PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, August 20, 2019

TIME: 2:01 p.m. - 4:30 p.m.

DOCKET NO.: G-7, Sub 743

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding

Chair Charlotte A. Mitchell

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Application of Piedmont Natural Gas Company, Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina, Continuation of Its IMR Mechanism, Adoption of an EDIT Rider, and Other Relief

VOLUME: 6

Noteworthy Reporting Services, LLC

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P R O C E E D I N G S

COMMISSIONER BROWN-BLAND: Let's come back to order. Go back on the record. Just a little bit ago, I was approached by Mr. Page and asked to be recognized.

MR. PAGE: Thank you, Madam Chair. Over the lunch recess, I've been advised by the Attorney General's office that they, in fact, do not have questions to ask to Mr. O'Donnell, who is CUCA witness.

So at this time, we'd like to ask that has prefiled testimony, appendix and four exhibits, KWO-1 through KWO-4, be admitted into evidence and ask that he be excused unless the Commission has questions for him.

COMMISSIONER BROWN-BLAND: All right. The Commission does not have questions.

Is there any objection to letting Mr. O'Donnell go from any other parties?

(No response.)

COMMISSIONER BROWN-BLAND: There being none, that motion will be allowed, and Witness O'Donnell's prefiled testimony will be received into evidence as if given orally from the witness stand; his four exhibits will be identified as they were when prefiled, and they will also be received into evidence.

MR. PAGE: Thank you, Madam Chairman.

COMMISSIONER BROWN-BLAND: Thank you.

(Exhibits KWO-1 through KWO-4 were admitted into evidence.)

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

BEFORE
NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:

Application of Piedmont Natural Gas Company for Adjustment of Rates and Charges Applicable to Natural Gas Service in North Carolina	) Docket No. G-9, Sub 743

FILED

JUL 19 2019

Clerk's Office
N.C. Utilities Commission

Direct Testimony

of

Kevin W. O'Donnell, CFA

On Behalf of

Carolina Utility Customers Association, Inc.

July 19, 2019

Contents

I. Introduction

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

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

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

A. I am testifying on behalf of the Carolina Utility Customers Association (CUCA). A number of CUCA members take natural gas service from the applicant, Piedmont Natural Gas Company (Piedmont or Company), and the outcome of this proceeding will have a direct bearing on these CUCA members.

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

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from the Florida State University. I earned the designation of Chartered Financial Analyst (CFA) in 1988. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission (NCUC). I left the NCUC Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail Rates for the North Carolina Electric Membership Corporation (1994-1995), and since then in my own consulting firm. I have been accepted as an expert witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the North

Carolina Utilities Commission, the South Carolina. Public Service Commission, the Wisconsin Public Service Commission, the Virginia State Commerce Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Utilities Commission, the Oklahoma Public Utilities Commission, the District of Columbia Public Service Commission, and the Florida Public Service Commission. In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in Appendix A attached to this testimony.

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

A. The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the proper rate of return, the appropriate rate design, and the allowable rate case expenses to grant Piedmont in the current proceeding.

Q. IN THE DIRECT TESTIMONY OF ITS RATE OF RETURN WITNESS, WHAT RATE OF RETURN DID PIEDMONT RECOMMEND THAT THE COMMISSION ACCEPT?

A. According to the testimony of Company Witness Hevert, Piedmont is seeking an overall rate of return of 7.68% based on the capital structure and cost rates as set out in Table 1 below.

Table 1: Piedmont Requested Cost of Capital

Component	Capital Structure Ratio (%)	Cost Rate (%)	Wgtd. Cost Rate (%)
Long-Term Debt	47.18%	4.55%	2.15%
Short-Term Debt	0.82%	2.82%	0.02%
Common Equity	52.00%	10.60%	5.51%
Total Capitalization	100.00%		7.68%

Q. DO YOU AGREE WITH PIEDMONT'S RATE OF RETURN REQUEST?

A. No. I disagree with Piedmont's requested return on equity.

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

- the proper return on equity on which to set rates for Piedmont in this proceeding should not exceed 9.0%.
- the overall rate of return that should be granted Piedmont in this case is 6.85%;
- the proper rate class changes are as follows: 9.5% increase for residential consumers; 5.60% increase for small GS customers; -5.0% for medium GS customers; 6.0% for Large GS customers; 8.0% increase for Large GS Transportation customers; 0% change for Interruptible Sales customers; 9.0% reduction for interruptible transportation customers; 5% increase for military customers; and a 10% increase for municipal customers; and
- Piedmont's rate case expenses are grossly in excess of the costs for consumer witnesses and cost recovery for those expenses should be

slashed from $1.18 million to $365,000 to put these costs on-par with similar expenses for Public Staff employees and consultants.

