize an accounting and ratemaking model that accounts for and recovers the coal ash cleanup costs as expenses on an as-spent basis, without specific identification

of, or accounting for, any costs as plant in service or other property.

Q. DOES THE FACT THAT THE COMPANY HAS CLASSIFIED THE PROPOSED CCR DEFERRED COST BALANCE IN ITS FILING AS "WORKING CAPITAL" MEAN THAT THE REGULATORY ASSET MUST BE INCLUDED IN RATE BASE?

A. No, it does not, because in my opinion, this classification is just a matter of convenience. True working capital is the investment made in materials and supplies, cash, and other similar items to finance and provide for the Company's present and future operations; in other words, to "do the work" of providing ongoing utility service. The proposed deferred coal ash compliance costs are expenses incurred in the past that the Company proposes to recover in the future; they have nothing to do with the Company's forward-looking obligation to provide utility service. Normally, it does no harm for the Company to group many disparate items under the heading of working capital; however, one should not mistake the nominal inclusion of the proposed coal ash cost deferred costs in this group for actual evidence that such costs are in fact "working capital."

The late Charles F. Phillips, Jr., Ph.D., former Professor of Economics at Washington and Lee University, described working capital in this manner:

> Working capital – the funds representing necessary investment in materials and supplies, and the cash required to meet current obligations and to maintain minimum bank balances – is included in the rate base so that investors are compensated for capital they have supplied to a utility.

Charles F. Phillips, Jr., The Regulation of Public Utilities, Third Edition (1993), p 348.

It is very important to note that the items of working capital described by Dr. Phillips – materials and supplies, minimum cash balances, and the cash necessary to meet current obligations (which is typically determined for large utilities through the use of a lead-lag study) – are all focused on doing the current and future work of the utility, unlike deferred CCR costs, which are expenditures made in the past that the Commission, if it approves the Company's amortization expense proposal, would allow the utility recover in the future. Thus, no matter how it is categorized on paper by a utility filing a general rate case, the CCR deferred costs neither enable or facilitate the provision of current or future utility service, and cannot be classified in substance as "working capital."

Q. PLEASE DESCRIBE HOW THE SECOND STEP YOU DESCRIBED PREVIOUSLY, THE CHOICE OF AN AMORTIZATION PERIOD, CAN BE USED TO ACHIEVE A SHARING OF COSTS BETWEEN THE UTILITY AND ITS RATEPAYERS.

A. Once it has been determined that the unamortized balance of the coal ash costs will not be included in rate base (i.e., there will be no return or carrying cost on the unamortized balance once amortization begins), the ability of the utility to recover those costs at a 100% level becomes entirely dependent upon the speed at which recovery can be achieved. The utility has already spent the money represented by the deferred costs in question; therefore, it will be required to borrow money or use equity to finance the spent costs until it can recover them from the ratepayers. If the utility was able to recover the total cost immediately, it would recover all of the costs at a 100% level; however, the ratepayers would also lose all of the time value of money that could be provided to them by a reasonable amortization period. Another way to look at this is that in that immediate recovery circumstance, the utility recovers 100% of the present value of the deferred costs at the time of deferral, and the ratepayers bear 100% of that cost. However, as the delay in utility recovery (i.e., the amortization period) increases, the utility's financing costs increase, and the burden of the loss of the time value of money on the ratepayers decreases. The utility recovers a lesser amount and lesser percentage of the present value of the underlying cost, and thus the ratepayers bear less of the burden. Considering the magnitude and inherent nature of the CCR costs themselves, as well as the issues articulated by Public Staff witness Lucas, it is inappropriate to ask ratepayers to bear 100% of the risk or fund a return to shareholders on these expenses.

Q. WHAT AMORTIZATION PERIOD DOES THE PUBLIC STAFF RECOMMEND IN THIS CASE FOR THE COMPANY'S COAL ASH COSTS AS ADJUSTED BY THE PUBLIC STAFF?

A. As shown on **Maness Exhibit I**, Schedule 1, the Public Staff recommends an amortization period of 19 years beginning on the date the rates approved in this proceeding become effective.

Q. WHAT SHARING PERCENTAGE DOES A 19-YEAR AMORTIZATION PERIOD PRODUCE?

A. At the net-of-tax overall rate of return recommended by the Public Staff, a 19-year amortization period results in the ratepayers bearing approximately 60% of the present value of the Deferral Period deferred costs at November 1, 2019 (with a return accrued to that point).[4] The Public Staff believes that an equitable sharing of the coal ash costs incurred in the Deferral Period is reasonable and appropriate for the reasons discussed above. The specific sharing ratio of 60% of the costs to be borne by ratepayers, and 40% of the costs to be borne by shareholders, is a qualitative judgment. The

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[4] If the Commission were to approve a rate of return different from that recommended by the Public Staff, the amortization period necessary to achieve a 60%-40% sharing would possibly change. A lower rate of return would tend to produce a higher ratepayer burden; a higher rate of return would produce a lower ratepayer burden.

large magnitude of costs that do not contribute to additional electric service is part of the judgment; another part is the available evidence on the extent of DENC's culpability for coal ash environmental contamination, which differs from the evidence in the most recent DEC and DEP rate cases.

Q. **WHY DO YOU BELIEVE THAT AN AMORTIZATION PERIOD THAT ASSIGNS 40% OF THE COST BURDEN TO SHAREHOLDERS, AS OPPOSED TO THE 50% SHAREHOLDER BURDEN THAT THE PUBLIC STAFF RECOMMENDED IN THE RECENT DEC AND DEP GENERAL RATE CASES, IS APPROPRIATE IN THIS CASE?**

A. Public Staff witness Lucas testifies that he believes that the culpability of DENC, at least as known at the present time, is less than that of DEC and DEP. Therefore, the Public Staff is recommending that in this proceeding DENC's shareholders be assigned a smaller proportional share of the Company's CCR costs (40%) than the Public Staff recommended in the case of DEC and DEP. However, Mr. Lucas notes that the Public Staff's opinion may change in the future, for costs incurred in future proceedings, when more data is available. Overall, the Public Staff's 60%-40% recommendation in this case is being made for the reasons Mr. Lucas and I set forth in our testimonies.

Q. IS IT ACCURATE TO SAY THAT YOU INDICATED IN THE DEP HEARING IN DOCKET NO. E-2, SUB 1142 THAT EVEN IF NO IMPRUDENCE HAD OCCURRED, THE PUBLIC STAFF WOULD LIKELY STILL RECOMMEND A 50-50 SHARING OF COSTS?

A. No, it is not accurate to say that about my testimony in the DEP case. My testimony was as follows:

> . . . as I said, even if you left out specific acts or omissions of the Company and assumed everything was prudent, aboveboard, it's still likely that we would recommend a sharing of the cost between the ratepayers and the shareholders.
>
> E-2, Sub 1142, T. Vol. 19, p 61.

My position in the DEP and DEC cases, and the present DENC case, has consistently been that culpability for coal ash environmental contamination is one, but not the only, factor relevant to determination of appropriate cost sharing percentages.

Q. IF THE PUBLIC STAFF BELIEVED THAT DENC WAS NOT CULPABLE AT ALL WITH REGARD TO ITS CCR COSTS, WOULD THE PUBLIC STAFF RECOMMEND A SHAREHOLDER ASSIGNMENT OF 0%?

A. Most likely not. There have been past abandonment cases where the Public Staff found no culpability on the part of the utility, yet still recommended (and the Commission approved) a sharing of costs (typically in the neighborhood of 30% assignment to the shareholders). Therefore, it is most likely that even in the absence of culpability, the Public Staff would recommend a sharing of some type due to the magnitude and/or the nature of the costs involved. This fact also contributes to the Public Staff's recommendation of a 40% stockholder responsibility, in that 40% reflects some degree of culpability, and thus a higher stockholder cost responsibility, than the Public Staff likely would have recommended in the absence of that culpability.

Q. **IN THE SUB 532 GENERAL RATE CASE, THE PUBLIC STAFF AGREED TO AN AMORTIZATION PERIOD OF FIVE YEARS FOR COAL ASH COSTS, WITH THE UNAMORTIZED BALANCE INCLUDED IN RATE BASE. WHY ARE YOU RECOMMENDING SUCH A DIFFERENT TREATMENT IN THIS CASE?**

A. One of the reasons for the different recommendation is sheer magnitude. In the Sub 532 case, the total paid-to-date system costs in question were only approximately 22% of the total Deferral Period system costs at issue in this case. Additionally, at that point in time, there was almost no evidence in the record of environmental problems related to DENC's coal ash facilities. As discussed by Public Staff witness Lucas, that is clearly not the case in this proceeding. I would also like to point out that the stipulation filed by the Company and the Public Staff in that proceeding stated that "[n]otwithstanding this agreement, the Stipulating Parties further agree that the appropriate amortization period for future CCR expenditures shall be determined on a case-by-case basis." The Sub 532 case does not serve as precedent for regulatory accounting recommendations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

QUALIFICATIONS AND EXPERIENCE

MICHAEL C. MANESS

I am a graduate of the University of North Carolina at Chapel Hill with a Bachelor of Science degree in Business Administration with Accounting. I am a Certified Public Accountant and a member of both the North Carolina Association of Certified Public Accountants and the American Institute of Certified Public Accountants.

As Director of the Accounting Division of the Public Staff, I am responsible for the performance, supervision, and management of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings. I have been employed by the Public Staff since July 12, 1982.

Since joining the Public Staff, I have filed testimony or affidavits in a number of general, fuel, and demand-side management/energy efficiency rate cases of the utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC., and Virginia Electric and Power Company (Dominion Energy North Carolina) as well as in several water and sewer general rate cases.

I have also filed testimony or affidavits in other proceedings, including applications for certificates of public convenience and necessity for the construction of generating facilities, applications for approval of self-generation deferral rates, applications for approval of cost and incentive recovery mechanisms for electric utility demand-side management and energy efficiency (DSM/EE) efforts, and applications for approval of cost and incentive recovery pursuant to those mechanisms.

I have also been involved in several other matters that have come before this Commission, including the investigation undertaken by the Public Staff into the operations of the Brunswick Nuclear Plant as part of the 1993 Carolina Power & Light Company fuel rate case (Docket No. E-2, Sub 644), the Public Staff's investigation of Duke Power's relationship with its affiliates (Docket No. E-7, Sub 557), and several applications for business combinations involving electric utilities regulated by this Commission. Additionally, I was responsible for performing an examination of Carolina Power & Light Company's accounting for the cost of Harris Unit 1 in conjunction with the prudence audit performed by the Public Staff and its consultants in 1986 and 1987.

I have had supervisory or management responsibility over the Electric Section of the Accounting Division since 1986, and also was assigned management duties over the Water Section of the Accounting Division during the 2009-2012 time frame. I was promoted to Director of the Accounting Division in late December 2016.

Q. And did you cause five pages of supplemental testimony to be filed in this proceeding?

A. (Michael Maness) Yes.

MS. CUMMINGS: Chair Mitchell, I request that the supplemental testimony also be moved into the record.

CHAIR MITCHELL: The motion is allowed.

(Maness Supplemental Exhibit 1 was premarked for identification.)

(Whereupon, the prefiled supplemental testimony of Michael C. Maness was copied into the record as if given orally from the stand.)

DOCKET NO. E-22, SUB 562
DOCKET NO. E-22, SUB 566

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562 In the Matter of Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-22, SUB 566 In the Matter of Petition of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for an Accounting Order to Defer Certain Capital and Operating Costs Associated with Greensville County Combined Cycle Addition	SUPPLEMENTAL TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

September 18, 2019

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

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. DID YOU FILE DIRECT TESTIMONY ON AUGUST 23, 2019 IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my supplemental testimony is to present a revision to the ratemaking adjustments that I am recommending for the costs of Dominion Energy North Carolina's (DENC or the Company) CCR activities. I have provided my revised adjustments to Public Staff witness Sonja R. Johnson for inclusion in her Settlement Exhibit 1, in which she calculates the revised overall increase in the Company's revenue requirement recommended by the Public Staff in accordance with the Agreement and Stipulation of Partial Settlement (Stipulation) filed in this proceeding between DENC and the Public Staff.

Q. WHAT REVISION ARE YOU MAKING TO YOUR RECOMMENDED ADJUSTMENTS IN THE AREA OF CCR COSTS?

A. My revision applies solely to my recommended adjustment to the amortization expense for deferred CCR costs. I am recommending a reduction in the amortization period for deferred CCR costs from 19 years to 18 years.

Q. WHY HAVE YOU REDUCED THE AMORTIZATION PERIOD TO 18 YEARS?

A. As reflected in the Stipulation, the Public Staff and DENC have agreed to a weighted overall rate of return of 7.20% for purposes of setting rates in this proceeding. In my initial direct testimony, I state that the Public Staff believes that a sharing rate of 60% to ratepayers and 40% to shareholders for CCR costs is most reasonable and appropriate. The overall rate of return, net of income taxes, affects the number of years of amortization needed to achieve this sharing. Because of the increase in the rate of return from that initially recommended by the Public Staff to the 7.20% agreed to in the Stipulation, the amortization period necessary to achieve an approximate 60%-40% sharing has decreased to 18 years.

Q. YOU STATE THAT THE 60%-40% SHARING IS "APPROXIMATE." WHY IS IT NOT EXACT?

A. I have calculated the recommended amortization period in whole years. An amortization period of 18 years produces a ratepayer sharing portion of 59.212%, which is the closest to the 60.000% target that can be arrived at using the stipulated rate of return and whole years without the ratepayer portion exceeding that target.

Q. WHAT IS THE IMPACT OF YOUR REVISION ON YOUR RECOMMENDED AMORTIZATION EXPENSE?

A. Reflection of the revision results in an increase in the recommended North Carolina retail amortization expense from $1,150,000 to $1,213,000, and thus a reduction in our recommended adjustment from $(6,153,000) to $(6,090,000). My revised adjustment is set forth on Maness Supplemental Exhibit I, Schedule 1, attached to this testimony.

Q. DOES THE INCREASE IN YOUR RECOMMENDED AMORTIZATION EXPENSE AFFECT RATE BASE?

A. No. The Public Staff continues to recommend that deferred CCR costs be excluded from rate base in their entirety, in order to achieve an equitable sharing of those costs between the ratepayers and the shareholders.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

Q. Do you have a summary of your testimony and supplemental testimony at this time?

A. (Michael Maness) Yes, I do. The purpose of my initial testimony, prefiled on August 23rd, 2019, is to recommend certain adjustments to the amount of amortization expense and rate base treatment proposed by the Company for the coal combustion residual, or CCR, expenditures that it incurred between July 1st, 2016, and June 30th, 2019, the Deferral Period.

My adjustments are as follows: one, calculation of the return during the Deferral Period using annual compounding, rather than monthly compounding; two, amortization of the June 30th, 2019, balance of deferred CCR expenditures over a 19-year period, rather than the three-year period proposed by the Company; and, three, reversal of the Company's inclusion of the unamortized balance of CCR expenditures in rate base.

Adjustment Number 1, related to the calculation of the interim return on CCR costs, has been accepted as reasonable by the Company, as noted in the rebuttal testimony of DENC Witness McLeod.

The purpose of Adjustment Numbers 2 and 3 is to set an amortization period for deferral period CCR costs that, one, recognizes that the Company's recommended amortization period is too short for costs of the magnitude and nature of these; and, two, most importantly, when coupled with the exclusion of the unamortized balance of the deferred costs from rate base, will result in an equitable sharing of the costs between shareholders and ratepayers.

There are two general reasons why the equitable sharing of DENC's deferral period CCR costs is reasonable and appropriate for ratemaking purposes. First, as testified to by Public Staff Witness Lucas, some degree of equitable sharing is appropriate in this particular circumstance because DENC has culpability for past non-compliance with environmental regulations and for creating a risk of future contamination from coal ash.

Second, even if culpability were not present, some level of sharing, comparable to that previously used for abandonment losses on cancelled nuclear generation facilities, would be appropriate and reasonable for DENC's CCR costs because of, (a), their magnitude; (b), the lack of any additional electric service or service improvement benefits to customers; and, (c), the Commission's past implementation of equitable sharing for incurred costs that did not provide any future benefits to retail customers.

With regard to magnitude, it is important to note that not only is the system level $377 million for which amortization is being requested in this case quite large, but also, as of December 2018, the Company testified to the Virginia Legislature that compliance with Virginia's CCR Excavation Act may cost between 2.4 billion and 5.7 billion dollars on a system basis.

Based on the circumstances of this case, the culpability of the Company and the magnitude and nature of the costs, as well as the general levels of equitable sharing effectively approved by the Commission in past cases, the Public Staff believes that shareholders should be required to bear 40 percent of the Deferral Period CCR costs.

At the overall rate of return recommended by the Public Staff in its initial direct testimony, coupling a 19-year amortization period with the exclusion of the Deferral Period CCR costs from rate base would achieve a shareholder burden of approximately 40 percent of the present value of the costs. It is most likely that even in the absence of culpability, the Public Staff would recommend a sharing of some type due to the -- due to the magnitude and/or the nature of the costs involved.

My recommendation of equitable sharing is supported by the Public Staff's legal analysis that the large majority of CCR expenditures are not entitled to a return. Rather, a return is discretionary with the

Commission, which provides the option for equitable sharing by allowing full amortization of the expenditures but denying a return on the unamortized balance.

The purpose of my supplemental testimony, prefiled on September 18th, 2019, is to present a revision to my recommended adjustment to the amortization expense for deferred CCR costs. I am recommending a reduction in the amortization period for deferred CCR costs from 19 years to 18 years. The reason for this reduction is that the increase in the rate of return from that initially recommended by the Public Staff to the 7.20 percent agreed to in the Stipulation has caused the amortization period necessary to achieve an approximate 60 percent/40 percent sharing to decrease to 18 years.

This completes my summary.

Q. Thank you, Mr. Maness.

MS. CUMMINGS: The panel is available for cross-examination.

MS. FORCE: Want me to go first? I thought maybe you would.

CROSS-EXAMINATION BY MS. FORCE:

Q. Hello. Margaret Force with the Attorney General's Office. I have a couple of questions. I think they're for Mr. Maness. I'm looking for some clarification with respect to ARO that's mentioned in Mr. McLeod's testimony. And he talks about the cost of coal ash, referring to the CCR disposal costs as CCR ARO costs.

Could you shed some light on -- on how the -- what an ARO is and how that relates to ratemaking, please?

A. (Michael Maness) Well, I guess as -- initially, I'll state that it's a little bit confusing, I think, when we just sort of generally refer to these CCR costs as ARO costs because ARO, which stands for asset retirement obligation, is really a -- a term that's used specifically within the accounting literature to a -- to a liability that has very specific methods and processes for its determination.

So when you look at financial accounting, when they're going to establish the ARO for financial accounting, they are actually looking at future estimated costs of CCR removal and disposal. And they take -- they make estimates of those future costs using a variety of accounting techniques and then they basically discount that to the present value as of today, using an appropriate discount rate, and they put that on their financial statements for financial investor purposes as a liability.

At the same time, they establish an asset called an asset retirement cost, or an ARC, as an asset on the balance sheet. And then to flow that through expense over some period of time, they depreciate it into the future in future financial statements using some sort of rational depreciation method, or if it's associated with an underlying asset, such as a coal plant that's already been retired, they will write it off to expense immediately.

One important thing to remember about that is that what goes into expense for purposes of their financial statements for investors has really nothing to do with the amount of cash that gets -- gets disbursed in any given year. In contrast, the method that the Company has proposed to be used for ratemaking purposes before this Commission looks directly at the actual expenditures that have already occurred and proposes to defer them and amortize them over some period of time.

That amortization expense -- that annual amortization expense will become the expense for the year for regulatory accounting and ratemaking purposes in this jurisdiction and, thus, is totally different from the expense that would be recorded for financial statement purposes to the -- to the wider body of investors.

Q. So when there's an asset retirement obligation recorded, it's -- it's the time that the Company is recognizing a legal obligation; is that correct?

A. Yes, a legal obligation to make expenditures at some point in the future.

Q. And so they haven't actually incurred the costs at that point, but are recognizing that they have that obligation. And so when you said expense, they might expense the entire amount for financial recording -- reporting purposes. Is that what you mean?

A. If it's related to an asset that's already been retired.

Q. Ah, I see.

A. If I can give an example, some -- in some cases, you may have an asset retirement obligation for a generating plant where the actual expenditures are not going to take place until many years into the future. So in that case, they will go ahead and record expenses -- they'll depreciate over the life of the plant. And they will incur those expenses at some future time, but they -- or those expenditures, but they will be recording an expense as they go along without actually spending any cash at all.

In other cases, you may have, such as we have for some of the coal plants involved here, plants that have already been retired. And so they still may not make those expenditures for some time into the future, but they will go ahead and immediately, for financial statement purposes, record the entire asset retirement cost related to that plant as an expense in the period in which it arises.

Q. Okay. And I have a -- another question that's related to that. When we're talking about the costs in this case, the coal ash costs that are the amounts in dispute, the CCR costs, are we talking about the costs that the Company incurs at its operating plant, such as to convert to dry ash handling that might have been required under those federal regulations or state regulations?

A. I'm probably not the technical person to answer about the different types of costs, but these are costs basically of -- I think the -- what -- terminal salvage has been used in some places. These are the costs of closing and -- the coal basins, moving the coal and finding a place for permanent disposal. They wouldn't be the same costs as the costs, say, for changing coal ash handling at an operating plant.

Q. So these are all end-of-life-type costs that -- that are being addressed through this mechanism; is that right?

A. Well, they're end of life in the sense that they are related in a certain sense to either retiring the entire plant or retiring a basin at a plant that would have to be done at some point to retire the entire plant.

Q. Okay.

A. Even if the expenditure happens before the plant's totally retired.

Q. Okay. Thank you. I don't have any other questions.

CROSS-EXAMINATION BY MS. GRIGG:

Q. Good afternoon, Mr. Maness, Mr. Lucas. I have a few questions for Mr. Maness, and then my colleague, Mr. Snukals, has some questions for Mr. Lucas.

Mr. Maness, I'll start with your concept of equitable sharing, as you characterize it.

A. (Michael Maness) Yes.

Q. You would probably agree that the Company does not agree with that characterization or nomenclature of it being equitable.

A. Not in this case, no.

Q. And you have not calculated any specific cost that the company has incurred since July of 2016 that you contend should be disallowed due to the Company's coal ash handling and disposal practices, correct?

A. Well, that would probably be a -- a question more properly addressed to Mr. Lucas, because he did that detailed review. But I believe the answer is no, but I'll look to Mr. Lucas to correct it.

A. (Jay Lucas) We didn't do any mathematical calculations, if that's your question.

Q. That is. And, yet, you believe some of the coal ash expenditures were incurred due to some concept of what you term culpability, correct?

A. (Michael Maness) Again, I'll turn to Mr. Lucas for that.

A. (Jay Lucas) Yes. We believe the Company's culpable and responsible for its coal ash handling practices. So it's culpable for some of the mismanagement and we believe not all those costs should be passed on to ratepayers.

Q. And --

A. (Michael Maness) And I've tried -- if I can just --

Q. Of course.

A. I've tried to reflect his testimony, to follow up on it and restate it in my testimony. So --

Q. That's correct, Mr. Maness. As a matter of fact, I think it's -- you use the term "culpability" no fewer than three times.

Starting on Page 31 of your testimony, you use it in the context of how you came up with the 60/40 ratio, correct?

A. Yes.

Q. And then you said again in that similar context that DENC at least at the present time is less culpable, as you call it, than DEC and DEP. That's Duke Energy Carolinas and Duke Energy Progress. Correct?

A. Yes. And I relied on Mr. Lucas's testimony for those uses of the word.

A. (Jay Lucas) Yeah. That comparison to -- to the Duke Energy companies is in my testimony.

Q. Thank you. Can you cite any NCUC order, Mr. Maness, that uses the phrase "culpability"?

A. (Michael Maness) I haven't done any sort of research into whether that term's been generally used. But I know that the Public Staff used the term in the recent Duke cases, but it was -- our position was not adopted by the Commission. But whether they used that term anywhere, I couldn't tell you.

Q. Okay. Thank you. And how -- how do you understand that term? As -- as I know that term, it's generally used in a criminal context.

Do you understand that that term is generally used in a criminal context?

A. I probably shouldn't comment on that, not being an attorney, but -- and I'm going to let Mr. Lucas follow up, but I -- I think of it in terms of here as responsibility. But I will let Mr. Lucas comment on that.

A. (Jay Lucas) Yeah, I agree with Mr. Maness. I'm not familiar with criminal cases, but we believe the Company shares in responsibility for the costs it incurred to remediate the coal ash sites.

Q. But you're not aware of any instance where the Company has pled or been found guilty of any criminal charges?

A. No.

Q. How does -- how does this concept of culpability compare to the prudency standard?

A. We didn't do a prudency evaluation. We -- to go back and try to recreate all the costs that the Company could have incurred in the past would be too speculative. But we do feel the Company bears some responsibility for the costs it has incurred, so we think it should share in those costs.

Q. So -- I think you just answered my next question. So neither you nor anyone at the Public Staff has conducted a prudency review of the coal ash the Company has incurred in 2016 to comply with the CCR Rule?

A. Well, we did review contract costs and those types of items, but what's in my testimony is just the culpability. We don't -- I didn't comment about my prudency review of the coal ash remediation contracts.

Q. So there's no finding of imprudence in your testimony?

A. That's correct.

Q. And, Mr. Maness, you proposed that the Company's CCR expenses should be amortized over a 19-year period, correct?

A. (Michael Maness) That's changed to 18 years --

Q. That's right.

A. -- with the supplemental testimony.

Q. You're exactly right. And -- and on that 18 years, there's no return on the unamortized portion, correct?

A. Correct.

Q. And that represents your 60/40 splitting of costs between ratepayers and the Company, correct?

A. Yes. That's correct.

Q. And I understand from your testimony, though, that you didn't do any calculations to arrive at that nine-year amortization recommendation, correct?

A. No. We did do calculations, and I think the -- the Company was supplied with the workpapers. Essentially, the way we do it is to first assume that the -- there's not going to be a rate base return, that the cash the company is going to get back, the funds it's going to recover from the ratepayers, is just going to be the amortized expenses over the -- over time.

So the longer you stretch out the amortization period, the more the stockholders have to bear because they're bearing the financing costs in the interim. And so we determined the amortization period by looking at where it would come to the -- 40 percent to shareholders, 60 percent to ratepayer split of that present value.

I probably should add -- and I stated this in my supplemental testimony. I don't think I stated it in my direct, is that we really try to determine the amortization period on a whole year basis, not on a number of months basis. And so we use the -- the number of years that would bring the ratepayer's share as close to 60 percent as we could get it without going over 60 percent. So that's why you'll see stated either or both my direct and supplemental testimony approximately 60 percent. It was actually calculated out to be fifty-nine-point-something percent to the ratepayers.

Q. So the lawyer, non-accountant in me understands. You took your 40 percent and backed in the 19, or 18 years as the case may be now.

A. Yes. That's correct.

Q. And in so doing, you did not -- that doesn't represent any specific cost. I think we determined that, correct? It doesn't represent 40 percent of any specific cost.

A. If I understand the -- the question correctly, it does -- when you do that and then you discount everything -- all the cash flows back to a present value basis, it would result in the ratepayers bearing 60 percent of that present value and the shareholders 40 percent.

Q. Right. And it's not related to transportation costs or cost of liners or caps, correct?

A. Well, that's an interesting question. Coming to that amortization period doesn't rely that you -- doesn't make it necessary for you know -- for you to know the costs, but we are actually amortizing the costs that have been identified and I think agreed to by the Company and Public Staff at this point over a certain period of years.

So there is a dollar outcome and it is based on the actual costs that the Company incurred during the deferral period for coal ash disposal and remediation.

Q. Right. But you're not segregating these are recoverable costs, these are not for these activities --

A. No. No.

Q. -- these activities are recoverable?

A. No, no specific segregation.

Q. And on Page 14 of your testimony at Lines 8 or 9, you state that, quote, some degree of sharing is appropriate, correct?

A. Could you tell me what line you're looking at?

Q. Sure. Starting on Line 8 in your -- I think referring to Mr. Lucas, you say, "He's of the opinion that some degree of equitable sharing is appropriate in this circumstance."

A. Yes. And I think then later in the testimony, we specify that the Public Staff believes that that is 40 percent.

Q. Correct. And isn't it true that in the Duke Energy Progress hearing last year, you recommended a 50/50 sharing of coal ash expense between shareholders and customers?

A. Yes.

Q. And in the Duke -- Duke Energy Carolina hearing, you recommended 51/49 equitable sharing?

A. It was 51/49, I think, but it actually -- again, we were trying to come as close to 50 percent without having the ratepayers bear more than 50 percent. And so that's the reason it sort of rounded out to 51/49.

Q. Correct. And as I -- as we've already established, you say that you assigned the 60/40 split to Dominion because Dominion was less culpable than the Duke Energy companies, correct?

A. Yes, and I rely on Mr. Lucas's testimony for that.

Q. If you didn't do any calculations, how did you determine that Dominion was approximately ten percent less culpable than the Duke Energy companies?

A. (Jay Lucas) I can answer that. If you look at my testimony on Page 81, Line 22, the very last line, I list some of the items. DENC has not been found guilty of criminal -- criminal negligence for its environmental impacts.

Going back to the top of Page 82, Line 1, DENC has not had significant state regulatory enforcement actions. And, three, while there are widespread environmental impacts, especially groundwater contamination, there is less evidence at this point of the extent of the impacts that was present in the DEP and DEC rate cases.

A. (Michael Maness) And if I could -- I'm sorry.

Q. No. I was just going to say thank you, Mr. Lucas.

A. And then I would also say that it is an exercise of judgment to determine what the appropriate sharing percentage should be when comparing it to instances such as the Duke cases and instances where there has been no finding of any sort of culpability.

And the Commission and the Public Staff, and the Company, for that matter, has to exercise judgments of that type several times during a general rate case when you're trying to decide on amortization period or maybe trying to decide on what the proper amount to allow in rates is. It's not anything unusual for regulatory bodies and companies to have to exercise that sort of judgment.

Q. Thank you both. And -- but you couldn't say with certainty whether the company was perhaps not 10 percent, but 20 percent or 30 percent less culpable than Duke, correct?

A. Well, we feel that the 10 percent differential is reasonable. Of course, we'll leave it to the Commission to decide what the final percentage should be.

Q. I'm looking at the list that Mr. Lucas just referred to on Page 82 of his testimony, which he talked about some of the factors you-all considered to make this recommendation.

Mr. Lucas, you say DENC has not had significant state regulatory enforcement actions taken against it. And that's your Number 2 point, correct?

A. (Jay Lucas) Yes, had some action. And also, I need to point out that the environmental impacts -- and the items I discuss in my testimony aren't the only reasons that we found the Company culpable and why we recommend the split that we do. Mr. Maness also goes into some detail in his testimony as to the other factors that went into our decision for the equitable sharing.

Q. How much weight, Mr. Lucas, did you give to this second point? Was it two percentage points, three percentage points?

A. Like I said earlier, we didn't do any mathematical calculations or assign specific percentages to any items in my testimony.

Q. So criminal violations also would not -- you can't assign any particular --

A. That's correct.

Q. -- weighting to that?

A. That's correct.

Q. And -- and, Mr. Maness, you state that even if there were no allegations of exceedances or a criminal violation, you would still recommend a 40 percent disallowance of the Company's cost, correct?

A. (Michael Maness) Could you refer me to a page in the testimony? I wanted to make sure I understand.

Q. Sure. Absolutely. Let's see. It may take me a second because -- to go -- refer back to my notes.

The lack of -- Maness Page --

MR. DROOZ: Page 14.

Q. -- 15 I'm looking. It was also in your summary, but I'm looking at Page 15, Lines 7-10. Thank you, Mr. Drooz.

The lack of any finding of specific imprudence or unreasonableness does not invalidate consideration of whether or not a sharing mechanism or sharing adjustment is appropriate and reasonable. That's Page 15 of your testimony --

A. Yes.

Q. -- Lines 7 through 10.

A. Yes.

Q. Isn't it true that the Commission in the DEP and DEC case rejected the equitable sharing proposal in part because there was insufficient justification for the allocation of responsibility?

A. I can't tell you -- sitting here, recall the reasons, but they did reject it.

Q. And I believe the Commission has taken judicial notice of the Duke Energy Progress order.

A. (Jay Lucas) I can't remember what the Commission's taken judicial notice of, but I need to point out the Public Staff has appealed those cases.

Q. That's correct. And you've taken the same position in this case as well on equitable sharing, correct?

A. It -- yeah, we've taken a very similar position.

Q. Mr. Maness, you talk about the Commission has a history of at least partially disallowing, through sharing or otherwise, recovery of extremely large costs from customers, correct?

A. (Michael Maness) Yes.

Q. And wouldn't you also agree that the Company has a history -- the Commission, excuse me, has a history of also allowing recovery of extremely large costs?

A. Well, in the cases that I'm talking about, yes, they did allow partial recovery. There have been certain cases, certainly, where they have -- they have allowed full recovery of large costs, yes. And -- but there may be differentiating factors.

I mean, if you have a -- a plant that's going into service that's going to serve the ratepayers and there's no issues of prudence or reasonableness involved, then the Commission would probably, in most cases, allow full recovery of those costs.

Q. And in the past, has not the Public Staff also argued that in order for costs to be deferred and recovered, they should be extraordinarily large, correct?

In other words, you don't defer costs that aren't large because the theory is they're otherwise in rates.

A. No. I think the -- but the -- I think the distinction here is when we talk about extraordinarily large in the senses of deferral in general, we're talking about in comparison to what you might expect to occur in a year -- in a normal year that may go up and down to a certain extent, but it's not way out of line with the expense that you would expect to be incurred.

Here, we look at these -- these costs are -- when we use the -- when I use the term extremely large, they're more in line with some of the nuclear abandonment costs that we've had in the past. And I think you also have to look at the nature of the costs as well. This is not a cost that was planned on by the Company or the customers. It's something that came along because of -- well, I'll leave it to Mr. Lucas to go into detail for the reasons, but you're talking about changes in laws and you're talking about discovered exceedances and other problems on the Company part. And we just don't think it's reasonable for the customers to have to bear 100 percent of those, as I characterize them, extremely large costs that have come about.

A. (Jay Lucas) I need to add we believe it's -- it's not really the customers' responsibility. The customers didn't make all the decisions. It's the Company that made the decisions that's led to these costs, and that's why we recommend equitable sharing.

Q. To follow up on your statement, Mr. Lucas, but it's -- the reason we have coal ash is because we had coal-fired plants for decades, correct?

A. It's -- well, we're not recommending the sharing because of the existence of coal ash. We're recommending the disallowance because of the mismanagement of coal ash.

Q. Mr. Maness, in this case, is it your understanding that Chesapeake Energy Center closure costs are included in rate base?

A. (Michael Maness) I can't speak to whether they're in rate base or not, since I didn't look at that part of the case, but they're not part of the CCR disallowance.

Q. Correct. But you don't know whether or not they're included in rate base, those closure costs?

A. I've only discussed that briefly with other members of the accounting division who are working on that part of the case. And I think there probably is some amount in the rate base, but I don't know what the amount is or how it would compare to the CCR costs.

Q. Thank you. With that, I'm going to pass the mic to my colleague, Mr. Snukals.

CROSS-EXAMINATION BY MR. SNUKALS:

Q. Good afternoon, gentlemen.

A. (Jay Lucas) Good afternoon.

Q. And, Mr. Lucas, my questions will be directed at you, unless Mr. Maness for some reason would like to contribute.

So, Mr. Lucas, you're not a lawyer, correct?

A. No, I'm not a lawyer.

Q. The Public Staff does have legal counsel, though, correct?

A. Yes.

Q. In the summary of your testimony a few minutes ago, you complained that the Company did not produce documents that it should have had in its possession.

Do you recall providing that testimony?

A. Yes.

Q. You do realize that there is a recourse for parties involved in these types of cases if they believe that another party is not being forthcoming in discovery.

You realize there is a recourse?

A. Yeah. We had considered a motion to compel. I can point you to where that is in my testimony, but our decision ultimately led to the Lucas Exhibit Number 9. It was a stipulation about information the Company could not obtain.

Q. So your decision surrounding the motion to compel was purely related to groundwater monitoring results?

A. Let's see. There were some other things in there, I believe. Let me go to that stipulation. There might have been some information on NPDES permits as well.

I see -- I guess one thing would help in the form of the very last sentence of the stipulation: "The Company acknowledges, however, that it has not been able to locate some historical VPDES permits and related documents for its CCR sites in Virginia and West Virginia."

Q. Sure. Going back to the issue of and the decision whether or not to file a motion to compel, Public Staff has filed motion to compels in the past?

A. It has.

Q. And, in fact, it filed one in Dominion's last rate case. You're aware of that, right?

A. I can't remember.

Q. Okay. Subject to check. And so filing a motion to compel in this case was certainly an option?

A. Yes, it was an option.

Q. But Public Staff legal counsel ultimately decided not to file one; is that correct?

A. Yes. Let me go to that part of my testimony. I can provide some more context.

Here it is. It's Page 65 of my testimony, Line 3. "The Public Staff contemplated filing a motion to compel with regard to our discovery requests on groundwater monitoring and exceedances. Rather than embroil the Commission in a discovery dispute, we worked for months to establish a good-faith understanding with the Company as to the basis -- as to the basis for its incomplete responses.

"The result is that the Company's inability to provide historic records pertaining to groundwater for its coal-fired generating facilities, as discussed above, is acknowledged in a stipulation between the Company and the -- and the Public Staff."

Q. Mr. Lucas, you're not aware of any legal requirement that would have required the Company to retain all environmental permitting records from the '70s, '80s or '90s, are you?

A. I'm not aware of the legal requirement, but it would be a good idea. When we talk about groundwater problems, groundwater moves slowly. The conditions change over a period of years. It would have -- it would have been wise for the Company to retrain -- retain records going back for a few decades.

Q. Just to clarify, there's no legal requirement to keep those records, though?

A. There may be some General -- I'm not a lawyer, but I believe there's some General Statutes regarding retention of records. I don't have those with me at the moment.

Q. As you sit here today, though, you can't identify any specific legal requirement?

A. I can't identify them, no.

Q. Mr. Lucas, the testimony that you filed in this case was submitted on behalf of the Public Staff, correct?

A. Yes.

Q. The Public Staff are not environmental regulators, are they?

A. No. We've established that. No, we're not environmental regulators.

Q. Okay. And so you recall giving deposition testimony in the Duke Energy Progress rate case.

Do you recall giving deposition testimony in that case?

A. Yes.

Q. Okay. And in your -- do you -- do you recall the following exchange between you and Mr. Drooz in that case? And I'm going to go ahead and pass around an exhibit.

Mr. Lucas, I'll direct you to Page 86, Lines 6 through 20. Again, this was a -- an exchange between you and your counsel, Mr. Drooz, and I'm going to ask you if you remember this -- this testimony.

Question, "You were asked if the Public Staff had raised any concerns regarding exceedances, seeps, dam safety issues in the past. What is the Public Staff's role as a state agency?"

Your answer was "The Public Staff is to protect the using and consuming public while reviewing the managerial, financial and technical aspects of the company. We're not environmental regulators."

Question, "Is the focus of the Commission authority and the Public Staff role regulation of cost and rates?"

Answer, "Yes."

Question, "And who does environmental regulation for the State of North Carolina?"

Answer, "That's the Department of Environmental Quality."

Do you recall giving that testimony?

A. I don't remember it, but it's -- it's clear right here. And I need to add, though, what we're doing here today, we're not trying to second-guess what environmental regulators knew or what they know now. What we're doing here is trying to figure out what's a fair cost for customers to pay.

I know we established that we're not environmental regulators, but we -- I've documented in my testimony about environmental problems created by the Company. And what we're doing here today is trying to figure out how much of those costs should be passed on to customers.

Q. Mr. Lucas, I appreciate that, and I do think your testimony will speak for itself where you have, in fact, second-guessed environmental regulators, but we're going to get to that in a little -- little while.

So in light of that testimony, Mr. Lucas, that means that you are not a -- as a member of Public Staff, are not an environmental regulator.

A. That's correct.

Q. Dominion has environmental regulators, correct?

A. Virginia has environmental regulators. I don't know if -- Dominion is not an environmental regulator.

Q. Sure.

A. I don't understand your question.

Q. It has environmental regulators that oversee its operations, correct?

A. Yes.

Q. In West Virginia, that's the Department of Environmental Protection, correct?

A. Also the EPA. And environmental regulator is not clearly defined. There are multiple government functions that could have environmental regulatory effects; like the Nuclear Regulatory Commission. So there could be multiple agencies that do regulate the environment.

Q. Okay. How about groundwater impacts, surface water discharges? Those are all regulated in Virginia or West Virginia by the Department of Environmental Quality or the Department of Environmental Protection or the EPA.

Those are the environmental regulators that handle those issues, correct?

A. Yes.

Q. The Company's environmental regulators, as I just discussed, are the ones that write and issue environmental permits, like NPDES permits and solid waste permits, for the Company's coal ash impoundments and landfills in those states, correct?

A. That's correct.

Q. You, personally, have never issued an environmental permit for a coal ash impoundment or landfill; is that correct?

A. Not to my knowledge. Years ago, I did do waste water permits for the North Carolina DEQ.

Q. Right. But none of that work related to coal ash impoundments, did it?

A. Not to my knowledge.

Q. Or coal ash landfills?

A. That's correct.

Q. Not only have you not regulated a coal ash impoundment or landfill, Mr. Lucas, you've never been in charge of managing a coal ash impoundment or landfill; is that correct?

A. That's correct.

Q. The Public Staff has no authority, nor the expertise, to issue the environmental permits necessary to operate and manage coal ash impoundments and landfills; is that correct?

A. I can't comment on what expertise. I have worked on waste water discharge permits, and I rely on some of that knowledge in my current role with the Public Staff.

Q. But Public Staff -- you're -- you're here to testify on behalf of the Public Staff, and you testified earlier that Public Staff, as a body, does not have -- is not an environmental regulator, correct?

A. That's correct.

Q. And you're aware of testimony actually earlier this year where the Public Staff offered testimony that it -- it does not have expertise in the area of impacts of electric generation on the environment?

A. Well, that's taken out of context. That was in a completely different case. That was for a solar photovoltaic facility. It wasn't -- did -- wasn't in any relation to coal ash.

Q. Mr. Lucas, that testimony was not just specific -- that piece of testimony was not just specific to -- to that issue and that case.

A. Yes, it was.

Q. May I -- I'm going to show you Exhibit 3. Let me pass it around.

CHAIR MITCHELL: This is a good time to take our afternoon break. We will come back for the last session of the day at 3:25. Let's go off the record, please.

(At this time, a recess was taken from 3:10 p.m. to 3:26 p.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please.

MR. SNUKALS: Thank you. And I think during the break we passed out what will be marked as DENC Lucas Cross Exhibit Number 2. And just for the record, the first document that we passed out, which was Mr. Lucas's deposition testimony from the DEP rate case will be marked as DENC Lucas Cross Exhibit 1.

CHAIR MITCHELL: The exhibits shall be so marked.

(DENC Lucas Cross Exhibit 1 and 2 were marked for identification.)

MR. SNUKALS: Thank you.

Q. Before we went -- went on break, Mr. Lucas, we were talking about prior testimony that the Public Staff has offered that -- where it has stated that it does not have particular expertise in the area of impacts of electric generation on the environment.

Do you recall that's where we were at?

A. Yes.

Q. And as I said, we passed out DENC Lucas Cross Exhibit Number 2, which is the testimony of Evan D. Lawrence, Utilities Engineer, Electric Division, from Docket No. EMP-103, Sub 0.

Do you see that?

A. Yes.

Q. By the way, Mr. Lawrence's title, Utilities Engineer, Electric Division, that's the same title you hold, correct?

A. Yes.

Q. Could you please turn to Page 6 of -- of his testimony in that case?

A. Okay. I'm on Page 6.

Q. Do you see a question, "Does the Public Staff have any recommendations regarding the siting of the proposed facility or its environmental impact?"

A. Yeah, I see that question.

Q. Do you see the answer, where it says, "No. The Public Staff has reviewed the consumer statements of position in this docket. With regard to the concerns raised regarding compatibility with existing land use's environmental impacts, the Public Staff believes that these concerns are more appropriately addressed through local permitting process and through environmental permitting process."

Do you see where it says that?

A. Yes.

Q. If you could, please move to Page 7, Line 1 of Mr. Lawrence's testimony. I'm going to continue reading and you tell me if I'm reading this accurately.

"In addition, the Public Staff does not have particular expertise in the area of environmental" -- sorry, "in the area of the impacts of electric generation on the environment. Those issues are best left to the purview of the environmental regulators who do have this expertise and who are responsible for issuing specific environmental permits for electric generating facilities."

Do you see that testimony?

A. I see that, but it's sort of taken out of context. That's not the purpose of this testimony. Going back, starting on Page 1 of this testimony, Line 11, it asks, "What's the purpose of your testimony," and I'll read this.

"The purpose of my testimony is to make recommendation to the Commission on the request for a certificate of public convenience and necessity filed by Albemarle Beach Solar to construct an 80-megawatt solar photovoltaic merchant electric generating facility in Washington County, North Carolina.

"The purpose of my testimony is as follows: to discuss the compliance of the application with North Carolina General Statute 62-110.1 and Commission Rule R8-63; number two, to discuss any concerns raised by the application; and, three, to make a recommendation whether the Commission should grant the requesting -- requested certificate."

There's nothing in here about coal ash. There's nothing in here about cost recovery. There's nothing in here about a rate case. So I -- I believe trying to say we don't have any environmental expertise is incorrect.

Q. Never suggested that this case did relate, but I do think it relates to Public Staff's understanding of its role and its expertise regarding environmental matters. That's the purpose of -- of you bringing this up.

And -- and to that point --

A. I didn't bring it up. You brought it up.

Q. The point in me bringing it up.

A. Yes.

Q. Yes. And to that point, Mr. Lucas, DENC's Bremo facility, that's an electric generation plant, correct?

A. That's correct.

Q. The Chesterfield facility, that's an electric generation facility, isn't it?

A. That's correct.

Q. Chesapeake, that's an electric generating plant, correct?

A. It was.

Q. Okay. Possum Point, that was an electric generating -- that is an electric generating plant?

A. Yes,

Q. Yorktown, electric generating plant, correct?

A. Yes.

Q. Okay. VCHEC, electric generating plant?

A. Yes.

Q. Am I missing any? Mount Storm?

A. Yes, that's an electric generating plant.

Q. Okay. And, again, any CCR that's generated -- or sorry. CCR are byproducts of electric generation, correct?

A. That's a -- yeah. Right. CCR's a byproduct, and there's nothing about CCR in this testimony I just quoted.

Q. I think earlier we were talking about whether Public Staff has authority to issue NPDES or solid waste permits, and I think we agreed that that -- that's not -- that authority does not exist within the --

A. Yes. The --

Q. -- Public Staff, correct?

A. That's correct. The Company came to the Public Staff with a data request. I hope this clears up this issue. We've been on it for a while.

This is the Company's Data Request Number 1, Question 16, and it asks about -- about the Public Staff and my -- my sworn deposition we just quoted from. And let me just give you the response that you've already seen this.

"The Public Staff is not a regulator. It is a -- it is a consumer advocate working in a regulatory forum. Neither the Public Staff nor the Commission create or enforce environmental regulations on coal ash storage or -- or disposal. However, the costs of environmental compliance or the costs of non-compliance which the Company seeks to recover from ratepayers are within the jurisdiction of the Public Staff and the Commission. Quality of service and management prudence are also within the purview of the Commission and the Public Staff's review."

Q. Thank you for that. And, Mr. Lucas, because the Public Staff is not environmental -- sorry.

Mr. Lucas, thank you. Because the Public Staff is not an environmental regulator, Public Staff has no authority or expertise to require groundwater monitoring at DENC's coal ash facilities?

A. Let me give an answer to your question. I'm not saying whether or not we have expertise whether to require groundwater monitoring, but we believe the Company should have required groundwater monitoring.

Also, in these cases where the Company has done some groundwater -- groundwater monitoring, the records are missing, which led us to the stipulation.

Q. The Public Staff does not have the authority to determine how many wells or expertise to determine how many wells should be drilled at a particular site; is that correct?

A. That's correct.

Q. Not only how many wells, but where those wells are located?

A. That's correct.

Q. How deep those wells are, that's not within the expertise or authority of the Public Staff, is it?

A. That's correct.

Q. Making -- all of those -- all of that authority is delegated to DENC's environmental regulators. That would be the EPA, West Virginia DEP or Virginia DEQ, correct?

A. That's correct.

Q. You're also aware that Public Staff has no authority to determine whether enforcement action should be taken against a utility for exceedances of groundwater standards, correct?

A. That's correct.

Q. Public Staff has no authority to issue notices of violation, right?

A. That's correct.

Q. And with regard to the agencies we just discussed who do have enforcement authority over the DENC, you've testified on Page 81, Line 22 through Page 82, Line 2 -- I'll let you turn to that -- that DENC has not been found guilty of criminal negligence for its environmental impacts and that DENC has not had significant state regulatory enforcement actions taken against it, correct?

A. That's correct. But what we're here today is to discuss the fact that the Company is having to correct environmental problems that it created. The customers were not the ones that made the decisions in the past coal ash management practices. Dominion is responsible. And we're here to discuss recovery of those costs.

Q. Yet, despite the fact that the Public Staff can't issue environmental permits, can't require environmental corrective action, can't take enforcement action against the Company, can't enforce environmental violations against the Company, does not have particular expertise in the area of impacts of electric generation on the environment, you've testify --

A. I disagree with you. We do have a lot of knowledge. I mean, we have some expertise. It's in my resume. And we've learned a lot over the years. We've learned a lot in the Duke Energy rate cases as well.

Q. Mr. Lucas, you're not testifying in your individual capacity here today, are you?

A. No.

Q. Okay. You're testifying on behalf of the Public Staff?

A. That's correct.

Q. All right. Despite the fact that Public Staff has no environmental regulatory authority over DENC, you have testified in this case that Dominion -- or DENC managed its coal ash improperly or should have done more to mitigate impacts to environment.

Didn't you provide testimony to that extent?

A. Yes.

Q. Okay. And, in fact, Mr. Lucas, in your testimony, you -- you actually attempt to tell the Company what they should have known, what they should have done or what they failed to do in the past with respect to its management of CCR?

A. Can you give me the page number and line number, please?

Q. Of course. Let's start with Page 5, Lines 19 through 22. In your testimony there, you testified that DENC has culpability for non-compliance with environmental regulations that are meant to protect groundwater and surface water from contamination by CCR constituents --

A. That's correct.

Q. -- is that correct?

A. Yeah.

Q. All right. Page 37, Lines 14 through 16.

A. I'm sorry. Say that again, please.

Q. Sorry. Page 37, Lines 14 through 16. You testified that DENC was a leader that failed to improve and modernize their practices despite the available knowledge described in my testimony above.

A. Yes. And -- and the result is that the Company has contaminated groundwater. It's got, as far as we know, 548 groundwater contamination exceedances. So, obviously, the Company's done something wrong. The Company is not allowed to contaminate the groundwater.

And the reason is Dominion doesn't own the groundwater and it doesn't even own the groundwater underneath its power plants. Virginia has an anti-degradation policy where the groundwater has to be -- be protected regardless of what any particular industry is practicing.

Q. Can you give me one specific action the Company should have taken in the past with respect to its CCR management practices that it did not take?

A. It should not have contaminated the groundwater.

Q. What action should the Company have taken to prevent contamination of the groundwater?

A. Oh, there's --

Q. Specifics.

A. Oh, okay. There's a wide range of actions the Company can -- could have taken. I'm not telling the Company exactly what it should have done or when it should have done it, but the Company had an obligation to protect the groundwater, period.

Like I said, the Company doesn't own the groundwater. Virginia has an anti-degradation policy which the Company appears to have violated.

Q. So you can't give me a single specific action the Company should have taken?

A. Oh, there's a wide range. There's liners, dry ash handling, grout curtain walls.

Q. When -- when should the Company have taken any of those actions? Give me a -- a date.

A. I don't have specific dates because, one thing, the Company doesn't have a lot of records of early dates when groundwater contamination occurred. So we don't know exactly when the Company began contaminating groundwater.

Q. Mr. Lucas, in the -- in the Duke Energy Progress case, you didn't give any specifics in that case either, did you?

A. That's correct.

Q. In that case, you said you had hundreds of thousands of documents at your disposal, right?

A. I can't remember a lot of the documents, but it was a lot of documents.

Q. I'll move to another example. Page 37, Lines 18 through 20, you testified "DENC and other utilities should have installed comprehensive groundwater monitoring well networks to determine if the risk was materializing."

A. That's correct. That's the best way to start determining how risks occur in groundwater.

Q. But you can't tell me how many wells, where the wells should be located, how deep the wells should have been drilled, constituents that should have been monitored. You can't tell me any of that information for any of the sites, can you?

A. That's correct. What we're doing here is trying to figure out what kind of cost recovery the customers are responsible for. Since the Company has contaminated groundwater and it's the Company's coal ash, we feel the Company should share in the cost of remediating those problems.

Q. So, Mr. Lucas, we just went through a couple of those examples where you attempt to tell the Company what they should have known, they should have done or -- or they failed to do in the past; is that correct?

A. That's correct.

Q. Okay. And by telling the company what it should have done or should not have done in the past, Mr. Lucas, that's a prudence review, isn't it?

A. Well, yeah, if they came at specific -- specific actions at specific times. But let me read you something. And we took judicial notice of Charles Junas's testimony.

Let me go back and take -- in his testimony, he does talk about preventive options that were suggested by others. And when I just mentioned things like grout curtains, liners, those types of things were suggested by other to control groundwater contamination.

Q. I understood that -- I understand that that was his testimony. But as we sit here today, you can't tell me whether the Company should have taken any of those specific actions or when they should have taken those actions?

A. No. The Company should have consulted its -- consulted -- should have gone to the consultants and its staff and not contaminated groundwater. It should have taken some sort of steps to prevent groundwater contamination.

Q. But you can't tell me those steps?

A. Not precisely. I've given you some good examples that would have helped.

Q. But you would agree the Public Staff did not conduct a prudence review of the Company's management practices regards its CCR impoundments or landfills, did it?

A. No. That would be too speculative. We can't go back in time and determine certain actions and certain costs.

Q. Mr. Lucas, didn't the Public Staff hire outside experts in the Duke Energy cases to do exactly that?

A. Yes, it did.

Q. Did the Public Staff hire outside experts in this case to do that, to -- to undertake that exercise?

A. No, it didn't. And what I was reading you, those different options for correcting groundwater, this is from the 1982 EPRI manual. That's Electric Power Research Institute, and I believe your witness said the Company is a member.

And this is -- this is from the EPRI manual. And it gives a list of actions that the Company can take to prevent groundwater contaminations. It says, "The following subsurface techniques are discussed in great detail as potential corrective actions to address groundwater contamination: gravity drains, sumps, wells, vacuum well point systems, slurry trench cutoff walls, grout curtains and sheets -- and sheet piling cutoff walls. And that's Page 6-48 of the 1982 EPRI manual."

So, certainly, in 1982, the Company had access to some good information how to prevent groundwater contamination.

Q. Mr. Lucas -- Mr. Lucas, do you recall giving live testimony in the Duke Energy Progress case?

A. Yes, I did.

Q. Okay. I've got your testimony from that case I'd like to pass out. Do you have a copy, Mr. Lucas?

A. Yes, I do.

MR. SNUKALS: Chair Mitchell, we're going to mark that -- that document as DENC Cross -- Lucas Cross Exhibit 3.

CHAIR MITCHELL: It shall be so marked.

(DENC Lucas Cross Exhibit 3 was marked for identification.)

MR. SNUKALS: Thank you.

Q. If you could, turn to Page 34, Line 19 through -- that's where this -- this starts, and then we're -- we'll be moving on to Page 35, Line 1. And this is Volume 19 of your hearing testimony in the DEP rate case.

Are you there?

A. I'm sorry. Page 34. What's the line number?

Q. Line 19.

A. Okay.

Q. And I'm going to read this and you correct me if -- if I didn't read this correctly. "We can't go back in time and say, 'Oh, they should have put a clay liner in 1978 or done dry ash stacking in the 1980s.' I mean, that's impossible to go back and put all these what-ifs together and say exactly here's what they should have done, here's what the cost would have been -- here's what would have been the cost and that cost would have been in rates today for customers."

Do you recall giving that testimony?

A. Yes.

Q. Do you also recall giving the testimony on Page 36, Line 23 -- and that goes through Page 37, Line 13? The question was asked of you "But you would agree with me that would be helpful if someone could simply tell me what I should have done and when I should have done it. Isn't that right, with specificity?"

Your response: "But that's going back to the past. Somebody could have -- could have gone back and said you could have -- you should have done back at a certain time and that's -- you could be talking about prudence, and I can't go back -- and I can't go back and tell you exactly what would have happened, what you should have done at a certain time. I'm not sure what good it would have done."

Did I read that correctly?

A. Yeah. Yeah. I'm not -- to put some context in that, what I'm saying here is that when I was sitting on the witness stand two years ago, I couldn't go back in time from that point and -- if I had come up with exactly any kind of remediation options, a cost, it would have been purely speculative.

Q. And those costs, if you tried to come up with them today as you sit here, those would also be speculative, correct?

A. If I tried to do that again, yes. And that's why we can't pin down a prudence review and that's why we come back to equitable sharing, because the Company is responsible for its coal ash handling and creating groundwater violations.

Q. Mr. Lucas, you have not identified -- the Public Staff has not identified a single cost or activity that the Company has incurred from July 1st, 2016, through June 30th, 2019, or discussed in Mr. Williams' and Mitchell's direct testimony in this case that Public Staff determined was imprudent or unreasonable?

MS. CUMMINGS: We've many times gone over there's no specific cost being recommended for disallowance here and no imprudence review.

MR. SNUKALS: I'm not sure that we've actually narrowed down the dates, but if -- if we have, I'll let the record reflect that. But I -- I promise I won't try to retread this again if I'm allowed to ask this question one more time.

CHAIR MITCHELL: Okay. All right. One more time I'll allow it.

MR. SNUKALS: Okay.

A. Okay. Please repeat the question.

Q. Sure. And just to be clear, Mr. Lucas, the Public Staff has not identified a single cost or activity that the Company has incurred or undertaken between July 1st, 2016, through June 30th, 2019, that is related to its CCR impoundments or landfills that is imprudent or unreasonable, correct?

A. They haven't identified any particular cost, but, certainly, 2017, 2018, the Company has shown a lot of groundwater contamination and it's -- that was found in EPA CCR Rule Appendix 3. The Company had to do some monitoring. They found contamination at every single coal-fired plant, which has triggered further monitoring.

So when you refer to 2016 through 2019, I'm not exactly sure if those CCR components are still contaminating our groundwater or not. They could be. But, definitely, there's some action going on -- it probably -- definitely occurred before 2016 -- that created groundwater contamination.

Q. You don't take any issue with how the Company is undertaking its compliance with the CCR Rule or any of the associated costs?

A. I don't take action -- don't take exception with any particular action. But what I'm saying in my testimony is the Company bears responsibility for having to incur those costs.

Q. Mr. Lucas, you're not aware of any instance in the 1970s, 1980s, 1990s, 2000s when the Public Staff recommended that the Company install comprehensive groundwater monitoring networks at its CCR impoundments or landfills, are you?

A. No, I'm not saying that.

Q. Okay. And you're not aware of any instance in the '70s, '80s, '90s or 2000s when the Public Staff told the Company that its CCR storage facilities, impoundments, landfills and its management practices were not sufficiently modern?

A. No. And the Company, to my knowledge, didn't try to recover any costs like we're doing today that were created by groundwater contamination.

Q. You're not aware of any instance in the 1970s, '80s, '90s or 2000s when the Public Staff told the Company that it was not sufficiently mitigating environmental impacts from its CCR impoundments or landfills, correct?

A. That's correct.

Q. This case is the first time the Public Staff is taking any position on -- on those issues, correct?

A. Well, we did in the previous rate case, 2016. We did discuss the Chesapeake cost recovery, but I believe that was settled with the Company.

Q. Mr. Lucas, I believe that together, you and Mr. Maness are -- are supporting this equitable sharing principle?

A. That's correct.

Q. And you've read Mr. Maness's testimony, I'm sure, where he says that even in the absence of your testimony, there would be some equitable sharing?

A. Can you tell me where -- the page number and line number, please?

Q. Sure. And it might just be easier to -- to look at Mr. Maness's summary where, on Page 3, he says, "It is most likely that even in the absence of culpability, the Public Staff would recommend a sharing of some type due to the magnitude and/or the nature of the costs involved."

Do you recall him giving that testimony today?

A. Yeah. I've got the -- let me see. I've got the -- Page 3 of Mr. Maness's summary here.

Yeah. It's the first complete sentence near the top. It says, "It is most likely that even in the absence of culpability, the Public Staff would recommend a sharing of some type due to the magnitude and/or the nature of the costs involved."

Q. Mr. Lucas, let's pretend your -- your testimony never existed in this case. What would the equitable sharing recommendation be?

A. We can't come up with a number. Do you want to add to that?

A. (Michael Maness) Sure. We didn't do an investigation of that nature as to exactly what it would be. I do point out in my testimony that in past cases where equitable sharing has been recommended and approved with the Commission with no evidence of culpability, it's been in the reasonable range of 30 -- around 30 percent.

Q. Are you saying that it would have been 30 percent absent Mr. --

A. No, I didn't say that. I said that we didn't do an investigation to determine exactly what it would be in this case, but that in past cases that it's been in the range of reasonableness around 30 percent.

Q. I have no further questions.

CHAIR MITCHELL: Redirect?

MS. CUMMINGS: Yes, I have a few questions for Mr. Lucas and I believe Mr. Drooz may have questions, too.

REDIRECT EXAMINATION BY MS. CUMMINGS:

Q. Mr. Lucas, you were asked about whether the Company had additional recourse to file a motion to compel in this case.

A. That's correct.

Q. And did you determine at the time and did the Public Staff's coal ash team determine at -- at the time that a motion to compel would not be fruitful if there were no documents to produce?

A. Yes. That's one thing we realized. We can't file a motion to compel against the Company if the documents don't exist or the Company no longer has possession of those documents.

Q. You were asked by Mr. Snukals about the Public Staff's authority and also the Public Staff's expertise.

A. That's correct.

MS. CUMMINGS: At this time, I'd like to pass out the Lucas Direct -- Redirect Exhibit 1, and this is Mr. Lucas's CV. I'd like to note that this CV has already been provided to the Company in discovery.

(Public Staff Lucas Redirect Exhibit 1 was marked for identification.)

Q. Mr. Lucas, do you have a professional engineer license?

A. Yes, I do.

Q. And do you have a master's of environmental engineering?

A. Yes, I do.

Q. And do you have experience in hazardous waste management?

A. Yes, I do.

Q. Can you tell us a little bit about that experience?

A. Yeah. When I was in the Air Force, we had a hazardous waste management program to make sure we had safe disposal. Also, we had a program similar to the Superfund that I've talked about in my testimony. It had a different name. It was called the Installation Restoration Program, and it was a program by which the military went back and tried to clean up contaminated soil and groundwater where it had past improperly disposed of hazardous waste and other types of wastes.

Q. And do you also have experience working in Virginia on water and waste water treatment plants?

A. Yes. I worked for a consulting firm, and in Virginia, we did work in the Norfolk, Virginia, area and we did studies and -- and management plans for waste oil.

Q. And do you have experience working for the North Carolina state environmental regulator?

A. Yes, I do.

Q. And how long have you been working with the Public Staff?

A. Nineteen years.

Q. And would you say that you fully understand the proper roles of the Public Staff versus the environmental regulator?

A. Yes, I do.

Q. And Mr. Snukals asked you whether or not you conflated authority and expertise. So you freely admit that we do not have the authority to issue NPDES permits, correct?

A. That's correct.

Q. But we do have the expertise to weigh in on federal and state regulations and compliance with those regulations in the course of our investigation?

A. That's correct.

Q. Thank you. And you were also asked about Garrett and Moore and them doing a prudence review in the prior DEC and DEP rate cases.

A. That's correct.

Q. The equitable sharing recommendation in the DEC and DEP cases was a separate review than the prudence review in those cases?

A. Yeah. We did a -- and I was included on some of that. We had a prudence review for some costs we definitely ruled out and were able to specify those costs down to the dollar which should be ruled out. But we also -- because of the speculative nature of some actions the Company should have taken or should not have taken in the past, we also did equitable sharing.

Q. That's right. So Garrett and Moore simply did a review of the most recent CCR and CAMA compliance review; is that correct?

A. They did that and they made some prudence recommendations.

Q. All right.

REDIRECT EXAMINATION BY MR. DROOZ:

Q. You were asked about culpability versus prudence. I wanted to follow up on that a little.

Mr. Lucas, you alluded to a policy not to degrade groundwater. What's the source of authority for that?

A. Well, initially, what I first cited was the Virginia Administrative Code, and I can read that anti-degradation policy into the record if necessary.

Q. Is it long?

A. No. It's just --

Q. Go ahead.

A. I can go ahead and -- it's, like, two or three sentences. And this is Chapter 9 of the Virginia Administrative Code, 25-28-30.

"If the concentration of any constituent in groundwater is less than the limit set forth by groundwater standards, the natural quality for the constituent shall be maintained. Natural quality shall also be maintained for all constituents, including temperature, not set forth in groundwater standards. If the concentration of any constituent in groundwater exceeds the limit in the standard for that constituent, no addition of that constituent to the naturally occurring concentration shall be made."

Q. Do you know if, in fact, Dominion did cause the groundwater to be degrading through leaching from its ash basins?

A. Yes.

Q. And was that, in your opinion, contrary to the policy in the Virginia Administrative Code you just read?

A. Yes.

Q. And is that a basis for your conclusion that the Company is -- bears some culpability in this case?

A. Yeah. That's part of -- part of my conclusion, yes.

Q. And this is for either one of you. In terms of disallowances, if the Public Staff finds a company has been imprudent, do we typically recommend a 100 percent disallowance of the cost or something less?

A. Usually, if the company's imprudent, we recommend a 100 percent disallowance.

Q. And with culpability in this case, how much is the effective disallowance?

A. The disallowance -- it's only 40 percent.

Q. Thank you. That's all my questions.

CHAIR MITCHELL: Questions from Commissioners? Commissioner Clodfelter?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Lucas, on cross-examination, if I -- if I wrote it down correctly, you cited to 548 exceedances. Did I get that right?

A. Yeah. Let me find that specifically. Yeah, 548 that we know of and that's just in 2017 to 2018. The -- we can't determine about other exceedances in the past.

Q. Is that taken from one of your exhibits? And if so, just cite me to it and I'll study it later.

A. Yeah, that's -- well, it's Lucas Exhibit 12 --

Q. 12?

A. -- regarding just the Chesapeake plant. And there's Lucas Exhibit 13 that regards other power plants.

Q. Okay. Now -- again, I'll study it at -- at -- at a later point, but just for the present purpose, are those exceedances of minimum standards or were those exceedances of the anti-degradation policy?

A. I'll go to that --

Q. Were they increases in natural concentration or were they violations of the minimum standard?

A. Let me go to that page in my testimony and I'll --

Q. Okay.

A. -- tell you exactly what it was.

Q. Thank you.

A. Those 548 exceedances shows statistically significant exceedances over natural background levels, maximum contaminant levels and/or groundwater protection standards.

Q. It's a mix of -- mix of all are --

A. Yeah. It's -- it's showing the Company created problems.

Q. I'm just trying to -- to characterize them.

A. Yes. Yes.

Q. Okay. Did any of those lead to corrective action orders or directives? Do you know?

A. Well, under the CCR Rule, the Company has to dictate what actions or what remediation is required. Those exceedances -- the Company's found that they have to do remediation under 40 CFR 257.101. That's the triggering requirement if the Company finds groundwater contamination.

Q. All under the CCR Rule, but nothing under Virginia regulations independently of Virginia's incorporation of the CCR Rule?

A. That's correct. I mean --

Q. Okay.

A. -- Virginia incorporated that rule, so --

Q. I understand. Thank you. Some clarifying questions on -- I'm going to your direct testimony now. You might want to have that --

A. Sure.

Q. -- available.

On Page 21, Footnote 48, in your footnote, you -- Page 21. Again, I just want to get a clarifying question.

In the last sentence, you state that the Mount

Storm plant can receive a variance for allowing exceedances for the coal storage site. Do you know whether or not Mount Storm has received any such variance?

A. No. It's just allowed to under the West Virginia rules.

Q. But you don't know whether it has applied for one, received one or been denied one or any -- any -- any of those?

A. I don't know.

Q. All right. I'm going to look now at Page 28, 29 of your direct testimony, where you discuss the two cases, West versus Virginia Electric Power Company and Morrow, regarding the two complaints filed by property owners.

Do you know the current status of that litigation?

A. I know the Company filed responses to those complaints on May 2nd, 2018, but I don't know the current status.

Q. Don't know the current status since the --

A. No, I don't. I know they're ongoing, but I don't know the current status.

Q. All right. All right. Thank you. Let's go to the records issue. And I'm -- I'm -- I'm interested, you indicated on Page 63 of your direct testimony that for some of the records that you were looking for that the Company did not have available, you got some of those from the Virginia environmental regulator.

Did you -- were you not able to obtain everything? Did they not have archives of everything you wanted?

A. They sent me -- depends on the -- the plant. With regard to Chesapeake, the Company did not provide any questions. And when we asked for all CCR-related problems or whether they were CCR-related or not -- and it looked suspicious that the Chesapeake plant didn't have any warning letters or any notice of violation or anything.

So I -- when I went to the Virginia regulators, I just wanted some examples of some missing documentation. They provided some. I -- I just -- one thing the Public Staff can't do, we just can't rely on the records research ability of the regulator -- of the environmental regulator.

Q. Well, did you do that just as an example, as you say? You didn't do that for all eight of -- of the --

A. I went -- I looked at several of the plants: Possum Point -- I looked at most of -- I can't remember them all, but I asked for as complete of records as possible for most of the coal-fired power plants.

Q. All right. Yeah. Well, did you find those records to be complete? Did you get everything you wanted for the ones you did look at?

A. To my knowledge, they were complete. I mean, I just -- I can't tell you what they didn't -- what they didn't give me. So --

Q. It wasn't -- wasn't there --

A. Yeah.

Q. -- because it wasn't there.

A. Yes.

Q. Right. Let me -- let me -- we've talked about culpability; we talked about prudence; and we talked about compliance with directives of an environmental regulator. So I want to take those three different things and I want to forget environmental regulation compliance. Forget it. I want to forget culpability, and I want to just talk about prudence.

And I want to sort of get the idea a little bit -- sort of sharpened up a little bit here. Let me give you an -- let's use an example that doesn't involve coal ash.

All right. So let's say I have an asset, a piece of equipment. Let's say it's a service truck and that service truck reaches the end of its useful life. Just too costly to repair or I don't need it anymore. I just don't even end it anymore. It doesn't have sort of a function, but it's at the end of useful life.

And one of the things I could do with that service truck is I could -- I could get a gas tack and -- tank and drain the radiator and empty the oil pan and sell it for scrap or salvage, whatever I could get for it for scrap or for salvage. That's one thing I could do for that.

Would that be prudent management on your part if I did that?

A. Yeah. If that was the best financial option, yes, that would be prudent.

Q. All right. Well -- well, suppose another option was to sort of just take it out on the back lot and park it and leave it for five years, ten years, 15 years, 25 years. I don't cover it. I don't put it in a closed garage. I just leave it out there exposed to the elements and, you know, it rusts and maybe the radiator springs a leak and maybe the oil leaks out. I don't know, but 25 years later, somebody comes around looking and says, "You got to -- you got to do something about this."

If I'd had the choice to do the other option 25 years earlier, would it have been prudent for me to sort of just park it on the back lot and let it sit for 25 years?

A. No, because it created risks. And to sort of tie it back to a utility, the utility has to manage its risks correctly. And in this case, we don't think Dominion managed -- managed that risk and -- and did something wrong by creating an environmental problem.

Q. Well, in the instance of my -- my truck that's rotting away on the back lot, would you consider that prudent management?

A. No, because it has a risk of creating environmental contamination.

Q. Would you consider it mismanagement?

A. Yes.

Q. Is it the Public Staff's position that any exceedance of a groundwater standard or any degradation of a naturally-occurring constituent is evidence of mismanagement?

A. Yes. And today, if just that one exceedance created costs that the Company tries to put on the customers, the Public Staff would have an opinion if we thought the Company had done something wrong to create that one exceedance that put cost on customers. The Public Staff would evaluate it and make some kind of recommendation like we've done today.

Q. Even -- even one instance?

A. If -- if it created costs to customers, even one -- one exceedance for arsenic that contaminated the next door neighbor's well and created cost, then Public Staff would have an opinion and try to determine culpability.

Q. Let me -- Mr. Williams -- you were -- you were here when Mr. Williams testified earlier today.

A. Yes. Yes.

Q. And he talked a little bit about Chisman Creek. I want to hear you walk me through again why -- the Public Staff's position on why the Chisman Creek situation is an evidence of -- well, is evidence to support the Public Staff's position. Let's put it -- let's generalize it.

A. Yeah. No. I'm --

Q. I don't want to use the word "culpability."

A. Well, Chisman Creek -- I know we talked about the petroleum waste, but also, the Chisman Creek site did receive coal ash. We asked questions about that because we were trying to get a general picture of the Company's management of coal ash.

Also, Chisman Creek was mentioned in the EPA's preamble for the CCR Rule. It mentioned Chisman Creek as an example of mismanagement of coal ash in -- in its determination of what should be in the CCR Rule.

Q. Well, I understand all that, but let me -- let me take it -- and again back it away from coal ash, because I'm really trying to get an understanding of the principles that are applied here.

So let's take it away from coal ash and -- and let's just say it's --

A. Sawdust.

Q. -- house -- sawdust.

A. Yeah.

Q. Waste paper from --

A. Yes. Yes.

Q. -- an office building and I hire a third-party contractor to -- to take my waste off site and dispose of it. And I have done a reasonable investigation of them. They're a reputable company. They have a branded name in the marketplace, and they do this for a lot of -- a lot of companies. And they take it off site and they dispose of it. And they dispose of it, and then it turns out they didn't do it right.

Is that an evidence of mismanagement or imprudence on my part that I contracted with them to dispose of my waste?

A. It could -- it could be. You have to do your due diligence --

Q. Well --

A. -- to make sure it's responsibly handled. And --

Q. If I do my due diligence, though, on the front end, how far do I have to go after that?

A. Well, it's my experience with hazardous waste there's a process called manifesting where people take possession and take responsibility along the line. But in -- and to go back to Chisman Creek, the -- Dominion was found responsible and had to -- was financially liable for remediating that.

Q. Under CERCLA?

A. Or the resource -- might have been under the resource --

Q. Under RCRA?

A. It might have been CERCLA or the -- RCRA.

Q. But we -- we -- we -- we've established, have we not, that -- that coal ash is not classified as a hazardous waste?

A. Yes, but, I mean, a lot of things aren't. I mean, things like used oil filters, landfill leachate, arsenic-treated wood, those things aren't hazardous waste either, but they don't belong in contact with the groundwater.

Q. They don't. But if I contract -- I'm a -- I'm a -- I'm a auto repair shop and if I contract for my waste oil filters from the cars I repair to be hauled off and managed, what's my responsibility to follow it after -- after I contract it?

A. I don't know the exact chain of events with the law as to when your responsibility would end and the next person's responsibility begins.

Q. On Page 90 of your testimony -- your direct testimony, you state that any insurance proceeds that may be recovered by the Company on account of policies that may be applicable and may -- may potentially cover some of these costs for which they're seeking recovery, you testified the Commission should require that the Company place all those proceeds in a regulatory liability account.

Are you -- is it Public Staff's position that a hundred percent of those proceeds go into the regulatory liability account or only -- that they're only deposited in accordance with the 60/40 equitable sharing formula?

A. We think -- well, insurance proceeds would be direct payments. I mean, it'd be a specific dollar amount. So --

Q. Right. But -- but what should be done with the dollars? Should the Company get -- keep a hundred percent of them or keep no percent of them or keep 60 percent of them? And --

A. Give me a minute. Let me take a look at that piece of my testimony.

Q. Okay. Sure. And, Mr. Maness, if you want to weigh in on any of this, you're free to do so.

A. First -- okay. I found that part of my testimony. We think it should be disbursed back to ratepayers because like the Public Staff's recommending, 60 percent of those costs are being paid by ratepayers. We think those insurance payments should be offset against that 60 percent that's being charged to the ratepayers.

Q. Okay. I just needed to understand what the position was on that.

Mr. Maness, a question for you. Are you familiar with the principle that our courts have announced from time to time that the costs of providing service to ratepayers in one period of time should be borne by the ratepayers in that period of time and not by subsequent ratepayers?

A. (Michael Maness) Yes.

Q. Does that principle have anything to do with your equitable sharing concept?

A. It does in the nature, I think -- and -- and if you look in the sections of my testimony where I talk about the magnitude and nature of the -- of the costs here as being part of the reason we would do equitable sharing outside of culpability, it does have something to do with that, because it's clear that at this point these costs are not going to provide any additional future benefit to the customers in terms of electric generation or improvements in service. They're just remediating things from the past.

So I think it does add into the factors that would make you consider equitable sharing to be a reasonable and appropriate resolution of the cost issues in this case from that standpoint.

Now, in terms of just for the fact that these events happened in the past, in general, of course, we think that cost should be borne by the ratepayers in the same period that the service is provided. But I cannot say that at times when companies have had unexpected costs that actually have to do with past service that we've always said you can't recover those because they have to do with past service, because sometimes the company's not aware of that.

So it's not a hard-and-fast rule that we would say you just can't recover it because you've now been faced with a cost that has something to do with a past year. But I think in this case it does play into the idea that when you have a cost of this magnitude that you need to look carefully at whether there's any additional future benefit that's going to be provided. And if not, that should be a factor in the decision as to whether to do equitable sharing.

Q. Is it just a question of magnitude or is it a question of time? What -- what -- what about costs that were incurred -- what about wastes that were generated prior to -- more than 50 years ago to provide electricity more than 50 years ago by a plant that had ceased operations before the test year?

A. Would we have a hard-and-fast rule? I don't know. I'm thinking about a situation with New River Light and Power where there's a dam -- I think Payne Branch is the name of it and they are doing some cleanup.

That dam was basically just abandoned and it's deteriorated over the years. And New River is incurring some expenses to sort of clean up that site. And we thought about the fact of, well, maybe we could oppose it because it had to do with service decades before. But we determined we wouldn't oppose it and did not take that position with the Commission.

So, again, if it's somewhat of a new cost that's being faced, there are times when we would say, yes, it's all right. It's a matter of judgment. There's some times when we might say, no, it's too related to prior years' service and it shouldn't be recovered.

And the magnitude then might play into our decision whether there should be some sort of equitable sharing because today's ratepayers just shouldn't bear the entire cost of that activity that's coming from -- or cost that's springing from service that was provided many years ago.

Q. What about in this case with respect to a plant that, say, ceased in 2003?

A. Yes. We're taking the position in this case that it should play in -- as I said in -- in my testimony, the fact that no additional service benefits are going to occur because of these costs should play into the decision as to whether to equitably share them or not.

Q. Another question to you. Do you -- do you -- is it the Public Staff's position that it matters if -- if the Commission grants a deferral and allows amortization of some of these costs or all of these costs as a regulatory asset, is it the Public's position that it matters whether or not those costs are classified as capital or operating in terms of whether or not the Commission does or does not allow them to be included in rate base?

A. I have two aspects of the response I want to give to that.

Q. Okay.

A. The first has to do with if we were talking about costs outside the CCR realm; you know, just costs that they were going to incur. Now, if some of those costs were property used and useful, then the Public Staff -- I can't speak for the entire Public Staff, but from my perspective as an accountant, I would tend to say -- and knowing what I've learned from counsel through the years -- that there would be at least a case to be made that a proper capital cost that is prudently incurred and reasonable in amount might need to be included in rate base if it could not be specifically disallowed.

Now, I will set off against that what I've learned from counsel regarding 62-133(d) and how it gives sort of an overlay to -- to make sure that the costs are reasonable and that the rates are reasonable.

Now, in the specific CCR context we're talking about this, there had been some conversation in this case between the Company and the Public Staff and data requests sent back -- and responses sent back and forth, and, certainly, there was discussion in the -- in the Duke cases, about whether just by the nature of it being an ARO and under financial accounting requirements being properly recorded as an asset, whether that means that it's -- it is obligatorily required to be put in plant and service. And we firmly say no.

The Company in this case, just like Duke in the Duke cases, has basically chosen to request deferral and treatment of this in a manner that is totally unlike the treatment that would go if they were going to account for it as a financial ARO.

Now -- so they have basically said we're not going to look at this as the ARO asset, as I was explaining earlier when Ms. Force was questioning me. In fact, the Company in its pro forma adjustments in this case completely eliminated the ARO assets and liabilities from the cost of service in this case and replaced them with this deferral of costs already expended in the proposed amortization.

So although one could say, well, the fundamental basis underlying this is the asset retirement obligation, that's just not the case, and there should -- it's totally up to the discretion of the Commission whether a return should be allowed. There is no ARO asset in this case because the ARO assets are related to the establishment of an ARO liability, which is based on expected future costs and how those should be expensed.

What we're talking about here are costs that have been incurred already and their want to defer and amortize those as an expense. If there was no ASC 410 requirement by the FASB for deferral and amortization, the Company could still come in here and request the same treatment they're requesting today.

However, because there is the SFAS 143 financial accounting requirement, they have to -- to do that, they have to also ask for the regulatory assets and liability recording to eliminate ARO accounting per the FASB from the cost of service in this case. Or another way to put it, they want to make regulatory asset and liability entries that overlay the ARO recording but, in fact, overlay them in a way that actually eliminates them.

Q. I think you know my position on the relevance of ARO accounting to the issues before the Commission. I think you know my position on that, but -- but I had a different question.

A. I'm sorry.

Q. Is -- is that in -- in terms of the exercise of the Commission's authority under 133(b) and 133(d), do you think it's important for the Commission to consider or be able to classify costs for which recovery is being requested by the Company as capital or operating?

A. I think it is important, and it's become more important because of these CCR cases. Because we have always viewed it as when you have a regulatory asset, which almost always -- not necessarily, but almost always deal with amounts that would have been written off as expenses, that even if those amounts are included in a rate -- in the rate base as a way of providing the return, I think it would be very beneficial for it to be clear when you're talking about a return that's discretionary to the Commission and a return that is required because of the statute.

Q. Thank you. That's all I have.

CHAIR MITCHELL: Commissioner Brown-Bland?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Lucas, around Page 91 and 93 of your testimony, you speak there about the Company using a totally new way of calculating depreciation expense adjustment.

A. (Jay Lucas) Yes.

Q. Is it -- is the public staff satisfied with the Company's new method? Can you say at this point?

A. We had a settlement on that, so I can't say --

Q. You don't want to --

A. One thing, that second method was filed on August 5th, and we just didn't have time to go through all the details and see if we were satisfied.

I do have some critique of it. I -- I didn't like the way they did it and -- but since we settled, we didn't pursue any resolution of my concerns.

Q. All right. That actually answers my question. And, Mr. Maness, can -- can you answer what the cost sharing percentage would be if the Commission decided on a five-year amortization with no return using the current stipulated numbers?

A. (Michael Maness) I can't do it sitting here. I'd be glad to provide it later.

Q. All right. And -- and the same for ten years, if you would do that.

A. Yes.

Q. And do you have a response to the Company's position that the Public Staff's position would create an unpredictable, unhealthy regulatory environment?

A. I don't agree. I think this is an unusual circumstance, and sometimes when unusual circumstances arise, the resolution of that is going to be not necessarily written down in stone beforehand and can't be predicted.

We -- I think that -- and we've tried to recommend what we think is a fair and reasonable recovery for this unique matter and it shouldn't necessarily affect matters of routine or ongoing costs and expenses in the future. But anytime you have something like this or major hurricanes, it's so unique, as we know, that the Legislature's considering something to do with that.

I think that we have to try our best to make a fair and reasonable recommendation to the Commission as to how those specific costs should be handled and not worry overly much about the fact that it might be something different than -- than what has been done before or what might be done in the future in other situations.

Q. And, generally, it's always said that the Company benefits from and -- and likes to have certainty. So does the Public Staff's position introduce uncertainty that -- that would be at a level that's harmful?

A. Certainly -- I just don't think that it's reasonable for a company to expect when they incur a cost that they have a certainty of recovery. It always has to be under the over -- oversight of the Commission to determine if those costs are prudently incurred and reasonable.

And I would point out, too, that this certainly is not the first time that the Commission has looked at whether there should be equitable sharing. It's been several years, but we have a long record with all of our electric companies to where this policy has been used before.

So while it might result in some uncertainty, I don't think, in general, it's more uncertainty than what the Company normally has when it comes to the Commission with -- with a large and unusual cost.

Q. All right. And do you have a response to Mr. McLeod's statement that the amortization period should be shorter so that the costs are paid during a period where there will be substantial 2020 fuel factor reduction, resulting in less rate volatility?

A. No. I haven't considered that in our case. We think it's more important that we have a fair and reasonable outcome to this particular issue than to try to worry about managing the rates to be at a certain level.

Q. All right. And, Mr. Lucas, in your Exhibit 8, you include several Public Staff data requests and the Dominion responses on the subject of --

A. (Jay Lucas) Yes.

Q. -- NPDES permits.

A. Yes, and -- and other things. It goes on for about 27 pages, 28 pages.

Q. Your exhibit doesn't include the documents that Dominion provided. Is that something that the Public Staff could file as a late-filed exhibit?

A. Well, some of them do. Some of these pages at the bottom part of the page gives the response. You want something more or --

Q. We're look -- we're looking specifically at Data Request 3-5 --

A. Yes.

Q. -- 10 and 11 and 16.

A. Okay. We can. We can provide the full response.

Q. All right. Thank you.

CHAIR MITCHELL: Any additional questions for the panel?

Questions on Commissioners' questions?

FURTHER CROSS-EXAMINATION BY MR. SNUKALS:

Q. I do have a couple of follow-up questions. They'll be directed at -- at you, Mr. Lucas.

Commissioner Clodfelter, I believe, was asking about exceedances that are referenced in your testimony. Do you recall that?

A. (Jay Lucas) Yes.

Q. And I believe the number that you have cited in one of your exhibits is 548 exceedances.

A. That's correct.

Q. And is it true that those exceedances reflect groundwater data collected in reports from 2017 through 2018?

A. That's correct. We can't get anything earlier than that. The number might have been higher if we had gotten earlier groundwater records.

Q. So all of those exceedances that you cite in your testimony are related to the -- compliance with the CCR Rule, correct?

A. Yeah. It was under the testing as required by the CCR Rule.

Q. Okay. As we sit here today, Mr. Lucas, you can't identify for me any instance where the Virginia Department of Environmental Quality has cited the Company for a violation of the anti-degradation policy, can you?

A. Well, you're talking about just for those -- those exceedances in 2017, 2018?

Q. Any time.

A. Well, Lucas Exhibit 3 and 4 talk about special order in the 1980s where the Company had contaminated groundwater and the Virginia Water Control Board issued a special order.

Q. Was that a violation?

A. Well, let me -- let me go to that, those two exhibits.

Q. Setting aside that instance, is that the only example that you have, Mr. Lucas?

A. Yes.

Q. So one example of where -- potentially where Virginia DEQ has cited the Company for a violation of the anti-degradation policy over the history of its operations of its impoundments and landfills; is that right?

A. I don't have documentation of other groundwater violations.

Q. Mr. Lucas, it's the CCR Rule that's requiring the

Company to close its ash impoundments, correct?

A. Well, the CCR Rule is pretty broad. We -- I mean, that's what the Company claims. But the Company hasn't been able to specify exactly which portion of the CCR Rule have required closure.

We've asked the Company. The Company just says the CCR Rule. So I can't say any specific portion of the CCR Rule is applying to the Company.

Q. The CCR Rule establishes minimum standards for ash impoundments, correct; federal minimum standards, right?

A. I mean, I haven't memorized the entire CCR Rule, but it sets some standards and has -- does set some closure requirements. For example, 40 CFR 257.60 requires the Company to do remediation if it put coal ash too close to the water -- to the aquifer.

If the Company has violated groundwater standards, that's 40 CFR 257.101. And the Company's recently found, yes, it has contaminated groundwater, so that is forcing some of the remediation.

Q. The CCR Rule is a -- a new regulatory requirement as of 2015, correct?

A. That's correct.

Q. The Company's obligations under the CCR Rule -- what they're doing is not being taken in response to an enforcement action by Virginia DEQ, is it?

A. No, but the CCR Rule sets its own requirements. Like I said, 40 CFR 257.101 requires the Company to start taking action if it finds groundwater contamination. It's just a condition in the rule. It's -- it's nothing that specific action has to be taken for that one particular event.

Q. Mr. Lucas, you've not identified a single cost in this case that should be disallowed due to exceedance of groundwater standards?

CHAIR MITCHELL: Mr. Snukals, make sure your questions refer to questions from the Commissioners.

A. Go ahead and say your question again, please.

Q. Sure. You have not identified a single cost in this case that should be disallowed due to a groundwater exceedance?

MS. CUMMINGS: Objection. The question does not relate to Commission questions.

MR. SNUKALS: I believe that Commissioner Clodfelter did ask about exceedances and -- and the number of exceedances. So I think in terms of this case, it's relevant to determine whether the Public Staff determined whether any of those exceedances have resulted in any costs.

MS. CUMMINGS: The number of exceedances is different from the cost.

A. Let me go back over this.

CHAIR MITCHELL: Let me -- Mr. Lucas, let me rule on the objection first and then --

THE WITNESS: Sorry.

CHAIR MITCHELL: I'm going to -- I'm going to sustain the objection. Let's move on to the next question, please.

MR. SNUKALS: Okay. I don't have any further questions.

FURTHER REDIRECT EXAMINATION BY MS. CUMMINGS:

Q. I do have a few questions, Mr. Lucas. And, again, Mr. Drooz may have some questions as well.

The CCR Rule -- prior to the CCR Rule -- the CCR Rule, it required some sort of -- it's -- it set federal minimum standards, but it required certain testing techniques, right?

Did we find in our -- in the course of our investigation that the Virginia DEQ was testing for dissolved metals?

A. Yes, and EPA --

MR. SNUKALS: Object. Objection. I don't believe that the -- that's within the scope of

Commissioner Clodfelter's or any of the Commissioners' questions.

MS. CUMMINGS: I'm following up on your EPA questions, CCR questions.

CHAIR MITCHELL: Let's -- Ms. Cummings, let's just keep our questions related to questions by the Commissioners.

Q. Commissioner Clodfelter asked you about the number of exceedances --

A. Yes.

Q. -- and whether or not those were required by the CCR Rule or whether or not they were required by the state.

Your Exhibits 12 and 13 detail those exceedances. Your Exhibit 12 is set out separately for Chesapeake because it's state groundwater standards, right?

A. That's correct.

Q. And that's because the CCR Rule did not apply to Chesapeake; is that correct?

A. That's correct.

Q. And state groundwater standards did?

A. That's correct.

Q. You were also asked by Commissioner Clodfelter if one exceedance would result in a culpability finding.

A. That's correct.

Q. We don't expect the Company to be perfect in its compliance record, do we?

A. No.

Q. In fact, we see notices all the time of environmental issues?

A. Yes.

Q. Does the amount of exceedances for you go towards the degree of culpability?

A. The number of exceedances, yes, because that's an example of contamination of groundwater and that's the Company's responsibility, to keep the groundwater clean.

Q. And you were also asked about Chisman Creek and how that applies to this case by Commissioner Clodfelter.

A. That's correct.

Q. What year was Chisman Creek? It was in 1980, correct?

A. Yeah. The groundwater contamination and drinking water contamination was found in 1980.

Q. And would that have been a signal to the Company that its ash products were causing groundwater contamination?

A. Yes. The Company should have --

MR. SNUKALS: Objection. Speculation.

MS. CUMMINGS: Excuse me?

MR. SNUKALS: Objection. Calls for speculation.

COMMISSIONER GRAY: I can't hear you.

MR. SNUKALS: Objection. Calls for speculation.

CHAIR MITCHELL: I think she's just asking for his opinion. We'll -- we'll -- I'll allow the question.

A. The Chisman Creek site did have coal ash from the Yorktown Power Plant and it was found to have contaminated groundwater and contaminated drinking water to the extent where the Company had to provide municipal water to the nearby residences. I think that should have been an indicator to the Company that coal ash was creating problems.

Q. In fact, it was a proven damage case cited for reason that the CCR Rule was enacted?

A. Yes. It was cited in the EPA's preamble to the CCR Rule.

FURTHER REDIRECT EXAMINATION BY MR. DROOZ:

Q. And speaking of the CCR Rule and the questions on that, have you looked through the preamble? Are you familiar with that?

A. Yes, I am.

Q. Okay. Did the EPA adopt or promulgate the CCR Rule, if you know, because regulation by state environmental agencies was not proving sufficient to control coal ash contamination?

A. Yeah. Reading through the preamble, you can see the EPA was suspicious of state regulatory programs. I can cite some examples, if necessary.

Q. Well, we can move on because I think the preamble speaks for itself.

Mr. Maness, you were asked about the distinction between -- by Commissioner Clodfelter regarding operating expenses versus capital costs.

A. (Michael Maness) Yes.

Q. Do you recall from discovery responses from the Company what percentage of the CCR expenditures in this case, the expenditures from July 2016 through June of 2019 -- what percentage were O&M costs in nature absent the use of FASB, ASC 410 accounting?

A. I could look up the specific number from the data response, but I believe it was close to 98 percent.

Q. Ninety-eight (98) percent were which, O&M or capital?

A. O&M.

Q. Thank you. That's all.

CHAIR MITCHELL: I do -- actually do have one question for the panel and then I'll allow the parties to ask questions on it if -- if there are any.

EXAMINATION BY CHAIR MITCHELL;

Q. Mr. Lucas, this is for you. I believe you were in the room earlier when I asked this question of Company witness; I believe it was Williams.

Prior to the most recent enaction of legislation by -- in Virginia related to the impoundments located in the Chesapeake Bay watershed, the Company's closure plans were closure in place for the -- for those particular impoundments and the legislation requires removal. That's as you know and have testified to.

What can you tell me about the -- the legislation and -- and sort of the -- this -- this change that has occurred from closure in place to removal?

A. (Jay Lucas) Yes. It's going to be very expensive. As the Company is trying to recover in this case, a lot of closure in place expenses and --

Q. And I -- and I -- and I'm -- I -- we -- I think we can all assume that it's going to be far more expensive to -- to remove as opposed to close in place. But I -- I'm actually interested in -- in risk.

A. Yeah. I've talked with some coal ash consultants and they're -- this new proposal or this new law passed in Virginia, this Senate Bill 1355, on one hand, it could reduce risks by eliminating some of the problems that can be created by cap in place, lateral movement of groundwater.

It also could increase risks. It appears under this new legislation, the Company's going to have to dig out every single ton of coal ash. It's all got to be loaded somehow, moved somehow. And I think that -- that creates risks as well for release of contaminants.

CHAIR MITCHELL: Okay. Questions on my question?

MR. SNUKALS: No questions.

FURTHER REDIRECT EXAMINATION BY MS. CUMMINGS:

Q. Mr. Lucas, in your testimony, you talk about your recommendation, and part of that recommendation is the future risk that this contamination causes.

Would you agree that the legislation speaks to that future risk as judged by legislative policy? It's a judgment on --

A. (Jay Lucas) Okay. Yeah. Let me turn to that -- turn to that rule real quick.

Q. That's Senate Bill 1355.

A. It does speak to some of the risks about transportation. I mean, it's -- it's in there and it -- the

Company's going to have to come up with a transportation plan.

Q. That's all my questions. Thank you.

MR. SNUKALS: Chair Mitchell, before we -- we -- is there any way we could go ahead and move DENC Lucas Cross Exhibits 1 and 3 into evidence?

CHAIR MITCHELL: Hearing no objection, your motion's allowed.

MR. SNUKALS: Thank you.

(DENC Lucas Cross Exhibits 1 and 3 were admitted into evidence.)

MS. CUMMINGS: Public Staff also move its exhibit into evidence.

CHAIR MITCHELL: Hearing no objection, motion is allowed.

(Public Staff Lucas Redirect Exhibit 1 was admitted into evidence.)

MS. GRIGG: At some point in time, we'd like to -- I think all parties would like to move in the testimony and exhibits of the witnesses who didn't appear. Obviously, your druthers of when you'd like us to do that.

CHAIR MITCHELL: Okay. Why don't we -- as these guys are packing up and stepping down, we conversation go ahead and -- and start that process now.

MS. GRIGG: Would you like to do it party by party or would a general motion suffice that for the witnesses who didn't appear that their testimony be read into the record?

CHAIR MITCHELL: For purposes of the record, let's do it party by party just to make sure we're clear.

And I believe that Dominion, you -- you-all can call your next witness while we're taking care of this business.

MS. GRIGG: Thank you, Chair Mitchell. At this point, the Company calls Mr. Paul McLeod.

Chair Mitchell, at this time, Dominion would like to move that the testimony -- the seven pages of direct testimony of Mr. Bruce Petrie in question and answer form and an appendix consisting of one page and one exhibit consisting of two pages, two pages of supplemental testimony and one exhibit be moved into the record at this time.

CHAIR MITCHELL: Motion will be allowed.

(Company Exhibit BEP-1 and Supplemental Exhibit BEP-1 were premarked for identification.)

(Whereupon, the prefiled direct and supplemental testimony of Bruce E. Petrie was copied into the record as if given orally from the stand.)

DIRECT TESTIMONY
OF
BRUCE E. PETRIE
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

Q. Please state your name, business address, and position of employment.

A. My name is Bruce E. Petrie, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am Manager of Generation System Planning for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Please describe your areas of responsibility within the Company.

A. I am responsible for forecasting total system fuel and purchased power expenses, and for financial studies related to the regulated generation assets. A statement of my background and qualifications is attached as Appendix A.

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

A. The purpose of my testimony is to present the Company's adjusted total system fuel expenses, which will be used by Company Witness Paul B. Haynes to calculate the base fuel rate. I will also provide an estimate of the system fuel expense for the period July 1, 2018 – June 30, 2019, and an estimate of the deferred fuel balance as of June 30, 2019.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. I am sponsoring Company Exhibit BEP-1, which consists of two schedules. This exhibit was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief.

Q. Describe the methodology that is being used to determine the adjusted total system fuel expense.

A. The system fuel expense is based on the same information that was filed by the Company in the most recent fuel factor case, Docket No. E-22, Sub 558, using fuel expenses for the historical period July 1, 2017 – June 30, 2018, and adjusted for normalization of nuclear generation and customer demand (growth and usage).

Q. What is the resulting adjusted total system fuel expense for the historical period July 1, 2017 – June 30, 2018?

A. Schedule 1 shows the adjusted system fuel expense for the historical period July 1, 2017 – June 30, 2018 of $1.824 billion, as approved by the North Carolina Utilities Commission's ("Commission") January 23, 2019, *Order Approving Fuel Charge Adjustment* issued in the Company's 2018 fuel proceeding, Docket No. E-22, Sub 558 (the "2018 Fuel Case Order"). This adjusted system fuel expense is used by Company Witness Haynes to calculate the placeholder base fuel rate included in the Application.

Q. What is the Company's forecast of the adjusted total system fuel expense for the period July 1, 2018 – June 30, 2019, based on eight months of history and four months of projected data?

A. Schedule 2 shows an estimate of the adjusted system fuel expense for the period July 1, 2018 – June 30, 2019 of $1.803 billion, which is approximately $21.4 million less than the system fuel expense approved in the 2018 Fuel Case Order. This adjusted system fuel expense is used by Company Witness Haynes to determine the Projected Base Fuel Rate.

Q. What are the contributing factors to the lower system fuel expense in the 2018-2019 period?

A. There is a decrease in system fuel expenses associated with the termination of the Company's wholesale power requirements contract with North Carolina Electric Membership Corporation ("NCEMC") at the end of 2019. The Company is not renewing the contract with NCEMC and an adjustment of $23.7 million is included in the fuel expense. In addition, there have been changes to the non-utility generator ("NUG") contracts, with several contracts that have expired since 2016. The 605 MW contract with Doswell ended in May, 2017, and the 116 MW and 85 MW contracts with the Spruance facility ended in July, 2017. The ROVA facility contract is expiring in March 2019. The Company also expects additional growth in solar energy production. Finally, there are reductions in the purchased power expense due to the benefits of a full year of operations at the Greensville County Generating Station ("Greensville County CC") and the reduction in the marketer percentage. All of these expense reductions are offset by increases in purchased power expense associated with the treatment of certain NUG expenses as a result of the enactment of North Carolina House Bills 589 and 374.

Q. How have commodity prices changed since the Company's previous fuel case was filed in August 2018?

A. Since July 1, 2018, natural gas, coal and power prices have increased gradually with moderate spikes related to weather. The weather during the winter of 2019 has been relatively moderate compared to the winter of 2018, when spot gas and power prices showed short term increases. Overall, the price changes are very minor since last year's fuel filing.

Q. Please explain the reduction in system fuel expense to reflect the Greensville station operations.

A. The addition of the 1,588 MW Greensville County CC in December 2018 will provide a benefit to the system fuel expense going forward. An adjustment of $22.7 million is included to reflect the additional fuel benefits related to twelve months of Greensville County CC operations.

Q. What are the impacts to system fuel expense resulting from the enactment of North Carolina House Bills 589 and 374?

A. Due to the enactment of North Carolina House Bill 589 on July 27, 2017, and House Bill 374 on June 27, 2018, the Company can now recover the total delivered costs, including capacity and non-capacity costs, associated with certain purchases of power from qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 ("PURPA") that are not subject to economic dispatch or curtailment. Reflecting these costs will increase system fuel expense allocated to the North Carolina jurisdiction by approximately $57 million.

Q. Do any other factors impact the system fuel expense?

A. The Company continuously evaluates the customer benefits versus expenses of the units in the Company's generation fleet. As part of this effort, the Company placed 10 older, less efficient coal, biomass, and natural gas generating units into "cold reserve" in 2018. These units, which total 1,292 MW of generation capacity, include Bellemeade Power Station, Bremo Power Station units 3 and 4, Chesterfield Power Station units 3 and 4, Mecklenburg Power Station units 1 and 2, Pittsylvania Power Station, and Possum Point Power Station units 3 and 4. These units are currently not in operation and will be retired. The Company does not anticipate a significant impact to system fuel expense from these changes.

Q. Has the Company evaluated the current marketer percentage calculation?

A. Yes. The system fuel expense includes PJM energy market purchases, NUG energy purchases and off-system sales. Generally, purchases from the PJM energy market and certain NUG purchases do not provide fuel cost data. The marketer percentage is a proxy used to approximate the percentage of these purchase costs related to fuel and is applied to these fuel expenses. Consistent with the Commission's conclusions in the 2018 Fuel Case Order, the Company has updated the calculation of the marketer percentage based on the PJM State of the Market Reports for 2017 and 2018, using the same averaging method that was applied in the 2018 fuel case as well as the Company's 2016 general rate case, Docket No. E-22, Sub 532. The updated marketer percentage is 71% and a line item adjustment of $30.4 million has been included on my Schedule 2 showing the calculation of the system projected fuel expense.

Q. **What is the forecast of the Company's fuel expense recovery position for the period July 1, 2018 – June 30, 2019?**

A. As of February 28, 2019, the Company's fuel recovery position since July 1, 2018 is an under-recovery of about $6.7 million. Since the new Rider A fuel rate went into effect on February 1, 2019, the Company's monthly fuel expenses are closer to the monthly fuel revenues. Based on projected data, the cumulative fuel under-recovery position for the 12-month test period ending June 30, 2019 is expected to be approximately $1-3 million. As explained in the Application, the Company will update the historical test period system fuel expense using actual data for purposes of submitting both its 2019 fuel factor filing in August and the Company's supplemental filing in support of the Company's Application to be filed in late summer 2019, following the submission of the 2019 fuel case.

Q. Please describe the Company's forecast of fuel expense recoveries in the second half of 2019.

A. As the current Rider A fuel rate will remain in effect through the end of 2019, the Company expects a small monthly over-recovery of fuel expenses through the end of 2019, barring any major changes in unit availability or commodity prices. During the period July – December 2019, the over-recoveries could be in the range of $1 to $3 million, to offset the expected $1 to $3 million under-recovery as of June 30, 2019.

Q. Do you have any other forms or schedules to sponsor?

A. Yes. I am sponsoring Item 46(f) of NCUC Form E-1, which is included in the Company's filing. Item 46(f) contains information about actual fuel consumption and fuel expenses for 2018, and forecasted information for 2019 and 2020.

Q. Mr. Petrie, does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF BRUCE E. PETRIE

Mr. Petrie graduated from Clarkson University in 1983 with a Bachelor of Science degree in Mechanical Engineering. He earned a Master of Business Administration degree from Virginia Tech in 1988.

Mr. Petrie worked for Niagara Mohawk Power Corporation from 1988 through 1998 in generation planning, fuel procurement, and wholesale power marketing, and then at Old Dominion Electric Cooperative from 1998 until 2001 as a power supply analyst. He joined Virginia Power in April 2001 as an electric pricing and structuring analyst. His responsibilities included the pricing and structuring of wholesale electric transactions, project financial analysis, and analytical support to the Energy Supply group.

In October 2007, Mr. Petrie was promoted to Manager of Generation System Planning for Dominion Virginia Power. He is currently responsible for the Company's mid-term operational forecast.

**SUPPLEMENTAL DIRECT TESTIMONY
OF
BRUCE E. PETRIE
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562**

Q. Please state your name, business address, and position of employment.

A. My name is Bruce E. Petrie, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am Manager of Generation System Planning for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Have you previously filed testimony in this proceeding?

A. Yes. I pre-filed direct testimony on March 29, 2019, in support of the Company's Application in this proceeding.

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

A. The purpose of my testimony is to present the Company's actual adjusted total system fuel expenses for the twelve-month period ending June 30, 2019, and to provide a projection of the Company's deferred fuel balance during the period of July through December 2019.

Q. During the course of your testimony, will you introduce an exhibit?

A. Yes. I am sponsoring Company Supplemental Exhibit BEP-1, which consists of one schedule.

Q. What is the forecasted normalized and adjusted total system fuel expense, based on the historical period July 1, 2018 through June 30, 2019?

A. My Supplemental Schedule 1 shows the adjusted system fuel expense of $1.78 billion. This adjusted system fuel expense was calculated using the same pricing methodology that has been used for the past several annual fuel cases, and is based on the 71% marketer percentage as proposed by the Company in this proceeding.

Q. Mr. Petrie, does this conclude your supplemental direct testimony?

A. Yes. It does.

MS. GRIGG: Thank you. We'd also like to move the five pages of supplemental testimony in question and answer form of Deanna Kesler, with an appendix consisting of one page, and one exhibit, consisting of 85 pages, into the record.

CHAIR MITCHELL: Motion is allowed.

(Company Supplemental Exhibit DRK-1 were premarked for identification.)

(Whereupon, the prefiled supplemental testimony of Deanna Kesler was copied into the record as if given orally from the stand.)

SUPPLEMENTAL DIRECT TESTIMONY
OF
DEANNA R. KESLER
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

Q. Please state your name, business address, and position of employment.

A. My name is Deanna R. Kesler, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am a Regulatory Consultant in Demand Side Planning, which is part of the Integrated Resource Planning organization of Virginia Electric and Power Company, operating in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). A statement of my background and qualifications is attached as Appendix A.

Q. Have you previously filed testimony in this proceeding?

A. No, I have not. I am filing my direct testimony today as part of the Company's supplemental filing.

Q. Please briefly describe your area of responsibility with the Company.

A. I am responsible for the evaluation of DENC's demand-side management ("DSM") and energy efficiency ("EE") programs ("DSM/EE Programs" or "Programs"). This includes detailed analyses of approved and proposed DSM/EE Programs and the incorporation of DSM and EE measures into the Company's integrated resource planning ("IRP") process and long-term integrated resource plan. My responsibilities also include planning, organizing, and coordinating evaluation, measurement and verification ("EM&V") work for all DSM/EE Programs through an independent third-party EM&V contractor, DNV GL (formerly DNV KEMA Energy & Sustainability). This includes ensuring EM&V data is collected and made available to DNV GL for review and analysis, reviewing EM&V processes and reports, and coordinating all pertinent EM&V activities.

Q. **Ms. Kesler, what is the purpose of your supplemental direct testimony?**

A. My testimony supports the Company's estimation of reduced sales (kwh) resulting from DENC's 17 approved EE Programs for the period January 1, 2018, through June 30, 2019, the end of the update period in this proceeding. My testimony in this proceeding is consistent with information to be filed in my direct testimony in the Company's 2019 DSM/EE cost recovery proceeding, Docket No. E-22, Sub 577.

Q. **Please describe the Company's approved EE and DSM programs.**

A. Since 2010, the Company has filed for and obtained Commission approval of six "phases" of EE and DSM programs consisting of the following 18 individual DSM/EE Programs: Residential Air Conditioning Cycling Program; Residential Low Income Program; Residential Lighting Program; Non-Residential HVAC Upgrade Program; Non-Residential Lighting Program; Residential Home Energy Check-Up; Residential Duct Sealing; Residential Heat Pump Upgrade; Residential Heat Pump Tune-up; Residential Income & Age Qualifying Home Improvement Program; Residential Retail LED Lighting Program (NC only); Non-Residential Energy Audit; Non-

Residential Duct Testing & Sealing; Non-Residential Window Film; Non-Residential Lighting Systems & Controls; Non-Residential Heating & Cooling Efficiency; Non-Residential Small Business Improvement Program; and Non-Residential Prescriptive Program.[1]

Q. Ms. Kesler, of the 18 previously-approved DSM/EE Programs, will all 18 generate energy savings to be used in the calculation of lost revenues?

A. No. Only the 17 EE Programs will generate energy savings to be used in the calculation of lost revenues. The Residential Air Conditioning Cycling Program is designed as a peak shaving program. Therefore, no energy savings are measured for this program and no lost revenues will be calculated for it. While some of the programs have now closed to new participation, previously installed measures are still producing energy efficiency savings, but new measures are not being deployed.

Q. Has the Company previously reported on the energy savings achieved by the Company's approved EE programs to the Commission?

A. Yes. As directed by the Commission's December 13, 2011 Order issued in Docket No. E-22, Sub 473, the Company annually files its EM&V report on May 1 of each year, with the most recent EM&V Report having been filed with the Commission on May l, 2019 ("2019 EM&V Report"), in Docket No. E-22, Sub 556. The 2019 EM&V Report presents North Carolina Program activity from initial Program implementation beginning in June 2011 through

[1] Orders approving the Programs were issued in Docket No. E-22, Subs 463, 465, 467, 468, 469, 495, 496, 497, 498, 499, 500, 507, 508, 509, 523, 538, 539, and 543.

the end of calendar year 2018. More specifically, the 2019 EM&V Report provides the following information for each DSM/EE Program: (1) the number of participating customers; (2) estimated gross and net kW and kwh impacts for each of the Programs; (3) associated Program costs; and (4) any recommendations or observations following the analysis of the EM&V data. Data included in the 2019 EM&V Report also included the kWh energy savings achieved by the Company's EE Programs.

Q. Ms. Kesler, are you sponsoring any exhibits or schedules in connection with your testimony?

A. Yes. Company Supplemental Exhibit DRK-1, consisting of Schedules 1-2, was prepared under my supervision and is accurate and complete to the best of my knowledge and belief. My Schedule 1 supports the calculation of energy savings for the Company's 17 approved EE Programs over the January 1, 2018, through June 30, 2019 period, which is based on actual EM&V data collected and analyzed by DNV GL. My Schedule 2, including a public and a confidential version to be filed under seal, provides the North Carolina program summary tracking data tables prepared by DNV GL for each of the Company's 17 approved EE Programs.

Q. How does the Company calculate the energy savings for the January 1, 2018, through June 30, 2019 period?

A. The Company used 18 months of actual EM&V data (starting January 1, 2018, through June 30, 2019) as reported by DNV GL. DNV GL's Program Tracking Summary data over this time period is reflected in my Schedule 2 and uses the same Standard Tracking Engineering Protocol formulas presented in the Company's 2019 EM&V Report. Since DNV GL's energy savings are annualized, they developed cumulative monthly net energy savings over the January 1, 2018, through June 30, 2019 time period for each EE Program in my Schedule 1, which represents the estimated energy savings by month.

Q. **How are the energy savings presented in your Schedule 1 being used?**

A. This information is used by Company Witness Paul B. Haynes to calculate the DSM/EE Lost Revenue Adjustment.

Q. **Does this conclude your supplemental direct testimony?**

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS

OF

DEANNA R. KESLER

Ms. Kesler has held various positions with Dominion Virginia Power in the Power Operations Management Services, Generation and System Planning, Production Costing, Energy Efficiency, and Integrated Resource Planning areas. She originally joined Dominion Virginia Power in 1984 and returned in 2008. She has also had a variety of leadership roles prior to rejoining the Company both as a consultant and as an internal employee for several major corporations.

Ms. Kesler has a Master's in Business Administration from Virginia Commonwealth University. She also studied Business Administration at Virginia Commonwealth University and Chemical Engineering and Finance at Virginia Polytechnic Institute and State University.

MS. GRIGG: And, finally, the ten pages of direct testimony of Bobby McGuire in question and answer form and an appendix, consisting of one page, be moved into the record.

CHAIR MITCHELL: Your motion is allowed.

MS. GRIGG: Thank you.

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

DIRECT TESTIMONY
OF
BOBBY E. MCGUIRE
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

Q. Please state your name, position, business address and professional background.

A. My name is Bobby E. McGuire. I am employed by Virginia Electric and Power Company ("VEPCO"), doing business in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company") as Director, Electric Transmission Project Development & Execution. My business address is 10900 Nuckols Road, Glen Allen, Virginia 23060. A statement of my background and qualifications is attached as Appendix A.

Q. Please describe your area of responsibility within the Company.

A. Since 2005, I have been responsible for the development and oversight of electric transmission projects for DENC, including design and engineering, permitting, real estate acquisition and overall project management. I have over 170 employees and contract personnel on my staff, including 13 project managers who report directly to me. Under my direction over the last decade, the Company has completed more than $6.6 billion in electric transmission asset construction projects with more than $4.3 billion of new transmission projects currently in the development, engineering or construction phase across the Company's electric transmission footprint in North Carolina, Virginia, and West Virginia.

Q. Please summarize your testimony in this proceeding.

A. My testimony supports the Company's overall request to adjust North Carolina base rates to recover the cost of providing reliable electric service to our customers in North Carolina. Specifically, I will explain the Company's major investments in its transmission and North Carolina distribution ("T&D") electric system during the period 2016 through 2018 and describe the benefits to our customers resulting from those investments.