Q. COULD YOU PERFORM A COST OF EQUITY ANALYSIS DIRECTLY ON PIEDMONT NATURAL GAS?

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

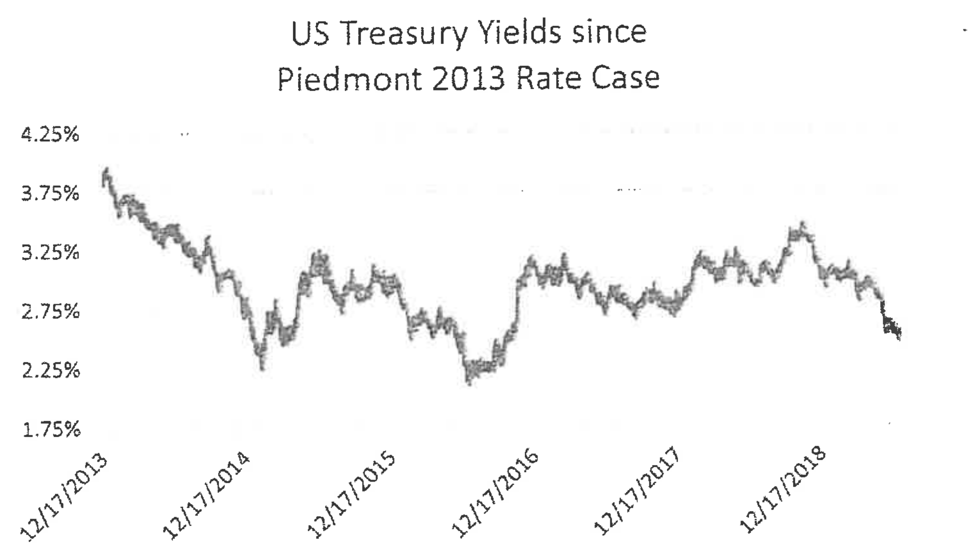
II. Current State of Financial Markets

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

A. The Company's last rate case was in 2013 and a final order was issued on Dec. 17, 2013.[1] Long-term interest rates have fallen since the Company's last rate case. In Chart 1 below, I have provided the change in the 30-year US Treasury bonds since Dec. 20, 2013. On that date, the yield on 30-year US Treasury bonds was 3.88%. As of July 5, 2019, the yield on 30-year US Treasury bonds was 2.54%, which equates to a 134 basis point decrease in the yield on 30-year US Treasury bonds.

[1] Data taken from snl.com

Chart 1: Yield on 30-Year US Treasury Bonds



Source for raw data: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2013-2019

Q. DIDN'T THE FEDERAL RESERVE JUST RAISE INTEREST RATES?

A. Yes, on December 19, 2018, the Federal Reserve increased the Federal Funds rates from 2.25% to 2.50%.[2]

Q. DOES THIS MEAN THAT THE COST OF CAPITAL HAS INCREASED FOR COMPANIES LIKE PIEDMONT?

A. No. The interest rate increase represents only the interest rate at which banks borrow short-term money. The interest rate hike from the Federal Reserve does not always result in an increase in long-term rates. As noted in Chart 1 above, the yield on 30-year US Treasury rates has been falling since the announcement of the Federal Reserve rate hike.