Q. Please generally describe DENC's T&D electric system in North Carolina.

A. DENC's T&D system delivers electric service to more than 120,000 customers in northeastern North Carolina across a service territory of approximately 2,600 square miles, including Roanoke Rapids, Ahoskie, Williamston, Elizabeth City, and the Outer Banks. The Company's retail service territory is located within the Company's electric transmission zone, which also includes North Carolina Electric Membership Corporation ("NCEMC") and North Carolina Eastern Municipal Power Agency ("NCEMPA") customers.

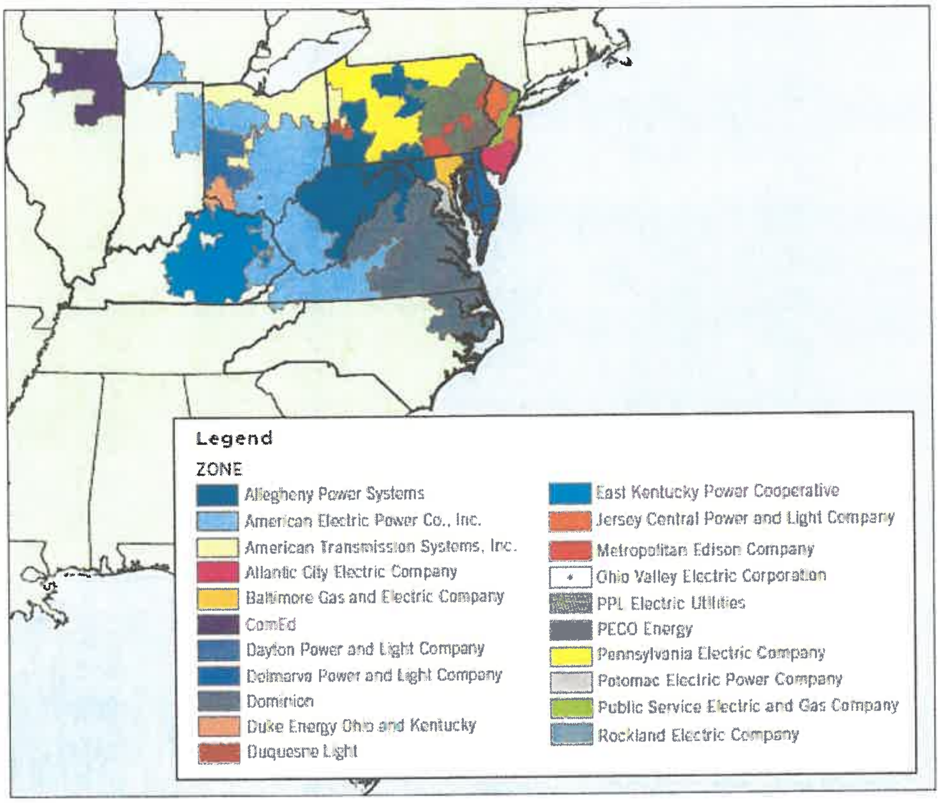
The Company's T&D electric system in North Carolina includes approximately 1,000 miles of transmission lines, providing electricity to approximately 30 delivery points, including directly to North Carolina industrial customers taking service at transmission voltage. DENC also operates seven transmission voltage interties with Duke Energy Progress at the southern border of DENC's system. The Company also operates more than 4,000 miles of overhead distribution lines and 900 miles of underground distribution lines. In addition to power lines and substations, the Company's T&D system includes various other equipment and facilities such as control houses, communications facilities, transformers, capacitors, street lights, meters, and protective relays. Together, these assets provide the Company's T&D system with considerable operational capability and flexibility and allow DENC to provide safe, reliable, and economical power to the Company's customers in North Carolina.

Q. Please provide an overview of the Company's electric transmission system.

A. DENC's transmission system extends throughout the Company's service territories in North Carolina and Virginia to support the provision of reliable electric service to all of our retail customers. In addition, the Company provides wholesale transmission service to other utilities and electric service providers – including a number of Virginia electric cooperatives, NCEMC and NCEMPA – for redelivery to their respective customers. The Company also provides interconnection and transmission service to both DENC-owned and non-utility generation ("NUG") power generation facilities interconnected to the electric grid at transmission voltage, which generally consists of fossil, nuclear, biomass and, increasingly, wind and solar energy generating facilities at or above 20 megawatts (MW) in the Dominion transmission zone.

DENC's transmission system is operated as part of the PJM Interconnection, L.L.C. ("PJM") regional transmission organization which provides service to a large portion of the eastern United States and is the designated "Transmission Operator" for the Dominion transmission zone (the "DOM Zone"). My Figure 1 presents a map of the DOM Zone within the PJM footprint.

FIGURE 1



Broadly, PJM is currently responsible for ensuring the reliability and coordinating the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Based on PJM's most recent load forecast, released in January 2019, the DOM Zone is expected to be the fastest growing zone in PJM, with average peak demand growth rates of 0.9% (summer) and 1.1% (winter) over the next 10 years. This growth rate is significant when compared to other PJM participant zones which are projected to grow at an average rate of 0.3% (summer) and 0.4% (winter) over the same period.

The Company also actively studies its transmission zone and its ties with neighboring utilities to ensure reliable delivery of electricity can be maintained at all times and in all contingency situations. PJM provides additional support in both these zonal studies as well as its review of overall system conditions, including generator deliverability studies targeted to evaluate network abilities and ensure generation capacity resources can deliver energy to load areas.

Q. **Please explain why investment in electric transmission is key to providing safe, reliable, and economical power to customers.**

A. At the highest level, the Company invests in its electric transmission system to ensure reliability and ongoing compliance with NERC reliability standards and requirements, address load growth, and repair or replace aging infrastructure. These investments ensure the Company's continued ability to provide safe, reliable, and economical power to our customers.

Q. Please highlight some of the major transmission projects that DENC has completed in North Carolina since 2016.

A. DENC completed approximately $268 million of electric transmission projects located in North Carolina during the period of 2016-2018, including construction of a new 44-mile 115 kV line from Pantego to Trowbridge; construction of a new 25-mile 115 kV line from Halifax to Scotland Neck; and rebuilding and refurbishment of approximately 90 miles of existing 115 kV lines, including one single circuit line between Roanoke Rapids and Ahoskie, two lines between Roanoke Rapids and Lake Gaston, and a single circuit line between Roanoke Rapids and Emporia. The Company has also completed a Static Var Compensator replacement project in the Nags Head area to address voltage conditions, as well as construction of a new substation in the Battleboro area.

Q. What direct benefits do North Carolina customers receive from these transmission projects?

A. As described above, investments in the electric transmission system are needed to support economical power delivery and reliable electric distribution service to the Company's retail customers, in addition to directly serving the electric transmission needs of wholesale customers and cooperatives for redelivery.

For example, the two new 115 kV lines from Pantego to Trowbridge and Halifax to Scotland Neck provide more reliable network service in areas which were previously served exclusively by radial transmission lines and without redundancy. Now that these lines are networked, the Company is able to restore service when outages occur *before* completing repairs on the damaged section of the transmission line, thus minimizing the time customers are without power. These two lines serve approximately 16,000 customers—including residential, commercial and industrial—within an expansive service area that encompasses Halifax, Martin, Bertie, Hyde, and Beaufort Counties.

Q. Do the Company's electric transmission system investments completed in Virginia also provide benefits to North Carolina customers?

A. Yes. Because the electric transmission system is networked and crosses state boundaries, it is difficult to ascribe particular benefits to any one geographic region. Over decades, the Company has built and maintained its transmission system to cost-effectively deliver power generated throughout the DENC system, as well as in other areas of PJM, and provide highly reliable electric service to all our customers. An example of transmission-voltage interconnections are the 500 kV facilities constructed to support the Company's Brunswick and Greensville County Power Stations. These interconnections represented 25 line miles of new 500 kV line and three new substations at a cost of approximately $185 million.

Another example is the Company's ongoing program to rebuild and refurbish the 500 kV system that serves as the backbone of its transmission network. In the period between 2016 and 2018, DENC has completed, in whole or in part, seven line segments of its 500 kV system with a total approximate length of 130 miles and investment of $292 million. These rebuilds increased the line capacity of each line on average by more than 50% and have an expected service life of 70 years. Each of the rebuilds was identified as part of the Company's end of life analysis that evaluates the condition of the existing structure and conductor as well as the present and ongoing need for these legacy facilities.

Q. Is the Company planning additional transmission system improvements over the next few years?

A. Yes. The Company is planning to invest approximately $4.3 billion in new transmission system improvements over the next five years. Of that amount, $200 million is planned specifically for strengthening our North Carolina transmission system.

Q. Please describe the Company's recent and ongoing investments to strengthen and expand its distribution system in North Carolina.

A. As noted previously, the Company serves over 120,000 retail customers in northeastern North Carolina.

Over the past three years, DENC has invested over $29 million in the Company's North Carolina distribution system to support load growth and distribution system reliability. Notable electric distribution projects completed since 2016 include: completion of a third circuit to Roanoke Island from Nags Head that includes a 3.3 mile underwater crossing of the Roanoke Sound; installation of a second transformer at Sligo Substation to support load growth in Currituck and Camden Counties; upgrades to two distribution transformers which increased capacity by 22 MVA in Washington County; and converting the Trap 827 Circuit to a higher voltage for five miles to support load growth in Bertie County.

Additional distribution system projects continuing into 2019 include: upgrading conductor on the Seaboard 817 Circuit for four miles to support load growth in Northampton County and adding capacity to sections of the Colington 427 Circuit to support load growth on Colington Island in Dare County. Although DENC's retail loads have remained relatively flat over this period, winter peak demands in some areas of our North Carolina service area, including the Outer Banks and parts of Currituck and Camden Counties, have increased by 10% or more since 2016.

The Company has also supported the interconnection of 85 non-net metered solar generating facilities at distribution voltage, totaling 578 MW of capacity, which are now operating in parallel with Company's distribution system in North Carolina. The Company continues to connect a high volume of power export generation customers on the distribution system.

Q. Please characterize the reliability of DENC's distribution retail service in North Carolina.

A. The Company's investments to expand and strengthen our transmission and distribution infrastructure in northeastern North Carolina are intended to support the Company's provision of dependable and reliable electric service for our customers. System Average Interruption Duration Index ("SAIDI") is an industry accepted measure of reliability performance for retail service. The Company's distribution operations maintained an average annual SAIDI of 115 minutes over the last three years excluding major storms. The Company's northeastern North Carolina service territory remains exposed to severe weather events as evidenced by the impact of Hurricanes Hermine and Matthew in 2016, when SAIDI including major storms was 1,120 minutes.

DENC continues to strengthen its transmission and distribution infrastructure in northeastern North Carolina to improve daily distribution system performance as well as to proactively prepare for severe weather events.

Q. **In your opinion, and based upon your experience, has the Company made reasonable and prudent investments in its T&D system to ensure adequate and reliable electric service to DENC's customers in North Carolina?**

A. Yes. The Company has invested strategically to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina, and throughout our system, as part of DENC's core mission to ensure reliability, operational excellence, and efficient service for our customers. In my opinion, these investments have been prudently incurred and are intended to ensure adequate and reliable electric service to DENC's retail customers in North Carolina.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS
OF
BOBBY E. MCGUIRE

Bobby McGuire received a Bachelor of Science degree in Electrical Engineering from North Carolina State University in 1981. He is a Registered Professional Engineer in the Commonwealth of Virginia. He has been employed by the Company for 34 years and during this employment has held numerous field and corporate positions covering a variety of activities, including Director Electric Transmission Planning from 2000 to 2002, and Project Manager between 2002 and 2005, leading the Dominion Energy technical team for PJM integration.

He has previously provided testimony before the Federal Energy Regulatory Commission.

MR. EASON: Madam Chair, on behalf of Nucor Steel, we'd like to introduce, including the table of contents and cover, 26 pages of testimony in question and answer format for Paul J. Wielgus, together with --

THE REPORTER: I'm sorry. Can you use your microphone?

MR. EASON: I'm sorry. Together with -- did you get the prior part?

THE REPORTER: I did not.

MR. EASON: Okay. The testimony of Paul J. Wielgus, consisting, including table of contents and cover page of 26 pages of testimony in question and answer format; three exhibits, including his curriculum vitae, of Exhibits Numbers 1 through 3, consisting of 11 pages; and in addition, the prefiled testimony [of Jacob M. Thomas], again including table of contents and cover, of eight pages with Exhibits 1 through 6, comprised of six pages, and that represents the evidence proffered by Nucor Steel. We move its admission.

CHAIR MITCHELL: Hearing no objection, your motion is allowed.

(Nucor Exhibit PJW-1 through PJW-3, and Nucor Exhibit JMT-1 through JMT-6 were premarked for identification.)

(Whereupon, the prefiled direct testimony of Paul J. Wielgus and prefiled direct testimony of Jacob M. Thomas were copied into the record as if given orally from the stand.)

VIRGINIA ELECTRIC AND POWER COMPANY
D/B/A DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 562

TESTIMONY
OF
PAUL J. WIELGUS

WITNESS
FOR
NUCOR STEEL–HERTFORD

August 23, 2019

DOCKET NO. E-22, SUB 562
TESTIMONY
OF
PAUL J. WIELGUS

WITNESS
FOR
NUCOR STEEL–HERTFORD

TABLE OF CONTENTS

EXHIBITS:

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Paul J. Wielgus. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by GDS Associates, Inc. ("GDS") at its Marietta, Georgia, headquarters.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. Nucor Steel–Hertford ("Nucor"), located in Hertford County, North Carolina.

Q. PLEASE OUTLINE YOUR PROFESSIONAL AND EDUCATIONAL QUALIFICATIONS.

A. I am a Managing Director with GDS. Prior to joining GDS, I was a senior energy executive engaged in the development and implementation of commercial business plans. Initiatives undertaken included long-term energy sales and marketing arrangements, energy procurement, development projects, asset expansions, asset management, mergers and acquisitions, and regulatory activities. With GDS, I provide energy advisory services to clients involving the above matters and perform other energy related work assignments on the behalf of clients including expert testimony. I have a B.S. in Economics, an M.S. in Mineral and Energy Resources, an MBA, and a JD. I am licensed to practice law in Texas. My resume is attached as Exhibit PJW-1.

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

A. Yes. I submitted testimony on behalf of Nucor in Docket No. E-22, Sub. 451 and Sub 558.

Q. **HAVE YOU PREVIOUSLY TESTIFIED IN OTHER PROCEEDINGS?**

A. Yes.

II. PURPOSE OF TESTIMONY

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I have conducted a review of the filing made by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("Company or DENC") in this Docket No. E-22, Sub 562 related to the Company's allocation of production costs.

III. SUMMARY OF THE COMPANY'S FILING

Q. **PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE COMPANY'S FILING.**

A. DENC is proposing to increase its base rates and charges.[1] The Company is requesting approval to increase base rates claiming that its current rates are no longer just and reasonable and that those rates are increasingly insufficient to recover the Company's costs to serve customers and to provide the return required by investors who fund the Company's capital requirements.[2] The Company's requested increase in base revenue is approximately $25 million.[3]

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[1] Direct Testimony of Mark D. Mitchell at 1, lines 10-17.

[2] *See id.* at 3, lines 13-23.

[3] Supplemental Direct Testimony of Paul M. McLeod at 2, lines 6-8.

Q. WHAT IS THE IMPACT OF THE COMPANY'S REQUESTED INCREASE ON NUCOR'S FACILITY IN HERTFORD COUNTY?

A. Under the Summer Winter Peak and Average ("SWPA") allocation method used by the Company to allocate the costs and the increase, the Company's proposed apportionment of the increase to Schedule NS, Nucor's facility would pay an estimated additional $2,300,000 per year in non-fuel base rates.[4] This equates to an 9% increase in base rates to Nucor's facility.[5]

Q. IS THIS INCREASE MATERIAL TO NUCOR'S FACILITY?

A. Yes. Like most manufacturers, this facility competes both nationally and globally in a competitive market. The cost of power is a significant factor that directly impacts this facility's ability to compete. I discuss later in my testimony how the Company acknowledges the importance of the economic vitality of customers like Nucor and its impact on the Company's service territory.

Q. DID THE COMPANY CONSIDER THE MATERIALITY OF THE INCREASE TO NUCOR'S FACILITY?

A. When asked if the Company considered various consequences of the proposed increase related to Nucor's facility, it answered that it cannot speculate about those consequences, even though the Company asserts the importance of the economic vitality of commercial and industrial customers in its North Carolina territory.[6]

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[4] Company Supplemental Exhibit REM-1, Schedule 4, page 1 of 1.

[5] ($27,953,720/$25,645,414) – 1 = 9.0%.

[6] Nucor Data Request No. 2, Questions 3 and 4.

Q. DO YOU AGREE WITH THE COMPANY'S VIEW OF THIS INCREASE IN NON-FUEL BASE RATES TO NUCOR'S FACILITY?

A. No. It's quite surprising that the Company hasn't analyzed the consequences of the increase given how significant the benefits of Nucor's load is to the Company's operations, to its other customers, and to the region. The proposed increase, which is incremental to Dominion's base rate increase that took effect as recently as 2017, is not insignificant and could materially harm Nucor's ability to compete.

IV. IMPACT OF THE COMPANY'S PROPOSED FIXED COST ALLOCATION METHOD ON THE APPORTIONMENT OF REVENUE REQUIREMENTS

Q. DOES THE FIXED COST ALLOCATION METHOD USED BY THE COMPANY IMPACT THE APPORTIONMENT OF THE COMPANY'S PROPOSED REVENUE INCREASE?

A. The Company's apportionment of their recommended revenue increase is driven in large part by each class' ROR index before the revenue increase. As described by Mr. Haynes, the rates of return and indices are "being used as a guide in apportioning the non-fuel base rate revenue increase."[7] Those rates of return are impacted by the allocation method selected by the Company to allocate fixed costs and their associated expenses. In particular, the allocation method selected can have a significant impact on the resultant ROR index for Schedule NS and therefore have

[7] Direct Testimony of Paul B. Haynes at 22, lines 6-7.

a significant impact on the decision-making process used by the Company to apportion the revenue increase to Schedule NS.

Q. CAN YOU EXPLAIN THE COMPANY'S ROR INDEX?

A. ROR stands for rate of return. The Company expresses class-specific RORs via an index that compares each class' ROR to the North Carolina jurisdictional ROR. An index greater than 1 represents a higher ROR compared to the North Carolina jurisdiction, while an index less than 1 represents a lower ROR compared to the North Carolina jurisdiction.

Q. HOW IS THE ROR INDEX USED BY THE COMPANY?

A. The Company uses the ROR index as a guide in apportioning the non-fuel base rate revenue increase.[8] According to the Company, generally, if a customer class has an ROR index less than 1, such class should receive a percentage increase that is greater than the overall jurisdictional percentage base rate increase. And, according to the Company, if a customer class has an ROR index greater than 1, the class should receive a percentage increase that is less than or equal to the overall jurisdictional percentage base rate increase.[9]

Q. EXPLAIN HOW THE COMPANY'S USE OF THE ROR INDEX IS INFLUENCED BY THE RESULTS OF THE FIXED COST ALLOCATION METHOD SELECTED BY THE COMPANY.

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[8] *See id.* at 22, lines 5-7.

[9] *See id.* at 22, lines 13-18.

A. As stated earlier, the Company's use of the ROR index to apportion the non-fuel base rate revenue increase is dictated in large part by the results of the allocation method selected by the Company for allocating production costs. To illustrate this point, at the Company's targeted ROR for Nucor, under the 1 CP allocation method which has been proposed by Nucor in previous Company proceedings, the revenue requirement would result in a decrease in revenue requirements for Nucor of approximately $10.5 million.[10] Bottom line, which allocation method is used, makes a significant difference.

Q. AS PART OF ITS SYSTEM OPERATIONS, DOES THE COMPANY ENCOUNTER THE USE OF THE CP ALLOCATION METHODOLOGY?

A. Yes. The Company operates its system in the PJM market, and it is my understanding that PJM uses a CP method when calculating capacity obligations and allocating capacity costs to load-serving entities.

Q. ARE YOU PROPOSING AN ALTERNATIVE ALLOCATION METHOD BE USED BY THE COMPANY INSTEAD OF THE COMPANY'S PROPOSED SWPA METHOD?

A. The 1 CP allocation method that has been proposed in previous filings would be preferable to SWPA since it is a fit at the system or Company level and at the class level. This method is aligned with why the Company invests in generation capacity and with the method used by PJM. It also recognizes the beneficial factors associated with the NS class. And as mentioned above, in response to this

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[10] Direct Testimony of Jacob M. Thomas at 5.

Commission's repeated rejection of 1 CP for purposes of allocating the Company's costs, I am not proposing that the Company adopt this method. It is interesting to note, however, that using the 1 CP cost allocation method, the ROR index for Nucor—before the proposed revenue apportionment—is 3.10 as compared with 0.79 using SWPA.[11]

Q. SHOULD THE COMMISION CONSIDER TAKING ACTION ON AN ALTERNATIVE ALLOCATION METHOD BE USED BY THE COMPANY INSTEAD OF THE COMPANY'S PROPOSED SWPA METHOD?

A. Because the choice of cost allocation methodology makes a significant difference, I recommend that the Commission examine, via a formal proceeding, whether requiring that the Company use 1 CP or 5 CP instead of SWPA would be most appropriate to account for the way PJM uses CP (where allocation is based on 5 CP) and the Commission's practice in the Duke Energy cases (where allocation is based on 1 CP).

Q. WHAT ARE YOU PROPOSING IN THIS FILING TO REMEDY THE COMPANY'S APPROACH?

A. I propose that adjustments be made to the Company's SWPA methodology to address shortfalls of SWPA at both the North Carolina jurisdictional level or Company system level and at the customer class level.

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[11] *See id.*

V. SHORTFALLS OF THE SWPA ALLOCATION METHOD IN RECOGNIZING THE SYSTEM'S NEED FOR GENERATION

Q. WHAT DRIVES THE COMPANY'S INVESTMENT IN GENERATION CAPACITY?

A. When asked if the Company invests in generation primarily to serve its annual or seasonal peak loads, it answered by stating that these investments help the Company meet its service obligations and manage the capacity performance risk in the PJM capacity market.[12] Its service obligation is to meet its peak load while at the same time managing its capacity risk in PJM. The Company makes capacity investments to meet these needs. In other words, it is the need for generation capacity to serve peak load that's driving the Company's generation costs.

Q. IS THE SWPA METHOD CONSISTENT WITH THE COMPANY'S PRIMARY NEED FOR GENERATION CAPACITY?

A. No. The SWPA method is not consistent with Company's primary need for generation capacity—the Company's need to serve its annual peak load. Unlike the 1 CP method which does not take account of energy or average demand at all in allocating generation capacity costs, the SWPA methodology does factor energy consumption into the equation.

Q. IN APPLYING SWPA PEAK AND AVERAGE METHOD, IS THE WEIGHTING OF THE AVERAGE DEMAND OR ENERGY COMPONENT

[12] Nucor Data Request No. 2, Question 21.

ALIGNED WITH THE COMPANY'S NEED FOR MAKING INVESTMENTS IN GENERATION CAPACITY?

A. No. Not only does the Company use a cost allocation method that includes energy consumption in allocating the cost of generation-related capacity costs but, to make matters worse, the Company puts more weight on energy than on the demand or capacity part. This is inequitable and even incredible considering the fact that the Company is located within the PJM footprint which uses a coincident peak method.

Q. WHAT ADJUSTMENTS SHOULD BE MADE TO THE ALLOCATION OF GENERATION CAPACITY COSTS TO MAKE IT CONSISTENT WITH THE COMPANY'S INVESMENT IN GENERATION CAPACITY?

A. Although SWPA should be replaced, given the history of these cases, I make a modest recommendation to adjust the weighting of the two SWPA components—demand and energy—such that more weight is on the demand part of SWPA than on the energy part.

Q. DOES THE COMPANY MAKE ADJUSTMENTS TO THE SWPA ALLOCATION METHODOLOGY?

A. Yes.[13]

Q. IS THERE RECOGNIZED SUPPORT FOR JUDGMENTALLY WEIGHTING THE TWO PARTS OF THE SWPA ALLOCATION METHODOLOGY?

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[13] *See* Direct Testimony of Paul B. Haynes at 10-11 and 12, lines 1-9.

A. Yes. The NARUC Electric Utility Cost Allocation Manual justifies incorporating a judgmentally established energy weighting.[14]

Q. WHAT SHOULD THE RELATIONSHIP BETWEEN AVERAGE DEMAND OR ENERGY AND DEMAND BE?

A. As noted above, demand drives the need for generation capacity and should carry much more weight than energy. Accordingly, at an absolute minimum, I recommend demand be weighted more than energy.

Q. HOW WOULD ADJUSTING THE WEIGHTING IMPACT THE RESULTS OF SWPA AS TO SCHEDULE NS COMPARED TO THE WEIGHTING AS FILED?

A. If the Commission were to require the Company to adjust the weighting of demand and average demand and after the Company apportioned the overall revenue increase to produce the same ROR index after the rate increase, the proposed increase to the NS class would be reduced. This would be a very modest change relative to implementing a 1 CP or into a more radical re-weighting of demand and average demand to reflect the importance of demand versus average demand as a determinant of the need for generation capacity.

VI. SYSTEM BENEFITS ASSOCIATED WITH THE NS CLASS

Q. WHAT IS IT ABOUT NUCOR'S LOAD THAT RESULTS IN SIGNIFICANT SYSTEM BENEFITS?

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[14] *See* Nat'l Ass'n of Regulatory Util. Comm'rs., Electric Utility Cost Allocation Manual 57-59 (1992).

A. There are three reasons why Nucor's load results in significant benefits to the Company's system. The first reason is the size of the facility's load relative to the Company's load. Nucor's facility is approximately 20% of the Company's load in North Carolina.[15] Nucor is the Company's largest single customer.[16] Cost savings associated with the economies of scale of this very large load at a single point provide benefits to the Company's system not provided by any other single customer. The second reason is this facility's high load factor, which unlike lower load factor customers, is very beneficial to the Company's system operations and corresponding costs. The third reason is the service arrangement between the Company and Nucor's facility. This service to Nucor is not firm, it is interruptible.[17] Under this arrangement Nucor must curtail if called upon to do so.[18] This very high value attribute unlocks cost savings in the form of avoided capacity costs while providing system and customer benefits. These three factors combine to deliver significant benefits to the Company's operations not available from any other customer.

Q. HOW DO THESE FACTORS COMBINE TO DELIVER SIGNIFICANT BENEFITS TO THE COMPANY'S SYSTEM?

A. Having this much of the Company's load being interruptible at a single point provides significant savings and ease in terms of avoiding capacity and the

[15] *See* Nucor Data Request No. 6, Question 10.

[16] Direct Testimony of Paul B. Haynes at 23, lines 10-11.

[17] Schedule NS Section III,

[18] Schedule NS, Sections III, IV.A.2.a.ii.

associated costs. Nucor provides an unmatched demand response or load side management tool. This unmatched tool provides significant value and savings to the Company's operations. And when not interrupted, the facility's high load factor offsets the lower load factors of the remaining customers, lifting the system load factor and providing system operations benefits not achievable but for Nucor.

Q. DOES THE COMPANY ACKNOWLEDGE THAT NUCOR'S LOAD PROVIDES SYSTEM BENEFITS?

A. Yes. The Company states that customers like Nucor may operate all hours of the day and typically vary less from hour to hour than other classes of customers.[19] Other factors the Company considered include favorable utilization and the economic vitality of the Company's North Carolina service territory. The Company considers high factory utilization and employment as good indictors of economic vitality in the region.[20] The Company also specifically acknowledges the unique nature of its service arrangement with Nucor and how that arrangement benefits its system and its customers.[21]

Q. DOES THE COMPANY GIVE THE NS CLASS CREDIT FOR THE SYSTEM BENEFITS IT PROVIDES?

A. The Company claims that it recognizes Nucor's operational and cost benefits to its system through the Company's assigned ROR index for Nucor.[22]

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[19] Direct Testimony of Paul B. Haynes at 23, lines 16-23.

[20] *See id.* at 24, lines 3-10.

[21] *See id.* at 24, lines 9-13.

[22] *See id.* at 28, lines 22-23.

Q. FROM YOUR REVIEW, IS THAT YOUR FINDING?

A. No. The Company does not adequately recognize Nucor's operational and cost benefits to its system through the Company's assigned ROR index. Given the fact that the supplemental filing indicates Schedule NS now has an ROR index of 0.79 before the revenue increase, if the Company were to adhere to Mr. Haynes' assertion that a 0.80 ROR index for Schedule NS is appropriate, the Company would ironically increase the burden on NS.[23] This higher assigned index does not adequately acknowledge the benefits of the arrangement with Nucor or the benefits it provides to the Company's system and customers. I will discuss this in more detail later in my testimony.

Q. HAVE YOU CALCULATED THE VALUE OF THE AVOIDED CAPACITY?

A. Yes. The peak load for Nucor's facility is 171 MWs. However, for the test year, Nucor's summer winter peak average is only 42 MWs. This means that the Company avoids 129 MWs of firm capacity while still capturing the acknowledged system benefits of Nucor's high usage. If Nucor was a firm customer, the Company would have to secure for Nucor an additional 129 MWs of capacity every day of the year. Based on the average capacity cost in the PJM market over the last 5 years, the annual cost of this 129 MWs of capacity would be $5.7 million.[24] These savings would be a direct assignment to the NS class.

[23] *See* Company Supplemental Exhibit REM-1, Schedule 4, page 1 of 1.

[24] $124/MW-day x 129 MW x 365.

Q. HAVE YOU VALUED THE IMPACT OF THE COMPANY'S SHORTFALL IN NOT RECOGNIZING THE BENEFITS ASSOCIATED WITH THIS LOAD'S HIGH USAGE?

A. First, even though the Company acknowledges that there is value in the form of system benefits as a result of the NS class' high energy usage, the NS class does not receive recognition of this under SWPA because the more energy Nucor uses, the higher the disproportionately large costs—as those disproportionately large costs are allocated by SWPA to the NS class per unit of the NS class' energy consumption (*i.e.*, per MWh). Second, as mentioned earlier, because the Company's weighting of the SWPA puts more weight on energy, this weighting exacerbates the impact on the NS class. For example, if the demand part was weighted at 60%, at the Company's targeted ROR index for Nucor (*i.e.*, 0.80), the revenue requirements to this class based on the Company's filing would decrease by $2 million.[25]

Q. DOES THE COMPANY ACKNOWLEDGE THAT THE USE OF SWPA VERSUS 1-CP HAS A GREATER NEGATIVE IMPACT ON THE NS CLASS AS COMPARED TO OTHER CLASSES?

A. The Company acknowledges that, with the exception of the relatively small Street Lights class, the use of SWPA versus 1-CP has a greater negative impact on—conveys a disproportionately large burden to—NS as compared with the other classes.[26] The cost shift to the NS class is unreasonable and highlights the

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[25] *See* Direct Testimony of Jacob M. Thomas at 5-6.

[26] *See* Nucor Data Request No. 4, Question 2.

disconnect between the acknowledged benefits Nucor delivers and the disproportionate cost burden.

VII. SHORTFALLS OF THE SWPA ALLOCATION METHOD IN RECOGNIZING THE SYSTEM BENEFITS ASSOCIATED WITH THE NS CLASS

Q. PLEASE EXPLAIN FURTHER WHY THE COMPANY'S ACKNOWLEDGEMENT OF THESE BENEFICIAL FACTORS IS NOT SUFFICIENTLY TAKEN INTO ACCOUNT IN THE COMPANY'S PROPOSED ALLOCATION OF FIXED COSTS.

A. The Company has used and still uses the SWPA methodology to allocate production and transmission fixed costs in the Company's jurisdictional customer and class cost of service studies.[27] SWPA is basically a two-part allocation methodology. One part of the methodology, peak demand, reflects the average of the summer and winter coincident peak demand. The methodology's second part, average demand, reflects the amount of energy purchased during the test year. The Company's method of weighting these factors puts more weight on the energy part than the demand part.[28]

Q. IS THE COMPANY'S WEIGHTING APPROPRIATE FOR THE NS CLASS?

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[27] *See* Direct Testimony of Paul B. Haynes at 5, lines 13-16, and 7, lines 6-8.

[28] Nucor Data Request No. 2, Question 17.

A. No. Attributing more weight to the average demand or energy consumption than to peak demand does not adequately reflect the unique Schedule NS interruptible service arrangement nor does it adequately reflect the acknowledgement by the Company of the value of the beneficial factors associated with this arrangement and Nucor's load. The weighting of the two-part methodology falls short in a material way.

Q. PLEASE EXPLAIN WHY THE AVERAGE DEMAND PART OF THE SWPA METHODOLOGY FALLS SHORT IN ADEQUATELY REFLECTING THE COMPANY'S ARRANGEMENT WITH NUCOR?

A. The Company acknowledges the beneficial factors of the Nucor arrangement that includes the size of Nucor's load, the arrangement being interruptible, the quantity of Nucor's electric usage, and the time and steadiness of its usage.[29] Despite this acknowledgment, the weighting of the average demand or energy part of SWPA does not recognize the benefits Nucor's load delivers to the Company's operations. In fact, SWPA does just the opposite.

Q. HOW DOES SWPA DO JUST THE OPPOSITE?

A. By attributing more weight to the average demand or energy consumption than to peak.

As mentioned earlier, if Nucor increases its usage, while maintaining its around the clock interruptible character, thereby adding more value to the system, Nucor would be allocated an even more disproportionately large share of the costs,

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[29] Direct Testimony of Paul B. Haynes at 23, lines 18-23, and 24, lines 1-2.

in effect further penalizing Schedule NS notwithstanding its improved energy-to-demand ratio. Weighting the average demand part of SWPA higher than the demand part of SWPA further adds to the disconnect between the benefits Nucor provides and the way costs are allocated by the Company under the SWPA methodology. The weighting should be adjusted to address this distorted and consequently unreasonable outcome.

VIII. ISSUES ASSOCIATED WITH THE COMPANY'S PROPOSED ROR INDEX FOR NUCOR

Q. WHAT IS THE COMPANY'S ASSIGNED ROR INDEX FOR NUCOR?

A. As stated earlier, the Company's assigned ROR index for Nucor is 0.80.

Q. HOW DID THE COMPANY ARRIVE AT THE ROR INDEX FOR NUCOR?

A. The Company believes the apportionment of the non-fuel revenue to this highly valued customer should move Nucor to an ROR index that is approximately 10 basis points below what the Company calls the ROR Parity Index Range ("PIR") of 1.10 to 0.90.[30]

Q. DO YOU AGREE WITH THE COMPANY'S CONCLUSIONS REGARDING THE COMPANY'S ASSIGNED ROR INDEX FOR NUCOR?

A. No. It doesn't take a ROE expert to conclude that the return associated with the Company's unmatched interruptible service arrangement with Nucor should be low. Simply taking it 10 basis points below the range is inadequate. Nucor's ROR

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[30] *See id.* at 22, lines 19-20, and 29, lines 1-3.

index should be closer to the ROR index for the Street Lights class, not the lower range of the Company's PIR as proposed by the Company.[31]

Q. PLEASE EXPLAIN WHY THE COMPANY'S ASSIGNED ROR FOR NUCOR IS EXCESSIVE AND WHY IT SHOULD BE CLOSER TO THE ROR INDEX FOR STREET LIGHTS.

A. The Company acknowledges that the Street Lights class does not normally operate during peak hours.[32] Under the Company's service arrangement for the Nucor facility, Nucor's load is subject to the Company's right to physically interrupt Nucor, including during peak hours. This unique ability to interrupt a significant portion of the jurisdictional load gives sound reasoning why Nucor's ROR index should be closer to the ROR index for Street Lights, not closer to the Company's low end of the PIR range. This range is representative of firm load, including the residential class. Simply taking Nucor's ROR 10 basis points below the PIR range falls short given the Street Lights class' ROR index after the Company's proposed apportionment of the revenue increase of 0.59 is 31 to 51 basis points below the PIR.

Q. BASED ON THIS, HOW SHOULD THE COMPANY'S ASSIGNED ROR INDEX FOR NUCOR BE SET?

A. Between the low end of the PIR and the index for Street Lights. Ultimately, the ROR index for Nucor should be set closer to the ROR index for Street Lights.

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[31] *See id.* at 25, line 1.

[32] *See id.* at 8, lines 16-17.

Q. ARE THERE OTHER REASONS WHY THE COMPANY'S BELIEF THAT NUCOR'S ROR INDEX SHOULD BE ONLY 10 BASIS POINTS LOWER THAN THE PIR INDEX FALLS SHORT?

A. Yes. The benefits of the Nucor load are unmatched and are not fully recognized by setting Nucor's ROR index only 10 basis points below the PIR range. The Company acknowledges the unique nature of its service arrangement with its largest and most energy intensive customer and how this arrangement benefits the system and the customers of the Company's North Carolina jurisdiction.[33] And again, this range is representative of lower load factor, firm load, including the residential class.

IX. COMPARING THE ROR FOR SCHEDULE NS TO THAT OF OTHER CUSTOMER CLASSES

Q. HOW DOES THE PROPOSED ROR FOR SCHEDULE NS COMPARE TO THE ROR FOR OTHER CLASSES?

A. The ROR index for Schedule NS is set at 0.80 or 10 points below the lower end of the PIR range, but for Schedule NS' interruptible load, it should be closer to that for Street Lights—a class that is usually not operating during peak hours—than it is to the PIR range. The ROR index for Street Lights is 0.59.

Q. PLEASE BE MORE SPECIFIC ABOUT THE APPROPRIATE ROR INDEX FOR RATE SCHEDULE NS.

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[33] *See id.* at 23, lines 9-13.

A. I recommend that the ROR index for Schedule NS' interruptible load after the company recommended revenue increase be set at the mid-point between Street Lights ROR index of 0.59 and the proposed ROR index for Schedule NS of 0.80, or approximately 20 points below the low end of the PIR range.

X. COMPARING DENC'S PROPOSED INCREASE TO SCHEDULE NS VERSUS OTHER INDUSTRIAL CUSTOMERS

Q. HOW DOES THE PROPOSED INCREASE TO NUCOR COMPARE TO THE PROPOSED INCREASE TO OTHER INDUSTRIAL CUSTOMERS?

A. The percentage increase proposed for the NS class is over three times greater than the proposed increase to the 6 VP and LGS industrial classes.[34] The justification for the larger percentage increase is based on the Company's flawed SWPA cost allocation approach and inadequate recognition of the value the Nucor load provides to the system, as discussed earlier.

Q. HOW WOULD SCHEDULE NS BE IMPACTED BY THIS RECOMMENDED CHANGE?

A. Setting the increase at the average for the 6 VP and LGS industrial classes would lower the proposed increase to Nucor by approximately $1.6 million, which is significant and is essentially a portion of the unjustified penalty to the NS class.[35]

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[34] 6 VP 2.8%, LGS 2.9%, NS 9.0%. *See* Company Supplemental Exhibit REM-1, Schedule 3 (Base Non-Fuel Revenues); Company Supplemental Exhibit REM-1, Schedule 4 (Revenue Increase). Divide Revenue Increase by Base Non-Fuel Revenues (Percent Increase).

[35] $2,308,306 - $730,894 = $1,577,412.

XI. SUMMARY OF FINDINGS

Q. BASED ON YOUR REVIEW WHAT ARE YOUR FINDINGS?

A. Based on my review, my findings are as follows:

1. The impact of the proposed 9% increase in non-fuel base rates to the NS class is significant.
2. The Company's recommended SWPA cost allocation method is not aligned with the Company's need for investing in generation capacity.
3. The Company's application of SWPA is not aligned with the method PJM uses in calculating capacity obligations and allocating capacity costs.
4. The ROR index is heavily dependent on the allocation method selected.
5. At the Company's assigned ROR for Nucor, under the 1 CP allocation method, the revenue requirement would result in a decrease in revenue requirements for Nucor of nearly $10.5 million.
6. The Company acknowledges that the arrangement with the NS class benefits the system and its customers in the North Carolina jurisdiction.
7. The Company's acknowledgement of the beneficial factors associated with the NS class' load is not adequately reflected in its proposed base rate changes.
8. The Company does not adequately recognize the benefits associated with the NS class as confirmed by assigning it an ROR index of 0.80.
9. The assigned ROR for the NS class should be closer to the Street Lights class ROR index because of the Company's right to physically interrupt the NS class, including during peak hours.

10. The Company's increase in requested revenues from the NS class is three times greater than the Company's increase to the 6 VP and LGS industrial classes.

XII. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR CONCLUSIONS?

A. Based on my review, for the following reasons, adjustments must to be made to the Company's method of allocating the revenue increase to the NS class:

1. The Company's proposed revenue increase for the NS class is material and unjust relative to the increase to other industrial classes.
2. The Company's use of SWPA is not aligned with the Company's primary reason for investing in generation capacity nor is not aligned with the coincident peak method that PJM uses to calculate capacity obligations and to allocate capacity costs to its load-serving entities.
3. The Company's targeted ROR index for the NS class does not sufficiently acknowledge the unique interruptible service arrangement between the Company and the NS class nor the benefits that this class's high usage provides to the Company's system and its other customers.
4. The Company's weighting of the demand and energy parts of SWPA does not sufficiently recognize the unique interruptible service arrangement between the Company and the NS class nor the benefits that this class's high usage provides to the Company's system and its other customers.
5. The Company's proposed increase to Schedule NS, an industrial load schedule for service to Nucor Steel–Hertford, the Company's largest industrial load, is inconsistent with the economic development concerns the Company expresses

regarding industrial load in the context of its proposed increases to rate schedules LGS and 6 VP.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. Based on my findings and conclusions, I recommend the following:

1. The demand part of the SWPA allocation method should be weighted at 60%, giving more weight to the demand part than the energy part;
2. The assigned ROR index for the NS class should approach that of the Street Lighting class. In any case, the ROR index for NS should not exceed the mid-point between the proposed ROR index for Schedule NS and the Company's index for ROR for the Street Lighting class which is 0.80 and 0.59, respectively;
3. The percentage increase in base rates to Schedule NS should not exceed the average of the percentage increases applied to rate schedules LGS and 6 VP; and
4. If does not do so in this docket, the Commission should commit to examine via a formal docket whether requiring 1 CP or 5 CP instead of SWPA, would be most appropriate for the Company to account for the way in which PJM calculates capacity obligations and allocates capacity costs, based on 5 CP, and the Commission's practice in the Duke Energy cases, based on 1 CP. SWPA is not the best, or even an appropriate method for allocating the Company's generation-related capacity costs.
5. Regardless of the total non-fuel base rate increase the Commission approves, I recommend that the revenue spread parameters I describe be used in assigning the rate increase to DENC's customer classes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VIRGINIA ELECTRIC AND POWER COMPANY
D/B/A DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 562

TESTIMONY
OF
JACOB M. THOMAS, P.E.

WITNESS
FOR
NUCOR STEEL–HERTFORD

August 23, 2019

DOCKET NO. E-22, SUB 562
TESTIMONY
OF
JACOB M. THOMAS, P.E.

WITNESS
FOR
NUCOR STEEL–HERTFORD

TABLE OF CONTENTS

EXHIBITS:

Exhibit JMT-1 – Resume of Jacob M. Thomas

Exhibit JMT-2 – 1-CP Allocation Factor 1

Exhibit JMT-3 – 1-CP Cost of Service Summary Results

Exhibit JMT-4 – Re-weighted SWPA Allocation Factor 1

Exhibit JMT-5 – Re-weighted SWPA Cost of Service Summary Results

Exhibit JMT-6 – Alternative Re-weighted SWPA Cost of Service Summary Results

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Jacob M. Thomas. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by GDS Associates, Inc. ("GDS") at its Marietta, Georgia, headquarters.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. Nucor Steel–Hertford ("Nucor"), located in Hertford County, North Carolina.

Q. PLEASE OUTLINE YOUR PROFESSIONAL AND EDUCATIONAL QUALIFICATIONS.

A. I am a Principal at GDS, where I have compiled over twenty years of experience in the areas of cost of service modeling, retail and wholesale rate design, economic impact analysis, benefit-cost analysis, and data analytics. I have developed in excess of thirty cost of service ("COS") models for distribution cooperatives, generation and transmission cooperatives, and municipal systems in Alabama, Alaska, Arkansas, Florida, Georgia, Indiana, Massachusetts, Ohio, Pennsylvania, South Carolina, Texas, Virginia, and Washington. I have assisted other experts in the review and evaluation of COS models filed by Investor Owned Utilities in several proceedings as well, including assisting experts representing Nucor Steel–Hertford ("Nucor") in the current and three preceding rate filings by Virginia and Electric Power Company, d/b/a Dominion Energy North Carolina ("DENC").[1]

[1] Docket Nos. E-22, Sub 459, Sub 479, Sub 532, and Sub 562.

I received a Master of Business Administration degree with a concentration in Finance from Auburn University in 2006. I earned a Bachelor of Science in Industrial Engineering from the Georgia Institute of Technology in 2000. I am a registered professional engineer in the state of Georgia.

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

A. Yes. I submitted testimony on behalf of Nucor in Docket No. E-22, Sub 532.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN OTHER PROCEEDINGS?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents two COS models that I prepared in support of Nucor witness Paul J. Wielgus's testimony. Specifically, I used the Company's COS modeling spreadsheet to prepare two variations on the allocation of production costs: (1) a 1-Coincident Peak ("CP") model, and (2) a re-weighted Summer Winter Peak and Average ("SWPA") model. My testimony will describe how I computed the allocators and ran each COS scenario and present summary results from each model.

III. 1-CP COST OF SERVICE MODEL

Q. HOW DOES THE 1-CP MODEL DIFFER FROM THE MODEL THE COMPANY PRESENTED IN THIS PROCEEDING?

A. As described by Company witness Haynes, the Company allocates production and transmission plant and their related expenses using the SWPA allocator for both the jurisdictional and class COS models. The average demand component is weighted based on the system load factor and the summer/winter peak demand is weighted based on one minus the load factor.[2]

For the 1-CP model, I replace the SWPA allocator as proposed by the Company with the single highest coincident peak demand. The winter peak demand from the SWPA allocator is the highest demand in the current test year. In the jurisdictional model, each jurisdiction's contribution to the winter peak demand net of North Anna is used to allocate production and transmission plant and related expenses. Similarly, the class allocation is based on each class's contribution to the winter peak demand. Allocator Factors 1 and 61 are the allocators that get replaced with a 1-CP in the 1-CP model. Furthermore, allocators that are derived from those Factors are updated. The computation of the 1-CP allocator Factor 1 is provided in Exhibit JMT-2.

Q. HOW DO YOU COMPUTE A 1-CP COS MODEL GIVEN THE 1-CP ALLOCATORS?

A. The Company worked with Utility's International ("UI") to develop a spreadsheet-based application that would enable intervenors to perform COS model variations.[3] I started from that model provided by the Company and replaced Factors 1, 61, and all other factors derived from those factors with the 1-CP allocation factors I

[2] *See* Direct Testimony of Paul B. Haynes at 7, lines 1-5.

[3] *See* Direct Testimony of Robert E. Miller at 15, lines 8-17.

computed. The resultant model produces jurisdictional and class COS results under a 1-CP allocation methodology with ratemaking adjustments and before the proposed revenue increase. For purposes of comparison with the Company's COS results after their proposed revenue increase, I computed a revenue increase to achieve each class's requested rate of return ("ROR"). The resultant COS outputs for the 1-CP model are provided in summary form as Exhibit JMT-3.

IV. RE-WEIGHTED SWPA COST OF SERVICE MODEL

Q. HOW DOES THE RE-WEIGHTED SWPA MODEL DIFFER FROM THE MODEL THE COMPANY PRESENTED IN THIS PROCEEDING?

A. For a different scenario, I prepared a COS model which still uses an SWPA methodology to allocate production and transmission plant and related expenses but weights the peak and average components of the allocators differently from the Company's weighting. As described earlier, the Company uses the system load factor as the weight on the average demand (or energy) component of the factor. The system load factor is 58.9%. In my re-weighted scenario, I use a 60% weight for the summer/winter peak demand component and a 40% weight for the average demand (energy) component. The computation of the re-weighted SWPA allocation Factor 1 is provided in Exhibit JMT-4.

Q. HOW DO YOU COMPUTE A RE-WEIGHTED SWPA COS MODEL GIVEN THE REVISED ALLOCATORS?

A. I started from the working spreadsheet model provided by the Company and replaced Factors 1, 61, and all other factors derived from those factors with the re-weighted SWPA allocation factors I computed. The resultant model produces jurisdictional and class COS results under this allocation methodology scenario with ratemaking adjustments and before the proposed revenue increase. For purposes of comparison with the Company's COS results after their proposed revenue increase, I computed a revenue increase to achieve each class's requested ROR. The resultant COS outputs for the re-weighted SWPA model are provided in summary form as Exhibit JMT-5.[4]

V. CONCLUSIONS

Q. WHAT ARE THE RESULTS OF A COMPARISON BETWEEN THE COMPANY'S MODEL AND THE TWO SCENARIOS YOU RAN?

A. The 1-CP scenario shows that, all other aspects being held constant at the Company's recommended original filing, Nucor (Schedule NS) would have a relative ROR index before the revenue increase of 3.10. This is significantly higher than the 0.84 index computed by the Company under their SWPA scenario.[5] Under my re-weighted SWPA scenario, Schedule NS has a relative ROR index after ratemaking adjustments and before the revenue increase of 1.20.

The Company's proposed increase to NS achieves an ROR index of 0.80 for Schedule NS.[6] To achieve the same relative ROR index of 0.80 for NS under the 1-CP scenario, Nucor's base revenues would have to decrease by nearly $10.5 million. Under the re-weighted SWPA scenario in Exhibit JMT-5, Nucor's base

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[4] I produced a second re-weighted scenario weighting the summer/winter peak and average demand (energy) components at 50% each. The computation of the re-weighted SWPA allocation Factor 1 (at 50% for each component) is provided in Exhibit JMT-6.

[5] *See* Company Exhibit REM-1, Schedule 4, page 1.

[6] *Id.*

revenues would be decreased by approximately $2 million to achieve the Company's proposed ROR index of 0.80.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. HICKS: Madam Chair, on behalf of CIGFUR I, I move that the prefiled direct testimony of Nicholas Phillips, Jr., which was filed on August 23rd, totaling 22 pages, plus an Appendix A, which is four pages, as well as the premarked exhibit NP-1, which is one page, be received into the record as if given orally from the stand as prefiled and premarked.

CHAIR MITCHELL: Your motion will be allowed.

(Exhibit NP-1 was premarked for identification.)

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

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

In the Matter of **Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustments of Rates and Charges Applicable to Electric Utility Service in North Carolina**	**Docket No. E-22, Sub 562**

<u>Direct Testimony of Nicholas Phillips, Jr.</u>

<u>Introduction</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a managing principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants. Our firm and its predecessor firms have been in this field since 1937 and have participated in more than 1,000 proceedings in 40 states and in various provinces in Canada. We have experience with more than 350 utilities, including many electric utilities, gas pipelines, and local distribution companies. I have testified in many electric and gas rate proceedings on virtually all aspects of ratemaking. More details are provided in Appendix A of this testimony.

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A Yes. I have been involved in numerous prior proceedings before this Commission and have presented testimony in many of those proceedings. Most recently, I testified before Commission in Dominion Energy North Carolina's ("DENC") general rate case, Docket No. E-22, Sub 532; Duke Energy Progress' ("DEP") general rate case, Docket No. E-2, Sub 1142; Duke Energy Carolina's ("DEC") general rate case, Docket No. E-7, Sub 1146; DENC's fuel charge adjustment proceeding, Docket No. E-22, Sub 558; and Piedmont Natural Gas' ("PNG") general rate case, Docket No. G-9, Sub 743.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of the Carolina Industrial Group for Fair Utility Rates I ("CIGFUR I"), a group of large industrial customers that purchase power from DENC. CIGFUR I's members are Cummins Rocky Mount Engine Plant ("Cummins RMEP"), Domtar Corporation ("Domtar"), Pfizer, Inc.[1] ("Pfizer"), and WestRock.[2] CIGFUR I's members are served under Schedules 6VP and 6P.

Q HAVE YOU PREPARED ANY EXHIBITS?

A Yes, I prepared Exhibit NP-1.

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[1]Formerly Hospira, Inc.
[2]Formerly KapStone Paper and Packaging Corporation.

Purpose of Testimony & Recommendations

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony highlights the concerns and priorities of CIGFUR I members, who are representative of DENC's high-load industrial customers. I am presenting testimony concerning the appropriate cost allocation methodology for use in this proceeding, the revenue distribution to classes of any amount of rate increase granted by the Commission (including fuel included in base rates), and the proper design of DENC's electric rates. I discuss certain general principles that should form the basis for cost allocation, revenue distribution, and rate design. I have examined the testimony and exhibits presented by DENC in this proceeding with respect to cost allocation and rate design, and I will comment on the deleterious impact of an improper allocation on a declining industrial base. My testimony also includes recommendations regarding the return on equity and capital structure proposed by DENC.

Q DOES YOUR TESTIMONY ADDRESS DENC'S NEED FOR AN INCREASE IN ELECTRIC RATES?

A In order to make my presentation consistent with the revenue levels requested by DENC, I have, in many instances, used its proposed figures for rate base, operating income, fuel and rate of return. Use of these numbers should not be interpreted as an endorsement of them for purposes of determining the total dollar amount of rate increase to which DENC may be entitled. I focus my recommendations instead on the appropriate distribution to classes of any amount of rate increase allowed by the Commission.

Q **WHY ARE CIGFUR I MEMBERS, AND MORE GENERALLY INDUSTRIAL RATEPAYERS, CONCERNED WITH ELECTRIC RATES?**

A Industrial energy users, such as CIGFUR I members, use power for around-the-clock manufacturing operations. Electricity represents a significant portion of industrial energy users' operating costs. Especially in light of global competitive concerns—both externally for customers and internally for capital—market forces increasingly dictate production and siting decisions for large manufacturers. It is no surprise, then, that electricity-intensive industrial customers show dramatic responses to changes in electricity prices. A material change in the cost of electricity has the potential to impact employment, production and investment levels for large customers such as CIGFUR I members. A rate increase is a serious concern for CIGFUR I members and the Commission should consider the impact thereof thoroughly and carefully to ensure that any increase in DENC's industrial rates are cost-based and only the minimum amount necessary for the utility to provide adequate and reliable service.

Q **DESCRIBE THE CONTRIBUTIONS OF CIGFUR I MEMBERS TO THEIR LOCAL COMMUNITIES AND DENC'S OTHER RATEPAYERS.**

A According to the latest information published on the North Carolina Department of Commerce's website,[3] WestRock (appearing as WestRock Services Inc.) and Pfizer (appearing as Hospira Inc.) are among North Carolina's largest manufacturing employers. WestRock's Roanoke Rapids Mill (Halifax County) employs approximately 450 people, including contractors. Pfizer, located in Rocky Mount, Nash County, employs approximately 3,000 people. Cummins RMEP is sited in

[3] https://www.nccommerce.com/documents/nc-manufacturing-employers-only

Whitakers, Nash County, and employs approximately 2,100 people, including contractors. Finally, Domtar is located in Plymouth, Washington County, and employs approximately 350 people. The jobs provided by CIGFUR I members vital are the local economy of northeastern North Carolina.

Further, CIGFUR I members constitute a significant portion of the industrial base of DENC's service area. Industrial energy users play an important role in preserving the balance of the electric marketplace and their presence in the system is beneficial to residential and commercial customers. When large industrial load is lost, remaining customers must pay the fixed cost portion of revenues previously borne by the lost industrial load.

Q **WHY SHOULD THE COMMISSION BE CONCERNED WITH THE HEALTH OF DENC'S INDUSTRIAL BASE?**

A The northeastern portion of North Carolina, which includes DENC's service area, is a traditionally disadvantaged area in terms of jobs, wages and income. In its 2018 Integrated Resource Plan (Docket No. E-100, Sub 157), DENC's Appendix 2C shows that the industrial class will decrease by 69,000 MWh or about 3.9% from 2018 to projected 2033. During that period, residential sales are projected to increase by 267,000 MWh (16%) and commercial sales are projected to increase by almost 307,000 MWh or 36%. The industrial base in DENC's service area has been shrinking in this century and is not expected to return to prior levels during DENC's current planning horizon. In DENC's last general rate case, E-22, Sub 532, Company witness Paul Haynes stated at pages 10-11 of his direct testimony that the Company was keenly aware of the reduction in industrial customers and industrial usage in its North Carolina service territory and that the loss of industrial customers and industrial electric usage can have drastic negative impacts on the economic well-being of local communities and the State as a whole. Witness Haynes recognized that the loss of an industrial customer often equates to the loss of jobs and can directly impact the economic vitality of a locality and even an entire region of the State.

Q **IS IT APPROPRIATE TO TAKE ECONOMIC CONDITIONS INTO ACCOUNT IN SETTING RATES FOR LARGE EMPLOYERS?**

A Yes. I am advised that the Commission, in designing rates, may properly consider the "economic and political factors which are inherent in the ratemaking process." In my view, these considerations combined with a reasonable and fair cost of service approach support the cost allocations between the customer classes proposed by DENC. Stagnation in the industrial class is a concern throughout North Carolina. It would be short sighted to favor residential and commercial customers, whose classes are growing and projected to continue to grow, while making it more difficult for industrial customers—who face global competition and compete internally for capital.

Q **WHAT FACTORS EQUATE TO FAIR AND REASONABLE RATES?**

A First, service should be supplied at the lowest feasible cost to present and future customers. Second, rates for service should be based on the actual costs of providing service. Third, no customer class should subsidize any other class of customers. Fourth, business climate should not be adversely impacted.

Q IN ADDITION TO FAIR AND REASONABLE RATES, DO CIGFUR I'S MEMBERS HAVE OTHER ENERGY PRIORITIES?

A Yes. Service should be available to all present and future customers in quantities and of the quality required by these customers. Just as electric cost can adversely impact business climate, unreliable service and inconsistent voltage negatively impact operations and are unacceptable to CIGFUR I members. In addition to cost, reliable and consistent service is paramount to CIGFUR I's members.

Q WOULD YOU BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A Yes. A summary of CIGFUR I's positions is listed below:

1. Because DENC's proposed method of distributing the requested increase to classes moves rates closer to cost in a meaningful manner, it should be implemented as proposed. However, in fact, DENC's use of the summer winter peak and average ("SWPA") method allocates excessive cost to high load factor customers and is not truly reflective of each customer class's cost of service. A more equitable cost of service study would be the peak demand method. CIGFUR I encourages DENC to utilize the peak demand method in future proceedings.

2. DENC's request to earn 10.75% ROE is excessive compared to the national average of authorized returns which was 9.57% for the first half of 2019. The national average ROE of 9.57% should be considered as an upper limit on the ROE approved in this proceeding.

3. DENC's proposed capital structure is inappropriate in light of national trends and recent findings by this Commission. The upper boundary on equity percentage should be 52.00%.

4. The Commission should return excess deferred taxes to customers to the maximum extent practicable.

Cost of Service and Rate Design Principles

Q PLEASE EXPLAIN THE BASIS FOR YOUR EVALUATION AND DESIGN OF RATES.

A The ratemaking process has three steps. First, we determine the utility's total revenue requirement and whether an increase in revenues is necessary. Second, we must determine how any increase in revenues is to be distributed among the various customer classes. A determination of how many dollars of revenue should be produced by each class is essential for obtaining the appropriate level of rates. Finally, individual tariffs must be designed to produce the required amount of revenues for each class of service and to reflect the cost of serving customers within the class.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is universally agreed that the utility is entitled to an increase only to the extent that its actual cost of service has increased. If current rate levels exceed the utility's revenue requirement, a rate reduction is required. In short, rate revenues should equal actual cost of service. The same principle should apply in the second two steps. Each customer class should, to the extent practicable, produce revenues equal to the cost of serving that particular class, no more and no less. This may require a rate increase for some classes and a rate decrease for other classes. The standard tool for determining this is a class cost of service study that shows the rates of return produced by each customer class of service. Rate levels should be modified so that each class of service provides approximately the same rate of return. Finally, in designing individual tariffs, the goal should also be to relate the rate design to the cost of service so that each customer's rate equals, to the extent practicable, the utility's cost of providing that service.

Q **WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATE DESIGN PROCESS?**

A The basic reasons for using cost of service as the primary factor in the rate design process are equity, engineering efficiency (cost minimization), conservation, and stability.

Q **HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?**

A When rates are based on cost, each customer (to the extent practical) pays what it costs the utility to provide service to that customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenues by subsidizing service provided to other customers. This is inherently inequitable.

Q **HOW DO COST-BASED RATES ACHIEVE THE ENGINEERING EFFICIENCY (COST MINIMIZATION) OBJECTIVE?**

A Cost minimization is achieved when customers receive the appropriate price signals through the rates that they pay. Rate design is the step that follows the allocation of costs to classes. In designing rates, it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand, and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

From a rate design perspective, over-pricing the energy portion of the rate and under-pricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from high load factor customers.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses are discouraged or minimized. Only when rates are based on actual costs do customers receive a balanced price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted signals. It is important that the costs associated with certain conservation and demand management programs do not create a new form of subsidization and move rates away from cost.

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the earnings impact on the utility of changes in customer use patterns will be minimized as a result of rates being designed in the first instance to track changes in the level of costs. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need for filings for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than costs, it becomes much more difficult for customers to translate expected utility-wide cost changes (i.e., expected increases in overall revenue requirements) into changes in the rates charged to particular customer classes (and to customers within the class). This situation reduces the attractiveness of expansion, as well as of continued operations, because of the lessened ability to plan.

Q **WHEN YOU SAY "COST," TO WHAT TYPE OF COST ARE YOU REFERRING?**

A I am referring to the utility's "embedded" or actual accounting costs of rendering services; that is, those costs that are used by the Commission in establishing DENC's overall revenue requirement.

Q **IN YOUR OPINION, IS IT APPROPRIATE TO CLASSIFY ALL PRODUCTION INVESTMENT AS DEMAND-RELATED?**

A Yes. Consumers take for granted that when they flip the switch, an electric light or appliance will turn on and run. Since electric energy cannot be stored in large quantities for any significant length of time, utilities must provide adequate generating capacity to meet the demands of their customers when those customers decide to make those demands. Therefore, investment in generation plant is properly classified as a demand-related cost.

Q **WHAT ABOUT THE ARGUMENT THAT SOME PORTION OF THE INVESTMENT IN BASE LOAD PLANT SHOULD BE CLASSIFIED AS ENERGY-RELATED, BASED ON THE THEORY THAT A UTILITY IS WILLING TO MAKE CERTAIN ADDITIONAL CAPITAL INVESTMENTS TO REDUCE ITS LEVEL OF FUEL COSTS?**

A With respect to this argument, it should be noted that the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs, and therefore is a function of average total costs. The capital cost of peaking plants is lower than the capital cost of base load plants, but the operating costs of peaking plants are higher than the operating costs of base load plants. Moreover, when the hours of use are considered, the fixed cost per kWh for base load plant is usually less than the fixed cost per kWh for the peaking plant. Of course, since the fuel costs of base load plants are lower than the fuel costs of peaking plants, the overall cost per kWh for base load plants is also less than the overall cost per kWh for peaking plants.

It is necessary, therefore, to look at both capital costs and operating costs in light of the expected capacity factor of the plant. The fact that base load plants have lower fuel costs than peaking plants does not mean that the investment in base load plants is strictly to achieve lower fuel costs. Investment in a base load plant is made to achieve lower *total* costs, of which fixed costs and fuel costs are the primary ingredients.

For any given system, the capital costs are not a function of the number of kWh generated, but are fixed and therefore are properly related to system demands, not to kWh sold. These costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are related to the existence of the property and not to the number of kWh sold. If sales volumes change, these costs are not affected, but continue to be incurred, making them fixed or demand-related in nature.

It is not proper to classify a portion of the fixed costs related to production based on energy. However, if an attempt were made to increase the allocation of investment to one group of customers, on the theory that those customers benefit more than others from the lower energy costs that result from the operation of a base load plant as opposed to a peaking plant, as is done in the SWPA method, the analysis should be carried to its logical conclusion. The logical conclusion would be to fairly and symmetrically allocate lower energy costs to the group of customers who are forced to bear the higher capital costs allocated to them on a kWh basis. Energy costs allocated to the high load factor class should recognize lower operating costs which result from the higher capital costs of the base load plants. However, DENC has not proposed the lower fuel costs for the industrial class of customers.

DENC 2018 Cost of Service Study

Q **HAVE YOU BEEN INVOLVED IN PREVIOUS DENC BASE RATE PROCEEDINGS?**

A Yes. I have been involved in DENC's base rate proceedings for more than 25 years. I am familiar with DENC's cost of service studies and have testified on issues related to them over a long time period. To my knowledge, Virginia Electric and Power Company uses the SWPA method only in North Carolina, which is about 5% of their system. A different cost allocation methodology is used in Virginia as stated in the Direct Testimony of Mr. Haynes.

Q **HAVE YOU REVIEWED THE 2018 COST OF SERVICE STUDY FILED BY DENC IN THIS PROCEEDING?**

A Yes. DENC proposes to use a 2018 cost of service study based on the SWPA method. Using the Summer/Winter peaks makes sense based on DENC's actual planning for future capacity requirements. Using average demand, which is not actually demand but around-the-clock kilowatthour usage, does not. This is particularly true for Schedule 6VP, a very sophisticated rate which signals customers when capacity is constrained and sends very strong pricing signals to reduce usage during capacity constrained hours. The SWPA without a symmetrical fuel allocation is neither fair nor reasonable for these efficient customers.

Even this faulty methodology shows an above average rate of return of 7.65% (index 1.26) for the Schedule 6VP class under current rates. However, the rate of return for Schedule 6VP is significantly understated because the SWPA allocates excess cost to high load factor customers.

Q HAVE YOU REVIEWED DENC'S RECENT IRP?

A Yes. DENC filed its most recent IRP on May 1, 2018 in Docket No. E-100, Sub 157. DENC forecasts continued load growth which requires additional generation capacity. The load growth and customer count growth is attributable to the residential and commercial classes. The industrial class shows declining load.[4]

With respect to DENC planning and obligations, the IRP states:

> "As a PJM member, the Company is signatory to PJM's Reliability Assurance Agreement, which obligates the Company to own or procure sufficient capacity to maintain overall system reliability." (2018 IRP, p. 52)

Regarding actions to meet load growth, the 2018 IRP sates:

> "The SCC approved a certificate of public convenience & necessity ("CPCN") for the Greensville Power Station (1,585 MW CC Unit) on March 29, 2016. It is currently under construction and is expected to be online by 2019." (2018 IRP, p. 43)

Q WHAT DOES THE 2018 IRP INDICATE WITH REGARD TO CAPACITY PLANNING FOR THE FORECAST PERIOD?

A DENC is required to add capacity to meet its PJM-determined capacity requirements. In that regard, the IRP states:

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[4] 2018 IRP, Appendix 2C, page 145 and Appendix 2F, page 148.

> "Specifically, PJM's planning year runs from June 1st to May 31st. Because the Company and PJM are both historically summer peaking entities, and because the summer period of PJM's planning year coincides with the calendar year summer period, calendar and planning year reserve requirement estimates are determined based on the identical summer time period. For example, the Company uses PJM's 2019/2020 delivery year assumptions for the 2019 calendar year in this 2018 Plan because it represents the expected peak load during the summer of 2019."

Q DO YOU HAVE AN EXAMPLE OF A COMMISSION THAT HAS DROPPED THE ENERGY WEIGHTING IN THE ALLOCATION OF FIXED PRODUCTION INVESTMENT?

A Yes. The North Carolina Utilities Commission has approved the use of the one hour summer coincident peak (1CP) methodology to allocate fixed production cost for both DEP, in Dockets E-2, Sub 1032 and E-2, Sub 1142, and DEC, in Dockets E-7, Sub 989, E-7, Sub 1026 and E-7, Sub 1146.

Q DOES THE 2018 IRP PROVIDE ADDITIONAL SUPPORT FOR THE USE OF THE SUMMER/WINTER COINCIDENT PEAK METHOD ("S/W CP") COST OF SERVICE METHOD?

A Yes. According to the 2018 IRP, both the Company and PJM forecast a summer peak throughout the planning period. However, in 2014, 2015, 2017 and 2018, the system peak occurred during the winter. Therefore, it is reasonable to give weight to both the summer and winter peak demands when developing allocation factors for use in the cost of service study.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE 2018 COST OF SERVICE STUDY.

A The SWPA method is inconsistent with both DENC's method of planning for future capacity requirements, and the increase in the portion of its generating mix represented by natural gas, as outlined in its 2018 IRP. Additionally, the SWPA method over-allocates cost to large, high load factor, customers without a symmetrical fuel cost allocation. In contrast, the S/W CP cost of service study is consistent with system planning and cost causation principles, and corrects the over-allocation of costs to large, energy intensive industrial customers, such as those served under Schedule 6VP.

Revenue Distribution

Q WHAT IS THE MAIN OBJECTIVE OF THE COMPANY'S PROPOSED REVENUE APPORTIONMENT AMONG ITS CUSTOMER CLASSES?

A The main objective of the Company's revenue distribution is to apportion the revenue increase among the customer classes in a manner that brings each customer class closer to its cost of service, and closer to parity with the jurisdictional rate of return. While working to meet this goal, the Company also aims to be fair to each customer class, as well as to the body of customers as a whole.

Q **DID YOU FOLLOW THE DENC PROPOSED SWPA COST OF SERVICE OR A PEAK DAY DEMAND METHOD IN THE DEVELOPMENT OF THE REVENUE DISTRIBUTION TO CLASSES TO ACCOMPLISH TO COST BASED FAIR RESULT?**

A I used the SWPA cost of service in the development of my recommended revenue distribution. The reason is that use of the summer/winter peak method would not have altered my recommended revenue distribution in any meaningful way. Since rate impact is a limiting factor, the resulting revenue distribution would not change in a meaningful manner for the LGS and 6VP classes if the peak demand was used in preference to the SWPA. To limit the issues in the proceeding, I am using the SWPA as the basis for the revenue distribution to classes although the method allocates approximately 50% more generation plant investment to the Rate 6VP class compared to the peak method.

Q **DOES DENC'S PROPOSED REVENUE DISTRIBUTION BASED ON THE SWPA METHOD TREAT EACH CUSTOMER CLASS, AND THE BODY OF CUSTOMERS AS A WHOLE, FAIRLY?**

A Basically, yes. The SWPA cost of service results indicate that several customer classes are currently providing returns above the system average including LGS and 6VP. DENC proposes to move those classes closer to cost by recommending below average increases to the LGS class and the 6VP class.

Q DOES DENC'S REVENUE DISTRIBUTION TO CLASSES BASED ON THE SWPA METHOD MAKE A MEANINGFUL MOVEMENT TOWARD COST OF SERVICE FOR THE 6VP CLASS AND THE LGS CLASS?

A DENC's proposed distribution moves the rate of return for the Rate 6VP class and the LGS class closer to cost and the system average rate of return. The Rate 6VP class has been providing excess returns to DENC both in this case and the most recent case E-22, Sub 532 which used a 2015 Test Year. I have included a DENC exhibit from E-22, Sub 532 included as Exhibit NP-1 showing the Rate 6VP rate of return of 8.19% under current rates (index of 1.62) and a rate of return on 9.42% under proposed rates (index of 1.21). These excessive returns are based on the SWPA cost study. The excessive rates paid by these customers over the last five years should be corrected in this proceeding. Additionally, if the Commission determines that the appropriate revenue requirement is less than that proposed by the Company, any reduction in the revenue requirement should be used to move Rate 6VP and LGS customers closer to their respective cost of service.

Return on Equity & Capital Structure

Q IS DENC'S PROPOSED 10.75% ROE APPROPRIATE?

A No. DENC's requested ROE of 10.75% is excessive when compared with recent rate ROEs approved by commissions nationwide and the Commission's recent decisions and should be rejected. The Company's current authorized ROE is 9.9%, which was authorized in the Commission's Final Order in Docket No. E-22, Sub 532, issued on December 22, 2016. It is important to note that, market costs of capital have not increased since DENC's last rate case. Further, the national average ROE has been below 10% for electric utilities since 2014.

Every quarter, Regulatory Research Associates, an affiliate of SNL Financial, updates its *Major Rate Case Decisions* report that covers electric and natural gas utility rate case outcomes. Specifically, this report tracks the authorized ROEs resulting from utility rate cases. The most recent report issued July 22, 2019 has been updated through June 30, 2019, and shows that the average authorized ROE for electric utilities in rate cases (and excluding limited-issue rider cases) decided during the first half of 2019 was 9.57%. This is 33 basis points below DENC's currently authorized ROE of 9.9% and 118 basis points below DENC's requested ROE of 10.75% in its current application.

Further, DENC's requested ROE of 10.75% is inconsistent with ROEs authorized by the Commission in recent general rate cases. I have prepared the following table illustrating the Commission's authorized ROEs for electric and natural gas utilities for the past decade.

TABLE 1

NCUC's Authorized ROEs

Company	Service	NCUC Docket	Date of Order	NCUC Allowed Return on Equity
DEC	Electric	E-7, Sub 909	12/7/2009	10.70%
DENC	Electric	E-22, Sub 459	12/13/2010	10.70%
DEC	Electric	E-7, Sub 989	1/27/2012	10.50%
DENC	Electric	E-22, Sub 479	12/21/2012	10.20%
DEP	Electric	E-2, Sub 1023	5/30/2013	10.20%
DEC	Electric	E-7, Sub 1026	9/24/2013	10.20%
PNG	Gas	G-9, Sub 631	12/17/2013	10.00%
PSNC	Gas	G-5, Sub 565	10/26/2016	9.70%
DENC	Electric	E-22, Sub 532	12/22/2016	9.90%
DEP	Electric	E-2, Sub 1142	2/23/2018	9.90%
DEC	Electric	E-7, Sub 1146	6/22/2018	9.90%

As is evident from the table, the Commission has not approved an authorized ROE in excess of 10.00% since 2013 and has not approved an ROE in excess of 10.50% since 2010. DENC's proposed 10.75% ROE is inconsistent with broader electric industry trends and the Commission's recent decisions. Finally, the Commission should carefully consider how its authorized ROE impacts industrial ratepayers competing in the global market. I recommend that the Commission authorize a ROE that does not exceed the national average of 9.57%.

Q IS DENC'S PROPOSED CAPITAL STRUCTURE OF 53.649% EQUITY APPROPRIATE?

A Nationally, Regulatory Research Associates' *Major Rate Case Decisions* reports that "to offset the negative cash flow impact of federal tax reform, many utilities [are seeking] higher common equity ratios," nonetheless the average authorized equity ratio for electric utility cases nationwide was 50.10% during the first half of 2019 and 51.76% excluding jurisdictions that authorize capital structures that include cost-free items or tax credit balances.

Further, DENC's requested capital structure is inconsistent with those authorized by the Commission in recent general rate cases. I have prepared the following table illustrating the Commission's approved equity percentage of overall capital structure for electric and natural gas utilities for the past decade.

TABLE 2

NCUC's Approved Equity Percentage

Company	Service	NCUC Docket	Date of Order	NCUC Allowed % Equity
DEC	Electric	E-7, Sub 909	12/7/2009	52.50%
DENC	Electric	E-22, Sub 459	12/13/2010	51.00%
DEC	Electric	E-7, Sub 989	1/27/2012	53.00%
DENC	Electric	E-22, Sub 479	12/21/2012	51.00%
DEP	Electric	E-2, Sub 1023	5/30/2013	53.00%
DEC	Electric	E-7, Sub 1026	9/24/2013	53.00%
PNG	Gas	G-9, Sub 631	12/17/2013	50.66%
PSNC	Gas	G-5, Sub 565	10/26/2016	52.00%
DENC	Electric	E-22, Sub 532	12/22/2016	51.75%
DEP	Electric	E-2, Sub 1142	2/23/2018	52.00%
DEC	Electric	E-7, Sub 1146	6/22/2018	52.00%

As is evident from the table, the Commission has not approved a capital structure with 53.00% equity since 2013. DENC's proposed equity percent is inconsistent with broader electric industry trends and the Commission's recent decisions. I recommend that the Company's capital structure not exceed 52.00% equity.

Q IS CIGFUR I SUGGESTING THAT THE COMMISSION IS BOUND BY NATIONAL TRENDS OR THE FINDINGS OF OTHER STATE COMMISSIONS?

A No. The Commission is not bound by the decisions of other state regulatory commissions. Also, it is important to note that each commission considers the unique circumstances in each specific case in arriving at a regulated utility's authorized ROE and capital structure. However, I believe this information is illustrative of national trends in authorized ROEs and capital structures of regulated electric utilities that compete in the same capital markets as DENC's holding company, Dominion Energy, Inc. Evidence of national trends may serve as a general gauge of reasonableness for the cost-of-equity and capital structure recommendations presented in this proceeding.

Rider EDIT

Q HAVE YOU REVIEWED DENC'S PROPOSAL TO REFUND EXCESS DEFERRED INCOME TAXES ("EDIT") TO CUSTOMERS?

A Yes. DENC is proposing that federal EDIT amortization attributable to the 20-month period January 1, 2018 through October 31, 2019 be credited to customers through Rider EDIT over one year. Excess deferred taxes are basically overpayments by DENC customers and those amounts should be returned as soon as possible.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Nicholas Phillips, Jr.

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.**

A I graduated from Lawrence Institute of Technology in 1968 with a Bachelor of Science Degree in Electrical Engineering. I received a Master's of Business Administration Degree from Wayne State University in 1972. Since that time I have taken many Masters and Ph.D. level courses in the field of Economics at Wayne State University and the University of Missouri.

I was employed by The Detroit Edison Company in June of 1968 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included the overhead and underground design, construction, operation and specifications for transmission and distribution equipment; budgeting and cost control for operations and capital expenditures; equipment performance under field and laboratory conditions; and emergency service restoration. I also worked in various districts, planning system expansion and construction based on increased and changing loads.

Since 1973, I have been engaged in the preparation of studies involving revenue requirements based on the cost to serve electric, steam, water and other portions of utility operations.

Other responsibilities have included power plant studies; profitability of various segments of utility operations; administration and recovery of fuel and purchased power costs; sale of utility plant; rate investigations; depreciation accrual rates; economic investigations; the determination of rate base, operating income, rate of return; contract analysis; rate design and revenue requirements in general.

I have held various positions including Supervisor of Cost of Service, Supervisor of Economic studies and Depreciation, Assistant Director of Load Research, and was designated as Manager of various rate cases before the Michigan Public Service Commission and the Federal Energy Regulatory Commission. I was acting as Director of Revenue Requirements when I left Detroit Edison to accept a position at Drazen-Brubaker & Associates, Inc., in May of 1979.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff.

Our firm has prepared many studies involving original cost and annual depreciation accrual rates relating to electric, steam, gas and water properties, as well as cost of service studies in connection with rate cases and negotiation of contracts for substantial quantities of gas and electricity for industrial use. In these cases, it was necessary to analyze property records, depreciation accrual rates and reserves, rate base determinations, operating revenues, operating expenses, cost of capital and all other elements relating to cost of service.

In general, we are engaged in valuation and depreciation studies, rate work, feasibility, economic and cost of service studies and the design of rates for utility services. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q WHAT ADDITIONAL EDUCATIONAL, PROFESSIONAL EXPERIENCE AND AFFILIATIONS HAVE YOU HAD?

A I have completed various courses and attended many seminars concerned with rate design, load research, capital recovery, depreciation, and financial evaluation. I have served as an instructor of mathematics of finance at the Detroit College of Business located in Dearborn, Michigan. I have also lectured on rate and revenue requirement topics.

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A Yes. I have appeared before the New Jersey Board of Public Utilities, the Public Service Commissions of Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Montana, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Virginia, West Virginia, and Wisconsin, the Lansing Board of Water and Light, the District of Columbia, and the Council of the City of New Orleans in numerous proceedings concerning cost of service, rate base, unit costs, pro forma operating income, appropriate class rates of return, adjustments to the income statement, revenue requirements, rate design, integrated resource planning, power plant operations, fuel cost recovery, regulatory issues, rate-making issues, environmental compliance, avoided costs, cogeneration, cost recovery, economic dispatch, rate of return, demand-side management, regulatory accounting and various other items.

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MS. FENNELL: The Public Staff would like to move the following testimony of its witnesses on direct that was filed on 8/23/2019 be moved into the record: Boswell, consisting of seven pages and in addition an Appendix A and an Exhibit 1; David Williamson, consisting of 16 pages and an Exhibit A and six exhibits; Tommy Williamson, consisting of nine pages and an Appendix A; Roxie McCullar, consisting of 22 pages and an Appendix A and three exhibits; Jeff Thomas, consisting of 24 pages, an Appendix A and one exhibit; and Randy Woolridge, consisting of 128 pages, an Appendix A and 10 exhibits.

CHAIR MITCHELL: That motion will be allowed.

(Exhibits JRW-1 through JRW-10; Boswell Exhibit 1; Public Staff-D Williamson Exhibits 1-5; Confidential Public Staff-D Williamson Exhibit 6; Exhibits RMM-1 through RMM-3; Public Staff-Thomas Exhibit 1 were premarked for identification.)

(Whereupon, the prefiled direct testimony of Michelle M. Boswell, David Williamson, Tommy Williamson, Roxie McCullar, Jeff T. Thomas, and Randy Woolridge were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

In the Matter of Application of Dominion Energy North Carolina, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF MICHELLE M. BOSWELL PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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

A. My name is Michelle M. Boswell. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Staff Accountant with the Accounting Division of the Public Staff – North Carolina Utilities Commission.

Q. **BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.**

A. My qualifications and duties are included in Appendix A.

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

A. The purpose of my testimony is to present the accounting and ratemaking adjustments I am recommending regarding federal protected Excess Deferred Income Taxes (EDIT), federal unprotected EDIT, and the Rider EDIT proposed by the Company.

Q. **MS. BOSWELL, PLEASE DESCRIBE THE SCOPE OF YOUR INVESTIGATION INTO THE COMPANY'S FILING.**

A. My investigation included a review of the application, testimony, exhibits, and other data filed by Dominion Energy North Carolina (Company). The Public Staff has also conducted extensive discovery in this matter, including the review of numerous data responses provided by the Company in response to data requests and participation in conference calls with the Company.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSALS RELATED TO FEDERAL EDIT.

A. The Company has proposed four adjustments related to federal EDIT. First, the Company has proposed to flow back federal protected EDIT utilizing the ARAM methodology in accordance with IRS normalization rules. Second, the Company has created an artificial category of federal "plant-unprotected" EDIT that it proposes to treat like protected EDIT and collect utilizing the ARAM methodology. Third, the Company has recommended collecting the remainder of federal unprotected EDIT over a period of 30 years. Finally, the Company has proposed a one-year levelized rider for the amortization of protected, plant-unprotected, and unprotected EDIT effective January 1, 2018.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.

A. My adjustments are described below.

FEDERAL EXCESS DEFERRED INCOME TAXES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO FEDERAL EXCESS DEFERRED INCOME TAXES.

A. The federal EDIT consist of two categories, protected and unprotected. The protected EDIT are deferred taxes related to timing differences arising from the utilization of accelerated depreciation for tax purposes and another depreciation method for book purposes.

These deferred taxes are deemed protected because the Internal Revenue Service (IRS) does not permit regulators to flow back the excess to ratepayers immediately, but instead requires that the excess be flowed back to ratepayers ratably over the life of the timing difference that gave rise to the excess, per Internal Revenue Code (IRC) Section 203(e). EDIT resulting from all other timing differences are unprotected, and can be flowed back to or recovered from ratepayers however quickly regulators deem reasonable.

Based upon the foregoing, I recommend three adjustments to the federal EDIT, one relating to protected and two relating to unprotected.

First, I agree with the Company's proposal to flow back the federal protected EDIT utilizing the ARAM as required under IRS normalization rules. The Company updated the amount in Company Supplemental Exhibit PMM-2, Schedule 1, page 1. Unfortunately, I am unable to calculate the protected EDIT amortization for the current case, as the Company was unable to provide a breakout of the protected EDIT from the unprotected EDIT and combined both categories in Company Supplemental Exhibit PMM-2, Schedule 2, page 2. Therefore, I recommend that the Commission require the Company to file schedules that provide the EDIT amounts broken out by protected and plant-unprotected, in order for the appropriate balance to be flowed back to ratepayers.

Second, I disagree with the Company's adjustment to include a portion of unprotected EDIT, labeled by the Company as plant-unprotected, to be recovered utilizing the ARAM calculation, as presented in Company Supplemental Exhibit PMM-2, Schedule 2, page 1. The Company does not dispute that the $1.777 million categorized as "plant-unprotected" for North Carolina jurisdiction is unprotected according to IRS rules, and that the Commission has the discretion to flow back all of the unprotected EDIT over any time period it finds appropriate. I recommend including the "plant-unprotected" balance with the unprotected EDIT, and collecting the balance on a levelized basis over a five year period as described below.

For the total unprotected EDIT balance including the "plant-unprotected" portion, I recommend removing the entire amount from rate base, and placing it in a rider to be collected from ratepayers over five years on a levelized basis, with carrying costs. The calculation of the total unprotected EDIT adjustment is shown on Boswell Exhibit I, Schedule 1.

The Public Staff recognizes in the present case that the total unprotected EDIT balance of $5.928 million is a debit balance owed to the Company. The Public Staff believes that regardless of the credit or debit status of the unprotected balance, the amount should be flowed back or recovered over the same period utilizing the same methodology as previously recommended by the Public Staff.

Q. PLEASE EXPLAIN WHY THE UNPROTECTED EDIT SHOULD BE COLLECTED FROM RATEPAYERS OVER A FIVE-YEAR PERIOD.

A. The tax normalization rules are very clear - either EDIT is protected, or it is not. The EDIT that the Company designates as "plant-unprotected" is still clearly unprotected, a fact conceded by the Company. The Company's assertion that it should only return or recover this plant-unprotected EDIT over the same period of time it would have paid the funds to the IRS had the tax law not been passed is not supported by any logical accounting or ratemaking principle, and should not dictate this Commission's decision as to what is a reasonable amount of time within which to collect these funds from ratepayers.

Q. DOES THE PUBLIC STAFF HAVE ANY ISSUE REGARDING THE COMPANY'S EDIT RIDER PROPOSAL?

A. The Public Staff does not object in theory to the Company's proposal to flow back the federal protected and unprotected amortization since January 1, 2018, as a one-year levelized rider. However, as discussed previously in my testimony; since the Company has not provided a breakout of the protected and unprotected EDIT amortization shown on Company Supplemental Exhibit PMM-2, Schedule 2, page 2, the appropriate calculation of the amortization to be flowed back cannot be calculated at this time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

MICHELLE M. BOSWELL

I graduated from North Carolina State University in 2000 with a Bachelor of Science degree in Accounting. I am a Certified Public Accountant.

I am responsible for analyzing testimony, exhibits, and other data presented by parties before this Commission. I have the further responsibility of performing the examinations of books and records of utilities involved in proceedings before the Commission, and summarizing the results into testimony and exhibits for presentation to the Commission.

I joined the Public Staff in September 2000. I have performed numerous audits and/or presented testimony and exhibits before the Commission addressing a wide range of electric, natural gas, and water topics. I have performed audits and/or presented testimony in Duke Energy's 2010 REPS Cost Recovery Rider; the 2008 REPS Compliance Reports for North Carolina Municipal Power Agency 1, North Carolina Eastern Municipal Power Agency, GreenCo Solutions, Inc., and EnergyUnited Electric Membership; Duke Energy Carolina LLC 2017 rate case, four recent Piedmont rate cases; the 2016 rate case of Public Service Company of North Carolina (PSNC), the 2012 rate case for Dominion Energy North Carolina (DENC, formerly Dominion North Carolina Power), Duke Energy Progress LLC 2013 and 2017 rate case, several Piedmont, NUI Utilities Inc. (NUI), and Toccoa annual gas cost reviews; the merger of Piedmont and NUI; and the merger of Piedmont and North Carolina Natural Gas (NCNG).

Additionally, I have filed testimony and exhibits in numerous water rate cases and performed investigations addressing a wide range of topics and issues related to the water, electric, and telephone industries.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

In the Matter of Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF DAVID M. WILLIAMSON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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

A. My name is David M. Williamson. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Commission the Public Staff's analysis and recommendations of the appropriateness of the recovery of mitigation expenses associated with the newly commissioned Skiffes Creek 500 kilovolt (kV) transmission line by Dominion Energy North Carolina (DENC or the Company) , as proposed in this general rate case.

Q. PLEASE DESCRIBE THE VARIOUS SECTIONS THAT MAKE UP THE SKIFFES CREEK TRANMSSION LINE PROJECT.

A. The Skiffes Creek 500 kV transmission line project consists of three components:

1. Surry-Skiffes Creek 500 kV line route
   A total of 8.0 miles spanning from the Surry Power Station to the new Skiffes Creek Switching Station; approximately 4.1 miles of overhead line crossing the James River; a total of 17 structures are located in the James River.

2. <u>Skiffes Creek-Whealton 230 kV line route</u>
   A total of 20.2 miles of new line spanning from the new Skiffes Creek Switching Station, running parallel with an existing 230 kV transmission line, to the existing Whealton Substation east of Skiffes Creek.

3. <u>Skiffes Creek 500 kV-230 kV-115 kV Switching Station</u>
   Located in the southern portion of James City County; this switching station is to serve as the cross section of 500 kV-230 kV-115 kV transmission lines.

A diagram of the finalized and approved route is attached as Williamson Exhibit 1.

Q. PLEASE DISCUSS THE REGULATORY APPROVAL FOR THIS PROJECT.

A. The Virginia State Corporation Commission (SCC) approved the route for this project on November 26, 2013. *Virginia Electric and Power Company d/b/a Dominion Virginia Power, Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line and Skiffes Creek 500 kV-230kV-115 kV Switching Station*, PUE-2012-00029, Order, November 26, 2013. (SCC 2013 Order). The route for the project is referred to as "Variation 4" in the SCC 2013 Order. The SCC modified the route on February 28, 2014. *Id.*, Order, February 28, 2014. (SCC 2014 Order). This modification is referred to as "Variation 1." In both orders, the SCC found that the project is needed to maintain electric reliability on the peninsula of the North Hampton Roads area in Virginia.[1]

The initial need for this project, as discussed by Company witness Peter Nedwick in Dominion Energy Virginia's (DEV) initial testimony on this project filed with the SCC on June 11, 2012, was determined by DEV and PJM Interconnection, LLC (PJM) through PJM's Power Flow studies performed during its 2012 Load Forecast in order to comply with North American Electric Reliability Corporation (NERC) Reliability Standards involving thermal overloading, voltage issues, and right-of way outages in the North Hampton Roads area. In addition to normal load growth, absent the project, the Company identified the likelihood of NERC reliability violations as early as the summer of 2015 due to the early retirement of the Company's coal-fired Yorktown Power Station Units 1 and 2.

Q. HAS THIS TRANSMISSION LINE PROJECT BEEN PLACED INTO SERVICE?

A. Yes. After several years of delays experienced during the permitting process, the Skiffes Creek 500 kV transmission line was placed into service on February 26, 2019. Yorktown Coal-fired Power Station Units 1 and 2 were retired in March of 2019.

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[1] The North Hampton Roads area refers to the counties of Charles City, James City, York, Essex, King William, King and Queen, Middlesex, Mathews, Gloucester, King George, Westmoreland, Northumberland, Richmond, and Lancaster; and the cities of Williamsburg, Yorktown, Newport News, Poquoson, Hampton, West Point, and Colonial Beach.

Q. DOES THE PUBLIC STAFF QUESTION THE NEED FOR THIS PROJECT?

A. No. The Public Staff does not dispute the need for this project. As detailed in both the SCC 2013 and SCC 2014 Orders, the SCC fully and carefully analyzed the need for the project. The need established by the SCC, in large part, was based on federal mandates and NERC reliability violations.

Q. WHAT IS THE PUBLIC STAFF'S CONCERN REGARDING THIS PROJECT?

A. The Public Staff takes the position that the mitigation costs for this project were not incurred for the purpose of constructing or operating the Skiffes Creek transmission line project, nor do they provide additional benefits to the Company's North Carolina retail customers and should not be recovered from North Carolina customers. Specifically, these costs were incurred to address aesthetic issues claimed by local organizations, historical groups, and citizens located in Virginia within the view shed of the project. While the new transmission line provides reliability benefits to the grid that will benefit all customers of Dominion Energy, including North Carolina retail customers, the mitigation costs do not provide any additional benefit, whether it be aesthetic, reliability, or politically, to the Company's North Carolina retail customers. The benefits derived from these mitigation costs inure solely to the benefit of Virginia and Virginia-based organizations and citizens.

Q. DID THE COMPANY ANTICIPATE THE PAYMENT OF MITIGATION COSTS AS PART OF THE SKIFFES CREEK TRANMSSION LINE PROJECT?

A. No. In the Company's original proposal to the SCC, mitigation-related expenses were not included in the estimate of the project's total cost. In response to Public Staff data requests, the Company provided a spreadsheet that detailed the estimated costs of various categories, including a category for mitigation costs, for this project at different points in time. The spreadsheet also provides the actual expenditure for each category through June 30, 2019. This spreadsheet is attached as Williamson Exhibit 2.

History of the Project

Q. PLEASE DISCUSS THE HISTORY OF THE CERTIFICATION PROCESS FOR THE SKIFFES CREEK TRANMSSION LINE PROJECT.

A. The Company originally filed its application for approval and certification to construct the Surry – Skiffes Creek – Whealton 500 kV transmission line project with the SCC on June 11, 2012. *Id.*, Application for Approval of Electric Facilities, June 11, 2012.

The Company's filing proposed two potential routes, one of which contained a number of variations for crossing the James River. As described in both the SCC 2013 and SCC 2014 Orders, numerous parties opposed to the project intervened in this proceeding, filing letters and participating in public meetings. The SCC's 2013 Order acknowledged that there was significant public interest with this project, as more than 1,400 written and electronic public comments were filed in the docket in response to the application.

After public and evidentiary hearings, the SCC issued its 2013 Order, granting a certificate for construction based on a route that utilized the James River crossing as proposed by the Company (Variation 4).

In its 2014 Order, the SCC amended its 2013 Order by agreeing with the Company's December 16, 2013 Petition asserting that Variation 4 was no longer a viable route, and that a different route (Variation 1), which still crossed the James River but in a different location, was the better alternative. *Id.*, Petition for Reconsideration, December 16, 2013. The SCC granted an amended certificate for Variation 1. *Id.*, Order Granting Reconsideration, December 17, 2013. As noted above, this finalized route selection is shown in Williamson Exhibit 1.

Q. DID THE COMPANY CONTINUE TO EXPERIENCE POST-CERTIFICATION OPPOSITION TO THE PROJECT?

A. Yes. Even after the SCC granted the Company a certificate to construct the transmission line, the Company faced numerous hurdles throughout the permitting process. Many local, state, and federal historical organizations, as well as federally recognized Indian tribes, continued to oppose the line on the grounds that it negatively impacted their property aesthetically.

Q. PLEASE DISCUSS THE HISTORY OF THE PROJECT POST-CERTIFICATION.

A. By Order dated June 5, 2015, the SCC required the Company to submit updates every 21 days to allow the SCC to monitor progress on this project that the SCC found to be critical to electric reliability of the North Hampton Roads Area. *Id.*, Order, June 5, 2015.[2]

The February 27, 2019 update filing, while not the only filing made by the Company, was submitted immediately after the line was energized and placed into service, and provides the most complete and up to date record of the actions that occurred post-certification. *Id.* Update on Status of Certificated Project (February 27, 2019), February 27, 2019. This update is attached as Williamson Exhibit 3. I have provided a brief summary of the February 27, 2019 update filing below:

- On August 28, 2013, November 13, 2014, and May 21, 2015, the Norfolk District Office of the U.S. Army Corps of Engineers (Corps) issued public notices to better assist in the evaluation of the effects of the project on the identified historic properties, and the evaluation

[2] This Order was in response to an Opinion of the Supreme Court of Virginia on April 16, 2015, whereby the Supreme Court held that the SCC had erred in including the Skiffes Creek Switching Station within the CPCN it granted for the transmission line, instead finding that the switching station was subject to local zoning regulations. The requirement for updates was ordered by the SCC so that it could remain regularly informed of the status of any particular issues occurring while construction was underway. In this Order, the SCC stated that the need for this project was "severe and fast approaching."

of alternatives or modifications which could avoid, minimize, or mitigate adverse effects of the undertaking.

- After the public meetings, the Corps published its Consolidated Effects Report on October 1, 2015. Subsequent to this report, the Corps and the State Historic Preservation Office (SHPO) reached agreement on the list of adversely affected historic properties.
- As a result of this agreement between the Corps and the SHPO, the Company and associated parties began discussions with the impacted property owners.
- On April 24, 2017, after many meetings, conference calls, and back and forth negotiations between the Company and various parties, a Memorandum of Agreement (MOA) was executed.
- On June 12, 2017, the Corps issued a provisional construction permit to the Company conditioned upon: (1) the issuance of a permit by the Virginia Marine Resources Commission (VMRC); and (2) certification by the Department of Environmental Quality (DEQ) that the Company has obtained a Section 401 Water Quality Certification /Virginia Water Protection Permit.
- On July 3, 2017, the Corps issued the Company a final construction permit under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act of 1899.

- On March 21, 2018, the Company sent a letter to the Corps providing notice that, as of March 7, 2018, it had completed all prerequisite actions required by the MOA to begin construction on the James River.

Memorandum of Agreement

Q. PLEASE DISCUSS THE MEMORANDUM OF AGREEMENT SIGNED BY THE VARIOUS PARTIES.

A. The MOA, attached as Williamson Exhibit 4 sheds additional light on the negotiations among the various parties. The signed MOA also contains multiple attachments (identified as Attachments A-F to the MOA), which, among other things, provide clarity on the history of the MOA, the mitigation impacts targeted in the MOA, the agreed payment amounts to each party, and the reasoning behind the creation of a MOA. The MOA describes individual contributions, as well as other donations, to be provided to each entity by the Company, as well as the purpose. These identified contributions and donations are broken down by party member in Williamson Exhibit 5. Moreover, Attachment F of the signed MOA provides a more in-depth description of the intended uses of these funds.

Q. PLEASE LIST THE VARIOUS PARTY MEMBERS ASSOCITATED WITH THE MEMORANDUM OF AGREEMENT.

A. The following are the specifics on the MOA's various parties:

1. Signatory parties: U.S. Army Corps of Engineers, Virginia State Historic Preservation Office, and the Advisory Council on Historic Preservation.

2. Invited Parties: Commonwealth of Virginia and Dominion Energy.

3. Concurring Parties: National Parks Conservation Association, Save the James Alliance, Chesapeake Conservancy, U.S. Department of Interior (National Park Service, Colonial National Historic Park), U.S. Department of Interior (National Park Service, Northeast Region), James City County, The Colonial Williamsburg Foundation, Preservation Virginia, Scenic Virginia, National Trust for Historic Preservation, Christian & Barton, LLP (on behalf of BASF CORP), James River Association, U.S. Department of Interior (National Park Service, American Battlefield Protection Program), First California Company Jamestown Society, Delaware Tribe of Indians, Chickahominy Tribe, Council of Virginia Archaeologists, Margaret Nelson Fowler, Pamunkey Indian Tribe, and Escalante Kingsmill Resort, LLC.

Q. PLEASE PROVIDE THE AMOUNT OF MITIGATION EXPENSES THAT ARE INCLUDED IN THIS GENERAL RATE CASE APPLICATION AS A RESULT OF THE MOA.

A. The Company includes $105,611,862 (system basis) in this rate case as a result of the mitigation expenditures.

Q. ARE THERE ANY ADDITONAL COSTS THAT THE COMPANY IS INCURRING RELATED TO THE CONSTRUCTION OF THE SKIFFES CREEK PROJECT?

A. Yes. The Company is currently engaged in ongoing litigation at the United States District Court involving the Corps and its use of an Environmental Assessment when issuing the required permits as opposed to conducting an Environmental Impact Study (EIS). As a result of this litigation, the Corps is initiating an EIS, which is currently scheduled to be completed during the summer of 2020. The additional costs of this ongoing litigation and additional studies are unknown at this time.[3]

Internal Auditing

Q. IN ADDITION TO THE PERMITTING PROCESS, WERE OTHER AUDITING OR REVIEW-TYPE PROCESSES PERFORMED OVER THE COURSE OF THIS PROJECT?

A. Yes. On November 27, 2018, the Company issued a confidential internal audit report titled the "Surry – Skiffes Creek – Whealton Electric Transmission Line Construction Project." This report was designed to

[3] The Company is still filing update reports with the SCC every 21 days, per SCC order. Any update toward the ruling of the District Court on this project will be filed in that docket.

evaluate the current status and any potential assessments of risk for the project. The scope of this report spanned from project inception in 2011 through July 20, 2018. This report is attached as Williamson Confidential Exhibit 6.

Q. **PLEASE PROVIDE PERTINENT DETAILS FROM THE AUDIT REGARDING COST OVERRUNS.**

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

[END CONFIDENTIAL]

Q. **WHAT CAUSES OF THE COST OVERRUNS WERE IDENTIFIED IN THE AUDIT?**

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[4] Since the completion of the internal audit, the total cost for the project has since increased. As of June 30, 2019, the system level total cost for the Skiffes Creek transmission line that DENC is including in this rate case is approximately $438.6 million, as shown in Williamson Exhibit 2.

A. The cost overruns identified in the Company's internal audit were primarily driven by costs related to Construction, Material, and Other (Army Corps MOA). These categories were either never anticipated in the original SCC approval application or were products of several years of delays centered on the permitting process.

Public Staff's Conclusion

Q. THE PUBLIC STAFF IS RECOMMENDING EXCLUSION OF THE MITIGATION COSTS BECAUSE THE COSTS DO NOT PROVIDE ANY ADDITIONAL BENEFIT, WHETHER IT BE AESTHETIC-, RELIABILITY-, OR POLITICALLY-, TO THE COMPANY'S NORTH CAROLINA RETAIL CUSTOMERS. HAS THE COMMISSION MADE ADJUSTMENTS IN A GENERAL RATE CASE BEFORE ON THE BASIS OF DEALING WITH EXPENSES RELATED TO LOCALIZED AESTHETIC AND POLITICAL CONCERNS?

A. Yes. As required by the Commission in the Company's 2012 General Rate Case, the Company is currently including E-1, Item 10 adjustments NC-38, 46, 69, 76, and 90 to eliminate the incremental costs associated with undergrounding three transmission lines in the northern Virginia area near the District of Columbia. *Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North* Carolina, Order Granting Rate Increase, December 21, 2012, Docket No. E-22, Sub 479.

(Sub 479 Order). The incremental costs to underground the three transmission lines were not deemed reasonable for recovery from North Carolina customers because the incremental costs to underground were incurred solely for the purpose of addressing aesthetic and political opposition in the Northern Virginia area where the lines were being constructed. *Id*. The Commission's explanation for excluding incremental undergrounding costs from recovery is as follows:

> In addition, the Commission is not persuaded that any significant benefits accrue to DNCP's North Carolina ratepayers due to the choice of the more costly installation of the transmission lines underground. Rather, the lines were undergrounded for purely aesthetic reasons arising out of local concerns. It would have been feasible and less costly to build all of the projects overhead. With respect to Pleasant View-Hamilton and Beaumeade-NIVO, the projects were approved for undergrounding as a result of Virginia legislation crafted as a result of local concerns regarding the aesthetics of overhead construction and with the assistance of the Company. As to the Garrisonville project, it is clear from the evidence that the overhead alternative met with substantial local opposition and concern because of aesthetics and other reasons unrelated to reliability, and was approved as an underground "pilot" project as a way to address those local concerns. (emphasis added).*Id*. at Finding of Fact 27.

Like the incremental undergrounding costs in the Sub 479 Order, the mitigation costs in the Skiffes Creek Project were incurred as a result of local concerns regarding aesthetics and other reasons unrelated to reliability. For that reason, I am recommending exclusion of the $105,611,862 (system) in mitigation costs in this case. I have provided this recommendation to Public Staff witness Sonja Johnson for inclusion in her testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DAVID M. WILLIAMSON

I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. My current responsibilities within the Electric Division include reviewing applications and making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service; reviewing applications and making recommendations on transmission proposals for certificates of environmental compatibility and public convenience and necessity; and also interpreting and applying utility service rules and regulations.

My primary responsibility within the Public Staff is reviewing and making recommendations on DSM/EE filings for initial program approval, program modifications, EM&V evaluations, and on-going program performance of DEC, DEP, and DENC's portfolio of programs. I filed affidavits and testimony in various DEC, DEP, and DENC's DSM/EE rider proceedings.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

In the Matter of		
Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF TOMMY C. WILLIAMSON, JR. PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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

A. My name is Tommy C. Williamson, Jr. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Public Utilities Engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Commission the Public Staff's position on Dominion Energy North Carolina's (DENC or Company) current Vegetation Management practices and its overall Quality of Service, as well as to discuss the Company's future plans for the grid located in its North Carolina service territory, as presented in the general rate case filed in Docket No. E-22, Sub 562, on March 29, 2019.

VEGETATION MANAGEMENT

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT VEGETATION MANAGEMENT ACTIVITIES.

A. The Company's Vegetation Management Plan is filed in Docket No. E-22, Sub 491, and no significant changes have been made since its April 1, 2014 filing. This plan established the parameters for the application of Company's Vegetation Management (VM) activities.

The Company's current Distribution Vegetation Management plan shows that on a system basis, the Company has approximately 33,000 miles of Right-of-Way (ROW) that it maintains and targets to trim approximately 7,000 miles annually. For its North Carolina territory, the Company has approximately 4,160 miles of ROW that it maintains and targets to trim approximately 800 miles annually.

The Company's current Transmission Vegetation Management plan, shows that on a system basis, the Company trims approximately 1,200-1,300 miles annually. For its North Carolina territory, the Company trims approximately 200-300 miles annually.

The Company does not categorize its territory into individual VM regions. As a result, the Company has established that all transmission circuit ROWs, regardless of the region VM characteristics, will be trimmed on a three to four year target cycle, not to exceed five years and all distribution circuit ROWs, regardless of the region VM characteristics, will be trimmed on a four to five year cycle.

Q. DOES THE PUBLIC STAFF HAVE ANY CONCERNS ABOUT THE COMPANY'S CURRENT VM PLAN?

A. No. The Public Staff believes the Company's current plan is reasonable in ensuring that all annual targeted trim miles are maintained within their planned trim cycle periods.

QUALITY OF SERVICE

Q. WHAT FACTORS DID YOU CONSIDER IN EVALUATING DENC'S OVERALL QUALITY OF SERVICE?

A. I reviewed the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) filed by DENC in Docket No. E-100, Sub 138A; informal complaints and inquiries from DENC customers received by the Public Staff Consumer Services Division; customer statements of position filed in this docket; and my individual interactions with DENC personnel and customers.

Q. WHAT HAS BEEN THE COMPANY'S SAIDI AND SAIFI PERFORMANCE SINCE 2009?

A. The SAIDI and SAIFI data filed by DENC in Docket No. E-100, Sub 138A represents its North Carolina service territory only. The data shows that for non-Major Event Days (non-MED), both SAIDI and SAIFI results have been stable, and slightly improving.

Q. HOW WOULD YOU SUMMARIZE THE INQUIRES MADE BY DENC CUSTOMERS THROUGH THE PUBLIC STAFF'S CONSUMER SERVICES DIVISION?

A. For the period January 1, 2018, through June 30, 2019, approximately 274 inquiries were received. The vast majority, 172 (64%), were requests to establish or modify payment arrangements. No other category of inquiry exceeded 4% of the total.

Q. WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S QUALITY OF SERVICE?

A. I conclude that the quality of service provided by DENC to its North Carolina retail customers is adequate at this time.

FUTURE GRID ACTIVITIES

Q. PLEASE DESCRIBE THE COMPANY'S RECENT AND PLANNED DISTRIBUTION AND TRANSMISSION EXPENDITURES.

A. According to responses to Public Staff data requests, the Company incurred the following expenditures during 2017 and 2018 in the categories of Distribution and Transmission:

	2017	2018
Distribution	$ 686,915,692	$ 721,256,143
Transmission	$ 477,707,332	$ 1,098,943,143
Total:	**$ 1,164,623,024**	**$ 1,820,199,286**

As discussed in Company witness McGuire's testimony, the Company plans to invest approximately $4.3 billion in new transmission system improvements over the next five years. Of that $4.3 billion amount, $200 million is specific to the Company's North Carolina territory.

Q. WHAT IS DRIVING THIS LEVEL OF GRID EXPENDITURE?

A. On March 9, 2018, the Virginia General Assembly enacted Senate Bill 966 (SB 966), more commonly known as the Grid Transformation and Security Act (GTSA)[1]. SB 966 addressed various categories of Virginia's electric investor-owned utilities' operations and planning for their electric grids, but more specifically addressed the definition and conditional acceptance of what are known as "Electric Distribution Grid Transformation projects," which are defined by law as:

> "a project associated with electric distribution infrastructure, including related data analytics equipment, that is designed to accommodate or facilitate the integration of utility-owned or customer-owned renewable electric generation resources with the utility's electric distribution grid or to otherwise enhance electric distribution grid reliability, electric distribution grid security, customer service, or energy efficiency and conservation, including advanced metering infrastructure; intelligent grid devices for real time system and asset information; automated control systems for electric distribution circuits and substations; communications networks for service meters; intelligent grid devices and other distribution equipment; distribution system hardening projects for circuits, other than the conversion of overhead tap lines to underground service, and substations designed to reduce service outages or service restoration times; physical security measures at key distribution substations; cyber security measures; energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability, or resiliency or provide temporary backup energy supply; electrical facilities and infrastructure necessary to support

[1] https://lis.virginia.gov/cgi-bin/legp604.exe?181+ful+CHAP0296+pdf

> electric vehicle charging systems; LED street light conversions; and new customer information platforms designed to provide improved customer access, greater service options, and expanded access to energy usage information."

Since the enactment of this bill, the Company has made various filings with both the Virginia State Corporation Commission (SCC) and this Commission regarding work that they intend to initiate in the respective service territories.

Q. WHAT SPECIFIC FILINGS HAS THE COMPANY MADE PERTAINING TO THIS NEW VIRGINIA LEGISLATION?

A. The Company has made several filings that relate to or have impacts regarding grid modernization activities.

On May 1, 2018, Dominion Energy Virginia (DEV) filed its Integrated Resource Plan (IRP) with the SCC.[2] Contemporaneously with the Virginia filing, DENC filed with this Commission its 2018 IRP and 2018 Smart Grid Plan for its North Carolina service territory in Docket No. E-100, Sub 157.

On July 24, 2018, DEV filed, in response to SB 966, its grid transformation projects proposal.[3] This proposal was a request for approval of certain projects to be initiated across its Virginia service territory for the first three years ("Phase 1") of a ten year plan. All of the items addressed in this filing

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[2] PUR-2018-00065.

[3] PUR-2018-00100.

were acknowledged in the Company's 2018 Smart Grid Plan filed with this Commission as being work that the Company intends in its North Carolina territory.

On December 7, 2018, the SCC rejected DEV's IRP, stating that it did not address the impacts of SB 966, and required DEV to re-run and re-file the corrected results of its 2018 IRP within 90 days.

On January 17, 2019, the SCC issued a final order on DEV's GTSA proposal.[4] Of the items initially proposed by DEV, only physical and cyber security upgrades were approved by the SCC.

DEV made its corrected 2018 IRP filing with the SCC on March 7, 2019; DENC made the same filing with this Commission on March 7, 2019, in Docket No. E-100, Sub 157.

On June 27, 2019, the SCC approved Dominion's refiled IRP with numerous additional reporting requirements in future IRP filings.[5]

Q. HAS DENC INITIATED ANY GRID WORK PURSUANT TO ITS 2018 SMART GRID PLAN IN NORTH CAROLINA?

A. The Company has initiated work on certain aspects of its 2018 Smart Grid Plan, but much of the grid work planned for in its North Carolina service

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[4] http://www.scc.virginia.gov/docketsearch/DOCS/4dv801!.PDF

[5] http://www.scc.virginia.gov/docketsearch/DOCS/4hfb01!.PDF

territory is predicated on the SCC's approval for similar work to begin in its Virginia service territory.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

TOMMY C. WILLIAMSON, JR.

I am an Engineer with the Public Staff's Electric Division. I graduated from North Carolina State University with a Bachelor in Science in Electrical Engineering. I have approximately 3 years of electrical distribution design and construction experience with Florida Power & Light Company. During that time I designed distribution circuits for overhead and underground services from the substation through to end users. This was inclusive of but not limited to; customer load analysis, feeder line loading analysis, facilities construction and installation. I then served 11 years as an Engineer with General Electric Company. In this role at General Electric Company, I represented the company with electrical design engineers, industrial and commercial end customers, and installation contractors to develop technical specifications for the procurement and use of electrical distribution equipment.

Since my employment with the Public Staff, I have reviewed customer quality of service complaints, transmission and distribution construction projects, vegetation management, small generator interconnection procedures, and filed testimony in general rate cases and the North Carolina Interconnection Procedures proceedings.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

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

Table of Contents

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. WHAT IS YOUR PRESENT OCCUPATION?

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

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have 20 years of experience consulting in regulatory rate cases and have addressed depreciation rate issues in numerous jurisdictions nationwide. I am a Certified Public Accountant licensed in the state of Illinois. I am a Certified Depreciation Professional through the Society of Depreciation Professionals. I received my Master of Arts degree in Accounting from the University of Illinois in Springfield. I received my Bachelor of Science degree in Mathematics from Illinois State University in Normal.

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

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

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the depreciation rates to be used by Dominion Energy North Carolina ("DENC" or "Company") in North Carolina.

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

A. Yes. On July 17-19, 2019, I participated in field visits of several different DENC facilities or project locations.[1] At each location, Company personnel and/or outside contractors discussed the facilities and ongoing projects with me.

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[1] I visited the Ladysmith CT Power Station, Bear Garden CC Power Station, Chesterfield Power Station, Roanoke Rapids Hydroelectric Power Station, North Anna Nuclear Power Station, Scott Solar Facility, and Chickahominy Substation. I also visited two sites where active aerial and underground projects were underway.

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

A. The annualized accrual based on December 31, 2016, investments using the Public Staff's proposed depreciation rates compared to DENC's proposed depreciation rates is summarized below:

Table 1: Comparison of Annual Depreciation Accrual Amount[2]

Functional Category	**12/31/16 Plant in Service**	**DENC Proposed Annual Accrual Amount**	**Public Staff Proposed Annual Accrual Amount**	**Public Staff Difference from DENC Proposed**
A	B	C	D	E=D-C
Steam Production Plant	6,606,171,190	197,233,046	197,233,046	0
Nuclear Production Plant	4,851,607,346	141,864,443	141,864,443	0
Hydraulic Production Plant	1,130,658,337	28,241,837	28,241,837	0
Combined Cycle Production Plant	3,464,692,816	103,407,081	103,407,081	0
Simple Cycle Production Plant	781,294,291	26,960,517	26,960,517	0
Solar Production Plant	142,759,660	6,427,607	5,275,434	(1,152,173)
Total Production Plant	*16,977,183,639*	*504,134,531*	*502,982,358*	*(1,152,173)*
Transmission Plant	7,786,018,104	196,844,678	189,272,772	(7,571,906)
Distribution Plant	10,483,298,547	348,844,508	331,783,174	(17,061,334)
General Plant	687,723,572	36,582,760	36,582,760	0
Total TDG Plant	*18,957,040,223*	*582,271,946*	*557,638,705*	*(24,633,241)*
Total Depreciable Plant	**35,934,223,862**	**1,086,406,477**	**1,060,621,063**	**(25,785,414)**

The Public Staff's proposed depreciation rates compared to DENC's proposed depreciation rates are summarized below:

[2] These amounts are based on December 31, 2016, investments and prior to any jurisdictional allocations.

Table 2: Comparison of Depreciation Accrual Rates

Functional Category	12/31/16 Plant in Service	DENC Proposed Depreciation Rate	Public Staff Proposed Depreciation Rate	Public Staff Difference from DENC Proposed
A	B	C	D	E=D-C
Steam Production Plant	6,606,171,190	2.99%	2.99%	0.00%
Nuclear Production Plant	4,851,607,346	2.92%	2.92%	0.00%
Hydraulic Production Plant	1,130,658,337	2.50%	2.50%	0.00%
Combined Cycle Production Plant	3,464,692,816	2.98%	2.98%	0.00%
Simple Cycle Production Plant	781,294,291	3.45%	3.45%	0.00%
Solar Production Plant	142,759,660	4.50%	3.70%	-0.81%
Total Production Plant	*16,977,183,639*	*2.97%*	*2.96%*	*-0.01%*
Transmission Plant	7,786,018,104	2.53%	2.43%	-0.10%
Distribution Plant	10,483,298,547	3.33%	3.16%	-0.16%
General Plant	687,723,572	5.32%	5.32%	0.00%
Total TDG Plant	*18,957,040,223*	*3.07%*	*2.94%*	*-0.13%*
Total Depreciable Plant	**35,934,223,862**	**3.02%**	**2.95%**	**-0.07%**

Q. PLEASE DESCRIBE YOUR EXHIBIT RMM-1.

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

II. Definition of Depreciation

Q. COULD YOU PLEASE PROVIDE THE DEFINITION OF DEPRECIATION?

A. Yes. The Federal Energy Regulatory Commission ("FERC") definitions contained in the FERC Uniform System of Accounts (18 CFR part 101 ("FERC USOA")) state:

> 12. *Depreciation,* as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[3]

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

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

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

A. The remaining life depreciation rate formula is:

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

[3] FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. (18 CFR part 101).
[4] FERC USOA Definition 37 (18 CFR part 101).

In the formula above, the book reserve percent is the actual reserve on the Company's books divided by the actual plant in service investment on the Company's books at the time of the Depreciation Study.

The Depreciation Study estimates the projected average service life of the assets, the retirement pattern of those assets, and the cost of removing or retiring those assets, less any expected salvage from the sale, scrap, insurance, reimbursements, etc. of those assets. These estimates are referred to as depreciation parameters.

The projected average service life and retirement pattern (survivor curve) are the two parameters from the Depreciation Study that calculate the average remaining life.

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

III. Solar Production Plant Probable Retirement Year

Q. HAS DENC'S ASSUMED RETIREMENT YEAR FOR SOLAR PRODUCTION FACILITIES CHANGED SINCE THE FILING OF THE 2016 DEPRECIATION STUDY?

A. Yes. In the filed 2016 Depreciation Study, DENC proposed a 2041 probable retirement year for Woodland Solar, Whitehouse Solar, and Scott Solar.[5] However, in response to discovery DENC provided "updated depreciation schedules" that used the year 2051 as the probable retirement year for Woodland Solar, Whitehouse Solar, and Scott Solar.[6]

DENC's response to Public Staff Data Request No. 111-1 states:

> "The updated depreciation schedules utilize 06-2051 as the probable retirement date for the Woodland, Whitehouse, and Scott solar facilities."[7]

The Public Staff recommended depreciation rates for the Woodland Solar, Whitehouse Solar, and Scott Solar in Exhibit RMM-1 are based on DENC's updated depreciation schedules.

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[5] Page VI-13 of 2016 Depreciation Study Related to Electric Generation Plant filed on August 23, 2017 in Docket E-22, Sub 493.
[6] DENC Response to Public Staff Data Request No. 111-1, attached as Exhibit RMM-2.
[7] DENC Response to Public Staff Data Request No. 111-1, attached as Exhibit RMM-2.

IV. Mass Property Future Net Salvage

Q. DID YOU REVIEW THE FUTURE NET SALVAGE FOR MASS PROPERTY ACCOUNTS?

A. Yes. For Account 353, Transmission-Station Equipment, Account 355, Transmission-Poles and Fixtures, Account 356, Overhead Conductors and Devices, Account 362, Distribution-Station Equipment, Account 364, Distribution-Poles, Towers, and Fixtures, Account 365, Distribution-Overhead Conductors and Devices, Account 367, Distribution-Underground Conductors and Devices, Account 369.10, Services-Overhead, and Account 369.20, Services-Underground, I recommend future net salvage ("FNS") percents that differ from DENC's proposal as shown in Table 3 below:

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

Account	DENC 2005 Depreciation Study Proposed FNS%[8]	DENC 2016 Depreciation Study Proposed FNS%[9]	Public Staff Proposed FNS%
353, Transmission-Station Equipment	-10%	-15%	-10%
355, Transmission-Poles and Fixtures	-30%	-40%	-35%
356, Overhead Conductors and Devices	-20%	-30%	-25%
362, Distribution-Station Equipment	-10%	-20%	-15%
364, Distribution-Poles, Towers, and Fixtures	-40%	-50%	-45%
365, Distribution-Overhead Conductors and Devices	-25%	-35%	-30%
367, Distribution-Underground Conductors and Devices	-20%	-25%	-20%
369.10, Services-Overhead	-35%	-50%	-45%
369.20, Services-Underground	-35%	-50%	-35%

Q. PLEASE EXPLAIN WHAT IS MEANT BY NET SALVAGE.

A. NARUC's *Public Utilities Depreciation Practices* defines net salvage as "the gross salvage for the property retired less its cost of

[8] 2005 Depreciation Study Related to Electric Transmission, Distribution, and General Plant filed August 27, 2010 in Docket No. E-22, Sub 459.
[9] 2016 Depreciation Study Related to Electric Transmission, Distribution, and General Plant filed on August 23, 2017 in Docket E-22, Sub 493.

removal."[10] Gross salvage is defined as "the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property."[11] Cost of removal is defined as "the costs incurred in connection with the retirement from service and the disposition of depreciable plant. Cost of removal may be incurred for plant that is retired in place."[12]

Q. WHY IS THE ESTIMATED FUTURE NET SALVAGE SHOWN AS A PERCENT IN THE TABLE ABOVE?

A. The depreciation rates are calculated in the depreciation study based on the per book amounts and experience as of December 31, 2016. The depreciation rates resulting from the depreciation study are then applied to the investment amounts as of the date of the test year in the rate proceeding. Since the depreciation study produces a depreciation rate, the future net salvage is included in the depreciation rate formula as a percent of the investment as of December 31, 2016.

[10] Page 322, *Public Utilities Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[11] Page 320, *Public Utilities Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[12] Page 317, *Public Utilities Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

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

A. Positive net salvage results in a lower depreciation rate, all other things being equal. Negative net salvage results in a higher depreciation rate, all other things being equal.

As stated in NARUC's *Public Utilities Depreciation Practices*:

> "Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage."[13]

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

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

A. Yes. I have compared the future net salvage costs included in DENC's proposed depreciation rates and the actual net salvage

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[13] Page 18, *Public Utilities Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

costs incurred by DENC on average over the recent five-year period at the functional level.

Q. PLEASE EXPLAIN WHY YOU DID THE COMPARISON ON THE FUNCTIONAL LEVEL INSTEAD OF AT THE ACCOUNT LEVEL.

A. In response to discovery, DENC stated that the actual net salvage is "only recorded at the functional level by year", so I was not able to perform a comparison by account.[14]

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

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

[14] DENC Response to Public Staff Data Request 71-9, attached as Exhibit RMM-3.

Table 4: Comparison of Actually Incurred Net Salvage and Net Salvage in Proposed Depreciation Rates as of December 31, 2016 Investments[15]

Description		Average Annual Net Salvage Actually Incurred[16]	Net Salvage Recovery Included in DENC's Proposed Depr Rates	DENC Proposed / Actually Incurred	Net Salvage Recovery Included in Staff's Proposed Depr Rates	Staff Proposed / Actually Incurred
		A	B	C=B/A	D	E=D/A
Transmission Plant						
352.00	Structures & Improvements		371,656		371,656	
353.00	*Station Equipment*		*13,728,744*		*9,081,602*	
354.00	Towers and Fixtures		6,276,726		6,276,726	
355.00	*Poles and Fixtures*		*9,249,303*		*8,048,573*	
356.00	*Overhead Conductors & Devices*		*4,531,007*		*3,749,320*	
357.00	Underground Conduit		0		0	
358.00	Underground Conductors & Devices		374,621		374,621	
359.00	Roads and Trails		0		0	
Total Transmission Plant		**13,097,103**	**34,532,057**	**2.6**	**27,902,498**	**2.1**
Distribution Plant						
361.00	Structures & Improvements		66,241		66,241	
362.00	*Station Equipment*		*4,409,984*		*3,266,968*	
364.00	*Poles, Towers, and Fixtures*		*9,587,013*		*8,507,012*	
365.00	*Overhead Conductors & Devices*		*12,432,581*		*10,537,385*	
366.00	Underground Conduit		304,623		304,623	
367.00	*Underground Conductors & Devices*		*19,239,902*		*15,045,157*	
368.00	Line Transformers		6,000,900		6,000,900	
369.10	*Services-Overhead*		*3,037,279*		*2,683,876*	
369.20	*Services-Underground*		*12,179,497*		*8,017,454*	
370.00	Meters		516,184		516,184	
370.20	AMI Meters		175,029		175,029	
371.00	Installations on Customers' Premises		0		0	
371.20	Air Conditioning Cycling Program		0		0	
373.00	Street Lighting and Signal Systems		2,128,153		2,128,153	
Total Distribution Plant		**36,088,545**	**70,077,386**	**1.9**	**57,248,982**	**1.6**

[15] This table is based on 12/31/2016 investment levels used in the Depreciation Study.
[16] Five-year average net salvage actually incurred calculated from Excel file "Attachment Public Staff Set 71-3 DVP - 2016 - TDG - Simulated Net Salvage" provided by DENC in response to discovery.

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

A. No, which is supported by the fact that my proposed future net salvage accrual amounts are not equal to the average annual historical amount as shown in Table 4 above. My proposed future net salvage accrual amounts are in current dollars that consider DENC's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY LESS ACCELERATED FUTURE NET SALVAGE AMOUNTS.

A. Using Distribution Plant for discussion, as shown on Table 4 above, DENC actually incurred $36,088,545 on average per year, however, DENC proposes to collect an $70,077,386 net salvage annual accrual.[17] The annual accrual amount is an expense to be recovered from ratepayers in customer charges.[18]

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[17] Annual accrual amount based on investments as of 12/31/16.
[18] The exact amount to be recovered from ratepayers will vary when calculated on investments other than the investment as of 12/31/16.

For Distribution Plant, the annual accrual DENC is proposing for net salvage is about 1.9 times the average annual amount DENC has actually incurred for net salvage.

Under my recommendation, the annual accrual for Distribution Plant net salvage would still be $57,248,982, which is about 1.6 times the average annual amount DENC actually incurred.[19] My recommendation, which is about 1.6 times the current average annual amount, provides recovery of the expected cost of removal in the near future and builds the reserve for future cost of removal associated with future retirements.

Table 4 above shows a similar comparison for Transmission Plant.

Q. DID DENC ALSO CONSIDER THE HISTORICAL NET SALVAGE IN THE DEPRECIATION STUDY NET SALVAGE ANALYSIS?

A. Yes. The DENC depreciation study included the analysis of the historic data of incurred net salvage and related retirements. Regarding historic net salvage, DENC's depreciation study states:

> "The estimates of net salvage by account were based in part on historical data compiled through 2016. Cost of removal and salvage were expressed as percents of

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[19] Annual accrual amount based on investments as of 12/31/16. I am not recommending or implying a change from the "accrual" basis to the "cash" basis for the recovery of future net salvage costs. In other words, I am not recommending or implying that the depreciation accrual no longer be credited to the Accumulated Provision for Depreciation or that the net salvage costs be "expensed".

> the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration."[20]

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

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

> "Salvage ratios are a function of inflation."[21]

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

> "One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels."[22]

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[20] Page IV-2 of the 2016 Depreciation Study Related to Electric Transmission, Distribution, and General Plant filed on August 23, 2017 in Docket E-22, Sub 493.
[21] Page 267, Wolf, Frank K. and W. Chester Fitch, *Depreciation Systems* Iowa State University Press, 1994.
[22] Page 53, Wolf, Frank K. and W. Chester Fitch, *Depreciation Systems* Iowa State University Press, 1994.

The calculation of the historic net salvage ratio includes the impact of high historic inflation rates, since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic dollars. In other words, due to inflation the amounts in numerator and denominator of the net salvage ratio are at different price levels.

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

A. Yes. NARUC's *Public Utilities Depreciation Practices*, regarding inflation states:

> "The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices."[23]

NARUC concludes that careful consideration should be given to the net salvage estimate stating:

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[23] Page 19, *Public Utilities Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

> "Cost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate."[24]

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

A. Yes. I am aware of several jurisdictions that have adopted future net salvage percents that recognize the inflated dollars included in the historic net salvage ratio. The Commissions in Connecticut,[25] District

[24] Page 19, *Public Utilities Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

[25] Connecticut Docket No. 16-06-04. In the December 14, 2016 Commission "Decision" the Commission accepted net salvage depreciation rates that produced "an annual accrual that is 1.2 times the annual incurred distribution plant net salvage costs" stating that the "distribution net salvage depreciation rates still comfortably cover the actual incurred net salvage costs." (p. 46 of the December 14, 2016 "Decision").

of Columbia,[26] Maryland,[27] New Jersey,[28] and Pennsylvania[29] have adopted methods of setting the future net salvage percent that recognizes the time value of cost of removal due to inflation.

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[26] Formal Case No. 1076, paragraph 252 of Order No. 15710. In Order No. 15710, the Public Service Commission of the District of Columbia stated: "Fairness and equity require that the Commission adopt a methodology that, to the extent possible, balances the interest of current and future ratepayers." And went on to state: "Pepco should not be allowed to charge current customers for future inflation, nor should Pepco be allowed to charge current customers in higher-value current dollars for a future cost of removal amount that is calculated in lower-value future dollars."

[27] Maryland Case No. 9092. In Order No. 81517, the Commission stated: "The Commission has carefully reviewed the record and finds that the Present Value Method should be adopted for the recovery of removal costs. The Straight Line Method recovers the same annual cost in nominal dollars from ratepayers today as it does at the time plant is removed from service. However, a dollar is worth substantially more today than it will be 20 to 40 years from now. Consequently, today's ratepayers would pay more in "real" dollars under the Straight Line Method for the recovery costs of the plant they consume than would future ratepayers when net salvage is negative, as everyone projects." (page 30 of Order No. 81517).

[28] New Jersey Docket No. ER02080506. In the May 17, 2004 Final Order, the Board found: "As a result of this data and the underlying concept of FASB 143 as discussed in this matter, the Board FINDS it appropriate to revisit the concept of including estimated future net salvage in current depreciation rates. The Board HEREBY FINDS the recommendation of the Ratepayer Advocate and Staff to exclude estimated net salvage from depreciation rates to be appropriate. The Board FURTHER FINDS that the Ratepayer Advocate and Staff's proposed utilization of a five-year average of actual salvage expense in depreciation expense is reasonable as it more closely aligns the amount recovered in base rates with the historical level of expenses incurred. The Board concurs with Staff that the ten-year window of actual experience rather than the five-year rolling average proposed by the Ratepayer Advocate is appropriate." (page 129-130 of the May 14, 2004 Final Order)

[29] Pennsylvania, Superior Court of Pennsylvania in Penn Sheraton Hotel v. Pennsylvania Public Utility Commission, 184 A.2d 324, 329 (Pa. Super. Ct. 1962). The court found: "Negative salvage attributed to existing plant is purely prospective; it is a cost which has not yet been incurred; it is uncertain when and if it will be incurred; and it is not a part of the original cost of construction of the facilities when first devoted to public service. To permit the recovery of prospective negative salvage is to permit the recovery of a total amount in excess of the original cost of construction prior to the actual expenditure of those costs and, in our opinion, represents the recovery of something in the nature of a future reproduction cost. The established law in this Commonwealth does not permit the recovery by annual depreciation of any such prospective excess. It is therefore the prospective nature of future negative salvage that prevents it from being considered either in accrued depreciation or in the allowance for annual depreciation; they must have a consistent basis under our law. Although prospective negative salvage is not entitled to consideration, the negative salvage actually incurred by the utility either upon the actual retirement of a property without replacement or upon the replacement of an item of property is of course entitled to consideration in a rate proceeding. It is then no longer prospective but actual. If the utility retires and removes a property without replacing it or replaces it after removal and incurs actual negative salvage in doing so, the expenditure should be capitalized and amortized by some reasonable method and for and over a reasonable length of time."

Q. ARE YOUR PROPOSED FUTURE NET SALVAGE PERCENTS BASED ONLY ON THE HISTORICAL ANALYSIS DISCUSSED ABOVE?

A. No. As is shown in Table 4 above, I propose less accelerated future net salvage amounts than DENC's proposal.

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

V. Conclusion

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

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

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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

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

Education

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

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

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

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

Relevant Coursework:

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

Current Position: Consultant at William Dunkel and Associates

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

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

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2019	Utah	Public Service Commission of Utah	19-057-03	Dominion Energy Utah	Natural Gas Depreciation Issues	Division of Public Utilities
2019	Kansas	Kansas Corporation Commission	19-EPDE-223-RTS	Empire District Electric Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2019	Arizona	Arizona Corporation Commission	T-03214A-17-0305	Citizens Telecommunications Company	Arizona Universal Service Fund	The Utilities Division Staff Arizona Corporation Commission
2018	Kansas	Kansas Corporation Commission	18-KGSG-560-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2018	Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4800	SUEZ Water	Water Depreciation Issues	Division of Public Utilities and Carriers
2018	Rhode Island	Rhode Island and Providence Plantations Public Utilities Commission	4770	Narragansett Electric Company	Electric & Natural Gas Depreciation Issues	Division of Public Utilities and Carriers
2018	North Carolina	North Carolina Utilities Commission	E-7, SUB 1146	Duke Energy Carolinas, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	DC	District of Columbia Public Service Commission	FC1150	Potomac Electric Power Company	Electric Depreciation Issues	District of Columbia Public Service Commission
2017	North Carolina	North Carolina Utilities Commission	E-2, SUB 1142	Duke Energy Progress, LLC	Electric Depreciation Issues	Public Staff - North Carolina Utilities Commission
2017	Washington	Washington Utilities & Transportation Commission	UE-170033 & UG-170034	Puget Sound Energy	Electric & Natural Gas Depreciation Issues	Washington State Office of the Attorney General, Public Council Unit
2017	Florida	Florida Public Service Commission	160186-EI & 160170-EI	Gulf Power Company	Electric Depreciation Issues	The Citizens of the State of Florida

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2016	Kansas	Kansas Corporation Commission	16-KGSG-491-RTS	Kansas Gas Service	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2016	DC	District of Columbia Public Service Commission	FC1139	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2016	Arizona	Arizona Corporation Commission	E-01933A-15-0239 & E-01933A-15-0322	Tucson Electric Power Company	Electric Depreciation Issues	The Utilities Division Staff Arizona Corporation Commission
2016	Georgia	Georgia Public Service Commission	40161	Georgia Power Company	Addressed Depreciation Issues	Georgia Public Service Commission Public Interest Advocacy Staff
2016	DC	District of Columbia Public Service Commission	FC1137	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2015	Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Amos Energy	Natural Gas Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-TWVT-213-AUD	Twin Valley Telephone, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power & Light Company	Electric Depreciation Issues	Kansas Corporation Commission Staff
2015	Kansas	Kansas Corporation Commission	15-MRGT-097-AUD	Moundridge Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-S&TT-525-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2014	Kansas	Kansas Corporation Commission	14-WTCT-142-KSF	Wamego Telecommunications Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2013	Kansas	Kansas Corporation Commission	13-PLTT-678-KSF	Peoples Telecommunications, LLC	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	New Jersey	State of New Jersey Board of Public Utilities	BPU ER12121071	Atlantic City Electric Company	Electric Depreciation Issues	New Jersey Rate Counsel
2013	Kansas	Kansas Corporation Commission	13-JBNT-437-KSF	J.B.N. Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	Kansas	Kansas Corporation Commission	13-ZENT-065-AUD	Zenda Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2013	DC	District of Columbia Public Service Commission	FC1103	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2012	Kansas	Kansas Corporation Commission	12-LHPT-875-AUD	LaHarpe Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-GRHT-633-KSF	Gorham Telephone Company	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2012	Kansas	Kansas Corporation Commission	12-S&TT-234-KSF	S&T Telephone Cooperative Association, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2011	DC	District of Columbia Public Service Commission	FC1093	Washington Gas & Light	Depreciation Issues	District of Columbia Public Service Commission
2011	Kansas	Kansas Corporation Commission	11-CNHT-659-KSF	Cunningham Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2011	Kansas	Kansas Corporation Commission	11-PNRT-315-KSF	Pioneer Telephone Association	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2010	Kansas	Kansas Corporation Commission	10-HVDT-288-KSF	Haviland Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2009	Kansas	Kansas Corporation Commission	09-BLVT-913-KSF	Blue Valley Tele-Communications, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2009	DC	District of Columbia Public Service Commission	FC1076	Potomac Electric Power Company	Depreciation Issues	District of Columbia Public Service Commission
2008	Kansas	Kansas Corporation Commission	09-MTLT-091-KSF	Mutual Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	08-MRGT-221-KSF	Moundridge Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-PLTT-1289-AUD	Peoples Telecommunications, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	07-MDTT-195-AUD	Madison Telephone, LLC	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2007	Kansas	Kansas Corporation Commission	06-RNBT-1322-AUD	Rainbow Telecommunications Assn., Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-WCTC-1020-AUD	Wamego Telecommunications Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2006	Kansas	Kansas Corporation Commission	06-H&BT-1007-AUD	H&B Communications, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2006	Kansas	Kansas Corporation Commission	06-ELKT-365-AUD	Elkhart Telephone Company, Inc.	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-SCNT-1048-AUD	South Central Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Utah	Public Service Commission of Utah	05-2302-01	Carbon/Emery Telecom, Inc.	Cost Study Issues & Depreciation Issues	Utah Committee of Consumer Services
2005	Kansas	Kansas Corporation Commission	05-TTHT-895-AUD	Totah Communications, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Maine	Public Utilities Commission of the State of Maine	2005-155	Verizon	Depreciation Issues	Office of Public Advocate
2005	Kansas	Kansas Corporation Commission	05-TRCT-607-KSF	Tri-County Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-CNHT-020-AUD	Cunningham Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2005	Kansas	Kansas Corporation Commission	05-KOKT-060-AUD	KanOkla Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-UTAT-690-AUD	United Telephone Association, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	04-CGTT-679-RTS	Council Grove Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2004	Kansas	Kansas Corporation Commission	04-GNBT-130-AUD	Golden Belt Telephone Association	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2004	Kansas	Kansas Corporation Commission	03-TWVT-1031-AUD	Twin Valley Telephone, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-HVDT-664-RTS	Haviland Telephone Company	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-WHST-503-AUD	Wheat State Telephone Company, Inc.	Cost Study Issues & Support Fund Adjustments	Kansas Corporation Commission Staff
2003	Kansas	Kansas Corporation Commission	03-S&AT-160-AUD	S&A Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-JBNT-846-AUD	JBN Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-S&TT-390-AUD	S&T Telephone Cooperative Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2002	Kansas	Kansas Corporation Commission	02-BLVT-377-AUD	Blue Valley Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-PNRT-929-AUD	Pioneer Telephone Association, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-BSST-878-AUD	Bluestem Telephone Company	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SFLT-879-AUD	Sunflower Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-CRKT-713-AUD	Craw-Kan Telephone Cooperative, Inc.	Cost Study Issues	Kansas Corporation Commission Staff

Previous Experience

Year	State	Commission	Docket	Company	Description	On Behalf of
2001	Kansas	Kansas Corporation Commission	11-RNBT-608-KSF	Rainbow Telecommunications Association	Cost Study Issues, Allocation of FTTH Equipment, & Support Fund Adjustments	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-SNKT-544-AUD	Southern Kansas Telephone Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2001	Kansas	Kansas Corporation Commission	01-RRLT-518-KSF	Rural Telephone Service Company, Inc.	Cost Study Issues	Kansas Corporation Commission Staff
2000	Illinois	Illinois Commerce Commission	98-0252	Ameritech	Cost Study Issues	Government and Consumer Intervenors

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

In the Matter of Application of Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	TESTIMONY OF JEFF T. THOMAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

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

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

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present to the Commission the Public Staff's position on whether Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company), should be permitted to recover the costs associated with specific capital investments at its coal-fired Mount Storm Power Station location in Grant County, West Virginia. Specifically, my testimony discusses DENC's August 5, 2019, Supplemental Filing accounting adjustment 5 (SUPP-5), in which DENC proposed for the first time a regulatory asset associated with the project impairment of an abandoned Coal-Yard Fuel Flexibility Project (CYFFP) at Mount Storm. In this case, DENC is seeking recovery of all CYFFP costs incurred to date, approximately $62 million (system basis).

The remainder of my testimony is organized as follows:

- An overview of Mount Storm and the CYFFP, including a project timeline.
- A summary of the proposed adjustment.
- The Public Staff's concerns with the project and associated cost recovery.
- The Public Staff's recommendations.

Overview of Mount Storm and the CYFFP

Q. PLEASE PROVIDE AN OVERVIEW OF THE MOUNT STORM CYFFP.

A. Mount Storm Power Station is a 1,629 megawatt (MW) three-unit coal-fired generating facility located in Grant County, West Virginia. Unit 1 began commercial operation in 1965. Mount Storm is located near a coal mine, allowing it to receive substantial coal deliveries by truck, which historically resulted in reduced costs of coal transportation for deliveries to the plant. In 2011, the Mount Storm facility could only receive approximately 40% of its coal via rail due to rail design limitations. In addition, according to DENC, Mount Storm's traditional source of fuel (local coal that could be trucked by Metikki, the dominant local supplier) was either "being depleted or becoming very expensive to mine due to deteriorating geologic and quality conditions."[1] DENC contends that its contract with Metikki was in danger of not being renewed after 2013 due to these factors.[2]

DENC undertook the CYFFP in order to expand the capability of Mount Storm to receive coal by rail in order to increase competition between rail and trucking companies, with the ultimate goal of reaching 100% rail capability in the event of problems with truck deliveries. Due to quality differences between truck and rail delivered coal and the emissions limits established by Mount Storm air permits, as well as the specific boiler design characteristics of the Mount Storm units, coal blending facilities were required. DENC originally planned to construct four coal stacking tubes and a dry coal storage enclosure, and to make significant changes to its rail system, along with supplementary fire suppression systems. The Company's actual project expenditures are summarized in Table 1 below.

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[1] Attached to my testimony is an April 12, 2019 "Project Evaluation Summary" (PES), provided to the Public Staff on August 1, 2019, submitted as Exhibit 1. See Exhibit 1, slide 2.

[2] *Id.*

[BEGIN CONFIDENTIAL]

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

[END CONFIDENTIAL]

Q. WHAT WAS THE ORIGINAL BUDGET AND TIMELINE FOR THE PROJECT?

A. Based upon high level estimates from 2012, the original budget for the project was approximately $35 million, with an expected operational date of 2014.

Q. DID THIS BUDGET AND TIMELINE CHANGE?

A. Yes. While the Public Staff understands that project budgets and timelines, particularly in the preliminary stages, can change as a project progresses, the CYFFP budget underwent significant increases in both budget and expected operational date from 2011 through 2019, with a final 2019 estimate of $211 million and a completion date of 2021.[3]

Q. PLEASE DESCRIBE THE CHANGES TO THE BUDGET AND THEIR STATED JUSTIFICATION.

A. DENC has provided high-level justification for the budget increases. These justifications are summarized in Table 2 below.

Table 2: CYFFP Budget Increases by Year[4]

Year	Budget ($M)	Budget Increase ($M)	DENC Explanation
2011	35		
2012	35	0	
2013	70	35	
2014	116	46	Extensive design additions
2015	146	30	Design changes and contractor bids exceeding estimates
2016	184	38	General contractor bids significantly higher than estimates; increased fire protection scope; escalation on deferred/delayed work
2017	184	0	Site activities closed out
2018	184	0	Partial project being evaluated
2019	211	27	Contractor bids received

In 2017, site activities were closed out, and DENC discussed internally the possibly of canceling the project. In 2018, DENC began exploring "partial

[3] See Exhibit 1, slide 10.

[4] See Exhibit 1.

project" options based on a reduced project scope,[5] as the full project NPV was now negative. The project was cancelled on May 8, 2019.

Q. WHAT ANALYSES DID THE COMPANY PERFORM ESTIMATING THE PROJECT BENEFITS?

A. In 2013, DENC's Fossil and Hydro generation fuel strategy team made a recommendation to management to move forward with the project based upon an estimate that a failure to invest in this project would result in "predicted replacement power costs of $14 million to $42 million per year,"[6] because Mount Storm would not be able to run at full capacity if the project were not pursued. The Public Staff has requested supporting documentation and support for these figures and is still attempting to understand the actual generation limitations placed upon Mount Storm due to coal delivery contracts. It is not readily apparent from currently available data that Mount Storm faced any constraints on its generation capacity due to limitations on coal supply. A summary of Mount Storm's capacity factor is displayed in Figure 1 below, indicating a steady reduction beginning in 2016. What is known, however, is that DENC deferred maintenance on Mount Storm during this time, which may have negatively impacted its availability factor and, as a result, could have decreased its capacity factor.

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[5] The reduced project scope removed the dry covered storage enclosure, two coal stacking tubes, and several conveyor systems, along with other modifications.

[6] Exhibit 1, slide 4.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

DENC performed a Financial Analysis in 2012 that calculated a **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] [END CONFIDENTIAL] Our concerns with these price estimates and the actual contract price are addressed in more detail later in my testimony.

The Company also performed a CYFFP cost-benefit analysis (CBA) between the base case and the blending case (assuming project completion), performed in 2014 (2014 CBA). The 2014 CBA explored both a high volume case **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and a low volume case **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Project benefits were quantified by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Based upon the net present value (NPV) of the annual savings and the NPV of the revenue requirement, the project was determined to have a positive

NPV, with a payback period of between 3.5 to 6.5 years.[7] **[BEGIN CONFIDENTIAL]** [redacted]

[END CONFIDENTIAL]

I will discuss the Public Staff's concerns with these analyses in more detail below.

Q. WHY DID DENC CANCEL THE PROJECT?

A. According to DENC witness Paul M. McLeod, changing market conditions have resulted in decreased power prices, which have led to lower capacity factors and coal consumption at Mount Storm. In addition, witness McLeod states that, at the same time, prices from general contractors have steadily increased, "making the project uneconomical to complete."[8] At the time of the project cancellation, DENC estimates that the project was 30%

[7] See Exhibit 1, slide 5.

[8] See Supplemental Direct Testimony of Paul M. McLeod at 22.

complete on a cost basis, and site construction work was approximately 5% complete.

Q. HAS THE PUBLIC STAFF REVIEWED ANY OTHER COST-BENEFIT ANALYSES OF THE CYFFP?

A. Yes. As discussed *supra*, DENC provided a 2012 Financial Analysis, which looked at the possible benefits of the project to determine the **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This 2012 Financial Analysis recommended delaying the project to continue to evaluate market conditions and the renegotiated Metikki contract.[9]

DENC also provided a qualitative 2013 Strategic Fuel Delivery/Blending Plan Recommendation, which discussed **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

[9] See Exhibit 1, slide 3.

However, after 2014, the only CBAs provided are from 2017, which evaluated reduced scope options against project cancellation and project completion.[10]

Proposed DENC Adjustment

Q. PLEASE DESCRIBE THE PROPOSED ADJUSTMENT.

A. DENC is seeking the recovery of all CYFFP costs incurred to date, which are reflected as an increase to "Other Operating & Maintenance Expenses".[11] System costs to date are approximately $62,364,000, incurred between 2011 and 2019. DENC proposes to amortize the North Carolina retail portion[12] over three years, yielding a North Carolina retail regulatory asset amortization adjustment of $1,029,000. This proposed adjustment included in DENC's supplemental filing is the first time the Public Staff became aware of this project and has had an opportunity to review the costs and underlying analyses.

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S INVESTIGATION OF THIS ADJUSTMENT.

A. On July 24, 2019, during a call with the Public Staff to discuss DENC's expected supplemental filing, several supplemental accounting adjustments

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[10] See Exhibit 1, slides 5-8.

[11] See Supplemental Testimony of Paul McLeod, Exhibit PMM-1, Schedule 1, page 1, line 9, column 4 and Exhibit PMM-1, Schedule 3, page 2.

[12] This adjustment was allocated to North Carolina retail customers using Allocation Factor 1 (Production), 4.9507%.

were identified. At the time, no technical details were made available to the Public Staff.

On July 25, 2019, DENC accounting personnel held a conference call with the Public Staff to discuss the Mount Storm accounting adjustment, among several other accounting adjustments. DENC provided a draft adjustment form, but no technical details were made available.

On July 26, 2019, the Public Staff sent a written data request to DENC seeking additional high level and technical details. The response to this data request was received on August 6, 2019.

On August 1, 2019, DENC technical personnel held a conference call with the Public Staff. A presentation was provided with a timeline of each years' expenditures, and DENC answered questions from the Public Staff. This Project Evaluation Summary (PES) presentation is attached as Thomas Exhibit 1.

On August 2, 2019, the Public Staff sent a detailed follow up data request to DENC seeking specific information regarding project contracts, decision making processes, the significant budget increases, and other issues. A partial response was received August 14, 2019.

On August 5, 2019, DENC filed its Supplemental Direct Testimony and Exhibits, which contained no additional technical information regarding the Mount Storm CYFFP beyond that provided on the July 26 conference call.

Q. ARE THERE OTHER COSTS ASSOCIATED WITH THIS PROJECT THAT ARE NOT INCLUDED IN THE ADJUSTMENT?

A. Yes. DENC estimates that in addition to the $62 million write off, there is an additional approximately $14 million in system expenses associated with project demolition and deferred maintenance and repairs.[13] It is my understanding that DENC will seek recovery of these costs in a future rate case once the costs have been incurred. Putting aside for now the Public Staff's concerns about the deleterious impact of deferred maintenance on Mount Storm and other Company-owned coal plants,[14] because DENC is not seeking recovery of these estimated costs in this proceeding, the Public Staff is not making any recommendations regarding this deferred maintenance and associated costs at this time, but reserves its right to raise this issue in a future proceeding.

Public Staff Concerns

Q. DOES THE PUBLIC STAFF HAVE ANY CONCERNS ABOUT THE PROJECT?

A. Yes. First, estimates of replacement power costs calculated in 2013 associated with not completing the project[15] appear to have been based

[13] See Exhibit 1, slide 10.

[14] The Public Staff notes that since 2014, Mount Storm's Equivalent Availability Factor (EAF) has fallen from 80% (average of all units) to 67.5%. During the same time period, the national average, as calculated by NERC, has fallen from 81.4% to 77.0%.

[15] See Exhibit 1, slide 4.

upon **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Next, DENC's concerns in 2011 about the Metikki contract not being renewed in 2013 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

It also appears that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

In addition, presentations reviewed by the Public Staff indicate that the maximum amount of coal available from rail **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

I am also concerned that significant commitments and associated expenditures with the project appear to have been made prior to completion of detailed engineering work,[16] and relatively little cost-benefit analyses were performed until 2014, three years and $2.1 million into the project. A 2012 financial analysis recommended delaying the rail project to continue

[16] Information provided as part of discovery indicated that the engineering contractor had reached a 21% complete milestone on January 1, 2015.

to evaluate market conditions. A 2013 Strategic Fuel Delivery/Blending Plan recommended **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The 2014 CBA also does not appear to consider the impact to flexibility at Mount Storm as a result of the CYFFP construction activity, which reduced the nominal capacity of the fuel yard from 850,000 tons to 600,000 tons.

Q. PLEASE EXPAND UPON YOUR CONCERNS WITH THE 2014 COST BENEFIT ANALYSIS.

A. I am concerned that the 2014 CBA was not sufficient to justify proceeding with the estimated level of investment in this project, as it: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

For example, I reviewed the fuel price forecasts used in this analysis and compared them to the fuel price forecasts used in DENC's past IRPs. Figure 2 below shows that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]** Figure 3 below shows the Metikki coal price used in the 2014 CBA with the coal price forecasts and actual coal price data that DENC had available in 2014.

[17] See Docket Nos. E-100 Sub 137 (PS DR 1-16) and E-100 Sub 141 (PS DR 1-13).

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

In addition, DENC was well aware of the effects of the dramatic increase in the production of shale gas, as natural gas prices had been falling since 2010. Also, it appears that DENC did not assume any shift towards natural gas resources in its 2014 CBA, despite significant planned natural gas generation included in its IRPs since 2012.[18] **[BEGIN CONFIDENTIAL]** [redacted]

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[18] The 1,337 MW Warren County Power Station was included in the 2012 IRP. The 1,368 MW Brunswick County Power Station was included in the 2013 IRP Update. The 1,585 MW Greensville County Power Station was included in the 2016 IRP.

The 2014 IRP also identified that the need for additional natural gas pipelines continue to "increase as coal generation units retire and natural gas-fired generation increases." The 2015 IRP Update was the first to identify the Company's request to secure firm pipeline capacity on the Atlantic Coast Pipeline.

[redacted] **[END CONFIDENTIAL]** despite DENC's own IRPs from 2010 and 2012 that included a price of carbon in future years, indicating an awareness that carbon regulation was likely in the future – which would result in reduced coal-fired generation.[19]

Figure 4 below summarizes the Company's natural gas price forecasts over time. The 2012 and 2014 IRPs show significantly lower prices than were forecast in 2010. The Public Staff is concerned that these dramatically falling natural gas price forecasts apparently did not play any role in the Company's decision to continue with the CYFFP past 2014. It is the Public Staff's position that, based upon what was known in 2014 regarding natural gas prices and the expectation of carbon regulation, it was unreasonable and imprudent for DENC to assume that coal-fired generation would see no decline through 2042, and therefore management's reliance on the CBA justifying the project's continuation was unreasonable and imprudent.

[19] See Docket No. E-100 Sub 128, Dominion's 2010 Integrated Resource Plan, at 52.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

To further cast doubt on the 2014 CBA's projected coal burn estimates, DENC's own IRP forecasts showed increased coal retirements and lower utilization of coal generation assets. Figure 5 summarizes this information by presenting, for each IRP from 2010, the (i) expected total coal retirements in the planning horizon; (ii) total projected coal capacity in 2025; (iii) projected average capacity factor from the year of the IRP through the end of the planning horizon; and (iv) projected coal fleet capacity factor from the year of the IRP through the end of the planning horizon. This reflects a growing recognition that the Company's coal-fired generation was becoming less economic to run; of particular note, the Company forecasted that the Mount Storm units would see a significant drop off in their capacity factor in the 2015 IRP Update.

Figure 5: Summary of IRP Coal Projections

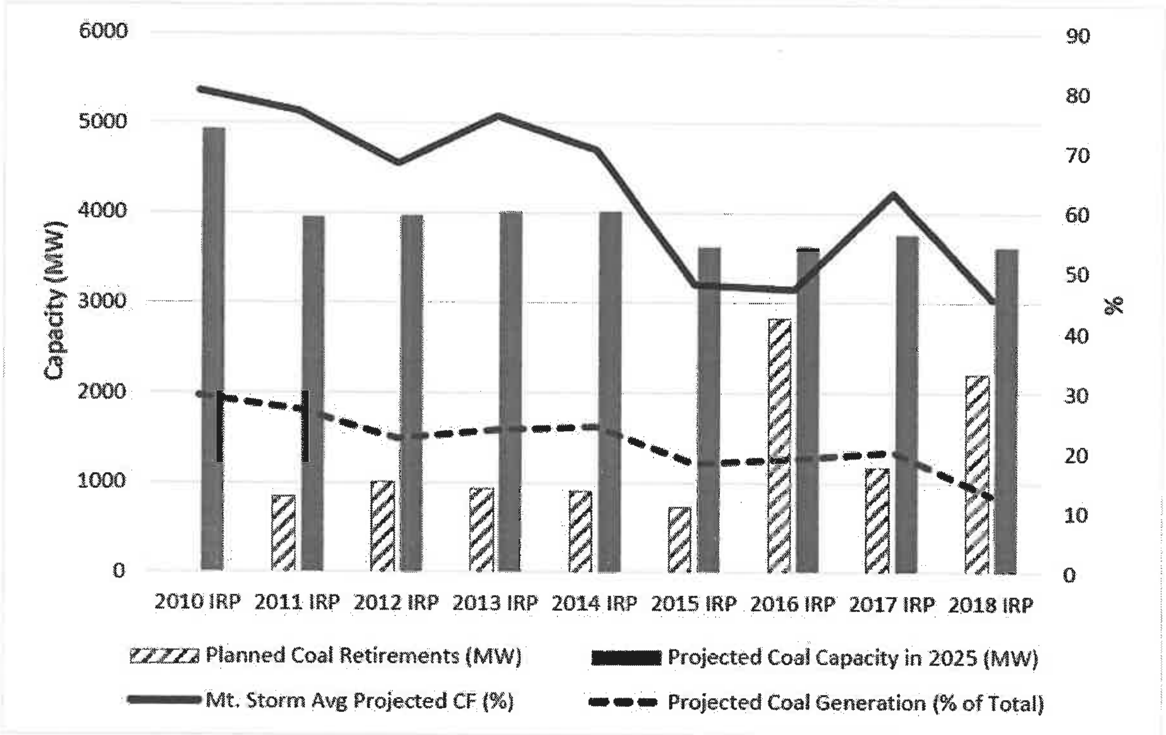
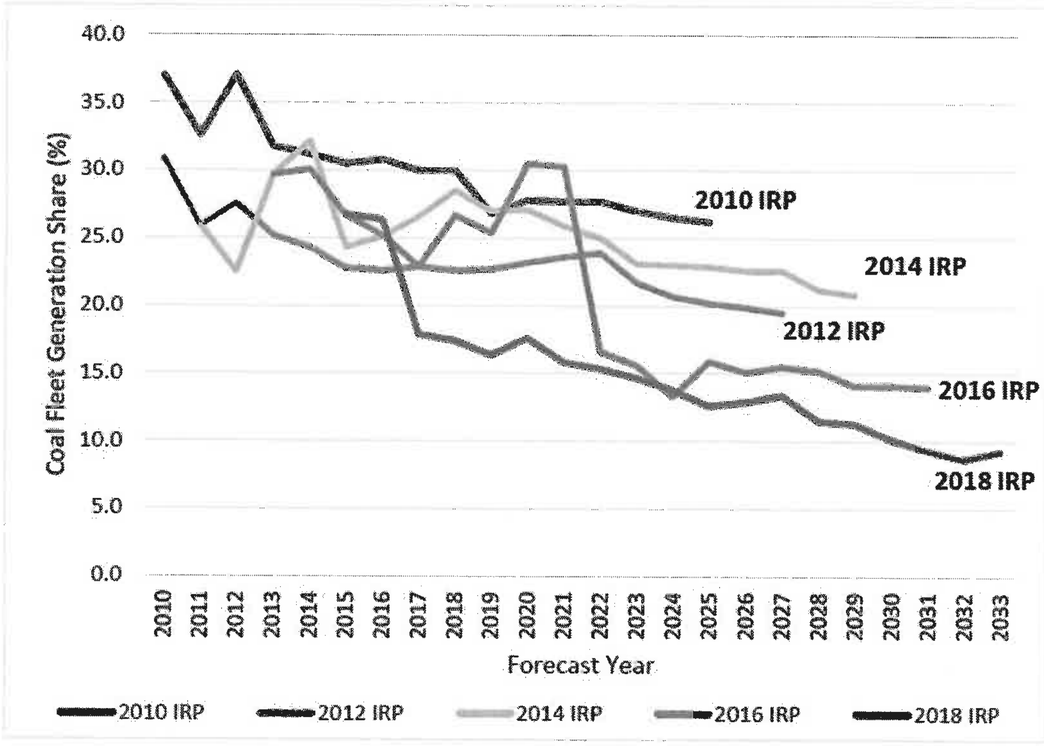


Figure 6 shows the coal fleet generation share from each IRP, demonstrating that the 2010, 2012, and 2014 IRPs all showed significant expected declines in coal fleet utilization. Upon review of the Company's past IRPs, the Public Staff believes that the significant investments planned and made at Mount Storm did not consider the Company's own internal forecasts of coal fleet utilization, Mount Storm projected capacity factor, natural gas forecasts, and other changing market conditions.

Figure 6: Coal Fleet Generation as a % of all generation, from IRPs (generally, Appendix 3H).



In discovery, the Company provided a 2012 Financial Review, in which **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The 2012 Financial Review recommended that the project be delayed, that negotiations with Metikki continue, and that market conditions, projected coal burns, and the best offer from Metikki be evaluated.[20]

In summary, it is my position that the flawed 2014 CBA, which ignored DENC's own IRP projections and then-effective Metikki contract, and did

[20] See Exhibit 1, slide 3.

not account for a dynamic power market, paved the way for over $60 million in spending from 2015 through 2019. It is my position that supporting a $116 million project with a static cost-benefit analysis that **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]** exposed ratepayers to excessive risk and was unreasonable and imprudent.

Public Staff Recommendation

Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION?

A. It is the Public Staff's opinion that by 2014, DENC should have been aware of changing market conditions within both the natural gas and coal markets, and the increased risk that the project would not deliver the expected benefits. In addition, the Public Staff believes that the 2014 CBA justifying the project had significant shortcomings and was not a reasonable or prudent analysis to justify a project that, at the time, had an estimated cost of $116 million. As such, the Public Staff recommends that the Commission disallow $60,179,000 in system costs from recovery.[21]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[21] This number is calculated by adding all CYFFP-related expenses from Table 1, including those related to the fire suppression system, from 2015 through 2019.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JEFFREY T. THOMAS

I graduated from the University of Illinois Champaign-Urbana in 2009, earning a Bachelor of Science Degree in General Engineering. Afterwards, I worked in various operations management roles for General Electric, United Technologies Corporation, and Danaher Corporation. Originally a manufacturing and process engineer in GE's Operations Management and Leadership program, I eventually became a production supervisor, where I was responsible for the safety and productivity of a team of employees. I left manufacturing in 2015 to attend North Carolina State University, earning a Master of Science degree in Environmental Engineering. At NC State, I performed cost benefit analysis research on smart grid components at the Future Renewable Energy Electricity Delivery and Management Systems Engineering Research Center. My master's thesis focused on electric power system modeling, capacity expansion planning, linear programming techniques, and the effect of various state and national energy policies on North Carolina's generation portfolio and electricity costs. After obtaining my degree, I joined the Public Staff in November 2017. In my current role, I have filed testimony, testified before the North Carolina Utilities Commission, and have been involved in the implementation of HB 589 programs, utility cost recovery, determination of avoided costs, renewable energy program management, customer complaints, and other aspects of utility regulation.

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

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

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A. I have been asked by the Public Staff - North Carolina Utilities Commission ("Public Staff") to provide an overall fair rate of return or cost of capital recommendation for Dominion Energy North Carolina ("DENC" or "Company").[1]

Q. HOW IS YOUR TESTIMONY ORGANIZED?

[1] In my testimony, I use the terms 'rate of return' and 'cost of capital' interchangeably. This is because the required rate of return of investors on a company's capital is the cost of capital.

A. First, I summarize my cost of capital recommendation for the Company, and review the primary areas of contention on the Company's position. Second, I discuss the proxy groups that I have used to estimate an equity cost rate for DENC. Third, I review the Company's recommended capital structure and debt cost rates. Fourth, I estimate the equity cost rate for the Company. Finally, I critique DENC's rate of return analysis and testimony. Appendix A is a summary of my education and business experience.

A. Overview

Q. WHAT IS A UTILITY'S ROE INTENDED TO REFLECT?

A. A return on equity ("ROE") is most simply described as the allowed rate of profit for a regulated company. In a competitive market, a company's profit level is determined by a variety of factors, including the state of the economy, the degree of competition a company faces, the ease of entry into its markets, the existence of substitute or complementary products/services, the company's cost structure, the impact of technological changes, and the supply and demand for its services and/or products. For a regulated monopoly, the regulator determines the level of profit available to the public utility. The United States Supreme Court established the guiding principles for determining an appropriate level of profitability for regulated public utilities in two cases: (1) *Hope*[2] and (2) *Bluefield*.[3] In those cases, the Court 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.

Thus, the appropriate ROE for a regulated utility requires determining the market-based cost of capital. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. The purpose of all of the economic models and formulas in cost of capital testimony (including those presented later in my testimony) is to estimate, using market data of similar-risk firms, the rate of return on equity investors require for that risk-class of firms in order to set an appropriate ROE for a regulated firm.

B. Summary of Positions

Q. PLEASE REVIEW THE COMPANY'S PROPOSED RATE OF RETURN.

[2] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

[3] *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

A. As updated in its supplemental testimony filed August 6, 2019, the Company has proposed a capital structure of 46.351% long-term debt and 53.649% common equity. The Company has recommended a long-term debt cost rate of 4.442%. Mr. Hevert has recommended a common equity cost rate of 10.75%. The Company's overall proposed rate of return is 7.83%.

Q. HOW HAVE YOU CONDUCTED YOUR RATE OF RETURN STUDIES FOR THE COMPANY?

A. I have reviewed the Company's proposed capital structure and overall rate of return or cost of capital. The Company's proposed capital structure has a higher common equity ratio than its parent, Dominion Energy, as well as the average of my proxy group of electric utilities ("Electric Proxy Group") and Mr. Hevert's proxy group ("Hevert Proxy Group"). Therefore, as my primary recommendation, I am proposing a capital structure of 50.0% common equity and 50.0% debt, which is more consistent with the capital structures of electric utility companies. To estimate an equity cost rate for the Company, I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to the Electric Proxy Group. I have also used the Hevert Proxy Group. My studies indicate that a cost of equity or ROE for the Company is in the range of 7.20% to 8.95%.

Q. WHAT IS YOUR PRIMARY RATE OF RETURN RECOMMENDATION FOR THE COMPANY?

A. As noted, my equity cost rate studies indicate an ROE between 7.20% and 8.95%. I believe that this range accurately reflects current capital market data. However, I recognize that this range is below the authorized ROEs for electric utility companies nationally. Therefore, as a primary ROE for DENC, I am recommending 9.0%. This recommendation gives weight to the higher authorized ROEs for electric utility companies. Given my recommended capitalization ratios and senior capital cost rates, my rate of return or cost of capital recommendation for the Company is 6.73% and is summarized in Table 1 and Panel A of Exhibit JRW-1.

Table 1
Public Staff's Primary Rate of Return Recommendation

Capital Source	Capitalization Ratios*	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	4.44%	2.23%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	100.00%		6.73%

Q. ARE YOU ALSO PROVIDING AN ALTERNATIVE RATE OF RETURN RECOMMENDATION FOR THE COMPANY?

A. Yes. My alternative rate of return recommendation uses DENC's updated recommended capital structure consisting of 46.351% long-term debt, and 53.649% common equity. With respect to the ROE, as indicated above, I believe that my equity cost rate range, 7.20%

to 8.95%, accurately reflects current capital market data. Capital costs in the U.S. remain low, with low inflation and interest rates and very modest economic growth. To reflect these low capital costs, my alternative ROE recommendation is 8.75%, which is at the high end of my equity cost rate range. Given my recommended capitalization ratios and senior capital cost rates, my alternative rate of return or cost of capital recommendation for the Company is 6.75% and is summarized in Table 2 and Panel B of Exhibit JRW-1.

Table 2
Public Staff's Alternative Rate of Return Recommendation

Capital Source	Capitalization Ratios*	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.35%	4.44%	2.09%
Common Equity	53.65%	8.75%	4.69%
Total Capitalization	100.00%		6.75%

C. Primary Rate of Return on Equity Issues

Q. PLEASE PROVIDE AN OVERVIEW OF THE PRIMARY ISSUES REGARDING RATE OF RETURN IN THIS PROCEEDING.

A. The primary issues related to the Company's rate of return include the following:

Capital Market Conditions – Mr. Hevert's analyses, ROE results, and recommendations are based on assumptions of higher interest rates and capital costs. However, I show 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. In 2019 interest rates have fallen dramatically with slow economic growth and low inflation, and the 30-year yield has traded at all-time low levels.

Capital Structure – DENC's witness Mr. Richard M. Davis has proposed a capital structure consisting of 46.351% long-term debt and 53.649% common equity. The Company's proposed capital structure has a higher common equity ratio than the average of the Electric and Hevert Proxy Groups. In my primary rate of return recommendation, I am recommending adjusting DENC's proposed capital structure to use a common equity ratio of 50 percent, as that is more in line with the capital structures of the utilities in the two proxy groups as well as that of DENC's parent, Dominion Energy. In my alternative rate of return recommendation, I am using DENC's proposed updated capital structure, but I then employ a lower ROE to reflect the high common equity ratio and lower financial risk of the Company's proposed capitalization.

DENC's Investment Risk is Below the Averages of the Two Proxy Groups – Mr. Hevert cites the Company's capital expenditures to imply that DENC's investment risk is higher than the risk of his proxy group. In addition, he selects an ROE that is near the upper end of his 10.0% to 11.0% range. However, his assessment of DENC's risk is erroneous. The assessment of capital expenditures is part of the credit rating process, and DENC's S&P and Moody's credit ratings suggest that the Company's investment risk is below the average of the Hevert Proxy Group.

<u>Disconnect Between Mr. Hevert's Equity Cost Rate Studies and his 10.75% ROE Recommendation</u> – There is a disconnect between Mr. Hevert's equity cost rate results and his 10.75% ROE recommendation. Simply stated, the vast majority of his equity cost rate results point to a lower ROE. In fact, the only results that point to an ROE as high as 10.75% are his CAPM/empirical CAPM ("ECAPM") results using *Value Line* betas and market risk premium ("MRP"), which as I explain later in my testimony are flawed. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one model (the CAPM); and, even more narrowly, (2) only one source of financial information for betas and MRP (*Value Line*). Otherwise, Mr. Hevert provides no other equity cost rate studies that support his 10.75% ROE recommendation.

<u>DCF Equity Cost Rate</u> - The DCF Equity Cost Rate is estimated by summing the stock's dividend yield and investors' expected long-run growth rate in dividends paid per share. There are several errors in Mr. Hevert's DCF analyses: (1) he has given very little weight to his constant-growth DCF results; and (2) he has relied exclusively on the overly optimistic and upwardly biased earnings per share ("EPS") growth-rate forecasts of Wall Street analysts and *Value Line.* On the

other hand, when developing the DCF growth rate that I have used in my analysis, I have reviewed thirteen growth-rate measures, including historical and projected growth-rate measures, and have evaluated growth in dividends, book value, and earnings per share.

<u>CAPM Approach</u> - The CAPM approach requires an estimate of the risk-free interest rate, the beta, and the market or equity risk premium. There are three primary issues with Mr. Hevert's CAPM analyses. First, Mr. Hevert employs an excessively high, projected long-term risk-free interest rate. Second, his market risk premiums of 10.65% and 13.77% are exaggerated and do not reflect current market fundamentals. Mr. Hevert has employed analysts' three-to-five-year growth-rate projections for EPS to compute an expected market return and market risk premiums. These EPS growth-rate projections and the resulting expected market returns and market risk premiums include highly unrealistic assumptions regarding future economic and earnings growth and stock returns. Third, Mr. Hevert has employed an ad hoc version of the CAPM, the ECAPM, which makes inappropriate adjustments to the risk-free rate and the market risk premium and is an untested model in academic and profession research.

As I highlight in my testimony, there are three procedures for estimating a market or equity risk premium – historic returns, surveys, and expected return models. I have used an MRP of 5.50%, which: (1) factors in all three approaches – historic returns, surveys, and expected return models – to estimate a market premium; and (2) employs the results of many studies of the MRP. As I note, my MRP reflects the MRPs: (1) determined in recent academic studies by leading finance scholars; (2) employed by leading investment banks and management consulting firms; and (3) found in surveys of companies, financial forecasters, financial analysts, and corporate CFOs.

<u>Alternative Risk Premium Model</u> - Mr. Hevert estimates an equity cost rate using an alternative risk premium model which he calls the Bond Yield Risk Premium ("BYRP") approach. The risk premium in his BYRP method is based on the historical relationship between the yields on long-term Treasury yields and authorized ROEs for electric utility companies. There are several issues with this approach: (1) This approach is a gauge of commission behavior and not investor behavior. Capital costs are determined in the market place through the financial decisions of investors and are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments; (2) Mr. Hevert's methodology produces an inflated measure of the risk premium because his approach uses historical authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields; and

(3) the risk premium is inflated as a measure of investor's required risk premium, because electric utility companies have been selling at market-to-book ratios in excess of 1.0. This indicates that the authorized rates of return have been greater than the return that investors require.

<u>Expected Earnings Approach</u> - Mr. Hevert also uses the Expected Earnings approach to estimate an equity cost rate for the Company. Mr. Hevert computes the expected ROE as forecasted by *Value Line* for his proxy group of electric utilities. As I discuss in my critique of Mr. Hevert's presentation, the so-called "Expected Earnings" approach does not measure the market cost of equity capital, is independent of most cost of capital indicators, and has several other empirical issues. Therefore, the Commission should ignore Mr. Hevert's "Expected Earnings" approach in determining the appropriate ROE for DENC.

<u>Other Issues</u> - Mr. Hevert also considers two other factors in arriving at his 10.75% ROE recommendation. First, Mr. Hevert cites the Company's high level of capital expenditures in the coming years. However, as I note, capital expenditures are considered as a risk factor in the credit-rating process used by major rating agencies. In addition, as I noted above, DENC's investment risk as measured by S&P and Moody's is below the average of the two proxy groups. Second, Mr. Hevert also considers flotation costs in making his ROE

recommendation of 10.75%. However, he has not identified any flotation costs for DENC.[4]

North Carolina Economic Conditions – Mr. Hevert evaluates a number of factors such as employment and income levels and comes to the conclusion that DENC's proposed ROE of 10.75% is fair and reasonable to DENC, its shareholders, and its customers in light of the effect of those changing economic conditions. While I agree economic conditions have improved in North Carolina, the improvements do not necessarily justify such a high rate of return and ROE. Specifically, I highlight the following: (1) DENC's ROE request of 10.75% is over 100 basis points above the average authorized ROEs for electric utilities over the 2018-19 time period; (2) whereas North Carolina's unemployment rate has fallen by one-third since its peak in the 2009-2010 period and is slightly below the national average of 3.90%, the unemployment rate in DENC's

[4] In NC, flotation costs cannot lawfully be recovered when the Company does not expect to issue stock in the near future. In State ex rel. Utilities Com. v. Public Staff, 331 N.C. 215; 415 S.E.2d 354 (1992), the Court noted that:

> Prompted by the statement of Duke's chairman, Mr. Lee, that "the company's 'present expectation is that we will be back into the capital markets for new funds in about three to four years,'" the only evidence in the record on the probability of Duke's issuing new stock, we noted the record included no evidence that Duke would issue any new stock sooner than three or four years from the time of the hearing.

Id. at 219. The Court then ruled that,

> In light of the whole record on this issue, particularly the absence of any evidence that Duke intended to issue stock in the immediate future, there is simply no substantial evidentiary support for the Commission's addition of a 0.1% increment to Duke's rate of return on common equity to cover future stock issuance costs.

Id. at 221-222.

service territory is 4.95%, over 100 basis points higher than the national and North Carolina averages; and (3) whereas North Carolina's residential electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm.

II. CAPITAL MARKET CONDITIONS AND AUTHORIZED ROES

Q. PLEASE REVIEW THE FEDERAL RESERVE'S DECISIONS TO RAISE THE FEDERAL FUNDS RATE IN RECENT YEARS.

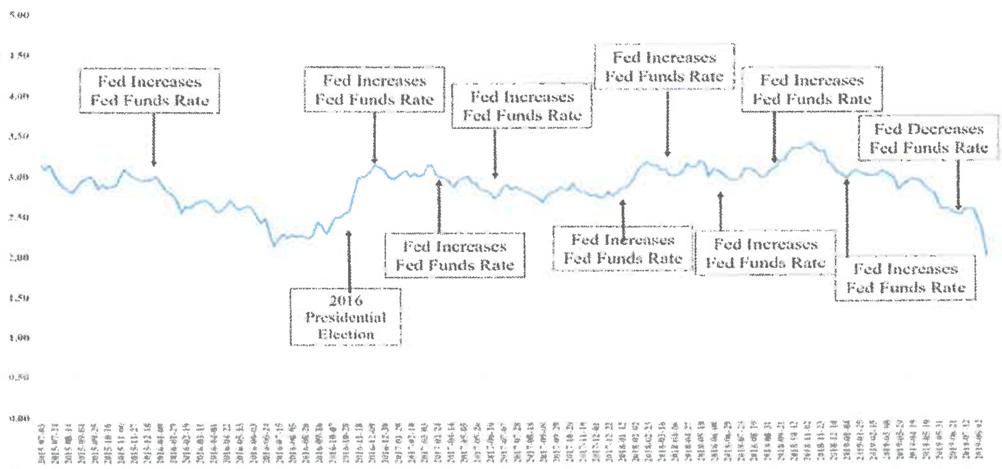
A. On December 16, 2015, the Federal Reserve increased its target rate for federal funds from 0.25 to 0.50 percent.[5] This increase came after the rate was kept in the 0.00 to 0.25 percent range for over five years in order to spur economic growth in the wake of the financial crisis associated with the Great Recession. As the economy has improved, with lower unemployment, steady but slow GDP growth, the Federal Reserve has increased the target federal funds rate on eight additional occasions: December 2016; March, June, and December of 2017; and March, June, September, and December of 2018.

[5] The federal funds rate is set by the Federal Reserve and is the borrowing rate applicable to the most creditworthy financial institutions when they borrow and lend funds overnight to each other.

Q. HOW HAVE LONG-TERM RATES RESPONDED TO THE ACTIONS OF THE FEDERAL RESERVE?

A. Figure 1, below, shows the yield on 30-year Treasury bonds over the period of 2015-2019. I have highlighted the dates when the Federal Reserve increased the federal funds rate. The 30-year Treasury yield hit its lowest point in the 2015 – 2016 timeframe in the summer of 2016 and subsequently increased with improvements in the economy. Financial markets moved significantly in the wake of the results in the U.S. presidential election on November 8, 2016. The stock market gained more than 10% and the 30-year Treasury yield increased about 50 basis points to 3.2% by year-end 2016. However, over the past three years, even as the Federal Reserve has increased the federal funds rate, the yield on thirty-year bonds remained in the 2.8% to 3.4% range through 2018. These yields peaked at 3.48% in November of 2018, shortly before the December 2018 rate increase by the Federal Reserve.

Figure 1
Thirty-Year Treasury Yield and Federal Reserve Fed Funds Rate Increases 2015-2019



Q. PLEASE REVIEW LONG-TERM TREASURY YIELDS IN 2019.

A. Despite the Fed's efforts to stimulate the economy, economic growth and inflation have remained low, even with record low unemployment levels. The rate increase in December of 2018 was seen by many as maybe too aggressive. And with the imposition of trade tariffs aimed at China, and with continued slow growth in Europe, concerns have grown that a recession is on the horizon in the U.S. This led the Federal Reserve to cut the federal fund rate to the 2.0%-2.25% range in July of 2019. Thirty-year Treasury yields, which began the year in the 3.0% range, have fallen to almost 2.0%. In fact, in August of 2019 the 30-year Treasury yield fell to record lows and even traded below 2.0%. The irony is, despite the record low levels, the 30-year Treasury yield in the U.S. is still somewhat higher than the government bond rates in Japan, the U.K., Germany, and much of the rest of Europe.

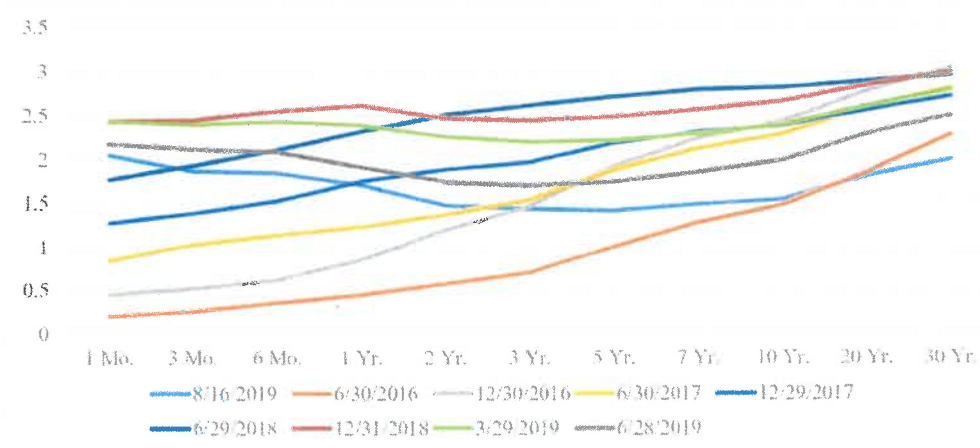
Q. WHY HAVE LONG-TERM TREASURY YIELDS REMAINED IN THE 2.0%-3.0% RANGE DESPITE THE FEDERAL RESERVE INCREASING SHORT-TERM RATES?

A. Whereas the Federal Reserve can directly affect short-term rates by adjustments to the federal funds rate, long-term rates are primarily driven by expected economic growth and inflation.[6] The relationship between short- and long-term rates is normally evaluated using the yield curve. The yield curve depicts the relationship between the yield-to-maturity and the time-to-maturity for U.S. Treasury bills, notes, and bonds. Figure 2, below, shows the yield curve on a semi-annual basis since the Federal Reserve started increasing the federal funds rate at the end of 2015. It shows that, from the time the Federal Reserve began increasing the federal fund rate in 2015 and until 2018, with the exception of mid-year 2016, the 30-year Treasury yield has remained in the 2.8%-3.4% range despite the fact that short-term rates have increased from near 0.0% to about 2.50%. As such, long-term interest rates and capital costs have not increased in any meaningful way even with the Federal Reserve's actions and the increase in short-term rates.

[6] Whereas economic growth picked up in 2018, partly in response to the personal and corporate tax cuts, projected real GDP growth for 2019 and beyond remains in the 2.0% to 2.5% range. In addition, inflation remains low and is also in the 2.0% to 2.5% range.

In 2019, with the large decline in long-term Treasury rates, the concern has been about an "inverted yield curve." An inverted yield curve occurs when short-term Treasury yields are above long-term Treasury yields and is commonly associated with a pending recession. In Figure 2, the yield curve for August 16, 2019, is shown in Carolina blue and is slightly inverted.

Figure 2
Semi-Annual Yield Curves
2015-2019



Date Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2019

Q. DO YOU RECOMMEND THE COMMISSION ACCEPT MR. HEVERT'S FORECASTS OF HIGHER INTEREST RATES AND CAPITAL COSTS?

A. No. I suggest that the Commission set an equity cost rate based on current indicators of market-cost rates and not speculate on the future direction of interest rates.

Economists have been predicting that interest rates would be going up for a decade, and they consistently have been wrong. For example, after the announcement of the end of the Quantitative Easing III ("QE III") program in 2014, all the economists in Bloomberg's interest rate survey forecast that interest rates would increase in 2014, and 100% of the economists were wrong. According to the *Market Watch* article:[7]

> The survey of economists' yield projections is generally skewed toward rising rates — only a few times since early 2009 have a majority of respondents to the Bloomberg survey thought rates would fall. But the unanimity of the rising rate forecasts in the spring was a stark reminder of how one-sided market views can become. It also teaches us that economists can be universally wrong.

Two other financial publications produced studies on how economists consistently predict higher interest rates, and yet they too, have been wrong. The first publication, entitled "How Interest Rates Keep Making People on Wall Street Look Like Fools," evaluated economists' forecasts for the yield on 10-year Treasury bonds at the beginning of the year for the last ten years.[8] The results

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[7] Ben Eisen, "Yes, 100% of economists were dead wrong about yields," *Market Watch*, (Oct. 22, 2014), https://www.marketwatch.com/story/yes-100-of-economists-were-dead-wrong-about-yields-2014-10-21. Perhaps reflecting this fact, *Bloomberg* reported that the Federal Reserve Bank of New York has stopped using the interest rate estimates of professional forecasters in the Bank's interest rate model due to the unreliability of those interest rate forecasts. *See* Susanne Walker and Liz Capo McCormick, "Unstoppable $100 Trillion Bond Market Renders Models Useless," *Bloomberg.com* (June 2, 2014), http://www.bloomberg.com/news/2014-06-01/the-unstoppable-100-trillion-bond-market-renders-models-useless.html.

[8] Joe Weisenthal, "How Interest Rates Keep Making People on Wall Street Look Like Fools,"

demonstrated that economists consistently predict that interest rates will go higher, and interest rates have not fulfilled those predictions.

The second study tracked economists' forecasts for the yield on 10-year Treasury bonds on an ongoing basis from 2010 until 2015.[9] The study, entitled "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," indicates that economists are continually forecasting that interest rates are going up, yet they do not. Indeed, as Bloomberg has reported, economists' continued failure in forecasting increasing interest rates has caused the Federal Reserve Bank of New York to stop using the interest-rate estimates of professional forecasters in the Bank's interest-rate model due to the unreliability of those interest-rate forecasts.[10]

Obviously, investors are aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. Investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns. For example, consider a utility that pays a dividend

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Bloomberg.com, (March 16, 2015), http://www.bloomberg.com/news/articles/2015-03-16/how-interest-rates-keep-making-people-on-wall-street-look-like-fools.

[9] Akin Oyedele, "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," *Business Insider*, (July 18, 2015), http://www.businessinsider.com/interest-rate-forecasts-are-wrong-most-of-the-time-2015-7.

[10] Ben Eisen, "Yes, 100% of economists were dead wrong about yields," *Market Watch*, (Oct. 22, 2014), https://www.marketwatch.com/story/yes-100-of-economists-were-dead-wrong-about-yields-2014-10-21.

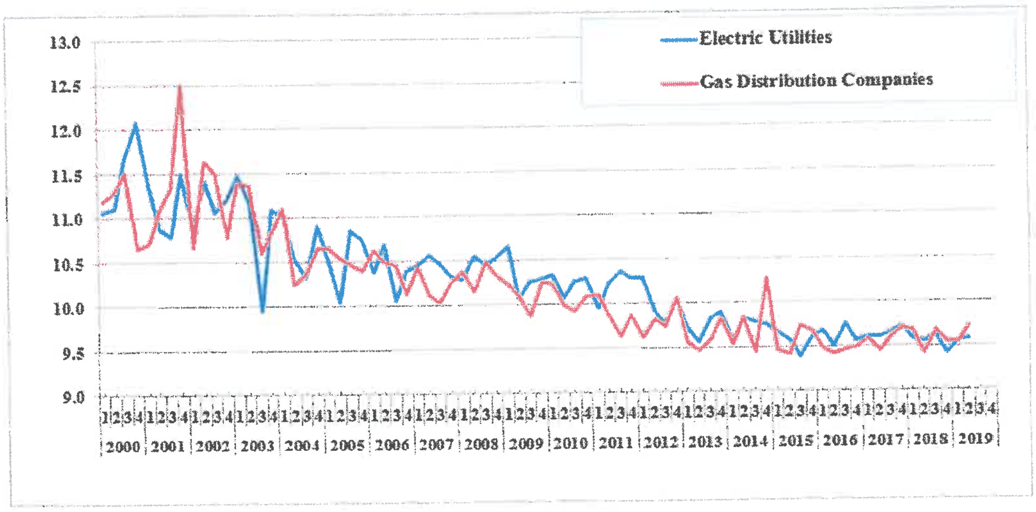
of $2.00 with a stock price of $50.00. The current dividend yield in that example is 4.0%. If, as Mr. Hevert suggests, interest rates and required utility yields increase, the price of the utility stock would decline. In the example above, if higher return requirements led the dividend yield to increase from 4.0% to 5.0% in the next year, the stock price would have to decline to $40, which would be a -20% return on the stock. Obviously, investors would not buy the utility stock with an expected return of -20% due to higher dividend yield requirements.

In sum, it is practically impossible to accurately forecast interest rates and prices of investments that are determined in financial markets, such as interest rates and prices for stocks and commodities. For interest rates, I am not aware of any study that suggests one forecasting service is consistently better than others or that interest-rate forecasts are consistently better than just assuming the current interest rate will be the rate in the future. As discussed above, investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns.

Q. PLEASE DISCUSS THE TREND IN AUTHORIZED RETURN ON EQUITY FOR ELECTRIC AND GAS COMPANIES.

A. Over the past five years, with the historically low interest rates and capital costs, authorized ROEs for electric utility and gas distribution companies have slowly declined to reflect the low capital cost environment. In Figure 3, below, I have graphed the quarterly authorized ROEs for electric and gas companies from 2000 to 2018. There is a clear downward trend in the data. On an annual basis, these authorized ROEs for electric utilities have declined from an average of 10.01% in 2012, 9.8% in 2013, 9.76% in 2014, 9.58% in 2015, 9.60% in 2016, 9.68% in 2017, 9.56% in 2018, and 9.56% in the first half of 2019, according to Regulatory Research Associates.[11]

Figure 3
Authorized ROEs for Electric Utility and Gas Distribution Companies
2000-2019



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[11] *Regulatory Focus*, Regulatory Research Associates, 2019. The electric utility authorized ROEs exclude the authorized ROEs in Virginia, which include generation adders.

III. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR THE COMPANY.

A. To develop a fair rate of return recommendation for DENC, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies ("Electric Proxy Group"). I have also used the group developed by Mr. Hevert ("Hevert Proxy Group").

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF COMPANIES.

A. The selection criteria for the Electric Proxy Group include the following:

(1) At least 50% of revenues come from regulated electric operations as reported in SEC Form 10-K Report;

(2) Listed as an Electric Utility by *Value Line Investment Survey*;

(3) 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) Not involved in an acquisition of another utility, and not the target of an acquisition; and

(6) Analysts' long-term EPS growth rate forecasts available from Yahoo, Reuters, and/or Zack's.

The Electric Proxy Group includes twenty-seven companies. Summary financial statistics for the proxy group are listed in Exhibit JRW-2. The median operating revenues and net plant among members of the Electric Proxy Group are $6,873.0 million and $22,810.0 million, respectively. The group on average receives 81% of its revenues from regulated electric operations, has a BBB+ bond rating from Standard & Poor's and a Baa1 rating from Moody's, a current average common equity ratio of 46.0%, and an earned return on common equity of 9.7%.

Q. PLEASE DESCRIBE THE HEVERT PROXY GROUP.

A. Mr. Hevert's group is smaller (twenty-one companies). Summary financial statistics for Mr. Hevert's proxy group are provided in Panel B of page 1 of Exhibit JRW-2. The median operating revenues and net plant for the Hevert Proxy Group are $4,275.9 million and $18,126.0 million, respectively. The group on average receives 77% of its revenues from regulated electric operations, has a BBB+ bond rating from Standard & Poor's ("S&P's") and a Baa1 rating from Moody's, a common equity ratio of 47.5%, and a current earned return on common equity of 9.7%.

Q. HOW DOES THE INVESTMENT RISK OF THE COMPANY COMPARE TO THAT OF YOUR ELECTRIC PROXY GROUP AND THE HEVERT PROXY GROUP?

A. I believe that bond ratings provide a good assessment of the investment risk of a company. The S&P and Moody's issuer credit ratings for DENC are BBB+ and A2, respectively. However, DENC and Dominion's S&P rating was A- but was downgraded on February 1, 2016 due to risk associated with Dominion's acquisition of Questar. This downgrade had nothing to do with the risk of DENC.[12] In addition, it should be noted that the Moody's rating for DENC's parent, Dominion Energy, is Baa2, which is three rating notches below DENC's A2 rating.

The average S&P and Moody's ratings for the Electric and Hevert Proxy Groups are BBB+ and Baa1. DENC's S&P rating is equal to the two groups (BBB+ vs. BBB+), while DENC's Moody's rating is two rating notches above the two groups (A2 vs. Baa1). This indicates that the investment risk of DENC is below the electric utilities in the two proxy groups.

On page 2 of Exhibit JRW-2, I have assessed the riskiness of the two proxy groups using five different risk measures. These

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[12] Standard & Poor's Rating Services, Ratings Direct, "Dominion Resources Inc. and Subsidiaries Downgraded to 'BBB+' On Acquisition of Questar Corp.; Outlook Stable" (Feb. 1, 2016).

measures include Beta, Financial Strength, Safety, Earnings Predictability, and Stock Price Stability. These risk measures indicate that the two proxy groups are similar in risk. The comparisons of the risk measures include Beta (0.59 vs. 0.58), Financial Strength (A vs. A), Safety (1.9 vs. 1.8), Earnings Predictability (78 vs. 81), and Stock Price Stability (96 vs. 96). On balance, these measures suggest that the two proxy groups – that is my Electric Proxy Group and the Hevert Proxy Group – are similar in risk.

Q. WHAT DO YOU CONCLUDE FROM YOUR RISK ANALYSIS?

A. First, based on the credit ratings from S&P and Moody's, I conclude that the Company is less risky than the average of the two proxy groups. Second, the S&P and Moody's credit ratings and the five *Value Line* risk ratings are very similar for the two groups, and therefore I conclude that the two groups are similar in risk. And third, the five *Value Line* risk ratings for the two groups suggest that electric utilities are very low risk. This is indicated by the low Betas as well as the high ratings for safety, financial strength, earnings predictability, and stock price stability.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. PLEASE DESCRIBE DENC'S PROPOSED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. DENC witness Mr. Richard M. Davis has proposed a capital structure of 46.351% long-term debt and 53.649% common equity and a long-term debt cost rate of 4.442%.

Q. HOW DO DENC'S PROPOSED CAPITAL STRUCTURE RATIOS COMPARE TO THE AVERAGE CAPITALIZATION RATIOS FOR COMPANIES IN THE PROXY GROUPS?

A. DENC's proposed capital structure ratios include a common equity ratio of 53.649%. As shown in Exhibit JRW-4, the average quarterly common equity ratio for the Electric and Hevert Proxy Groups as of December 31, 2018 were 46.0% and 47.5%, respectively. As such, DENC has proposed a capital structure that includes much more common equity in financing its utility operations than the average of the proxy group.

Q. IS IT APPROPRIATE TO USE THE COMMON EQUITY RATIOS OF THE PARENT HOLDING COMPANIES OR SUBSIDIARY OPERATING UTILITIES FOR COMPARISON PURPOSES WITH DENC'S PROPOSED CAPITALIZATION?

A. It is appropriate to use the common equity ratios of the utility holding companies. This is because the holding companies are publicly-traded and their stocks are used in the cost of equity capital studies. The equities of the operating utilities are not publicly-traded and hence their stocks cannot be used to compute the cost of equity capital for DENC.

Q. IS IT APPROPRIATE TO INCLUDE SHORT-TERM DEBT IN THE CAPITALIZATION IN COMPARING THE COMMON EQUITY RATIOS OF THE HOLDING COMPANIES WITH DENC'S PROPOSED CAPITALIZATION?

A. Yes. I am following North Carolina precedent and not recommending short-term debt in DENC's capital structure. However, in comparing the common equity ratios of the holding companies with DENC's recommendation, it is appropriate to include short-term debt when computing the holding company common equity ratios. That is because short-term debt, like long-term debt, has a higher claim on the assets and earnings of the company and requires timely payment of interest and repayment of principal. In addition, the financial risk of a company is based on total debt, which includes both short-term and long-term debt. This is why credit rating agencies use total debt in assessing the leverage and financial risk of companies.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO AUTHORIZED FOR ELECTRIC UTILITIES BY STATE REGULATORY COMMISSIONS?

A. According to Regulatory Research Associates, the average authorized common equity ratio for electric utilities in (1) calendar year 2018 and (2) for the first six months of 2019, were 48.95% and 50.10%, respectively.[13]

Q. HOW DO DENC'S PROPOSED CAPITAL STRUCTURE RATIOS COMPARE TO THE CAPITALIZATION RATIOS OF ITS PARENT, DOMINION ENERGY?

A. Panel B of Exhibit JRW-3 also provides Dominion Energy's December 31, 2018 average capitalization ratios both including and excluding short-term debt. Dominion Energy's common equity ratio was 36.5% including short-term debt and 39.1% excluding short-term debt. As a result, the Company's proposed capital structure includes a much higher common equity ratio (53.649%) than the common equity ratio of its parent, Dominion Energy.

Q. IS DOMINION ENERGY'S HIGH DEBT RATIO AND LOW EQUITY RATIO A FACTOR IN THE RISK ASSESSMENT OF DENC?

A. Yes. As previously noted, DENC's Moody's rating of A2 is three rating notches above Dominion Energy's rating of Baa2. In addition, Moody's noted that Dominion Energy's high debt level, or leverage, is a credit negative for DENC.[14]

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[13] *Regulatory Focus*, Regulatory Research Associates, (2019).

[14] Moody's Investors' Service, "Virginia Electric and Power Company: Update to Credit Analysis," January 10, 2019, p. 1.

Q. PLEASE DISCUSS THE ISSUE OF PUBLIC UTILITY HOLDING COMPANIES SUCH AS DOMINION ENERGY USING DEBT TO FINANCE THE EQUITY IN SUBSIDIARIES SUCH AS THE COMPANY.

A. Moody's published an article on the use of low-cost debt financing by public utility holding companies to increase their ROEs. The summary observations included the following: [15]

> US utilities use leverage at the holding-company level to invest in other businesses, make acquisitions and earn higher returns on equity. In some cases, an increase in leverage at the parent can hurt the credit profiles of its regulated subsidiaries.

This financial strategy has traditionally been known as double leverage. Moody's defined double leverage in the following way:[16]

> Double leverage is a financial strategy whereby the parent raises debt but downstreams the proceeds to its operating subsidiary, likely in the form of an equity investment. Therefore, the subsidiary's operations are financed by debt raised at the subsidiary level and by debt financed at the holding-company level. In this way, the subsidiary's equity is leveraged twice, once with the subsidiary debt and once with the holding-company debt. In a simple operating-company / holding-company structure, this practice results in a consolidated debt-to-capitalization ratio that is higher at the parent than at the subsidiary because of the additional debt at the parent.

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[15] Moody's Investors' Service, "High Leverage at the Parent Often Hurts the Whole Family," May 11, 2015, p. 1.

[16] *Ibid.* p. 5.

Moody's goes on to discuss the potential risk to utilities of the strategy, and specifically notes that regulators could take it into consideration in setting authorized ROEs.[17]

> **"Double leverage" drives returns for some utilities but could pose risks down the road.** The use of double leverage, a long-standing practice whereby a holding company takes on debt and downstreams the proceeds to an operating subsidiary as equity, could pose risks down the road if regulators were to ascribe the debt at the parent level to the subsidiaries or adjust the authorized return on capital.

Q. PLEASE DISCUSS THE SIGNIFICANCE OF THE AMOUNT OF EQUITY THAT IS INCLUDED IN A UTILITY'S CAPITAL STRUCTURE.

A. A utility's decision as to the amount of equity capital it will incorporate into its capital structure involves fundamental trade-offs relating to the amount of financial risk the firm carries, the overall revenue requirements its customers are required to bear through the rates they pay, and the return on equity that investors will require.

Q. PLEASE DISCUSS A UTILITY'S DECISION TO USE DEBT VERSUS EQUITY TO MEET ITS CAPITAL NEEDS.

A. Utilities satisfy their capital needs through a mix of equity and debt. Because equity capital is more expensive than debt, the issuance of debt enables a utility to raise more capital for a given commitment of

[17] *Ibid.* p. 1.

dollars than it could raise with just equity. Debt is, therefore, a means of "leveraging" capital dollars. However, as the amount of debt in the capital structure increases, financial risk increases and the risk of the utility, as perceived by equity investors, also increases. Significantly for this case, the converse is also true. As the amount of debt in the capital structure decreases, the financial risk decreases. The required return on equity capital is a function of the amount of overall risk that investors perceive, including financial risk in the form of debt.

Q. WHY IS THIS RELATIONSHIP IMPORTANT TO THE UTILITY'S CUSTOMERS?

A. Just as there is a direct correlation between the utility's authorized return on equity and the utility's revenue requirements (the higher the return, the greater the revenue requirement), there is a direct correlation between the amount of equity in the capital structure and the revenue requirements that customers are called on to bear. Again, equity capital is more expensive than debt. Not only does equity command a higher cost rate, it also adds more to the income tax burden that ratepayers are required to pay through rates. As the equity ratio increases, the utility's revenue requirements increase and the rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. For this reason, the utility's management should pursue a capital acquisition strategy that results in the proper balance in the capital structure.

Q. HOW HAVE UTILITIES TYPICALLY STRUCK THIS BALANCE?

A. Due to regulation and the essential nature of its output, a regulated utility is exposed to less business risk than other companies that are not regulated. This means that a utility can reasonably carry relatively more debt in its capital structure than can most unregulated companies. Thus, a utility should take appropriate advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements.

Q. GIVEN THAT DENC HAS PROPOSED AN EQUITY RATIO THAT IS HIGHER THAN (1) THE AVERAGE COMMON EQUITY RATIOS OF THE ELECTRIC AND HEVERT'S PROXY GROUPS, (2) THE AVERAGE AUTHORIZED COMMON EQUITY RATIO FOR ELECTRIC UTILITY COMPANIES, AND (3) THE COMMON EQUITY RATIO OF ITS PARENT COMPANY, WHAT OPTIONS DOES THE COMMISSION HAVE IN THIS RATEMAKING PROCEEDING?

A. When a regulated utility's actual capital structure contains a high equity ratio, the options are: (1) to impute a more reasonable capital structure that is comparable to the average of the proxy group used to determine the cost of equity and to reflect the imputed capital structure in revenue requirements; or (2) to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a common equity cost rate lower than that of the proxy group.

Q. PLEASE ELABORATE ON THIS "DOWNWARD IMPACT."

A. As I stated earlier, there is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. A relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. Stated differently, a utility cannot expect to "have it both ways." Specifically, a utility cannot maintain an unusually high equity ratio and not expect to have the resulting lower risk reflected in its authorized return on equity. The fundamental relationship between lower risk and the appropriate authorized return should not be ignored.

Q. GIVEN THIS DISCUSSION, PLEASE DISCUSS YOUR PRIMARY CAPITAL STRUCTURE RECOMMENDATION FOR DENC.

A. My primary capital structure recommendation is presented in Panel C of Exhibit JRW-3. As previously noted, DENC's proposed capital structure consists of more common equity and less financial risk than any of the other proxy electric companies. Therefore, in my primary rate of return recommendation, I am proposing a capital structure that includes a common equity ratio of 50.0%. This capital structure includes a common equity ratio that is about half-way between DENC's proposed capital structure of 53.649% and the average common equity ratios of the proxy groups of 46.00% and 47.75%. As shown in Table 3 and Panel C of Exhibit JRW-3, in this capital structure, I have grossed up the percentage amount of long-term debt to 50.0% and reduced the amount of common equity from 53.649% to 50.0%. As noted above, in my primary rate of return recommendation, I am using a ROE of 9.0%.

Table 3
Staff's Primary Capital Structure Recommendation

	DENC Proposed	Adjustment	Staff Proposed	Cost
Long-Term Debt	**46.65%**	**1.078725**	**50.00%**	**4.44%**
Common Equity	**53.35%**	**0.931984**	**50.00%**	-
Total Capital	**100.00%**		**100.00%**	

Q. **DO YOU BELIEVE THAT YOUR PROPOSED 50% EQUITY CAPITAL STRUCTURE IS FAIR TO DENC?**

A. Yes, for two reasons: (1) It includes a common equity ratio that is higher than the average common equity ratio for the Electric and Hevert Proxy Groups and therefore affords DENC with more common equity and less financial risk than other electric utility companies; and (2) it is in line with the average authorized common equity ratios for electric utility companies.

Q. **WHAT IS THE CAPITAL STRUCTURE IN YOUR ALTERNATIVE RATE OF RETURN RECOMMENDATION?**

A. In my alternative rate of return recommendation, I am using DENC's proposed capital structure which consists of 46.351% long-term debt and 53.649%. I am also using DENC's proposed long-term debt cost rate of 4.442%. As noted above, in my alternative rate of return recommendation, I am using an ROE of 8.75%. I believe that the 8.75% ROE reflects the current market cost of equity. In addition, if the Commission adopts DENC's proposed capital structure with its high common equity ratio, I believe that the Commission should employ a lower ROE to reflect the lower financial risk associated with a higher common equity ratio.

Table 4
Public Staff's Alternative Capital Structure Recommendation

	Percent of Total	Cost
Long-Term Debt	46.99%	4.442%
Common Equity	53.01%	
Total Capital	100.00%	

V. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and the economic benefit to society from avoiding duplication of these services and the construction of utility infrastructure facilities, many public utilities are monopolies. Because of the lack of competition and the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, sufficient to meet the operating and capital costs of the utility, *i.e.*, provide an adequate return on capital to attract investors.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of a company or firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where 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.

In a competitive market, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of those required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[18]

[18] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1986), p. 3.

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns a ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio 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 value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN ROE AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[19]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity– should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

To assess the relationship by industry, as suggested above, I performed a regression study between estimated ROE and market-to-book ratios using *Value Line*'s electric utilities and gas distribution companies. I used all electric utility and gas distribution companies that are covered by *Value Line* and have estimated ROE and market-to-book ratio data. The results are presented in Exhibit JRW-4. The R-square for the regression of estimated ROEs and market-to-book

[19] Benjamin Esty, "Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

ratios is 0.50.[20] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for electric utilities. Given 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.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-5 provides indicators of public utility equity cost rates.

Page 1 shows the yields on long-term A-rated public utility bonds. These yields decreased from 2000 until 2003, and then hovered in the 5.50%-6.50% range from mid-2003 until mid-2008. They peaked in November 2008 at 7.75% during the Great Recession. These yields have generally declined since then, dropping below 4.0% on five occasions - in mid-2013, in the first quarter of 2015, in the summer of 2016, in late 2018. In 2019, these yields have declined significantly are in the 3.50% to 3.75% range.

Page 2 of Exhibit JRW-5 provides the average dividend yields for electric utility companies over the past 16 years. The dividend yields for the electric group declined from 5.3% to 3.4% between the years 2001 to 2007, increased to over 5.0% in 2009, and have

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20 R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

declined steadily since that time. The average dividend yield was 3.2% in 2018.

Average earned returns on common equity and market-to-book ratios for electric utilities are on page 3 of Exhibit JRW-5. For the electric group, earned returns on common equity have declined gradually over the years. In the past three years, the average earned ROE for the group has been in the 9.0% to 10.0% range. The average market-to-book ratios for this group declined to about 1.1X in 2009 during the financial crisis and have increased since that time. As of 2018, the average market-to-book for the group was 1.80X. This means that, for at least the last decade, returns on common equity for electric utilities have been greater than the cost of capital, or more than necessary to meet investors' required returns. This also means that customers have been paying more than necessary to support an appropriate profit level for regulated utilities.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business risk and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF PUBLIC UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Page 4 of Exhibit JRW-5 provides an assessment of investment risk for 97 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey*. The study shows that the investment risk of utilities is very low. The average betas for electric, gas, and water utility companies are 0.60, 0.67, and 0.70, respectively.[21] As such,

[21] The beta for the *Value Line* Electric Utilities is the simple average of *Value Line*'s Electric East (0.55), Central (0.63), and West (0.62) group betas.

the cost of equity for utilities is the lowest of all industries in the U.S. based on modern capital market theory.

Q. WHAT IS THE COST OF COMMON EQUITY CAPITAL?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return requirement of the stockholder should be commensurate with the return requirement on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DID YOU ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the discounted cash flow ("DCF") model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a capital asset pricing model ("CAPM") study; however, I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. Discounted Cash Flow Analysis

Q. PLEASE DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_1, D_2, D_n is the dividends in year 1, 2, and in the future years n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are presented in Exhibit JRW-6, Page 1 of 2. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a maturity (or steady-state) stage. The dividend-payment stage of a firm depends on the profitability of its internal investments which, in turn, is largely a function of the life cycle of the product or service.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and an abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually, the company reaches a position where its new investment opportunities offer, on average, only slightly more attractive ROEs. At that time, its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. As I will explain below, the constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using the 3-stage model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where P is the current stock price, D_1 represents the expected dividend over the coming year, k is investor's required return on equity, and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). The dividend yield can be measured precisely at any point in time; however, it tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. WHAT DIVIDEND YIELDS HAVE YOU REVIEWED?

A. I have calculated the dividend yields for the companies in the proxy group using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. These dividend yields are provided in Panels A and B of page 2 of Exhibit JRW-7. I have shown the mean and median dividend yields using 30-day, 90-day, and 180-day average stock prices. Using both the means and medians, the dividend yields range from 2.8% to 3.3% for the Electric Proxy Group and 2.9% to 3.2% for the Hevert Proxy Group. Therefore, I will use a dividend yields of 3.10% and 3.05% for my Electric Proxy Group and the Hevert Proxy Group, respectively.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates the dividend paid over the coming period to the current stock price. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[22]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR DO YOU USE FOR YOUR DIVIDEND YIELD?

A. I adjust the dividend yield by one-half (1/2) of the expected growth to reflect growth over the coming year. The DCF equity cost rate ("K") is computed as:

$$K = [(D/P) * (1 + 0.5g)] + g$$

[22] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book-value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy groups. I reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to investors and are presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations, due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (*i.e.*, business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE SERVICES THAT PROVIDE ANALYSTS' EPS FORECASTS.

A. Analysts' EPS forecasts for companies are collected and published by several different investment information services, including Institutional Brokers Estimate System ("I/B/E/S"), Bloomberg, FactSet, Zacks, First Call, and Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. Bloomberg, FactSet, and Zacks each publish their own set of analysts' EPS forecasts for companies. These services do not reveal (1) the analysts who are solicited for forecasts or (2) the identity of the analysts who actually provide the EPS forecasts that are used in the compilations published by the services. I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. In contrast, Thompson Reuters and Zacks provide limited EPS forecast data free-of-charge on the Internet. Yahoo finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. The Reuters website (www.reuters.com) also publishes EPS forecasts from Thompson Reuters, but with more detail. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zacks estimates are also available on other websites, such as MSN.money (http://money.msn.com).

Q. PLEASE PROVIDE AN EXAMPLE OF THESE EPS FORECASTS.

A. The following example provides the EPS forecasts compiled by Reuters for Consolidated Edison (stock symbol "ED"). The figures are provided on page 2 of Exhibit JRW-6. Line one shows that twelve analysts have provided EPS estimates for the quarter ending September 30, 2019. The mean, high, and low estimates are $1.60, $1.70, and $1.53, respectively. The second line shows the quarterly EPS estimates for the quarter ending December 31, 2019 of $0.77 (mean), $0.85 (high), and $0.66 (low). Line three shows the annual EPS estimates for the fiscal year ending December 2019 of $4.35 (mean), $4.99 (high), and $4.30 (low). Line four shows the annual EPS estimates for the fiscal year ending December 2020 of $4.57 (mean), $4.73 (high), and $4.47 (low). The quarterly and annual EPS forecasts in lines 1-4 are expressed in dollars and cents. As in the ED case shown here, it is common for more analysts to provide estimates of annual EPS as opposed to quarterly EPS. The bottom line (5) shows the projected long-term EPS growth rate, which is expressed as a percentage. For ED, four analysts have provided a long-term EPS growth rate forecast, with mean, high, and low growth rates of 3.44%, 4.89%, and 2.00%.

Q. WHICH OF THESE EPS FORECASTS IS USED IN DEVELOPING A DCF GROWTH RATE?

A. The DCF growth rate is the long-term projected growth rate in EPS, DPS, and BVPS. Therefore, in developing an equity cost rate using the DCF model, the projected long-term growth rate is the projection used in the DCF model.

Q. WHY DO YOU NOT RELY EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, a study by Lacina, Lee, and Xu (2011) has shown that analysts' three-to-five year EPS growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[23] Employing data over a twenty-year period, these authors demonstrate that using the most recent year's actual EPS figure to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' three-to-five year EPS growth rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth-rate forecasts should be used with caution as inputs for valuation and cost of capital purposes. Finally, and most significantly, it is well known that the long-term EPS growth-rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years.[24] Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Easton and Sommers (2007) found that optimism in analysts' growth rate

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[23] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting (Vol. 8)*, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[24] The studies that demonstrate analysts' long-term EPS forecasts are overly-optimistic and upwardly biased include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance*, pp. 643–684, (2003); M. Lacina, B. Lee, and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8)*, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101; and Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[25]

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

A. Yes, I do believe that investors are well aware of the bias in analysts' EPS growth-rate forecasts, and therefore stock prices reflect the upward bias.

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. Because I believe that investors are aware of the upward bias in analysts' long-term EPS growth rate forecasts, stock prices reflect the bias. But the DCF growth rate needs to be adjusted downward from the projected EPS growth rate to reflect the upward bias in the DCF model.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE PROXY GROUPS, AS PROVIDED BY *VALUE LINE*.

A. Page 3 of Exhibit JRW-7 provides the 5- and 10- year historical growth rates for EPS, DPS, and BVPS for the companies in the two

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[25] Peter D. Easton & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, 45 J. ACCT. RES. 983–1015 (2007).

proxy groups, as published in the *Value Line Investment Survey*. The median historical growth measures for EPS, DPS, and BVPS for the Electric Proxy Group, as provided in Panel A, range from 4.0% to 6.5%, with an average of the medians of 4.8%. For the Hevert Proxy Group, as shown in Panel B of page 3 of Exhibit JRW-7, the historical growth measures in EPS, DPS, and BVPS, as measured by the medians, range from 4.0% to 5.5%, with an average of the medians of 4.7%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUPS.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-7. As stated above, due to the presence of outliers, the medians are used in the analysis. For the Electric Proxy Group, as shown in Panel A of page 4 of Exhibit JRW-7, the medians range from 4.0% to 5.5%, with an average of the medians of 5.1%. The range of the medians for the Hevert Proxy Group, shown in Panel B of page 4 of Exhibit JRW-7, is from 4.0% to 6.0%, with an average of the medians of 5.2%.

Also provided on page 4 of Exhibit JRW-7 are the prospective sustainable growth rates for the companies in the two proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable growth is a significant and a primary driver of long-run earnings growth. For the Electric and Hevert Proxy Groups, the median prospective sustainable growth rates are 3.8% and 3.7%, respectively.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Yahoo, Zacks, and Reuters collect, summarize, and publish Wall Street analysts' 5-year EPS growth-rate forecasts for the companies in the proxy groups. These forecasts are provided for the companies in the proxy groups on page 5 of Exhibit JRW-7. I have reported both the mean and median growth rates for the groups. Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate for each company. The mean/median of analysts' projected EPS growth rates for the Electric and Hevert Proxy Groups are 5.2%/5.5% and 5.7%/5.9%, respectively.[26]

[26] Given variation in the measures of central tendency of analysts' projected EPS growth rates proxy groups, I have considered both the means and medians figures in the growth rate analysis.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUPS.

A. Page 6 of Exhibit JRW-7 shows the summary DCF growth rate indicators for the proxy groups.

The historical growth rate indicators for my Electric Proxy Group imply a baseline growth rate of 4.8%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 5.1%, and *Value Line*'s projected sustainable growth rate is 3.8%. The projected EPS growth rates of Wall Street analysts for the Electric Proxy Group are 5.0% and 5.5% as measured by the mean and median growth rates. The overall range for the projected growth-rate indicators (ignoring historical growth) is 3.7% to 5.5%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate projected growth rate is 5.35%, which is the average of the mean and median projected EPS growth rates. This growth rate figure is in the upper end of the range of historic and projected growth rates for the Electric Proxy Group.

For the Hevert Proxy Group, the historical growth rate indicators suggest a growth rate of 4.7%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 5.2%, and *Value Line*'s projected sustainable growth rate is 3.7%. The projected EPS growth rates of Wall Street analysts are 5.7% and 5.9% as measured by the mean and median growth rates. The overall range for the projected growth rate indicators is 3.7% to 5.9%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate projected growth rate is 5.80%, which is the average of the mean and median projected EPS growth rates. This growth rate figure is in the upper end of the range of historic and projected growth rates for the Hevert Proxy Group.

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE PROXY GROUPS?

A. My DCF-derived equity cost rates for the groups are summarized on page 1 of Exhibit JRW-7 and in Table 5 below.

Table 5
DCF-Derived Equity Cost Rate/ROE

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	3.10%	1.02675	5.35%	8.55%
Hevert Proxy Group	3.05%	1.02900	5.80%	8.95%

The result for the Electric Proxy Group is the 3.10% dividend yield, times the one and one-half growth adjustment of 1.02675, plus the DCF growth rate of 5.35%, which results in an equity cost rate of 8.55%. The result for the Hevert Proxy Group is 8.95%, which includes a dividend yield of 3.05%, an adjustment factor of 1.02900, and a DCF growth rate of 5.80%.

C. Capital Asset Pricing Model

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL ("CAPM").

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term U.S. Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is expressed as:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- *K* represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected rate of return on the overall stock market. Frequently, the S&P 500 is used as a proxy for the "market";
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess rate of return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term U.S. Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium $(E(R_m) - (R_f))$. I will discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-8.

A. Exhibit JRW-8 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. As shown on page 2 of Exhibit JRW-8, the yield on 30-year U.S. Treasury bonds has been in the 2.0% to 4.0% range over the 2013–2019 time period. The current 30-year Treasury yield is near the bottom of this range as interest rates have declined significantly in 2019. Given the recent range of yields, I have chosen to use the top end of the range as my risk-free interest rate. Therefore, I am using 4.0% as the risk-free rate, or R_f, in my CAPM.

Q. DOES YOUR 4.0% RISK-FREE INTEREST RATE TAKE INTO CONSIDERATION FORECASTS OF HIGHER INTEREST RATES?

A. No, it does not. As I stated before, forecasts of higher interest rates have been notoriously wrong for a decade. My 4.0% risk-free interest rate takes into account the range of interest rates in the past and effectively synchronizes the risk-free rate with the market-risk premium ("MRP"). The risk-free rate and the MRP are interrelated in that the MRP is developed in relation to the risk-free rate. As discussed below, my MRP is based on the results of many studies and surveys that have been published over time. Therefore, my risk-free interest rate of 4.0% is effectively a normalized risk-free rate of interest.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-8, the slope of the regression line is the stock's ß. A steeper line indicates that the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater-than-average market risk. A less steep line indicates a lower ß and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy groups, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-8, the median betas for the companies in the Electric and Hevert Proxy Groups are 0.60 and 0.58, respectively.

Q. PLEASE DISCUSS THE MARKET RISK PREMIUM.

A. The MRP is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, $E(R_m)$ minus the risk-free rate of interest (R_f)). The MRP is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the MRP is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market - $E(R_m)$. As discussed below, there are different ways to measure $E(R_m)$, and studies have come up with significantly different magnitudes for $E(R_m)$. As Merton Miller, the 1990 Nobel Prize winner in economics indicated, $E(R_m)$ is very difficult to measure and is one of the great mysteries in finance.[27]

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE MRP.

A. Page 4 of Exhibit JRW-8 highlights the primary approaches to, and issues in, estimating the expected MRP. The traditional way to measure the MRP was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called *ex post* returns, were used as the measures of the market's expected return (known as the *ex ante* or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson, who popularized this method of using historical financial market returns as measures of expected returns. However, this historical evaluation of returns can be a problem because: (1) *ex post* returns are not the same as *ex ante* expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market conditions can change such that *ex post* historical returns are poor estimates of *ex ante* expectations.

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[27] Merton Miller, "The History of Finance: An Eyewitness Account," *Journal of Applied Corporate Finance*, 2000, p. 3.

The use of historical returns as market expectations has been criticized in numerous academic studies as discussed later in my testimony. The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "*Ex Ante* Models and Market Data," compute *ex ante* expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[28]

In addition, there are a number of surveys of financial professionals regarding the MRP. There have also been several published surveys of academics on the equity risk premium. *CFO Magazine* conducts a quarterly survey of CFOs, which includes questions regarding their views on the current expected returns on stocks and bonds. Usually, over 200 CFOs participate in the survey.[29] Questions regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters, which is published as the *Survey of*

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[28] Rajnish Mehra & Edward C. Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics*, 145 (1985).

[29] DUKE/CFO Magazine Global Business Outlook Survey, (June 2019), https://www.cfosurvey.org/wp-content/uploads/2019/06/Q2-2019-US-Toplines-1.pdf.

Professional Forecasters.[30] This survey of professional economists has been published for almost fifty years. In addition, Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.[31]

Q. PLEASE PROVIDE A SUMMARY OF THE MRP STUDIES.

A. Derrig and Orr (2003), Fernandez (2007), and Song (2007) completed the most comprehensive review of the research on the MRP.[32] Derrig and Orr's study evaluated the various approaches to estimating MRPs, as well as the issues with the alternative approaches and summarized the findings of the published research on the MRP. Fernandez examined four alternative measures of the MRP – historical, expected, required, and implied. He also reviewed the major studies of the MRP and presented the summary MRP

[30] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters* (Mar. 22, 2019),

https://www.philadelphiafed.org/-/media/research-and-data/real-time-center/survey-of-professional-forecasters/2019/spfq119.pdf?la=en. The Survey of Professional Forecasters was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

[31] Pablo Fernandez, Vitaly Pershin, and Isabel Fernandez Acín, "Market Risk Premium and Risk-Free Rate used for 59 countries in 2019: a survey," *IESE Business School*, (Apr. 2019), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3358901.

[32] *See* Richard Derrig & Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the MRP.

Page 5 of Exhibit JRW-8 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song, as well as other more recent studies of the MRP. In developing page 5 of Exhibit JRW-8, I have categorized the studies as discussed on page 4 of Exhibit JRW-8. I have also included the results of studies of the "Building Blocks" approach to estimating the equity risk premium. The Building Blocks approach is a hybrid approach employing elements of both historical and *ex ante* models.

Q. PLEASE DISCUSS PAGE 5 OF EXHIBIT JRW-8.

A. Page 5 of Exhibit JRW-8 provides a summary of the results of the MRP studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium, (2) *ex ante* MRP studies, (3) MRP surveys of CFOs, financial forecasters, analysts, companies and academics, and (4) the Building Blocks approach to the MRP. There are results reported for over thirty surveys and studies, and the median MRP is 4.83%.

Q. PLEASE HIGHLIGHT THE RESULTS OF THE MORE RECENT RISK PREMIUM STUDIES AND SURVEYS.

A. The studies cited on page 5 of Exhibit JRW-8 include every MRP study and survey I could identify that was published over the past fifteen years and that provided an MRP estimate. Many of these studies were published prior to the financial crisis that began in 2008. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as fifty years of data) and so were not estimating an MRP as of a specific point in time (e.g., the year 2001). To assess the effect of the earlier studies on the MRP, I have reconstructed page 5 of Exhibit JRW-8 on page 6 of Exhibit JRW-8; however, I have eliminated all studies dated before January 2, 2010. The median for this subset of studies is 5.09%.

Q. **PLEASE SUMMARIZE THE MRP STUDIES AND SURVEYS.**

A. As noted above, there are three approaches to estimating the MRP – historic stock and bond returns, ex ante or expected returns models, and surveys. The studies on pages 5 and 6 of Exhibit JRW-8 can be summarized in the following manners:

Historic Stock and Bond Returns - Historic stock and bond returns suggest an MRP in the 4.40% to 6.26% range, depending on whether one uses arithmetic or geometric mean returns.

Ex Ante Models - MRP studies that use expected or ex ante return models indicate MRPs in the range of 4.49% to 6.00%.

Surveys - MRPs developed from surveys of analysts, companies, financial professionals, and academics find lower MRPs, with a range from 1.85% to 5.7%.

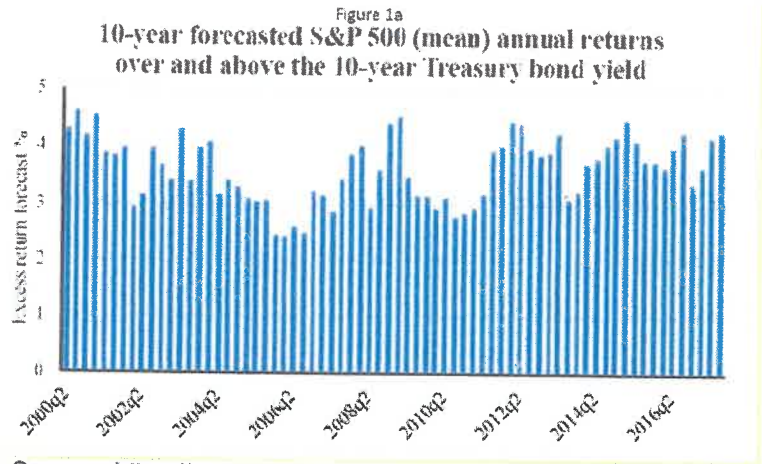
Q. PLEASE HIGHLIGHT THE EX ANTE MRP STUDIES AND SURVEYS THAT YOU BELIEVE ARE MOST TIMELY AND RELEVANT.

A. I will highlight several studies/surveys.

CFO Magazine conducts a quarterly survey of CFOs, which includes questions regarding their views on the current expected returns on stocks and bonds. In the June 2019 CFO survey conducted by *CFO Magazine* and Duke University, which included approximately 200 responses, the expected 10-year MRP was 4.05%.[33] Figure 4, below, shows the MRP associated with the CFO Survey, which has been in the 4.0% range in recent years.

[33] DUKE/CFO Magazine Global Business Outlook Survey, at 33, (June 2019), https://www.cfosurvey.org/wp-content/uploads/2019/06/Q2-2019-US-Toplines-1.pdf.

Figure 4
Market Risk Premium
CFO Survey



Source: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162

Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.[34] His survey results are included on pages 5 and 6 of Exhibit JRW-8. The results of his 2019 survey of academics, financial analysts, and companies, which included 4,000 responses, indicated a mean MRP employed by U.S. analysts and companies of 5.6%.[35] His estimated MRP for the U.S. has been in the 5.00%-5.50% range in recent years.

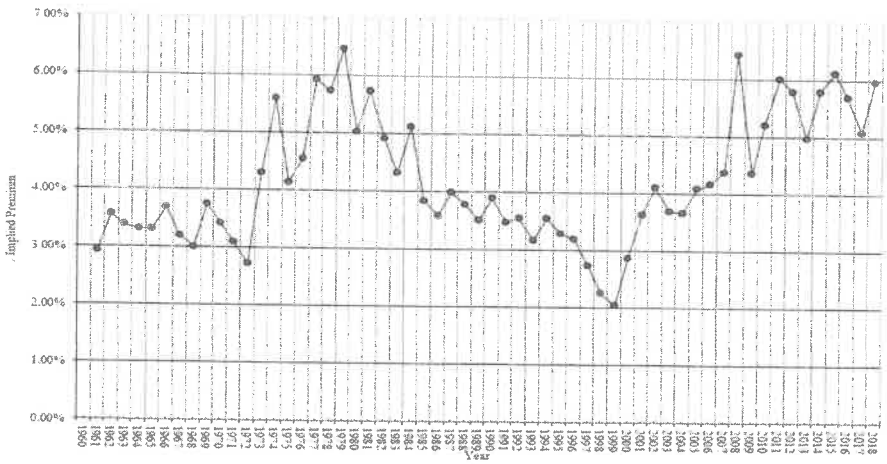
Professor Aswath Damodaran of NYU, a leading expert on valuation and the MRP, provides a monthly updated MRP which is

[34] Pablo Fernandez, Vitaly Pershin, and Isabel Fernandez Acín, "Market Risk Premium and Risk-Free Rate used for 59 countries in 2019: a survey," *IESE Business School*, (Apr. 2019), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3358901.

[35] *Ibid.*, p. 3.

based on projected S&P 500 EPS and stock price level and long-term interest rates. His estimated MRP, shown graphically in Figure 5, below, for the past twenty years, has primarily been in the range of 5.0% to 6.0% since 2010.

Figure 5
Damodaran Market Risk Premium



Source: http://pages.stern.nyu.edu/~adamodar/

Duff & Phelps, an investment advisory firm, provides recommendations for the risk-free interest rate and MRPs to be used in calculating the cost of capital data. Their recommendations over the 2008-2019 time periods are shown on page 7 of Exhibit JRW-8. Duff & Phelps' recommended MRP has been in the 5.0% to 6.0% over the past decade. Most recently, effective December 31, 2018, Duff & Phelps increased its recommended MRP from 5.00% to 5.50%.[36]

KPMG is one of the largest public accounting firms in the world. Its recommended MRP over the 2013-2019 time period is shown in Panel A of page 8 of Exhibit JRW-8. KPMG's recommended MRP has been in the 5.50% to 6.50% range over this time period. Since the third quarter of 2018, KPMG has recommended an MRP of 5.50%.[37]

Finally, the website *market-risk-premia.com* provides risk-free interest rates, implied MRPs, and overall cost of capital for thirty-six countries around the world. These parameters for the U.S. over the 2002-2019 time period are shown in Panel B of page 8 of Exhibit JRW-8. As of May 31, 2019, *market-risk-premia.com* estimated an implied cost of capital for the U.S. of 6.40%, consisting of a risk-free rate of 2.14% and an implied MRP of 4.26%.[38]

Q. GIVEN THESE RESULTS, WHAT MRP ARE YOU USING IN YOUR CAPM?

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[36] Duff & Phelps, "U.S. Equity Risk Premium Recommendation," (Feb. 19, 2019), https://www.duffandphelps.com/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates.

[37] KPMG, "Equity Market Risk Premium Research Summary," (Dec. 31, 2019), https://assets.kpmg/content/dam/kpmg/nl/pdf/2019/advisory/equity-market-research-summary.pdf.

[38] Market-Risk-Premia.com, "Implied Market-risk-premia (IMRP): USA," http://www.market-risk-premia.com/us.html.

A. The studies on page 6 of Exhibit JRW-8, and more importantly the more timely and relevant studies just cited, suggest that the appropriate MRP in the U.S. is in the 4.0% to 6.0% range. I will use an expected MRP of 5.50%, which is in the upper end of the range, as the MRP. I gave most weight to the MRP estimates of the CFO Survey, Duff & Phelps, the Fernandez survey, and Damodaran. This is a conservatively high estimate of the MRP considering the many studies and surveys of the MRP.

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy groups are summarized on page 1 of Exhibit JRW-8 and in Table 6 below.

Table 6
CAPM-Derived Equity Cost Rate/ROE
$$K = (R_f) + \beta * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Proxy Group	**4.0%**	**0.60**	**5.5%**	**7.3%**
Hevert Proxy Group	**4.0%**	**0.58**	**5.5%**	**7.2%**

For the Electric Proxy Group, the risk-free rate of 4.0% plus the product of the beta of 0.60 times the equity risk premium of 5.5% results in a 7.3% equity cost rate. For the Hevert Proxy Group, the risk-free rate of 4.0% plus the product of the beta of 0.58 times the equity risk premium of 5.5% results in a 7.2% equity cost rate.

Q. THESE CAPM EQUITY COST RATES SEEM LOW. WHY IS THAT?

A. One major factor is that the riskiness of utilities has declined in recent years, and this lower risk is reflected in their betas. Utility betas have been in the .70 to .75 range in recent years. But they have declined in the past year and are now are primarily in the 0.55 to 0.60 range.

D. Equity Cost Rate Summary

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY COST RATE STUDIES.

A. My DCF analyses for the Electric and Hevert Proxy Groups indicate equity cost rates of 8.55% and 8.95%, respectively. The CAPM equity cost rates for the groups are 7.3% and 7.2%. Table 7, below, shows these results.

Table 7
ROEs Derived from DCF and CAPM Models

	DCF	CAPM
Electric Proxy Group	8.55%	7.30%
Hevert Proxy Group	8.95%	7.20%

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUPS?

A. I conclude that the appropriate equity cost rate for companies in the Electric and Hevert Proxy Groups is in the 7.2% to 8.95% range.

Q. WHAT EQUITY COST RATE ARE YOU RECOMMENDING FOR DENC?

A. Given these results, I am recommending an equity cost rate or ROE for DENC of 8.75%. I believe that this equity cost rate accurately reflects the market cost of equity capital currently. As I previously noted, capital costs in the U.S. remain low, with low inflation and interest rates, very modest economic growth, and the stock market at an all-time high.

Q. PLEASE INDICATE WHY YOUR EQUITY COST RATE RECOMMENDATION IS APPROPRIATE FOR DENC.

A. There are a number of reasons why an equity cost rate of 8.75% is appropriate and fair for the Company in this case:

1. DENC's investment risk, as indicated by its S&P and Moody's credit ratings, is below the averages of the Electric and Hevert Proxy Groups;

2. As shown in Exhibits JRW-5, capital costs for utilities, as indicated by long-term utility bond yields, are still at historically low levels. In addition, given low inflationary expectations and slow global economic growth, interest rates are likely to remain at low levels for some time;

3. As shown in Exhibit JRW-5, the electric utility industry is among the lowest risk industries in the U.S. as measured by beta.

Most notably, the betas for electric utilities have been declining in recent years, which indicates the risk of the industry has declined. Overall, the cost of equity capital for this industry is the lowest in the U.S., according to the CAPM;

4. I have recommended an equity cost rate at the high end of the range of my ROE outcomes;

5. As shown in Figure 3, the authorized ROEs for electric utility and gas distribution companies have declined in recent years. The authorized ROEs for electric utilities have declined from 10.01% in 2012, to 9.8% in 2013, to 9.76% in 2014, 9.58% in 2015, 9.60% in 2016, 9.68% in 2017, 9.56% in 2018, and 9.56% in the first half of 2019, according to Regulatory Research Associates.[39] In my opinion, these authorized ROEs have lagged behind capital market cost rates, or in other words, authorized ROEs have been slow to reflect low capital market cost rates. However, the <u>trend</u> has been towards lower ROEs, and the <u>norm</u> now is below ten percent. Hence, I believe that my recommended ROE reflects the low capital cost rates in today's markets, and these low capital cost rates are finally being recognized by state utility commissions.

[39] *Regulatory Focus*, Regulatory Research Associates, 2019. The electric utility authorized ROEs exclude the authorized ROEs in Virginia, which include generation adders.

Q. DO YOU BELIEVE THAT YOUR ROE RECOMMENDATION MEETS *HOPE* AND *BLUEFIELD* STANDARDS?

A. Yes, I do. As previously noted, according to the *Hope* and *Bluefield* decisions, returns on capital 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. PLEASE ALSO DISCUSS YOUR RECOMMENDATION IN LIGHT OF A MOODY'S PUBLICATION ON ROES AND CREDIT QUALITY.

A. Moody's published an article on utility ROEs and credit quality. In the article, Moody's recognizes that authorized ROEs for electric and gas companies are declining due to lower interest rates. The article explains:[40]

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinize their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting

[40] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

> cash flow, for instance by targeting depreciation, or through special rate structures.

Moody's indicates that with the lower authorized ROEs, electric and gas companies are earning ROEs of 9.0% to 10.0%, yet this is not impairing their credit profiles and is not deterring them from raising record amounts of capital.

With respect to authorized ROEs, Moody's recognizes that utilities and regulatory commissions are having trouble justifying higher ROEs in the face of lower interest rates and cost recovery mechanisms:[41]

> Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

Overall, this article further supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital.

[41] *Id.*

Q. ARE UTILITIES ABLE TO ATTRACT CAPITAL WITH THE LOWER ROES?

A. Moody's also highlights in the article that utilities are raising about $50 billion a year in debt capital, despite the lower ROEs.

VI. CRITIQUE OF DENC'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE THE COMPANY'S COST OF EQUITY CAPITAL RECOMMENDATION.

A. The Company has proposed a capital structure of 46.351% long-term debt and 53.649% common equity and a long-term debt cost rate of 4.442%. Mr. Hevert has recommended a common equity cost rate of 10.75%. The Company's overall proposed rate of return is 7.83%.

Q. WHAT ISSUES DO YOU HAVE WITH THE COMPANY'S COST OF EQUITY CAPITAL POSITION?

A. I have a number of issues with the Company's ROE position:

1. Capital Structure – The Company has proposed a capital structure consisting of 46.351% long-term debt and 53.649% common equity. The Company's proposed capital structure has a higher common equity ratio than the average of the Electric and Hevert Proxy Groups. In my primary rate of return recommendation, I am recommending adjusting DENC's proposed capital structure to use a common equity ratio of 50

percent, as that is more in line with the capital structures of the utilities in the proxy group as well as DENC's parent, Dominion Energy. In my alternative rate of return recommendation, I am using DENC's proposed updated capital structure, but I then employ a lower ROE to reflect the high common equity ratio and lower financial risk of the Company's proposed capitalization.

2. Capital Market Conditions – Mr. Hevert's analyses and ROE results and recommendations reflect the assumption of higher interest rates and capital costs. However, I show 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. In 2019 interest rates have fallen dramatically with slow economic growth and low inflation, and the 30-year yield has traded at all-time low levels.

3. DENC's Investment Risk is Below the Averages of the Two Proxy Groups – Mr. Hevert cites the Company's capital expenditures to imply that DENC is riskier than his proxy group. In addition, he selects an ROE that is near the upper end of his 10.0% to 11.0% range. However, his assessment of DENC's risk is erroneous. The assessment of capital expenditures is part of the credit rating process, and DENC's S&P and Moody's credit rating suggest that the Company's investment risk is below the averages of the proxy groups.

4. Disconnect Between Mr. Hevert's Equity Cost Rate Studies and his 10.75% ROE Recommendation – There is a disconnect between Mr. Hevert's equity cost rate results and his 10.75% ROE recommendation. Simply stated, the vast majority of his equity cost rate results point to a lower ROE. In fact, the only results that point to an ROE as high as 10.75% are his CAPM/ECAPM results using *Value Line* betas and market risk premium ("MRP"), which as I explain later in my testimony are flawed. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one model (the CAPM); and, even more narrowly, (2) only one source of financial information for betas and MRP (*Value Line*). Otherwise, Mr. Hevert provides no other equity cost rate studies that support his 10.75% ROE recommendation.

5. DCF Equity Cost Rate - The DCF Equity Cost Rate is estimated by summing the stock's dividend yield and investors' expected long-run growth rate in dividends paid per share. There are several errors regarding Mr. Hevert's DCF analyses: (1) he has given very little weight to his constant-growth DCF results; and (2) he has relied exclusively on the overly optimistic and upwardly biased earnings per share ("EPS") growth-rate forecasts of Wall Street analysts and *Value Line*.

6. CAPM Approach - The CAPM approach requires an estimate of the risk-free interest rate, the beta, and the market or equity risk premium. There are three primary issues with Mr. Hevert's CAPM analyses: (1) he employs an excessively high, projected long-term risk-free interest rate; (2) his MRPs of 10.65% and 13.77% are exaggerated and do not reflect current market fundamentals. Mr. Hevert has employed analysts' three-to-five-year growth-rate projections for EPS to compute an expected market return and MRP. These EPS growth-rate projections and the resulting expected market returns and MRPs include highly unrealistic assumptions regarding future economic and earnings growth and stock returns; and (3) Mr. Hevert has employed an ad hoc version of the CAPM, the empirical CAPM ("ECAPM"), which makes inappropriate adjustments to the risk-free rate and the market risk premium and is an untested model in academic and profession research.

7. Alternative Risk Premium Model - Mr. Hevert estimates an equity cost rate using an alternative risks premium model which he calls the Bond Yield Risk Premium ("BYRP") approach. The risk premium in his BYRP method is based on the historical relationship between the yields on long-term Treasury yields and authorized ROEs for electric utility companies. There are several issues with this approach including: (1) this approach is a gauge

of commission behavior and not investor behavior; (2) Mr. Hevert's methodology produces an inflated measure of the risk premium because his approach uses historical authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields; and (3) the risk premium is inflated as a measure of investor's required risk premium, because electric utility companies have been selling at market-to-book ratios in excess of 1.0. This indicates that the authorized rates of return have been greater than the return that investors require.

8. Expected Earnings Approach - Mr. Hevert also uses the Expected Earnings approach to estimate an equity cost rate for the Company. Mr. Hevert computes the expected ROE as forecasted by *Value Line* for his proxy group as well as for *Value Line*'s universe of electric utilities. The biggest issue is that the so-called "Expected Earnings" approach does not measure the market cost of equity capital, is independent of most cost of capital indicators, and has several other empirical issues. Therefore, the Commission should ignore Mr. Hevert's "Expected Earnings" approach in determining the appropriate ROE for DENC.

9. Other Issues - Mr. Hevert also considers two other factors in arriving at his 10.75% ROE recommendation. First, Mr. Hevert cites the Company's high level of capital expenditures in the

coming years. However, as I note, capital expenditures are considered as a risk factor in the credit-rating process used by major rating agencies. In addition, as I noted above, DENC's investment risk as measured by S&P and Moody's is below the average of the proxy groups. Second, Mr. Hevert also considers flotation costs in making his ROE recommendation of 10.75%. However, he has not identified any flotation costs for DENC.

10. North Carolina Economic Conditions – Mr. Hevert evaluates a number of factors such as employment and income levels and comes to the conclusion that DENC's proposed ROE of 10.75% is fair and reasonable to DENC, its shareholders, and its customers in light of the effect of those changing economic conditions. While I agree economic conditions have improved in North Carolina, the improvements do not necessarily justify such a high rate of return and ROE. Specifically, I highlight the following: (1) DENC's ROE request of 10.75% is over 100 basis points above the average authorized ROEs for electric utilities over the 2018-19 time period; (2) whereas North Carolina's unemployment rate has fallen by one-third since its peak in the 2009-2010 period and is slightly below the national average of 3.90%, the unemployment rate in DENC's service territory is 4.95%, over 100 basis points higher than the national and North Carolina averages; and (3) whereas North Carolina's residential

electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm.

Capital market conditions, DENC's proposed capital structure, and the investment risk of DENC were previously discussed. The other issues are addressed below.

A. The Disconnect Between Mr. Hevert's Equity Cost Rate Results and His 10.75% ROE Recommendation

Q. PLEASE REVIEW MR. HEVERT'S EQUITY COST RATE RESULTS AND HIS 10.75% ROE RECOMMENDATION.

A. Page 1 of Exhibit JRW-9 shows Mr. Hevert's equity cost rate results using the DCF, CAPM, and BYRP approaches. There appears to be a disconnect between these results and his 10.75% ROE recommendation. First, it is very difficult to see exactly how he gets to his 10.75% ROE recommendation. He provides no details on how he weighted his equity cost rate results to get to 10.75%.

Second, the vast majority of his equity cost rate results point to a lower ROE. The average of his DCF results is 9.31%, to which he clearly gave no weight. His BYRP results, which are inflated because he has used projected interest rates, average 10.0%. His CAPM results, calculated using a Bloomberg MRP, are also inflated because he has used projected interest rates, and average less than 9.0%. These results clearly received no weight.

Finally, the only results that point to a ROE as high as 10.75% are his CAPM results using *Value Line* betas and MRP. As a result, Mr. Hevert's ROE recommendation is based on: (1) the results of only one model (the CAPM); and, even more narrowly, (2) only one source of financial information for betas and MRP (*Value Line*). In addition, as discussed below, there are a number of empirical issues with the *Value Line* projected EPS growth rates which result in an overstated expected market return and MRP. Otherwise, Mr. Hevert provides no other credible equity cost rate studies that support his 10.75% ROE recommendation. Therefore, his ROE recommendation is based on not only one model (CAPM/ECAPM), but also on only one information source (*Value Line*). There are obvious risks to relying on only one approach and information source to estimate the cost of equity capital.

B. DCF Approach

Q. PLEASE SUMMARIZE MR. HEVERT'S DCF ESTIMATES.

A. On pages 19-26 of his testimony and in Exhibit No. RBH-1, Mr. Hevert develops an equity cost rate by applying the DCF model to the Hevert Proxy Group. Mr. Hevert's DCF results are summarized on page 1 of my Exhibit JRW-9. He uses constant-growth and multistage growth DCF models. Mr. Hevert uses three dividend-yield measures (30, 90, and 180 days) in his DCF models. In his constant-growth and quarterly DCF models, Mr. Hevert has relied on the forecasted EPS growth rates of Zacks, IBES, and *Value Line*. For each model, he reports Mean Low, Mean, and Mean High results.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S DCF ANALYSES?

A. The primary errors in Mr. Hevert's DCF analyses are: (1) the low weight he gives to his constant-growth DCF results, and (2) his exclusive use of the overly optimistic and upwardly biased EPS growth rate forecasts of Wall Street analysts and *Value Line*.

1. The Low Weight Given to the DCF Results

Q. HOW MUCH WEIGHT HAS MR. HEVERT GIVEN HIS DCF RESULTS IN ARRIVING AT AN EQUITY COST RATE FOR THE COMPANY?

A. Apparently, very little, if any. The average of his mean constant-growth and multi-stage DCF equity cost rates is only 9.31%. Had he given these results more weight, he would have arrived at a much lower recommendation for his estimated cost of equity.

Q. IS THERE ANY REASON FOR MR. HEVERT TO IGNORE HIS DCF RESULTS DUE TO CURRENT MARKET CONDITIONS?

A. Mr. Hevert had expressed concerns with the constant-growth DCF model results because of current capital market conditions which includes high utility stock valuations. However, as discussed in the Moody's article I cite above, utilities have achieved higher market valuations due to cost recovery mechanisms that have reduced the risk of the utility industry, which have led to higher valuation levels.[42]

> As utilities increasingly secure more up-front assurance for cost recovery in their rate proceedings, we think regulators will increasingly view the sector as less risky. The combination of low capital costs, high equity market valuation multiples (which are better than or on par with the broader market despite the regulated utilities' low risk profile), and a transparent assurance of cost recovery tend to support the case for lower authorized returns, although because utilities will argue they should rise, or at least stay unchanged.

Therefore, Mr. Hevert's suggestion that the constant-growth DCF results may provide low results due to current market conditions is incorrect. As indicated by Moody's, the lower risk of utilities has led to higher valuation levels.

2. Wall Street Analysts' EPS Growth Rate Forecasts

Q. PLEASE DISCUSS MR. HEVERT'S EXCLUSIVE RELIANCE ON THE PROJECTED GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE* FOR HIS DCF ANALYSIS.

A. It seems highly unlikely that investors today would rely exclusively on the EPS growth rate forecasts of Wall Street analysts and ignore

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[42] *Id.* p. 3.

other growth rate measure in arriving at their expected growth rates for equity investments. As I previously stated, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historical prospective dividend growth, internal growth, as well as projected earnings growth.

Finally, and most significantly, it is well-known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.

Hence, using these growth rates as a DCF growth rate produces an overstated equity cost rate. A 2007 study by Easton and Sommers (2007) found that optimism in analysts' earnings growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[43]

Q. WHY IS MR. HEVERT'S EXCLUSIVE RELIANCE ON THE PROJECTED GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE* PROBLEMATIC?

A. As previously discussed, the long-term EPS growth rate estimates of Wall Street analysts have been shown to be upwardly biased and overly optimistic. Therefore, exclusive reliance on these forecasts for

[43] Easton, P., & Sommers, G. (2007). "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts." *Journal of Accounting Research*, 45(5), 983–1015.

a DCF growth rate results in failure of one the basic inputs in the equation.

Q. ON PAGES 23-24 OF HIS TESTIMONY, MR. HEVERT CITES NINE DIFFERENT STUDIES TO SUPPORT HIS USE OF ANALYSTS' EPS GROWTH RATE FORECASTS. PLEASE DISCUSS THESE STUDIES.

A. The studies Mr. Hevert cites to support his exclusive use of analysts' EPS growth rate forecasts are all at least twenty years old. There have been many research studies on this topic over the past twenty years. I reviewed these studies earlier in my testimony. The conclusion from the more recent studies is universal – analysts' three-to-five-year EPS growth rate forecasts are overly optimistic and upwardly biased.

C. CAPM Approach

Q. PLEASE DISCUSS MR. HEVERT'S CAPM.

A. On pages 26-34 of his testimony and in Exhibit Nos. RBH-2-RBH-4, Mr. Hevert develops an equity cost rate by applying the CAPM model to the companies in his proxy group. The CAPM approach requires an estimate of the risk-free interest rate, beta, and the MRP. Mr. Hevert uses two different measures of the 30-Year Treasury bond yield: (a) current yield of 3.04% and a near-term projected yield of 3.25%; (b) two different Betas (an average Bloomberg Beta of 0.49

and an average *Value Line* Beta of 0.59); and (c) two MRP measures – a Bloomberg, DCF-derived MRP of 10.65% and a *Value Line* DCF-derived MRP of 13.77%. Based on these figures, he finds a CAPM equity cost rate range from 8.25% to 11.34%. Mr. Hevert also employs an ad hoc version of the CAPM, the ECAPM, which makes inappropriate adjustments to the risk-free rate and the market risk premium and is an untested model in academic and profession research. Mr. Hevert's CAPM/ECAPM results are summarized on page 1 of Exhibit JRW-9.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S CAPM ANALYSES?

A. As explained further below, there are three issues with Mr. Hevert' CAPM analyses: (1) he has used current and projected risk-free rates of 3.04% and 3.25%; (2) Mr. Hevert's MRPs of 10.65% and 13.77% include highly unrealistic assumptions regarding future economic and earnings growth and stock returns; and (3) Mr. Hevert has employed an ad hoc version of the CAPM, the empirical CAPM ("ECAPM").

1. Current and Projected Risk-Free Interest Rates

Q. PLEASE DISCUSS THE RISK-FREE RATE OF INTEREST IN MR. HEVERT'S CAPM/ECAPM.

A. Mr. Hevert has used current sand projected risk-free rates of 3.04% and 3.25% in his CAPM/ECAPM analyses. The actual yield on 30-year

Treasury bonds has been in the 2.6% range in recent months. As such, Mr. Hevert's current and projected risk-free rates are 44 and 65 basis points above the current yield on long-term Treasury bonds. This forecasted yield is excessive for two reasons. First, as discussed previously, economists are always predicting that interest rates are going up, and yet they are almost always wrong. Obviously, investors are well aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. Second, investors would not be buying long-term Treasury bonds at their current yields if they expected interest rates to suddenly increase. If interest rates do increase, the prices of the bonds investors bought at today's yields, go down, thereby producing a negative return.

2. Market Risk Premiums

Q. PLEASE ASSESS MR. HEVERT'S MRPS DERIVED FROM APPLYING THE DCF MODEL TO THE S&P 500 AND *VALUE LINE INVESTMENT SURVEY*.

A. For his Bloomberg and *Value Line* MRPs, Mr. Hevert computes MRPs of 10.65% and 13.77%, respectively, by: (1) calculating an expected market return by applying the DCF model to the S&P 500; and then (2) subtracting the current 30-year Treasury bond yield of 3.04% from his estimate of the expected market return. Mr. Hevert also uses (1) a dividend yield of 2.21% and an expected DCF growth rate of 11.48% for Bloomberg and (2) a dividend yield of 2.08% and an expected DCF growth rate of 14.73% for *Value Line*. The resulting expected annual S&P 500 stock market returns using this approach are 13.68% (using Bloomberg three- to five-year EPS growth rate estimates) and 16.81% (using *Value Line* three- to five-year EPS growth rate estimates). These results are not realistic in today's market.

Q. ARE MR. HEVERT'S MRPS OF 10.65% AND 13.77% REFLECTIVE OF THE MRPS FOUND IN STUDIES AND SURVEYS OF THE MRP?

A. No. These are well in excess of MRPs: (1) found in studies of the MRP by leading academic scholars; (2) produced by analyses of historic stock and bond returns; and (3) found in surveys of financial professionals. Page 5 of Exhibit JRW-8 provides the results of over thirty MRP studies from the past fifteen years. Historic stock and bond returns suggest an MRP in the 4.5% to 7.0% range, depending on whether one uses arithmetic or geometric mean returns. There have been many studies using expected return (also called *ex ante*) models, and their MRP results vary from as low as 2.0% to as high as 7.31%. Finally, the MRPs developed from surveys of analysts, companies, financial professionals, and academics suggest lower MRPs, in a range of from 1.91% to 5.70%. The bottom line is that there is no support in historic return data, surveys, academic studies, or reports for investment firms for an MRP as high as those used by Mr. Hevert.

Q. PLEASE ONCE AGAIN ADDRESS THE ISSUES WITH ANALYSTS' EPS GROWTH RATE FORECASTS.

A. The key point is that Mr. Hevert's CAPM MRP methodology is based entirely on the concept that analyst projections of companies' three-to-five EPS growth rates reflect investors' expected *long-term* EPS growth for those companies. However, this seems highly unrealistic given the research on these projections. As previously noted, numerous studies have shown that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.[44] Moreover, a 2011 study showed that analysts' forecasts of EPS growth over the next three-to-five years earnings are no more accurate than their forecasts of the next single year's EPS growth.[45] The overly-optimistic inaccuracy of analysts' growth

[44] Such studies include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance*, pp. 643–684, (2003); M. Lacina, B. Lee, and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8)*, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[45] M. Lacina, B. Lee, & Z. Xu, *Advances in Business and Management Forecasting*, Vol. 8, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

rate forecasts leads to an upward bias in equity cost estimates that has been estimated at about 300 basis points.[46]

Q. HAVE CHANGES IN REGULATIONS IMPACTING WALL STREET ANALYSTS AND THEIR RESEARCH IMPACTED THE UPWARD BIAS IN THEIR THREE-TO-FIVE YEAR EPS GROWTH RATE FORECASTS?

A. No. A number of the studies I have cited here demonstrate that the upward bias has continued despite changes in regulations and reporting requirements over the past two decades. This observation is highlighted by a 2010 McKinsey study entitled "Equity Analysts: Still Too Bullish," which involved a study of the accuracy of analysts' long-term EPS growth rate forecasts. The authors conclude that after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. They made the following observation:[47]

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale

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[46] Peter D. Easton & Gregory A. Sommers, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts," 45, *Journal of Accounting Research*, pp. 983–1015 (2007).

[47] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," McKinsey on Finance, pp. 14-17, (Spring 2010) (emphasis added).

> worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. *Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.*

This is the same observation made in a *Bloomberg Businessweek* article.[48] The author concluded:

> ***The bottom line:*** *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

Q. IS THERE OTHER EVIDENCE THAT INDICATES THAT MR. HEVERT'S MRPS COMPUTED USING S&P 500 EPS GROWTH RATE ARE EXCESSIVE?

A. Beyond my previous discussion of the upwardly biased nature of analysts' projected EPS growth rates, the fact is that long-term EPS growth rates of 11.48% and 14.73% are inconsistent with both

[48] Roben Farzad, "For Analysts, Things Are Always Looking Up," *Bloomberg Businessweek* (June 10, 2010), https://www.bloomberg.com/news/articles/2010-06-10/for-analysts-things-are-always-looking-up.

historic and projected economic and earnings growth in the U.S for several reasons: (1) long-term EPS and economic growth is about one-half of Mr. Hevert's projected EPS growth rates of 11.48% and 14.73%; (2) as discussed below, long-term EPS and GDP growth are directly linked; and (3) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower economic and earnings growth in the future.

Long-Term Historic EPS and GDP Growth have been in the 6%-7% Range - I performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-10, and a summary is shown in Table 8, below.

Table 8
GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	**6.46**
S&P 500 Stock Price	**6.71**
S&P 500 EPS	**6.89**
S&P 500 DPS	**5.85**
Average	**6.48**

The results show that the historical long-run growth rates for GDP, S&P EPS, and S&P DPS are in the 6% to 7% range. By comparison, Mr. Hevert's long-run growth rate projections of 11.55% and 15.00% are at best overstated. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rate of EPS by 100% in the future, and (2) maintain that growth indefinitely in an economy that is expected to grow at about one-third of his projected growth rates.

There is a Direct Link Between Long-Term EPS and GDP Growth - The results in Exhibit JRW-10 and Table 6 show that historically there has been a close link between long-term EPS and GDP growth rates. Brad Cornell of the California Institute of Technology published a study on GDP growth, earnings growth, and equity returns. He finds that long-term EPS growth in the U.S. is directly related to GDP growth, with GDP growth providing an upward limit on EPS growth. In addition, he finds that long-term stock returns are determined by long-term earnings growth. He concludes with the following observations:[49]

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms.

[49] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February 2010), p. 63.

<u>The Trend and Projections Indicate Slower GDP Growth in the Future</u> - The components of nominal GDP growth are real GDP growth and inflation. Page 3 of Exhibit JRW-10 shows annual real GDP growth rate over the 1961 to 2018 time period. Real GDP growth has gradually declined from the 5.0% to 6.0% range in the 1960s to the 2.0% to 3.0% range during the most recent five-year period. The second component of nominal GDP growth is inflation. Page 4 of Exhibit JRW-10 shows inflation as measured by the annual growth rate in the Consumer Price Index (CPI) over the 1961 to 2018 time period. The large increase in prices from the late 1960s to the early 1980s is readily evident. Equally evident is the rapid decline in inflation during the 1980s as inflation declined from above 10% to about 4%. Since that time, inflation has gradually declined and has been in the 2.0% range or below over the past five years.

The graphs on pages 2, 3, and 4 of Exhibit JRW-10 provide clear evidence of the decline, in recent decades, in nominal GDP as well as its components, real GDP and inflation. To gauge the magnitude of the decline in nominal GDP growth, Table 5, below, provides the compounded GDP growth rates for 10-, 20-, 30-, 40- and 50- years. Whereas the 50-year compounded GDP growth rate is 6.63%, there has been a monotonic and significant decline in nominal GDP growth over subsequent 10-year intervals. These figures strongly suggest that 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.

Table 9
Historical Nominal GDP Growth Rates

10-Year Average		**3.37%**
20-Year Average		**4.17%**
30-Year Average		**4.65%**
40-Year Average		**5.56%**
50-Year Average		**6.36%**

<u>Long-Term GDP Projections also Indicate Slower GDP Growth in the Future</u> - A lower range is also consistent with long-term GDP forecasts. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in Panel B of on page 5 of Exhibit JRW-10. The mean 10-year nominal GDP growth forecast (as of March 2019) by economists in the recent *Survey of Financial Forecasters* is 4.27%.[50] The Energy Information Administration ("EIA"), in its projections used in preparing *Annual Energy Outlook*, forecasts long-term GDP growth of 4.3% for the period 2017-2050.[51] The Congressional Budget Office ("CBO"), in its forecasts for the period 2018 to 2048, projects a nominal GDP growth rate of 4.0%.[52] Finally, the Social Security

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[50] https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/

[51] U.S. Energy Information Administration, *Annual Energy Outlook 2018*, Table: Macroeconomic Indicators, *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2018&sourcekey=0.*

[52] Congressional Budget Office, The *2018 Long-Term Budget Outlook*, June 1, 2018 https://www.cbo.gov/system/files?file=2018-06/53919-2018ltbo.pdf.

Administration ("SSA"), in its Annual OASDI Report, provides a projection of nominal GDP from 2018-2095.[53] SSA's projected growth GDP growth rate over this period is 4.4%. Overall, these forecasts suggest long-term GDP growth rate in the 4.0% - 4.4% range. The trends and projections indicating slower GDP growth make Mr. Hevert's MRPs computed using analysts' projected EPS growth rates look even more unrealistic. Simply stated, Mr. Hevert's projected EPS growth rates of 11.48% and 14.73% are almost three times projected GDP growth.

Q. WHAT ARE THE FUNDAMENTAL FACTORS THAT HAVE LED TO THE DECLINE IN PROSPECTIVE GDP GROWTH?

A. As addressed in a study by the consulting firm McKinsey & Co., two factors drive real GDP growth over time: (a) the number of workers in the economy (employment); and (2) the productivity of those workers (usually defined as output per hour).[54] According to McKinsey, real GDP growth over the past 50 years was driven by population and productivity growth which grew at compound annual rates of 1.7% and 1.8%, respectively.

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[53] Social Security Administration, *2018 Annual Report of the Board of Trustees of the Old-Age, Survivors, and Disability Insurance (OASDI) Program*, Table VI.G4, p. 211 (June 15, 2018), https://www.ssa.gov/oact/tr/2018/lr6g4.html. The 4.4% represents the compounded growth rate in projected GDP from $20,307 trillion in 2018 to $548,108 trillion in 2095.

[54] McKinsey & Co., "Can Long-Term Growth be Saved?", McKinsey Global Institute, (Jan. 2015).

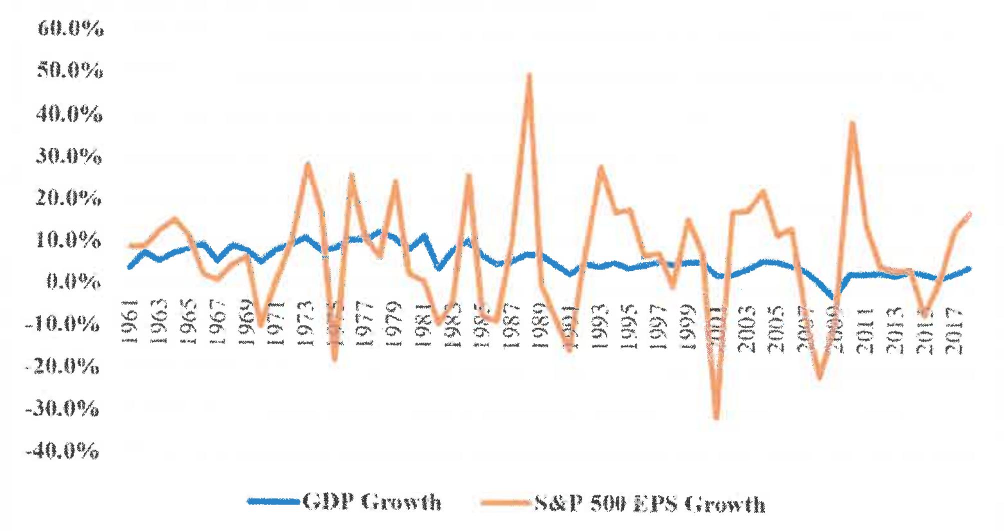
However, global economic growth is projected to slow significantly in the years to come. The primary factor leading to the decline is slow growth in employment (working-age population), which results from slower population growth and longer life expectancy. McKinsey estimates that employment growth will slow to 0.3% over the next fifty years. They conclude that even if productivity remains at the rapid rate of the past fifty years of 1.8%, real GDP growth will fall by 40 percent to 2.1%.

Q. PLEASE PROVIDE MORE INSIGHTS INTO THE RELATIONSHIP BETWEEN S&P 500 EPS AND GDP GROWTH.

A. Figure 6 shows the average annual growth rates for GDP and the S&P 500 EPS since 1960. The one very apparent difference between the two is that the S&P 500 EPS growth rates are much more volatile than the GDP growth rates, when compared using the relatively short, and somewhat arbitrary, annual conventions used in these data.[55] Volatility aside, however, it is clear that over the medium to long run, S&P 500 EPS growth does not outpace GDP growth.

[55] Timing conventions such as years and quarters are needed for measurement and benchmarking but are somewhat arbitrary. In reality, economic growth and profit accrual occur on continuous bases. A 2014 study evaluated the timing relationship between corporate profits and nominal GDP growth. The authors found that aggregate accounting earnings growth is a leading indicator of the GDP growth with a quarter-ahead forecast horizon. *See* Yaniv Konchitchki and Panos N. Patatoukas, "Accounting Earnings and Gross Domestic Product," *Journal of Accounting and Economics* 57 (2014), pp. 76–88.

Figure 6
Average Annual Growth Rates
GDP and S&P 500 EPS
1960-2018



Data Sources: GDPA - http://research.stlouisfed.org/fred2/series/GDPA/downloaddata.
S&P EPS - http://pages.stern.nyu.edu/~adamodar/

A fuller understanding of the relationship between GDP and S&P 500 EPS growth requires consideration of several other factors.

<u>Corporate Profits are Constrained by GDP</u> – Milton Friedman, the noted economist, warned investors and others not to expect corporate profit growth to sustainably exceed GDP growth, stating, "Beware of predictions that earnings can grow faster than the economy for long periods. When earnings are exceptionally high, they don't just keep booming."[56] Friedman also noted in the *Fortune* interview that profits must move back down to their traditional share

[56] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," Fortune, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

of GDP. In Table 10, below, I show that currently the aggregate net income levels for the S&P 500 companies, using 2018 figures, represent 6.73% of nominal GDP.

Table 10
S&P 500 Aggregate Net Income as a Percent of GDP

Aggregate Net Income for S&P 500 Companies ($B)	**$1,406,400.00**
2018 Nominal U.S. GDP ($B)	**$20,891,000.00**
Net Income/GDP (%)	**6.73%**

Data Sources: 2018 Net Income for S&P 500 companies – *Value Line* (March 12, 2019).
2018 Nominal GDP – Moody's - https://www.economy.com/united-states/nominal-gross-domestic-product.

Short-Term Factors Impact S&P 500 EPS – The growth rates in the S&P 500 EPS and GDP can diverge on a year-to-year basis due to short-term factors that impact S&P 500 EPS in a much greater way than GDP. As shown above, S&P EPS growth rates are much more volatile than GDP growth rates. The EPS growth for the S&P 500 companies has been influenced by low labor costs and interest rates, commodity prices, the recovery of different sectors such as the energy and financial sectors, the cut in corporate tax rates, etc. These short-term factors can make it appear that there is a disconnect between the economy and corporate profits.

The Differences Between the S&P 500 EPS and GDP – In the last two years, as the EPS for the S&P 500 has grown at a faster rate than U.S. nominal GDP, some have pointed to the differences between the S&P 500 and GDP.[57] These differences include: (a) corporate profits are about 2/3 manufacturing driven, while GDP is 2/3 services driven; (b) consumer discretionary spending accounts for a smaller share of S&P 500 profits (15%) than of GDP (23%); (c) corporate profits are more international-trade driven, while exports minus imports tend to drag on GDP; and (d) S&P 500 EPS is impacted not just by corporate profits but also by share buybacks on the positive side (fewer shares boost EPS) and by share dilution on the negative side (new shares dilute EPS). While these differences may seem significant, it must be remembered that the Income Approach to measure GDP includes corporate profits (in addition to employee compensation and taxes on production and imports) and therefore effectively accounts for the first three factors.[58]

The bottom line is that despite the intertemporal short-term differences between S&P 500 EPS and nominal GDP growth, the long-term link between corporate profits and GDP is inevitable.

[57] See the following studies: Burt White and Jeff Buchbinder, "The S&P and GDP are not the Same Thing," LPL Financial, (Nov. 4, 2014), https://www.businessinsider.com/sp-is-not-gdp-2014-11; Matt Comer, "How Do We Have 18.4% Earnings Growth In A 2.58% GDP Economy?," Seeking Alpha, (Apr. 2018), https://seekingalpha.com/article/4164052-18_4-percent-earnings-growth-2_58-percent-gdp-economy; Shaun Tully, "How on Earth Can Profits Grow at 10% in a 2% Economy?," Fortune, (July 27, 2017), http://fortune.com/2017/07/27/profits-economic-growth/.

[58] The Income Approach to measuring GDP includes wages, salaries, and supplementary labor income, corporate profits, interest and miscellaneous investment income, farmers' incomes, and income from non-farm unincorporated businesses.

Q. PLEASE PROVIDE ADDITIONAL EVIDENCE ON HOW UNREALISTIC THE S&P 500 EPS GROWTH RATES ARE THAT MR. HEVERT USES TO COMPUTE HIS MRPS.

A. Beyond my previous discussion, I have performed the following analysis of S&P 500 EPS and GDP growth in Table 11 below. Specifically, I started with the 2018 aggregate net income for the S&P 500 companies and 2018 nominal GDP for the U.S. As shown in Table 9, the aggregate profit for the S&P 500 companies represented 6.73% of nominal GDP in 2018. In Table 7, I then projected the aggregate net income level for the S&P 500 companies and GDP as of the year 2050. For the growth rate for the S&P 500 companies, I used the average of Mr. Hevert's Bloomberg and *Value Line* growth rates, 11.48% and 14.73%, which is 13.11%. As a growth rate for nominal GDP, I used the average of the long-term projected GDP growth rates from CBO, SSA, and EIA (4.0%, 4.4%, and 4.3%), which is 4.23%. The projected 2050 level for the aggregate net income level for the S&P 500 companies is $72.4 trillion. However, over the same period GDP only grows to $78.7 trillion. As such, if the aggregate net income for the S&P 500 grows in accordance with the growth rates used by Mr. Hevert, and if nominal GDP grows at rates projected by major government agencies, the net income of the S&P 500 companies will represent growth from 6.73% of GDP in 2018 to

91.9% of GDP in 2050. Obviously, it is implausible for the net income of the S&P 500 to become such a large part of GDP.

Table 11
Projected S&P 500 Earnings and Nominal GDP
2018-2050
S&P 500 Aggregate Net Income as a Percent of GDP

	2018 Value	Growth Rate	No. of Years	2050 Value
Aggregate Net Income for S&P 500 Companies	1,406,400.0	13.11%	32	72,364,670.4
2018 Nominal U.S. GDP	20,891,000.0	4.23%	32	78,735,624.7
Net Income/GDP (%)	6.73%			91.91%

Data Sources: 2018 Aggregate Net Income for S&P 500 companies – *Value Line* (March 12, 2019).
2018 Nominal GDP – Moody's - https://www.economy.com/united-states/nominal-gross-domestic-product.
S&P 500 EPS Growth Rate - Average of Hevert's Bloomberg and *Value Line* growth rates - 11.48% and 14.73%;
Nominal GDP Growth Rate – The average of the long-term projected GDP growth rates from CBO, SSA, and EIA (4.0%, 4.4%, and 4.3%).

Q. PLEASE PROVIDE A SUMMARY ANALYSIS OF GDP AND S&P 500 EPS GROWTH RATES.

A. As noted above, the long-term link between corporate profits and GDP is inevitable. The short-term differences in growth between the two has been highlighted by some notable market observers, including Warren Buffet, who indicated that corporate profits as a share of GDP tend to go far higher after periods where they are depressed, and then drop sharply after they have been hovering at historically high levels. In a famous 1999 *Fortune* article, Mr. Buffet made the following observation:[59]

> You know, someone once told me that New York has more lawyers than people. I think that's the same fellow who thinks profits will become larger than GDP. When you begin to expect the growth of a component factor to forever outpace that of the aggregate, you get into certain mathematical problems. In my opinion, you have to be wildly optimistic to believe that corporate profits as a percent of GDP can, for any sustained period, hold much above 6%. One thing keeping the percentage down will be competition, which is alive and well. In addition, there's a public-policy point: If corporate investors, in aggregate, are going to eat an ever-growing portion of the American economic pie, some other group will have to settle for a smaller portion. That would justifiably raise political problems – and in my view a major reslicing of the pie just isn't going to happen.

In sum, Mr. Hevert's long-term S&P 500 EPS growth rates of 11.48% and 14.73% are grossly overstated and have no basis in economic reality. In the end, the big question remains as to whether corporate profits can grow faster than GDP. Jeremy Siegel, the renowned finance professor at the Wharton School of the University of Pennsylvania, believes that going forward, earnings per share can grow about half a point faster than nominal GDP, or about 5.0%, due to the big gains in the technology sector. But he also believes that sustained EPS growth matching analysts' near-term projections is

[59] Carol Loomis, "Mr. Buffet on the Stock Market," *Fortune*, (Nov. 22, 1999), https://money.cnn.com/magazines/fortune/fortune_archive/1999/11/22/269071/.

absurd: "The idea of 8% or 10% or 12% growth is ridiculous. It will not happen."[60]

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE CAPM RESULTS FROM USING *VALUE LINE* DATA.

A. The are several additional issues with the *Value Line* results. Simply put, the 16.81% expected stock market return (Mr. Hevert's Exhibit RBH-2 at page 14) is simply outrageous. The compounded annual return in the U.S. stock market is about 10% (9.49% according to Damodaran between 1928-2018).[61] Mr. Hevert's *Value Line* CAPM results assume that return on the U.S. stock market will be more than 50% higher in the future than it has been in the past. The extremely high expected stock market return, and the resulting MRP and equity cost rate results, is directly related to the 14.73% expected EPS growth rate. There are numerous fallacies with this growth rate. First, the expected growth rate is not from today going forward, but instead it is computed from a three-year base period in the past (2015-2017) to a projected three-year period in the future (2021-2023). The problem here is that it incorporates historic growth in the base period, which can inflate projected growth for the future if the base period includes poor earnings. Second, and most significantly, a projected

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[60] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," *Fortune*, (Dec. 7, 2017), http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

[61] http://pages.stern.nyu.edu/~adamodar/

growth rate of 14.73% does not reflect economic reality. As noted above, it assumes that S&P 500 companies can grow their earnings in the future at a rate that is triple the expected GDP growth rate.

3. ECAPM

Q. WHAT ISSUES DO YOU HAVE WITH MR. HEVERT'S ECAPM?

A. Mr. Hevert has employed a variation of the CAPM which he calls the 'ECAPM.' The ECAPM, as popularized by rate of return consultant Dr. Roger Morin, attempts to model the well-known finding of tests of the CAPM that have indicated the Security Market Line ("SML") is not as steep as predicted by the CAPM. As such, the ECAPM is nothing more than an ad hoc version of the CAPM and has not been theoretically or empirically validated in refereed journals. The ECAPM provides for weights which are used to adjust the risk-free rate and MRP in applying the ECAPM. Mr. Hevert uses 0.25 and 0.75 factors in his ECAPM.

Besides the fact that the ECAPM is not a recognized equity cost rate model, Mr. Hevert has already accounted for any empirical issues with the CAPM by using adjusted betas for *Value Line*. Adjusted betas address the empirical issues with the CAPM by increasing the expected returns for low beta stocks and decreasing the returns for high beta stocks.

D. Bond Yield Risk Premium Approach

Q. PLEASE DISCUSS MR. HEVERT'S BYRP APPROACH.

A. On pages 34-7 of his testimony and in Exhibit No. RBH-5, Mr. Hevert develops an equity cost rate using his BYRP approach. Mr. Hevert develops an equity cost rate by: (1) regressing the average quarterly authorized returns on equity for electric utility companies from the January 1, 1992, to February 27, 2019, time period on the thirty-year Treasury Yield; and (2) adding the appropriate risk premium established in step (1) to three different thirty-year Treasury yields: (a) the current yield of 3.04%; (b) a near-term projected yield of 3.25%; and (c) a long-term projected yield of 4.05%. Mr. Hevert's risk premium results are provided on Exhibit JRW-9. He reports BYRP equity cost rates ranging from 9.93% to 10.17%.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S BYRP ANALYSIS?

A. The errors include the base yield as well as the measurement and magnitude of the risk premium.

1. Base Yields

Q. PLEASE DISCUSS THE BASE YIELD OF MR. HEVERT'S BYRP ANALYSIS.

A. Mr. Hevert has used current, near-term projected, and long-term projected risk-free rates of 3.04%, 3.25%, and 4.05% in his BYRP analyses. The actual yield on 30-year Treasury bonds has been in the

2.6% range in recent months. As such, Mr. Hevert's current, near-term projected, and long-term projected risk-free rates are 44, 65, and 145 basis points, respectively, above the current yield on long-term Treasury bonds. These current and forecasted yields are excessive for two reasons. First, as discussed previously, economists are always predicting that interest rates are going up, and yet they are almost always wrong. Obviously, investors are well aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. Second, investors would not be buying long-term Treasury bonds at their current yields if they expected interest rates to suddenly increase. If interest rates do increase, the prices of the bonds investors bought at today's yields go down, thereby producing a negative return.

2. Risk Premium

Q. WHAT ARE THE ISSUES WITH MR. HEVERT'S RISK PREMIUM?

A. There are several problems with his approach. First, his BYRP methodology produces an inflated measure of the risk premium because the approach uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury yields. Since Treasury yields are always forecasted to increase, the resulting risk premium would be smaller if calculated correctly, which would be to use projected Treasury yields in the analysis rather than historic Treasury yields.

In addition, Mr. Hevert's BYRP approach is a gauge of *commission* behavior and not *investor* behavior. Capital costs are determined in the market place through the financial decisions of investors and are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments. Regulatory commissions evaluate capital market data in setting authorized ROEs, but also consider other utility- and rate case-specific information in setting ROEs. As such, Mr. Hevert's approach and results reflect factors such as capital structure, credit ratings and other risk measures, service territory, capital expenditures, energy supply issues, rate design, investment and expense trackers, and other factors used by utility commissions in determining an appropriate ROE in addition to capital costs. This may especially be true when the authorized ROE data includes the results of rate cases that are settled and not fully litigated.

Finally, Mr. Hevert's methodology produces an inflated required rate of return because utilities have been selling at market-to-book ratios well in excess of 1.0 for many years. This indicates that the authorized and earned rates of return on equity have been greater than the return that investors require. The relationship between ROE, the equity cost rate, and market-to-book ratios was explained earlier in this testimony. In short, a market-to-book ratio above 1.0 indicates a company's ROE is above its equity cost rate. Therefore, the risk premium produced from the study is overstated as a measure of investor return requirements and produces an inflated equity cost rate.

E. Expected Earnings Approach

Q. PLEASE REVIEW MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. On pages 42-45 of his testimony and in Exhibit RBH-6, Mr. Hevert develops an equity cost rate using his Expected Earnings approach. Mr. Hevert's approach involves using *Value Line*'s projected ROE for the years 2021-23/2022-24 for his proxy group and then adjusting this ROE to account for the fact that *Value Line* uses year-end equity in computing ROE. Mr. Hevert reports Expected Earnings results of 10.38% and 10.52%.

Q. PLEASE ADDRESS THE ISSUES WITH MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. There are a number of issues with this so-called Expected Earnings approach. As such, I strongly suggest that the Commission ignore this approach in setting a ROE for DENC. These issues include:

The Expected Earnings Approach Does Not Measure the Market Cost of Equity Capital – First and foremost, this accounting-based methodology does not measure investor return requirements.

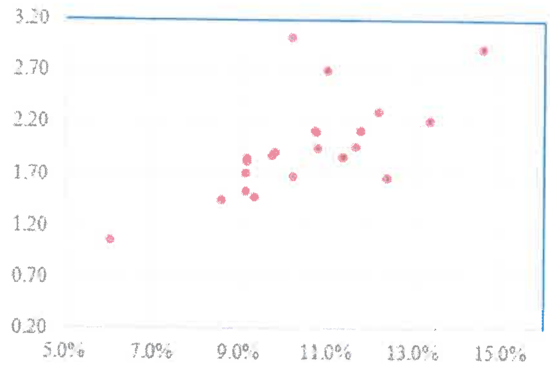
As indicated by Professor Roger Morin, a long-term utility rate of return consultant, "More simply, the Comparable (Expected) Earnings standard ignores capital markets. If interest rates go up 2% for example, investor requirements and the cost of equity should increase commensurably, but if regulation is based on accounting returns, no immediate change in equity cost results."[62] As such, this method does not measure the market cost of equity because there is no way to assess whether the earnings are greater than or less than the earnings investors require, and therefore this approach does not measure the market cost of equity capital.

<u>The Expected ROEs are not Related to Investors' Market-Priced Opportunities</u> – The ROE ratios are an accounting measure that do not measure investor return requirements. Investors had no opportunity to invest in the proxy companies at the accounting book value of equity. In other words, the equity's book value *to investors* is tied to market prices, which means that investors' required return on market-priced equity aligns with expected return on book equity only when the equity's market price and book value are aligned. Therefore, a market-based evaluation of the cost of equity to investors in the proxies requires an associated analysis of the proxies' market-to-book ("M/B") ratios. This was discussed at length

[62] Roger Morin, *New Regulatory Finance* (2006), p. 293.

earlier in my testimony. In addition, as shown in Figure 7, below, there is a strong positive relationship between Mr. Hevert's expected ROEs and the M/B ratios for his proxy companies.

Figure 7
Expected ROEs and M/B Ratios
Hevert Proxy Group



Data Sources: ROEs – Exhibit RBH 6, M/B Ratios – Exhibit JRW-2.

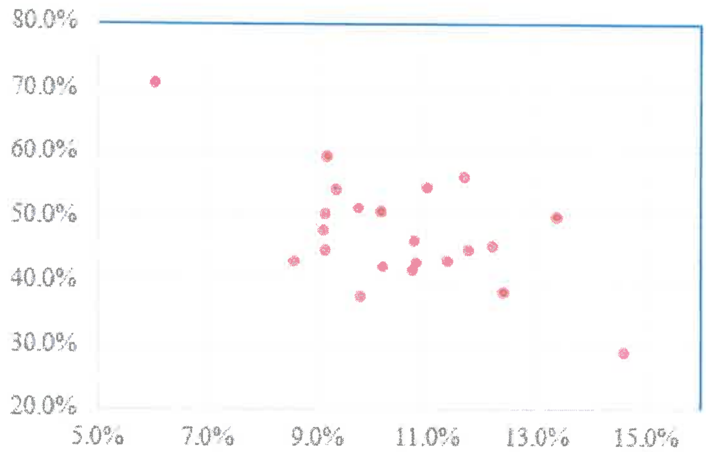
<u>Changes in ROE Ratios do not Track Capital Market Conditions</u> - As also indicated by Morin, "The denominator of accounting return, book equity, is a historical cost-based concept, which is insensitive to changes in investor return requirements. Only stock market price is sensitive to a change in investor requirements. Investors can only purchase new shares of common stock at current market prices and not at book value."[63]

<u>There is a Strong Negative Relationship between the ROE Ratios and the Common Equity Ratios for the Proxy Companies</u> - As shown in Figure 8 below, there is a strong negative relationship

[63] *Id.*

between the proxies' ROEs and their common equity ratios. That is, proxy companies with lower common equity ratios have higher ROEs, and vice-versa. Since the proxy companies have a lower average common equity ratio (45.2%) as opposed to DENC's proposed common equity ratios (51.65%), DENC's lower financial risk associated with a higher common equity ratio implies that DENC would have a lower ROE, if ROEs ratios correlated with equity's risks and costs.

Figure 8
Expected ROEs and Common Equity Ratios
Hevert Proxy Group



Data Sources: ROEs – Exhibit RBH 6, M/B Ratios – Exhibit JRW-2

<u>The Expected Earnings Approach is Circular</u> - The proxies' ROEs ratios are not determined by competitive market forces, but instead are largely the result of federal and state rate regulation, including the present proceedings.

The Proxies' ROEs Reflect Earnings on Business Activities that are not Representative of DENC's Rate-Regulated Utility Activities - The numerators of the proxy companies' ROEs include earnings from business activities that are riskier and produce more projected earnings per dollar of book investment than does regulated electric utility service. These include earnings from: (1) unregulated businesses including merchant generation; (2) electric generation; and (3) international operations.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. In short, Mr. Hevert's Expected Earnings approach does not measure the market cost of equity capital, is independent of most cost of capital indicators and, as shown above, has a number of other empirical issues. Therefore, the Commission should ignore this approach in determining the appropriate ROE for DENC.

F. Other Issues

1. DENC's Capital Expenditures

Q. PLEASE ADDRESS MR. HEVERT'S CONSIDERATION OF OTHER UNIQUE RISK FACTORS FACED BY DENC.

A. Mr. Hevert also considers the magnitude of DENC's capital expenditures in arriving at his 10.75% ROE recommendation. Capital expenditures are a risk factor considered as part of the credit-rating process used by major rating agencies. In addition, as I noted above, DENC's S&P and Moody's credit ratings of BBB+ and A2 suggest that the Company's investment risk is below the average of the proxy groups.

2. Flotation Costs

Q. PLEASE DISCUSS MR. HEVERT'S ADJUSTMENT FOR FLOTATION COSTS.

A. Mr. Hevert argues that a flotation cost adjustment is appropriate for DENC and he has considered flotation costs in arriving at his 10.75% ROE recommendation.

First and foremost, Mr. Hevert has not identified any flotation cost for DENC. Therefore, he is asking for higher revenues in the form of a higher ROE for expenses that he has not identified.

Second, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the existing shareholders. This is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for electric utility companies are over 1.95X actually suggests that there should be a flotation cost reduction (and

not an increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of electric utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, electric utility companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per-share

basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Therefore, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, and who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transaction costs, it has not accounted for other market transaction costs in determining its cost of equity. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by

investors to buy shares. If the Company had included these brokerage fees or transaction costs in its DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to its DCF equity cost rate.

VII. NORTH CAROLINA ECONOMIC CONDITIONS AND DENC'S RATE OF RETURN RECOMMENDATION

Q. PLEASE DISCUSS MR. HEVERT'S CONSIDERATION OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. Mr. Hevert has acknowledged that the North Carolina Utilities Commission must balance the interests of investors and customers in setting the ROE. In addition, Mr. Hevert notes 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.[64] On this issue, the ROE should be the minimum amount needed to meet the *Hope* and *Bluefield* standards. Finally, Mr. Hevert also highlights that the North Carolina Supreme Court has indicated that in retail utility service rate cases the Commission must make findings

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[64] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Sept. 24, 2013 at 24; *see also* DEC Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").

of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility.[65]

With respect to this latter mandate, Mr. Hevert evaluates a number of factors such as employment and income levels and, based on his review of the data, comes to the conclusion that DENC's proposed ROE of 10.75 percent is fair and reasonable to DENC, its shareholders, and its customers in light of the effect of those changing economic conditions.[66]

Q. DO YOU AGREE WITH MR. HEVERT'S ASSESSMENT OF ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. As highlighted by the correlations between U.S. and North Carolina economic data, I agree with Mr. Hevert that economic conditions in North Carolina have improved with the overall economy over the past decade.

Q. DO YOU AGREE WITH MR. HEVERT'S CONCLUSION THAT THE IMPROVEMENT IN ECONOMIC CONDITIONS IN NORTH CAROLINA AND THE COMPANY'S SERVICE TERRITORY JUSTIFY THE COMPANY'S PROPOSED RATE OF RETURN INCLUDING A 10.75% ROE?

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[65] *State of North Carolina ex rel. Utilities Commission v. Cooper*, 758 S.E.2d 635, 642 (2014) ("Cooper II").

[66] Hevert Testimony, pp. 57-58.

A. No. Whereas economic conditions have improved in North Carolina, it does not necessarily justify such a high rate of return and ROE. I have three observations on Mr. Hevert's assessment of the economic conditions in North Carolina and DENC's service territory and its requested ROE:

1. As previously discussed, DENC's ROE request of 10.75% is over 100 basis points above the average authorized ROEs for electric utilities over the 2018-19 time period;

2. Whereas North Carolina's unemployment rate has fallen by one-third since its peak in the 2009-2010 period and is slightly below the national average of 3.90%, the unemployment rate in DENC's service territory is 4.95%, over 100 basis points higher than the national and North Carolina averages; and

3. Whereas North Carolina's residential electric rates are below the national average, North Carolina's median household income is more than 10% below the U.S. norm.

Q. **WHAT IS YOUR CONCLUSION REGARDING THE ECONOMIC CONDITIONS IN NORTH CAROLINA AND THE COMPANY'S SERVICE TERRITORY?**

A. The lower level of household income in the state and the higher level of unemployment in DENC's service territory suggest that affordability can be an issue for an essential utility service such as electricity. Certainly, it does not justify an authorized ROE that is over 100 basis points above the national average. And DENC's overall rate of return request has a significant impact on its overall requested increase in revenues.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Educational Background, Research, and Related Business Experience

J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. He has taught Finance courses including corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on empirical issues in corporation finance and financial markets. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance*, the *Journal of Financial Economics,* and the *Harvard Business Review.* His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes, Fortune, The Economist*, *Barron's*, *Wall Street Journal*, *Business Week*, *Investors' Business Daily*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg's *Morning Call.*

Professor Woolridge's stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a textbook entitled *Basic Principles of Finance* (Kendall Hunt, 2011).

Professor Woolridge has also consulted with corporations, financial institutions, and government agencies. In addition, he has directed and participated in university- and company- sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Over the past twenty-five years, Dr. Woolridge has prepared testimony and/or provided consultation services in regulatory rate cases in the rate of return area in the following states: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Indiana, Kansas, Kentucky, Maryland, Massachusetts, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, Washington, West Virginia, and Wisconsin, as well as in Washington, D.C. He has also testified before the Federal Energy Regulatory Commission.

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Academic Experience

Professor of Finance, the Smeal College of Business Administration, the Pennsylvania State University (July 1, 1990 to the present).

President, Nittany Lion Fund LLC, (January 1, 2005 to the present)

Director, the Smeal College Trading Room (January 1, 2001 to the present)

Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration (July 1, 1987 to the present).

Associate Professor of Finance, College of Business Administration, the Pennsylvania State University (July 1, 1984 to June 30, 1990).

Assistant Professor of Finance, College of Business Administration, the Pennsylvania State University (September, 1979 to June 30, 1984).

Education

Doctor of Philosophy in Business Administration, the University of Iowa. Major field: Finance.

Master of Business Administration, the Pennsylvania State University.

Bachelor of Arts, the University of North Carolina. Major field: Economics.

Books

James A. Miles and J. Randall Woolridge, *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation), 1999
Patrick Cusatis, Gary Gray, and J. Randall Woolridge, *The StreetSmart Guide to Valuing a Stock* (2nd Edition, McGraw-Hill), 2003.
J. Randall Woolridge and Gary Gray, *The New Corporate Finance, Capital Markets, and Valuation: An Introductory Text* (Kendall Hunt, 2003).

Research

Dr. Woolridge has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.*

CHAIR MITCHELL: He's already been sworn. Good afternoon. You're already sworn in.

MR. McLEOD: Good afternoon.

PAUL M. McLEOD

having been previously sworn, was examined
and further testified as follows:

DIRECT EXAMINATION BY MS. GRIGG:

Q. Good afternoon, Mr. McLeod.

A. Good afternoon. Are you the same Paul McLeod who provided direct testimony to this Commission?

A. Yes, I am.

Q. Did you also cause to be prefiled in this document on September 17th, 2019, 25 pages of rebuttal testimony in question and answer form?

A. Yes.

Q. Do you have any changes or corrections to that rebuttal testimony?

A. Yes. I do have one correction to my rebuttal testimony. On Page 2, Line 11, it should say 24.2 million instead of 24.9.

Q. Other than that correction, if I were to ask you the same questions today, would your answers be the same?

A. Yes.

MS. GRIGG: Chair Mitchell, at this time, I would move the rebuttal testimony of Mr. McLeod be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Motion is allowed.

(Whereupon, the prefiled rebuttal testimony of Paul E. McLeod was copied into the record as if given orally from the stand.)

REBUTTAL TESTIMONY
OF
PAUL M. MCLEOD
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

Q. Please state your name, business address, and position of employment.

A. My name is Paul M. McLeod, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am a Regulatory Consultant with the Regulatory Accounting Group for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted direct testimony on behalf of the Company in support of DENC's application for authority to adjust and increase its retail electric rates and charges filed on March 29, 2019 ("Application"), which presented the Company's proposed North Carolina retail non-fuel base rate increase of $27.0 million. I also submitted supplemental direct testimony on August 5, 2019 ("Supplemental Testimony"), which presented the Company's revised North Carolina non-fuel base rate increase of $24.9 million. In addition, I proposed the Company's methodology for addressing excess deferred federal corporate income taxes ("federal EDIT") for ratemaking purposes, including a credit to customers through a one-year decrement rider representing federal EDIT amortization attributable to the 22-month period January 1, 2018 through October 31, 2019 ("Rider EDIT"). Lastly, I supported the Company's proposed deferral accounting treatment and associated amortization periods for certain new and existing North Carolina jurisdictional regulatory assets.

I also supported second supplemental direct testimony to reflect certain updates to the Company's proposed changes to base fuel and base non-fuel revenues. My second supplemental testimony updated the "placeholder" base fuel rate in the Application based on the base fuel factor and Rider A presented in the second supplemental testimony of Company Witness Paul B. Haynes. These adjustments reduce base fuel revenue by $2.2 million. I also presented the Company's revised North Carolina non-fuel base rate increase of $24.9.

Q. Mr. McLeod, what is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony of Public Staff Witness Michael C. Maness with regard to his proposals on the recovery of coal combustion residual ("CCR") asset retirement obligation ("ARO") costs.

Q. Are you introducing any exhibits with your rebuttal testimony?

A. No.

Q. Please briefly reintroduce how the Company is treating CCR-related costs for ratemaking purposes in this proceeding.

A. The Company is seeking recovery of costs relating to CCR remediation efforts at its coal-fired generating stations. Specifically, the Company is addressing the North Carolina jurisdictional portion of asset retirement obligation ("ARO") activities at seven different power stations during the period July 1, 2016 through June 30, 2019, as described by Company Witness Jason Williams. In total, the Company is seeking recovery of $21.9 million to be amortized over a three-year period.[1] The workpapers supporting this calculation can be found in Form E-1, Item 10, pp. 172-179.

Q. What is the significance of the period July 1, 2016 through June 30, 2019?

A. The Commission approved recovery of CCR expenditures incurred by the Company through June 30, 2016, the update period in the Company's 2016 Rate Case. The Company is now requesting recovery of costs incurred since the last rate case through the update period in the instant proceeding, June 30, 2019, the recovery of which has been deferred for financial reporting purposes pending approval by the Commission

Q. Has the Commission granted DENC authority to defer these costs for financial reporting purposes?

A. Yes, the 2016 Rate Order granted DENC continuing authority to establish a regulatory asset account and to defer the Company's CCR expenditures incurred after June 30, 2016 for consideration in a future rate case proceeding. As discussed in my direct testimony and also recognized by Public Staff Witness Maness, AROs are accounted for under Accounting Standard Codification ("ASC") 410 (formerly Statement of Financial Accounting

[1] The $21.9 million consists of the North Carolina jurisdictional portion of $376.7 million, or $19.2 million, plus financing costs of $2.7 million, based upon the proposed three-year amortization period.

Standard No. 143. The Commission initially granted deferral authority for all ARO costs in its *Order Allowing Utilization of Certain Accounts* in Docket No. E-22, Sub 420,[2] and the 2016 Rate Order specifically authorized DENC to use deferral accounting to provide the Company the opportunity to seek recovery of DENC's unexpected and extraordinary costs expended in response to the CCR Rule.[3]

Q. Public Staff Witness Maness states in his testimony that "the Company is asking the Commission to replace ASC 410 treatment with its own proposed ratemaking treatment." Do you agree with his characterization of the ratemaking treatment being presented in this case?

A. No. In the 2016 Rate Case, the Commission specifically "deem[ed] appropriate the establishment of a regulatory asset through which future CCR costs are accounted for . . ." and concluded that "the treatment of CCR costs incurred by [DENC] after June 30, 2016, shall be reviewed in a future rate case…"[4] The Company is following the Commission's direction in the 2016 Rate Order and is now presenting these deferred costs for review before the Commission in this proceeding.

[2] *See Order Allowing Utilization of Certain Accounts,* Docket No. E-22, Sub 420, (Aug. 6, 2004), Ordering paragraph 1.
[3] *Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions*, at 62 Docket No. E-22, Sub 532 (Dec. 21, 2016) ("2016 Rate Order").
[4] 2016 Rate Order, at 62, 63.

Q. Notwithstanding Mr. Maness' characterization of the Company's ongoing deferral accounting treatment of CCR costs, does the Public Staff take issue with the ratemaking treatment presented in this case?

A. No, in fact, Public Staff Witness Maness agrees with the concept and makes no objection (Maness at 8-9).

Q. How is the Company proposing to treat the unamortized balance for ratemaking purposes in this proceeding?

A. The unamortized CCR ARO regulatory asset balance is included as an addition to rate base, which provides for recovery of financing costs until the costs are recovered from customers. This is consistent with how regulatory assets are treated for ratemaking purposes in North Carolina under normal circumstances including similar CCR ARO costs in the Company's 2016 Rate Case in which the Commission found such expenditures are used and useful for the Company's customers.[5]

[5] 2016 Rate Order, at 60-61. In that proceeding, the Commission rejected the Office of the Attorney General's recommendation to exclude the unamortized balance of CCR ARO costs from rate base. The Commission stated "the current CCR repositories are and have service their purpose of storing CCRs for many years. In that respect they have been used and useful for [the Company's] ratepayers. However, pursuant to the CCR Final Rule, [the Company] must incur expenses to the existing repositories for environmental remediation… Like the existing CCR repositories, these permanent storage repositories will be used and useful for [the Company's] ratepayers."

<u>Public Staff Recommended Adjustments</u>

Q. Please describe the Public Staff's proposed adjustment related to the CCR expenditures regulatory asset?

A. Public Staff Witness Maness proposes three adjustments to the Company's proposed amortization and recovery of the CCR expenditures regulatory asset:

1. Calculation of the return between July 1, 2016 and June 30, 2019, using annual compounding, rather than monthly compounding;

2. Amortization of the balance of deferred coal ash expenditures as of June 30, 2019 over a 19-year period, rather than the 3-year period;

3. Reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base.

The latter two adjustments constitute Public Staff Witness Maness' "equitable sharing" proposal to split recovery of CCR costs 60/40 between North Carolina customers and shareholders effectuated by increasing the amortization period to 19 years and excluding the unamortized regulatory asset balance from in rate base.

<u>Return Compounding Adjustment</u>

Q. Do you accept Public Staff's Witness Maness recommendation to use annual compounding rather than monthly compounding for financing costs incurred on CCR ARO expenditures during the deferral period July 1, 2016 through June 30, 2019?

A. Yes, the Company accepts as reasonable the Public Staff's recommended adjustment to use annual compounding rather than monthly compounding for financing costs incurred on CCR ARO expenditures during the deferral period July 1, 2016 through June 30, 2019. This reduces the Company's Adjustment NC-33 by $23,000.

<u>"Equitable Sharing" Adjustment Made to Amortization Expense and Rate Base</u>

Q. Do you accept the Public Staff's proposed disallowance of CCR costs through the equitable sharing mechanism?

A. No, the Company opposes this adjustment. The Public Staff's proposal is neither equitable nor consistent with well-established ratemaking principles in North Carolina, providing that regulated utilities should be authorized to recover costs that are prudently and reasonably incurred in the provision of public utility service to customers.

Q. Please describe Public Staff Witness Maness' rationale for proposing an "equitable sharing" of CCR disposal costs.

A. Importantly, neither Mr. Lucas nor Mr. Maness identify any specific CCR ARO costs that are alleged to be imprudent or unreasonable. Instead, the Public Staff's rationale for its proposal is based, first, on Mr. Lucas' argument that the Company had a duty to guard against alleged potential adverse environmental impacts which now require costly remediation. And, because it is too difficult to undertake a prudency review of the Company's past actions, or to state which specific actions the Company should have taken in the past or to quantify the remediation costs for such actions, cost sharing between DENC and its customers is warranted. In addition, Mr. Maness argues that even in the absence of what Witness Lucas deems "culpability" for CCR costs, there is Commission precedent to support cost sharing between ratepayers and shareholders given the "extremely large" magnitude of the costs.

The Public Staff's proposed "sharing" mechanism is accomplished by amortizing the Company's CCR ARO expenditures over a 19-year period, as opposed to the Company's proposed 3-year recovery period and allowing no return on the unamortized balance (Maness at 30-31). While acknowledging that the proposed 60/40 sharing represents a "qualitative judgment" of the Public Staff, Mr. Maness contends that the proposed mechanism is reasonable due to (1) the magnitude of the incurred expenses, (2) the likelihood that significant additional costs will be incurred in the future, and (3) the lack of any future economic or service benefits to customers as a result of the costs.

Q. In your opinion is the Public Staff's rationale an appropriate basis for disallowing any of the Company's costs for complying with State and Federal CCR law, regulations and rules?

A. Absolutely not. The appropriate regulatory standard for denial of cost recovery is a finding that a specifically identified cost has been imprudently incurred or that the level of cost incurred is unreasonable. Simply relying on a "qualitative" sharing of prudent and reasonably incurred costs is not an appropriate method for determining cost recovery under North Carolina's ratemaking procedures.

Q. Can you elaborate on why you believe the Public Staff's "equitable sharing" approach is not an appropriate regulatory cost recovery standard?

A. I believe the Public Staff's proposal is standard-less. As both Mr. Lucas and Mr. Maness admit, the Public Staff's "equitable sharing" approach is not based upon application of the prudency standard. In fact, according to Mr. Maness, even if the Company had no "culpability," as Mr. Lucas terms it, "the Public Staff would [still] recommend a sharing of some type due to the magnitude and/or the nature of the costs involved."[6] Based on my experience, this type of approach advocating sharing of prudent and reasonable cost incurred in furtherance of providing utility service is subjective and inappropriate.

[6] Maness Testimony at 16.

Moreover, the Public Staff can point to no methodology that would support its selection of the proposed 60-40 sharing split. Instead, as the Commission observed in the most recent rate cases of Duke Energy Progress, LLP (the "2018 DEP Rate Case") and Duke Energy Carolinas, LLP (the "2018 DEC Rate Case," and, together with the 2018 DEP Rate Case, the "2018 Duke Rate Cases"), "[t]he 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[.]"[7] This is underscored by the fact that the Public Staff chose differing percentages for equitable sharing in each of the instances in which it has advocated for adoption of the principle—50-50 in the 2018 DEP Rate Case, 51-49 in the 2018 DEC Rate Case, and 60-40 in the instant case—while providing little explanation as to why an "equitable" split should differ for each regulated utility. With respect to the Public Staff's present 60-40 proposal, Mr. Maness states that the Public Staff is recommending DENC's shareholders be assigned a smaller proportional share of the Company's CCR costs than it recommended for DEP's and DEC's shareholders because, according to Mr. Lucas' testimony, "the culpability of DENC . . . is less than that of DEC and DEP."[8] But neither Mr. Lucas nor Mr. Maness explain how the Public Staff arrived at the conclusion that DENC was only approximately 10% less

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[7] *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction,* at 273 Docket No. E-7, Sub 1146 (June 22, 2018)("2018 DEC Order"); *see also Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase,* Docket No. E-2, Sub 1142 (Feb. 23, 2018) ("2018 DEP Order").

[8] Maness Testimony at 31.

culpable than either DEC or DEP. As recently explained by the Commission in the DEC Rate Case Order, the Public Staff thus "provides insufficient justification for the [60-40] split as opposed to [50-50] or 80-20"[9] or any other such ratio.

In short, Mr. Maness admits that "[t]he specific sharing ratio of 60% of the costs to be borne by ratepayers, and 40% of the costs to be borne by shareholders is a qualitative judgment."[10] Because the "qualitative judgment" of the Public Staff does not provide any recognized basis for disallowing the Company's reasonable and prudently incurred costs, adoption of the Public Staff's proposal is inappropriate as a regulatory cost recovery approach.

Q. How does Mr. Maness attempt to support the Public Staff's "equitable sharing" proposal?

A. Mr. Maness contends that there is precedent to support the concept of "equitable sharing" where the relevant costs are large and will not provide any future economic or service benefits to customers. In particular, Mr. Maness analogizes the Company's instant request to recover CCR remediation costs to the Commission's adoption of a cost sharing approach in two types of cases: (1) nuclear plant abandonment losses, including abandonment losses related to Surry Unit 3, Surry Unit 4, North Anna Unit 3, and North Anna Unit which

[9] 2018 DEP Order at 192.

[10] Maness Testimony at 32.

were addressed in DENC's 1983 general rate case; and (2) costs of environmental cleanup at manufactured gas plants.

Q. Do you agree with Mr. Maness that an equitable sharing of coal ash costs as proposed by the Public Staff is appropriate considering the Commission's treatment of losses associated with abandoned nuclear plant costs?

A. No. Abandoned nuclear plant costs are not comparable to the costs of CCR remediation. In the past, abandoned nuclear plant costs were never used and useful in providing utility service to customers and thus not eligible for inclusion in rate base.

Q. Has the Commission previously considered intervenor arguments that CCR costs should be treated in a manner similar to nuclear plant abandonment costs?

A. Yes, the Commission has consistently rejected this argument in three rate cases in the past three years. First, as described above, in the Company's 2016 rate case, the Commission found that CCR repositories were and continue to be used and useful and were therefore not abandoned. Indeed, the Commission specifically found that "the costs at issue in this case are test year remediation costs, not unamortized costs of abandoned plants."[11]

The Commission applied this rationale again in the 2018 DEP and DEC Rate Cases, distinguishing DEP's and DEC's request to recover the costs of CCR

[11] 2016 Rate Order, at 62.

remediation from abandoned nuclear plant costs on the grounds that the former costs were used and useful while the latter costs were not, as the nuclear facilities at issue had *never* been placed into service or otherwise used to generate electricity.[12] Accordingly, consistent with the Commission's determination in all three of these recent rate cases, the Company's CCR compliance costs are eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful utility property.

Q. Did the Commission provide any further guidance on this issue in the recent 2018 DEP and DEC Rate Cases?

A. Yes. In both the 2018 DEP and DEC Rate Cases, the Commission found that the 1988 DEP rate case provided an example of nuclear cost recovery that is more analogous to a request to recover the costs of CCR disposal. In that case, the relevant issue was the reasonableness and prudence of the costs of constructing and placing into service Unit 1 of the Shearon Harris nuclear plant. The Commission found that some nuclear costs related to Shearon Harris—particularly those related to Harris Unit 1—were prudently incurred and used and useful.[13] Accordingly, the Commission allowed full recovery of the prudently incurred, used and useful portion of the Shearon Harris Plant

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[12] 2018 DEC Order at 276 (noting that such costs "had never been placed in rate base as plant in service prior to the general rate cases at issue, and to the extent they were costs in abandoned nuclear facilities, they were facilities never used to generate electricity"); 2018 DEP Order at 194 ("There are . . . significant distinctions between [nuclear abandonment costs] and the present case. First and foremost, this case does not involve 'abandoned plan' or cancellation costs. Rather, it involves 'reasonable and prudent' and 'used and useful' expenditures to the Company[.]').

[13] See Order dated August 5, 1988, in Docket No. E-2, Sub 537.

costs. This is consistent with the treatment the Company is seeking in this case, which is full recovery of the prudently incurred and used and useful coal ash costs. I have been informed by counsel that the Commission's decision in this regard was upheld by the North Carolina Supreme Court.[14]

Q. Please respond to Mr. Maness's argument the Commission's prior treatment of environmental cleanup costs of manufactured gas plants supports an equitable sharing of coal ash costs.

A. I disagree with Mr. Maness, as there are a number of key differences between the costs associated with manufactured gas plants ("MGP") and coal ash costs that render the Commission's past treatment of MGP costs a poor analogy to the facts of the current case.

First, there is a significant timing difference between the actual usage of the facility and the environmental related cost recovery. The earliest North Carolina MGP cost recovery case that I am aware of was a 1992 Piedmont Natural Gas Company order in Docket No. G-9, Sub 333. However, Piedmont had changed over from using MGP to natural gas in 1952, some 40 years earlier.[15] This is also the case for the Public Service Company of North Carolina, Inc.'s ("PSNC") MGP facilities (Docket No. G-5, Sub 327). Therefore, unlike the current case, the MGP remediation cost were incurred and proposed for recovery more than 40 years after the facilities were retired.

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[14] *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 484, 489, 385 S.E.2d 463, 465 (1989).

[15] See http://law.justia.com/cases/north-carolina/supreme-court/1961/250-1-5.html.

In contrast, the Company's coal-fired generating units and/or the coal ash disposal facilities are either still providing services to customers or were providing service until very recently. The Commission came to this exact conclusion in the 2016 Rate Order:

> The issue is not recovery of costs of closed plants or costs of storing CCRs in repositories over past periods. The issue is recovery of remediation costs incurred in the test year as extended. In addition, a number of the electric generating plants from which CCRs are being and have been produced and the repositories are still in operation and have not been taken off line or closed.[16]

Second, the coal-fired generating plants that utilized the coal ash disposal facilities have always been in the ownership of the Company or its predecessors. This is not the case for many MGP sites that had several owners before being acquired by the regulated gas utilities that eventually undertook the MGP cleanup. The fact that the MGP sites had multiple owners, and not just the then-operating regulated gas utilities, is important because it means that other parties were potentially responsible parties for some of the MGP remediation costs and the utilities were apparently pursuing these claims.[17]

Third, as I introduced above and will explain later in my testimony, these environmental compliance costs are for expenditures that this Commission has

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[16] 2016 Rate Order, at 61.

[17] For example, PSNC has made this claim in financial filings indicating that: "The Company's actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims, ***and recoveries from other potentially responsible parties***." See: https://www.psncenergy.com/docs/librariesprovider6/pdfs/financial-statements/3q-2009-psnc-financials.pdf?sfvrsn=2 (emphasis added).

determined are used and useful. In contrast, the Commission specifically found the MGP sites were not used and useful similar to its findings related to abandoned nuclear facilities.[18]

Finally, I find it inappropriate for the Public Staff to rely on a cost recovery example in a different industry in a case that is more than 20 years old dealing with assets last used in providing regulated utility service more than 70 years ago when the best examples of how this Commission has treated these same types of costs arose in DENC's 2016 Rate Case and the 2018 DEP and DEC Rate Cases that were each decided in the last three years. This is particularly true given the Commission's acknowledgment in the 2018 DEP and DEC Rate Cases that its prior handling of MGP cost sharing was a minority approach among other states that granted full recovery of MGP costs and "not precedent the Commission chooses to follow to provide for sharing" of coal ash costs.[19]

Q. What is an appropriate analogy for the Commission in considering recovery of DENC's coal ash costs in this case?

A. A straightforward example of the appropriate and consistent cost recovery treatment for these costs is the cost recovery methodology used by this Commission in the Company's 2016 Rate Case and the 2018 DEP and DEC Rate Cases. In each of those cases, these very same types of coal ash related

[18] *In re Public Serv. Co. of North Carolina*, No. G-5 Sub 327, 156 PUR 4th 384 (Oct. 7, 1994) ("the MGP sites are not used and useful in providing gas service to current customers").
[19] 2018 DEP Order at 192.

costs were allowed to be amortized over five years and allowed a return on the unamortized balance.

Q. Are the Company's CCR ARO costs used and useful?

A. Yes. As a threshold matter, the coal plants associated with these costs and the related coal disposal facilities have been used and useful in providing low-cost, reliable power to North Carolina customers for decades. The Commission specifically and unequivocally found in the 2016 Rate Order that Company's ongoing costs of operating existing CCR repositories and constructing new CCR repositories represented used and useful expenditure incurred for the purposes of complying with the federal CCR rule:

> [P]ursuant to the CCR Final Rule, DNCP must incur expenses to the existing repositories for environmental remediation. . . . . DNCP is responding to the CCR Final Rule requirements in a responsible and prudent manner. The result of DNCP's efforts should be the expenditure of funds to establish permanent CCR storage repositories. Like the existing CCR repositories, ***these permanent storage repositories will be used and useful for DNCP's ratepayers.***
>
> . . . .
>
> Although four of the coal-fired generating plants that are the sites of DNCP's CCR remediation efforts are no longer generating electricity, DNCP is not seeking to defer undepreciated costs of these plants or inclusion of unamortized costs in rate base as part of its CCR cost recovery request. Also, the existing CCR repositories at these sites cannot be abandoned by DNCP. . . . . ***the existing CCR repositories continue to be used and useful for storing CCRs, and will continue to be used and useful until DNCP moves the CCRs to a permanent repository, or takes the necessary steps to cap and close the existing repository.***[20] (emphasis added)

[20] 2016 Rate Order, at 61.

The Commission also consistently found the costs associated with coal ash disposal to be used and useful in the 2018 DEP and DEC Rate Cases. Most recently, the Commission specifically explained in the 2018 DEC Rate Case that "[c]apital expenditures undertaken to enable compliance with the law qualify as 'used and useful,' in that the Company does not have the option to fail to comply, and . . . [such costs] are routinely recoverable in rates."[21]

Consistent with the Commission's determination in the 2016 Rate Order and the 2018 DEC and DEP Rate Cases, DENC's ongoing coal ash disposal costs continue to be used and useful and incurred to comply with the federal CCR Rule as well as various Virginia statutes, rules, and regulations. Consequently, these types of costs and, if any amount is deferred over time, a return would be appropriately recoverable in rates to ensure that the Company received the equivalent of the full amount of those costs.

Q. **Mr. Maness argues that the concept of used and useful property under North Carolina's ratemaking statute only applies to a public utility's property including "true working capital" and not to the expenses the utility incurs in the operation, maintenance, or disposal of that property. (Maness, at 24) Please respond.**

A. Mr. Maness' contention that the term "used and useful" does not apply to the expenses that a utility incurs in the operation, maintenance, or disposal of its property is patently incorrect. While I am not an attorney, I have been

[21] DEC Order at 268.

informed by counsel that the North Carolina Supreme Court in *State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co.*, 285 N.C. 398, 206 S.E.2d 283 (1974) ("*VEPCO*") held that working capital, including "funds reasonably invested in . . . materials and supplies and [the utility's] cash funds reasonably so held for payment of operating expenses" could be included in rate base so long as such funds were investor-furnished, not customer-furnished. The Commission recently applied the holding of *VEPCO* in both the 2018 DEP and DEC Rate Cases, finding that the because "the Company appropriately accounted for coal ash basin closure costs in the working capital section of rate base, and as these funds were investor-furnished, not customer-furnished, *VEPCO* holds that they are "used and useful" [and] the Company is entitled to earn a return on those funds over the period in which the costs are amortized."[22] Here, the Company has treated its coal ash-related cash expenditures in the same way as DEP and DEC treated their coal ash expenses in their respective 2018 rate cases and in the same way DENC treated its own coal ash expenditures in its 2016 Rate Case. Because DENC appropriately accounted for coal ash basin closure costs in the working capital section of rate base and such funds were paid for by investors, they are considered "used and useful" and the Company is entitled to earn a return.

[22] DEP Order at 195; 2017 DEC Order at 269 ("DEC is subject to these new legal requirements and must handle and store coal ash in a manner that complies with them. As such, . . . the capital costs of compliance are "used and useful," and the Company is authorized to recover them . . . along with a return as adjusted below on its outlay of these funds.").

Q. Putting aside the Public Staff's proposal to not allow the Company a return on the unamortized balance of CCR ARO costs, do you believe Mr. Maness' proposed 19-year amortization period is reasonable or in the best interest of customers or the Company?

A. No. In my opinion, such a lengthy recovery period for CCR costs does not serve the best interests of the North Carolina customers or the Company. Where, as authorized under current rates, the Company is afforded a return on the unamortized CCR deferral balance for ratemaking purposes, a longer amortization period results in greater carrying costs (at DENC's authorized overall rate of return) over the life of the asset. In essence, a longer amortization period costs customers more in the long run, while delaying the Company's recovery of actually-incurred costs in the short run.

The delayed recovery of these deferred costs also puts more pressure on rates in the future as the Company continues to incur significant additional environmental expenditures related to CCR regulatory compliance. If the Public Staff's 19-year amortization proposal is adopted by the Commission, the result will likely be overlapping vintages of CCR regulatory asset amortizations across multiple, future rate cases in which the Company will be requesting recovery of additional deferred CCR costs. Assuming Public Staff continues to advocate for a similar amortization approach in future rate cases, the cost recovery for CCR will likely extend more than 20 years into the future when the cumulative costs incurred over the next few years are fully recognized through rates. Under the shorter amortization period proposed by the Company, the regulatory asset from the instant proceeding will conclude and be replaced by the next regulatory asset in the next general rate case, allowing for a smoother transition from one case to the next, and more importantly, achieving greater rate stability for customers.

It is also important to recognize the current circumstances surrounding the Company's non-fuel base revenue requirement. The Company is proposing a substantial 2020 fuel factor reduction ($18.1 million) coupled with a substantial decrement rider, Rider EDIT, to refund certain federal excess deferred income taxes ("EDIT") to customers over a one-year period ($6.9 million). Customers have the near-term benefit of these reductions or offsets to the non-fuel base revenue requirement. It is both reasonable and appropriate for the Commission to consider all of these factors and to strike an appropriate balance between the substantial near-term benefits customers will receive through the 2020 fuel factor and Rider EDIT with timely recovery of CCR expenditures. Taking these circumstances into account, the Company's proposed 3-year amortization of these regulatory assets allows rates to be set at a "just and reasonable" level that positions the Company's current rate structure to recover these actually-incurred costs reasonably quickly while also ensuring that the Company's future rate structure will be able to absorb future, known incremental costs without the negative rate volatility.

Q. Is the Public Staff's proposed 19-year amortization period appropriate on grounds that recovery of CCR costs is similar to more lengthy recovery periods for plant abandonment losses?

A. No. The comparison of CCR expenditures to the abandonment and/or impairment and early retirement of a generating facility is neither reasonable nor accurate. The abandonment or impairment and retirement of a generating facility is a one-time, non-recurring event. In contrast, the CCR expenditures, first, will in fact be recurring and growing costs and, second, are environmental compliance and remediation costs, not abandoned plant, that will need to be recognized in future rate filings. I also find it notable that Mr. Maness advocated in the Company's 2016 rate case that a 10-year amortization of the Company's coal ash expenses was appropriate based essentially on the same theory he is putting forward in this case (the large size of the expense and purported lack of future economic or service benefit to customers) and precedent (abandoned nuclear facilities), which he now contends supports an amortization period of nearly double that amount.[23]

Q. How has the Commission responded to the Public Staff's recent advocacy for extremely lengthy amortization periods for recovery of CCR costs?

A. The Commission has consistently rejected the Public Staff's proposals for lengthy amortization periods for CCR costs, including most recently in the

[23] Testimony of Michael C. Maness, Docket No. E-22, Sub 532 (Sept. 7, 2016) ("the Public Staff believes that for purposes of this proceeding, a more appropriate and reasonable amortization period is ten years. . . . for costs of significant size related to retired or abandoned plants, the Public Staff in recent years has consistently recommended and amortization or levelization period of ten years[.]"

2018 DEC Rate Case (25 years) and 2018 DEP Rate Case (26 years). In these recent rate cases, as well as DENC's 2016 Rate Case, the Commission authorized recovery of all prudent and reasonably incurred CCR ARO costs to be amortized over five years with a return on the unamortized balance.

Q. **Do you have any comments on the Public Staff's proposal to account for CCR costs differently because they are an "extremely large cost"?**

A. Yes. Mr. Maness' proposal is not workable from a regulatory accounting perspective. Nowhere does he define just what is an "extremely large cost." Is such a cost defined by the total dollar amount, the dollars per customer, the dollars per kWh? Does the definition of "extremely large" costs change by utility, by year, and by the type of costs? In sum, adopting a regulatory order that bases its justification on a cost being subjectively and situationally defined as "extremely large" is inconsistent with my experience of regulatory ratemaking and with known principles of regulatory accounting.

In reality, there is no history of such sharing except in very different circumstances where the costs incurred were found not to be used and useful (which is not the case as it relates to these coal ash disposal costs). However, this Commission does have a history of allowing the Company to recover what I assume Mr. Maness would call extremely large costs from customers even when those costs are not the result of placing a new generating facility into service. Examples include the costs for transmission lines, storm restoration costs, and contract termination fees that are not related to new generation. As the Commission has acknowledged, "there is no provision in

Chapter 62 requiring different treatment for 'extremely large costs.'"[24] Juxtaposed to these examples of large costs that are routinely approved for recovery, "[t]he Commission determine[d] that this is another example of the arbitrariness inherent in the Public Staff's sharing proposal."[25]

To summarize, adopting that the Public Staff's position, which bases its justification on a cost being subjectively and situationally defined as "extremely large," undermines the basic actual cost recovery principles embodied in North Carolina utility regulation and subjects the state's utilities to a cost recovery standard that is unknowable.

Q. Mr. McLeod, please summarize the Company's position on the appropriate approach to recover the Company's prudent and reasonably incurred CCR ARO costs in this proceeding?

A. The Company continues to believe that its proposed 3-year amortization of the CCR costs that have already been deferred for recovery during the period July 1, 2016 to June 30, 2019, allows rates to be set at a "just and reasonable" level that positions the Company's current rate structure to recover these actually-incurred costs over a reasonable period while also ensuring that the Company's future rate structure will be able to absorb future, known incremental costs without the negative rate volatility – a result that would be detrimental both to the Company and our customers. However, in light of the

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[24] DEC Order at 275 (quoting testimony of DEP witness C. Wright, Tr. Vol. 12, pp. 156-21 – 156-22).

[25] *Id.*

Commission's recent determinations that a five year amortization period is appropriate the Company does not oppose a five-year amortization period if the Commission determines that period to be in the best interests of DENC's customers. Changing the amortization period from 3-years to 5-years results in a reduction to the base non-fuel revenue requirement of $2.8 million.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Mr. McLeod, do you have a summary of your rebuttal testimony?

A. I do.

Q. Would you please provide it to the Commission at this time?

A. My rebuttal testimony addresses Public Staff Witness Michael C. Maness' recommendation that recovery of costs the Company has incurred to dispose of and remediate its coal ash impoundments in compliance with various state and federal laws and regulations should be split 60 percent and 40 percent between North Carolina customers and Company shareholders, respectively, through a concept Mr. Maness refers to as, quote/unquote, equitable sharing.

I explain that the theory underlying Mr. Maness's recommended disallowance of these costs is unfounded, does not justify disallowance, and should be rejected by the Commission. My rebuttal testimony begins with a summary of how the Company is treating CCR-related costs for ratemaking purposes in this proceeding.

The Company is proposing to recover the North Carolina jurisdictional portion of $377 million in system-level cash expenditures for asset retirement obligation activities, referred to as AROs, at seven different power stations during the period from July 1st, 2016, through June 30th, 2019. In total, the Company is seeking recovery of $21.9 million. These cash expenditures have been deferred to a regulatory asset account and are being presented to the Commission for review in this proceeding pursuant to the Commission's directives in the Company's 2016 rate case, Docket Number E-22, Sub 532.

In that -- in that proceeding, the Commission stated that the establishment of a regulatory asset through which future CCR costs are accounted for allows the Company, quote, the opportunity to seek recovery for this unexpected and extraordinary cost expended in response to the CCR Final Rule, unquote.

I proposed to amortize this balance over a five-year period in my stipulation testimony, consistent with the Commission's treatment of similar deferred CCR costs in Duke Energy Progress' and Duke Energy Carolina's most recent general rate cases.

The unamortized CCR ARO regulatory asset balance is included in the working capital section of rate base, which provides for recovery of financing costs associated with these investor-supplied funds until they are recovered from customers. This is consistent with how regulatory assets are treated for ratemaking purposes in North Carolina under normal circumstances, including similar CCR ARO costs in the Company's 2016 rate case in which the Commission found such expenditures are used and useful for the Company's customers.

Public Staff Witness Maness recommends an effective disallowance of 40 percent of these costs achieved through amortization of the Company's deferred coal ash expenditures over a 19-year period, rather than the five-year period proposed by the Company, with no return on the unamortized balance. He suggests this proposed disallowance mechanism is reasonable due to, one, the magnitude of the incurred expenses; two, the likelihood that significant additional costs will be incurred in the future; and, three, the lack of any future economic or service benefits to customers as a result of these costs.

My rebuttal testimony explains that the justification for Mr. Maness' proposal is not based on any recognized rate of recovery standard. Instead, the appropriate regulatory standard for denial of cost recovery is a finding that a specifically identified cost has been imprudently incurred or that the level of cost incurred is unreasonable. Because neither Mr. Maness nor any of the Public Staff witnesses have argued that the Company's coal ash expenditures were imprudent or the costs were unreasonable, the Public Staff has not provided any reasoned basis for the Commission to disallow recovery of the costs.

I next explain why Mr. Maness' suggestion that there is Commission precedent to support his equitable -- equitable sharing proposal is unfounded. First, his contention that the Commission's treatment of abandoned nuclear plant supports the proposed cost sharing proposal is not appropriate because abandoned nuclear plant costs are not comparable to CCR costs.

The Commission has found abandoned nuclear costs not to be used and useful, and thus not eligible for rate base treatment. To the contrary, the coal plants associated with CCR expenditures have been used and useful in providing lo-cost, reliable power to North Carolina customers for more than 70 years and will continue to be used and useful.

This is consistent with the recent DEC and DEP rate cases, where the Commission found that CCR repositories were and continue to be used and useful, were therefore not abandoned, and were therefore eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful property.

Likewise, the Commission's treatment of environmental cleanup of manufactured gas plants does not support Mr. Maness' proposed cost sharing. MNG plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental related cost recovery, and in terms of ownership. Also, the MNG facilities, like abandoned nuclear plants, were found not to be used and useful.

Next, I respond to Mr. Maness' contention that a regulatory asset is not true -- quote/unquote, true working capital. I have been informed by counsel that the North Carolina Supreme Court held that working capital, including, quote, funds reasonably invested in materials and supplies and the utility's cash funds reasonably so held for payment of operating expenses, unquote, could be included in rate base so long as such funds were investor-furnished, not customer-furnished.

Because DENC appropriately accounted for coal ash basin closure costs in the working capital section of rate base and such funds were paid for by investors, they are considered -- considered used and useful and the Company is entitled to earn a return, absent a finding the costs were unreasonable or imprudently incurred.

Putting aside the Public Staff's proposal not to allow the Company a return on the unamortized balance of CCR ARO costs, I explain that Mr. Maness' proposed 19-year amortization period is not in the best interest of the Company's customers. Delayed recovery of these deferred costs puts more pressure on rates, as the Company will continue to incur significant additional environmental expenditures related to CCR regulatory compliance.

In this case, the total rate changes in the stipulation provides for an overall rate decrease for the North Carolina jurisdiction. This includes amortization of the CCR regulatory -- it should say regulatory asset over a five-year period with a return on the unamortized balance. If the Public Staff's 19-year amortization proposal is adopted by the Commission, the result -- the result will likely be overlapping vintages of CCR regulatory asset amortizations across multiple future rate cases in which the Company will be requesting recovery of additional deferred CCR costs.

The Company's proposed five-year amortization of these regulatory assets allows rates to be set at a just and reasonable level that positions the Company's current rate structure to recover these actually incurred costs over a reasonable amount of time.

Thank you.

Q. Thank you, Mr. McLeod.

MS. GRIGG: Chair Mitchell, before I release him for cross-examination, Mr. McLeod is able to answer a couple of the Commission's questions generally that he was not able to address on direct. If you'd like, he'd be happy to address those, the first of which was the follow-up following the SCANA merger when the Company will update the budget to reflect service company allocations.

A. Yes. Chair Mitchell and Commissioner Brown-Bland asked about that yesterday. The Company -- the Company is currently completing a five-year plan which is due to be completed in November and they're updating the forecasted settlement of the services company allocation factors for that process.

Q. Thank you. And the second question was Chair Mitchell's question regarding the relative cost difference of --

CHAIR MITCHELL: Thank you. The Company's previous closure plans versus what the Company's estimate of the cost will be under the new Virginia legislation.

A. I can answer it. Did you have a question about the --

Q. I did have one follow-up on the --

CHAIR MITCHELL: Oh.

Q. -- on the allocations. Do you know the point in time at which those updated allocations will be filed with this Commission?

A. So you did ask about that yesterday as well. The Company will be filing its next services company agreement in the third quarter of 2020.

Q. Okay.

A. But it's my understanding those -- those cases, I guess, address the methodologies. So I don't know if we'd necessarily be reflecting updated factors in the case.

Q. Okay.

EXAMINATION BY CHAIR MITCHELL:

Q. Thank you. Do you want me to ask the second question again or do you recall?

A. If you want to --

Q. It was the -- the cost -- the relative cost difference of the Company's previous closure plans versus what we estimate the cost will be with the new Virginia legislation.

A. Right. So there was a question, I believe, this morning on Virginia -- recent Virginia legislation on CCR. So at the end of the fourth quarter of 2018, the Company had an approximately $700 million we call legacy ARO prior to when the legislation passed.

At the end of the second quarter of 2019, the ARO is 2.5 billion, but I want to note, too, that the legacy ARO, because that -- that -- as Mike Maness was saying earlier, represents future obligations, some of that work hasn't net been done. So the legacy ARO was reduced by approximately 200 million. So the new legislation resulted in additional ARO of approximately two and a half billion.

Q. Okay. So it's -- it's 500 plus 2.5. Okay.

A. Right.

Q. Thank you. And -- and is the 2.5 just for the -- those impoundments subject to the legislation, not for the -- all of the impoundments?

A. That's my understanding.

Q. Okay. Thanks. Thank you.

MS. GRIGG: Mr. McLeod is available for cross-examination.

CROSS-EXAMINATION BY MR. DROOZ:

Q. Mr. McLeod, just to kind of start with the big picture, is it the Company's position that the five-year amortization with a return of the 377 million, the North Carolina share, that your reasons for proposing that essentially track the reasons that the -- that appear in the Commission's orders in the last Duke Progress and Duke Carolina cases?

A. The reasoning?

Q. Yes.

A. I think -- I think the -- my proposal is more guided by the fact that the Commission allowed a return on those assets. I think I have a more simplistic view of how the regulatory assets should be treated. You know, for purposes of ratemaking in North Carolina, we eliminate all ARO accounting and are -- are simply following the cash, so just kind of put all the ARO accounting to the side.

And, you know, my view is that the Company has spent, you know, 377 million in cash which represents investor-supplied funds, which are appropriately accounted for as working capital. I don't know if that tracks exactly what the Commission found in the Duke cases, but that's our position on why they should be in rate base.

Q. And is the nature of that 377 million roughly 98 percent O&M expense?

A. Can you point me to where that -- that came from, 98?

Q. Yeah. It's --

A. Is that discovery response?

Q. I think it's discovery response 166. I actually have that as an exhibit.

A. I have -- I think I have it here, too.

Q. I sort of jumped ahead of myself just because --

A. Well, I -- I'll accept it. It's a --

Q. It's a high percentage.

A. It's a large percentage of O&M. But, again, you know, our -- our position is that, you know, that O&M or capital, it -- you know, it doesn't -- the nature of it is somewhat irrelevant because those costs, you know, were excluded from rates in the last case and are being deferred, you know, for recovery in this case. So they're appropriately reflected, you know, in -- in rate base.

Q. Those expenditures were not available for recovery in the last case because they hadn't been spent yet, right, the 2016 to 2019 costs?

A. Yeah. The cash hadn't been spent. Right.

Q. Right. I believe in your testimony you referred to these expenditures as a capitalized asset; is that correct?

A. Can you point me to -- to that?

Q. I will further down the line. You know, I was trying to take a shortcut here. If -- if you're not sure of that, we'll move on and get to it.

A. Okay.

Q. I think at this point I'd like to ask some questions just to kind of get a basic understanding of GAAP accounting and regulatory accounting and beg forgiveness for -- from everyone. It's a dull subject at this point.

GAAP, G-A-A-P, stands for generally accepted accounting principles?

A. Yes. That's right.

Q. Okay. And those GAAP principles are largely established by the Financial Accounting Standards Board; is that correct?

A. Yes. Yeah.

Q. Which for the sake of the court reporter I'll say we sometimes call FASB or F-A-S-B?

A. Right.

Q. Now, VEPCO, as the subsidiary, and -- and Dominion Energy North Carolina, as a subsidiary of a publicly traded company, must follow the financial accounting and reporting requirements of the Securities and Exchange Commission?

A. Right.

Q. Okay. So has the Securities and Exchange Commission designated FASB as the organization to set those accounting requirements?

A. Yes.

Q. Okay. Now, is -- in general, is it -- is it fair to say the goal of the SEC is to have financial reporting that is transparent and accurate for potential investors and creditors of the Company?

A. Yeah.

Q. Okay. And Dominion also has to use GAAP principles for purposes of reporting to the Federal Energy Regulatory Commission, or FERC?

A. Right. And we have to comply by the FERC's accounting standards as well.

Q. And those are called the Uniform System of Accounts?

A. Correct.

Q. Okay. Are you familiar at all with North Carolina Rule R8-27 that essentially incorporates the Uniform System of Accounts into North Carolina retail jurisdiction reporting requirements?

A. Yes.

Q. Okay. And does that Rule R8-27 provide that the use of the Uniform System of Accounts is subject to certain exceptions or conditions for North Carolina retail purposes?

A. I'm -- I'm not sure offhand.

Q. I've got a copy of here, if I can approach -- if I may approach the witness.

CHAIR MITCHELL: You may.

A. (Witness examines document.) Okay.

Q. So would you like me to repeat the question?

A. Yes, please.

Q. Okay. Does that rule provide that the use of the Uniform System of Accounts is subject to conditions or exceptions for North Carolina retail jurisdictional purposes?

A. Yes, it does have those.

Q. Okay. And is one of those exceptions or conditions that Dominion must apply to the North Carolina Commission for any North Carolina retail jurisdictional use of regulatory asset or liability accounts?

A. Yes. I see that number two here.

Q. Okay. Does the use of that exception that's a regulatory asset or liability account help Dominion in the sense that it can match its accounting for the North Carolina retail jurisdiction with the ratemaking for the North Carolina retail jurisdiction so you don't show a big earnings drop?

A. Yeah, I -- I'd accept that, yeah.

Q. Okay. In Docket Number E-22, Sub 420, did Dominion apply for and receive permission to record its coal ash expenditures -- well, excuse me, to record legal obligations as a regulatory asset for North Carolina retail jurisdictional purposes?

A. Yeah. That's right.

Q. Okay. That was really looking -- back in Sub 420, that was really looking at nuclear decommissioning, but the language was broader and the companies interpreted that to include coal ash obligations?

A. I don't think the companies interpret it to include coal ash. I think that -- that order specifically says nuclear and -- looking at the order in Paragraph 2 here, nuclear decommissioning costs and other ARO costs --

Q. Okay.

A. -- which would include the CCR ARO costs.

Q. Okay. Thank you. And because of the federal CCR Rule and now Virginia's Senate Bill 1355, Dominion does have a legal obligation to close its coal ash basins; is that correct?

A. That's my understanding.

Q. Yeah. So the GAAP standard called Statement of Financial Accounting Standards Number 143, was that issued by FASB back around 2003?

A. Yes.

Q. And that relates to accounting for asset retirement obligations?

A. Right.

Q. Okay. And that's now codified as Accounting Standard Codification 410 -- ASC 410?

A. Yes.

Q. Okay. Has the FERC Uniform System of Accounts essentially adopted ASC 410?

A. Yeah. There's certain FERC guidance around how those are accounted for.

Q. Okay. And ASC 410 requires Dominion to record the estimated future closure costs of coal ash basins as an asset retirement obligation; is that right?

A. Right.

Q. And that's -- on your books, you record that as a liability, the ARO as a liability?

A. Yeah.

Q. Okay. Now, the recording of an ARO for ash basin closure costs under this ASC 410, that's done for purposes of financial presentation, isn't it?

A. You know, and as you said, it's also -- we're required to do that for financial and for FERC --

Q. Right.

A. -- regulation under FERC accounting standards.

Q. I think in your direct testimony at Page 21, you allude to this. You say, "ASC 410 requires for financial reporting purposes that companies recognize liabilities for the expected cost of retiring tangible long-lived assets for which legal obligation exists."

That's essentially what you said in your direct testimony?

A. Right.

Q. Okay. When we say financial presentation or financial reporting purposes, does that mean the purpose of the ARO, again, is to inform readers of the Company's FASB GAAP financial statements that there'll be future expenditures for the retirement or closing of the coal ash basins?

A. Yeah. I mean, it certainly informs investors; also, you know, Commission, regulators. It serves other purposes --

Q. Right.

A. -- as well.

Q. Creditors.

A. Yeah.

Q. That allows people reading those financial statements to get a better picture of the Company's long-term financial obligations?

A. Yeah, just thinking about the investors. Yeah.

Q. Yeah. So you've got the ARO recorded as a liability. There's also a corresponding or offsetting asset called an asset retirement cost or ARC?

A. Yeah. That would be -- that would be recognized if -- when establishing the ARO liability, if there was a related asset that was still in service --

Q. Uh-huh (yes).

A. -- it would establish the ARC. I think Mike Maness testified to this earlier, but --

Q. He did.

A. -- you know, to the extent that the plants are not operating, then it would -- it would just be charged to income.

Q. Okay. So when you first establish or record the ARO, there will be an ARC of equal amount, but then it could get immediately expensed if the plant under -- the plant has been retired?

A. I'm not sure if the accounting entries work exactly like that, but I guess you could charge it to income and set up a ARO liability at the same time.

But, again, I think -- you know, as I say in my testimony, all of these accounting entries and whatnot --

Q. Right.

A. -- we eliminate all of that for purposes of ratemaking in North Carolina.

Q. Right. And -- and to that extent, the -- would you say that ARO accounting or ASC 410 accounting is -- is not really pertinent to the cost recovery for North Carolina retail ratemaking purposes?

A. It's certainly informative. You know, I think it's -- like you said, it -- it provides information. It's something that's disclosed to our investors and in our FERC filings. But when we file rate cases -- you know, and I -- and I should say, too, it's also in our per books cost of service study --

Q. Uh-huh (yes).

A. -- that we prepare as well.

It's just when we -- we are doing these rate cases we come in and make accounting adjustments to remove all of that activity.

Q. Right. Your pro forma adjustments for the application in this case eliminated all that ASC 410?

A. Right.

Q. Okay. Thank you. Now, under this ASC 410 or ARO accounting, however we want to call it, are you required to depreciate the asset retirement cost into expenses over the life of the underlying asset?

A. To the extent that the -- that there is a capital asset that's related to -- you know, to be amortized over the remaining life.

Q. Okay. And for ash basins, the underlying asset would be the coal generating plant associated with that basin?

A. I believe they -- they look at the -- you know, the remaining life of the plant.

Q. Of -- of the coal generating --
A. Plant.
Q. -- plant?
A. Yeah.
Q. Okay. And, again, I think you said if the coal generating plant had been retired from service at the time the ARO or legal obligation first arose, then you would just immediately write it off to expense the entire ARC?
A. Yes. That's right.
Q. Okay. And -- and going along with that, if the plant -- the coal plant is not fully depreciated but still have some years of useful life left, then a portion of the ARC related to that asset would be depreciated over future years, right?
A. Yes, I think all of it would be.
Q. Okay. Whatever's left in the ARC would be depreciated over the future years?
A. I think if there was an ARO and there was a -- an asset that was still operating that the entire ARC would go into plant --
Q. Okay.
A. -- and then amortize off of the remaining life.
Q. Thank you. So is it accurate to say that the expensing of the ARC, asset retirement cost, asset is not

based on when the actual CCR expenditures are made?

A. You know, the -- I don't know if that's exactly correct. The -- you know, the ARC -- you know, as Mike -- as Mike testified to earlier as well, the ARC is established at the present value. So, yeah, that -- that is amortized off over a straight line. But then you do have accretion that occurs over the life of the asset as well to -- to build up that ARO to the final cash amount. So they are -- it is all tied together mathematically in the end.

Q. So -- yeah. In the end, you bring -- bring it down to zero, right?

A. Right. The -- but the ARC -- you know, the -- the amount that you established is based on whatever the projected cash flows are. So they are -- they are tied together.

Q. So the ARC, the asset retirement cost, is, I think you said, basically going to be written down as an expense on a straight-line basis over the remaining life of the underlying asset, the coal plant?

A. Yeah, to the extent that there's an ARC. Right.

Q. Okay. But your cash expenditures for CCR closure may proceed at a very different pace, not on a straight-line basis over the life of the -- remaining life of the plant, right?

A. Right. And that -- and that's what we're presenting in this case, is -- is the actual cash that we spent since our last rate case.

Q. Right. Yeah. At least for some coal plants, the actual cash expenditures to close are -- are going to be made well before the plant's retired and the ARC is fully expensed; is that right?

A. Yes, for the ones that are still operating.

Q. So under the ASC 410 or ARO accounting, am I correct that when the actual dollars are spent on CCR closure activity, those dollars simply reduce the ARO liability and they are not recorded as an expense on the Company's FASB GAAP books?

A. Are you saying in a situation where there's an ARC?

Q. Yes. Because you've got a straight-line --

A. Your actual -- yeah. Your actual cash payments would reduce the ARO life. And, again, we eliminate all that when we're filing these rate cases.

Q. Right. But they're not an expense on your FASB books reducing the ARC?

A. I know -- I think as -- as you -- as we have been discussing, the expense is recognized as the ARC is depreciated.

COMMISSIONER GRAY: Pull that microphone a little closer.

THE WITNESS: Oh, sorry. Sorry. Do I need to repeat that?

COMMISSIONER GRAY: Yes, please.

THE WITNESS: The -- the expense is recognized as the asset retirement cost, the asset side of the ARO, as that is depreciated over the useful life of the plant. That's when the expense is actually recognized for financial reporting purposes. And, again, that's not what we do for North Carolina ratemaking purposes.

Q. And to bring that a little closer to this case, the amount of the ARC, or ARC, that has been expensed from July 2016 through June of 2019 under ASC 410 is not the same as the coal ash expenditures you made over -- the Company made over that period; is that correct?

A. Yeah. You have a mix of plants that are operating and plants that are not operating. You know, so -- you know, some -- some of those AROs were immediately written off when they were established. Some have ARCs. You know, it's -- it's kind of a mixed bag how they're being accounted for for financial reporting purposes.

Q. And even for the operating plants, the amount expensed for ARCs during that period would not be the same as the actual cash expenditure for closure activity?

A. Can you say that one more time?

Q. Even for the operating plants, the amount you expense for the ARC under, you know, the FERC FASB accounting is not going to be the same as your 377 million actually spent for closure activities?

A. I mean, I think -- I think at the end of the day, when it's all said and done, it is because you have the accretion.

Q. I'm talking just about that 2016 to 2019 period.

A. Oh, no. The -- what's recognized for financial reporting purposes is not going to match the cash flows.

Q. Okay. Thank you. So I understand the Company's position and the Public Staff has -- has not put in different evidence in this case is that the coal ash residual expenditures in that time frame were prudent and reasonable; is that right?

A. Can you state that one more time?

Q. Your CCR costs were prudent and reasonable from 2016 to 2019, right?

A. That's the Company's position, yes.

Q. Yeah. And is it also the Company's position that those costs were expended for property used and useful?

A. Yes. And -- let's see.

Q. And I believe you alluded earlier to the concept that that comes in as working capital.

A. Yeah. And if you look at Page 17 of my rebuttal testimony --

Q. Uh-huh (yes).

A. -- that's really the basis for why we're saying it's -- it's used and useful.

But you're right. I mean, the -- the -- I guess the, quote/unquote, property would be the -- the cash that we spent that's investor-supplied and then that is reflected in working capital.

Q. So as I look at Page 17, I see a discussion there and it looks like that's a quotation from a 2016 order of this Commission; is that right?

A. Yeah. That's right.

Q. Okay. And it says the permanent storage -- I'm reading the italicized part. These permanent storage repositories will be used and useful for DNC -- DNCP's ratepayers.

So that's speaking to the -- the physical, tangible asset of the repositories as being used and useful; is that right?

A. I'm just trying to read it -- read this quote.

Give me one second.

Can you repeat the question?

Q. That quote which you used to support the Company's position indicates that the storage repositories themselves are property used and useful; is that correct?

A. Yes. That's what the order says.

Q. And those are tangible, physical assets, aren't they, the ash basins?

A. Right.

Q. Okay. That's a little different from working capital, isn't it?

A. Is working capital different than plant?

Q. Is it a tangible, physical asset that's, yeah, utility plant?

A. I think -- yeah, working capital includes non-plant investments in it. So PP&E is plant investments. Working capital includes non-plant investments, both of which investors supplied and haven't yet been recovered from customers.

Q. So I think we've covered some of these questions already, but we're still not going to finish today.

So Mr. Maness had talked about the deferral to regulatory asset or liability as effectively overlaying and supplementing -- this might be the wrong word, but it's really replacing the GAAP FERC entries on the Company's book, isn't it?

A. For North Carolina jurisdictional purposes, that's correct.

Q. Okay. We have some exhibits to hand out, and the first one --

CHAIR MITCHELL: Why don't we go ahead and -- and call it a day for today? And we'll start with your exhibits in the morning.

MR. DROOZ: Okay.

CHAIR MITCHELL: We'll be back on the record at 9:30 in the morning. Let's go off the record.

(The hearing was adjourned at 5:27 p.m. and set to reconvene at 9:30 a.m. on Wednesday, September 25, 2019.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF FRANKLIN)

I, Patricia C. Elliott, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly sworn; that the testimony of said witnesses was 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 this action; 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 27th day of September, 2019.

PATRICIA C. ELLIOTT
VERBATIM REPORTER/NOTARY PUBLIC
NOTARY #19940480043