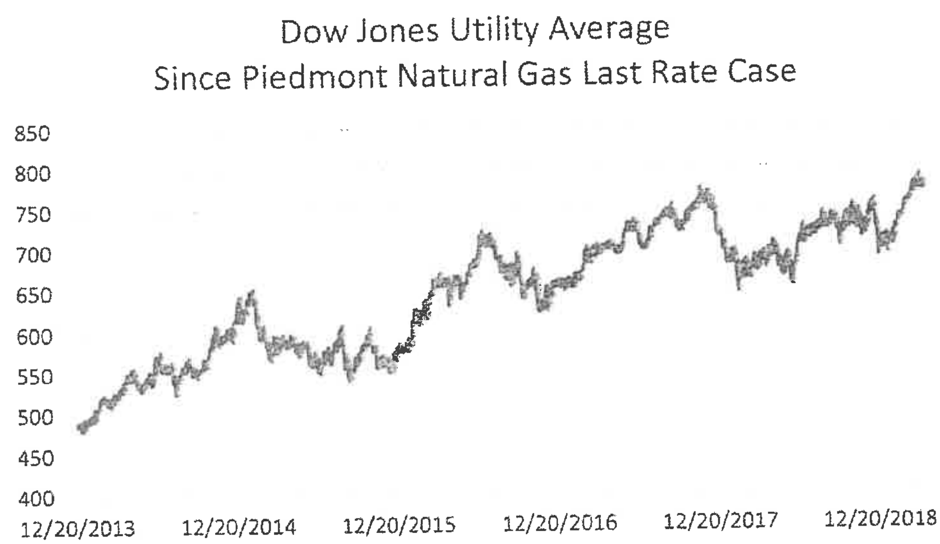
[2] https://www.cnbc.com/2018/12/19/fed-hikes-rates-by-a-quarter-point-.html.

Recently, the Federal Reserve has indicated that it does not intend to raise interest rates any further in 2019.[3]

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

A. Since May 1, 2018, the Dow Jones Utility Average has risen from 703.59 to 774.06, which equates to a return of 10% in less than one-year.

Chart 2: Dow Jones Utility Average



Source: Yahoo Finance accessed on 7-7-19.

Q. WHAT RETURN ON EQUITY (ROE) DID THE COMPANY SEEK IN ITS 2013 BASE RATE CASE AND WHAT WAS GRANTED BY THE COMMISSION?

A. The Company sought an 11.35% ROE in the last rate case.[4] The case was settled and the Commission agreed to a 10.0% ROE.[5] No ROE was presented in the settlement.

[3] https://www.cnbc.com/2019/03/20/fed-leaves-rates-unchanged.html.
[4] Final order in Docket No. G-9, Sub 631, p. 19

Q. WHAT ROE IS THE COMPANY SEEKING IN THIS RATE CASE?

A. In the current filing, the Company is seeking a 10.6% ROE.

Q. DO YOU BELIEVE THE COMPANY'S REQUEST IN THIS CASE IS APPROPRIATE GIVEN THE CHANGE IN THE COST OF CAPITAL SINCE ITS LAST RATE CASE?

A. No. Even though the cost of debt financing has fallen over 130 basis points and the Dow Jones Utility Average has nearly doubled since the Company's last rate case, the Company has actually INCREASED its requested ROE from the "settlement" ROE of 10.0% in the last rate case up to a requested 10.6% in this case. Failing to recognize the lower expected return on utility investments, as espoused by Company Witness Hevert, cannot be supported and is simply illogical.

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

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

A. The theory of utility regulation assumes that public utilities perform functions that are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. Even though deregulation for the procurement of natural gas and generation of electric power and energy is spreading, delivery of these products to end-use customers is still a monopoly business and will, for the foreseeable future, be regulated. On this basis, state legislatures or

[5] Id, p. 18

Commissions establish exclusive franchised territories to public utilities or determine territorial boundaries where disputes arise, in order for these utilities to provide services more efficiently and at the lowest reasonable cost. In exchange for the protection within its monopoly service area, the utility is obligated to provide adequate service at fair, regulated rates.

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

Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the fair rate of return for a utility.

Regulatory law and policy recognize that utilities compete with other firms in the market for investor capital. The United States Supreme Court set the guidelines for a fair rate of return in two often-cited cases: *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692; and the *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

In the Bluefield case, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[5]

In the above finding, the Court found that utilities are entitled to earn a return on investments of comparable risks and that corresponding return should be sufficient enough to support credit activities and to raise funds to carry out its mission.

In the often-cited case of *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944), the U.S. Supreme Court recognized that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn.

In *Hope Natural Gas*, the U.S. Supreme Court stated that the return to equity owners (or shareholders) of a regulated public utility should be "commensurate" to returns on investments in *other* enterprises whose "*risks* correspond" to those of the utility being examined:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure

confidence in the financial integrity of the enterprise so as to maintain credit and attract capital. (320 U.S. at 603).

IV. Development of Proxy Group

Q. **PLEASE DESCRIBE HOW YOU SELECTED A PROXY GROUP FOR ESTIMATING PIEDMONT'S RETURN ON EQUITY.**

A. The number of available gas utilities needed to develop a reasonably reliable proxy group is dwindling. Over the past three years, several gas utilities, such as AGL Resources and Piedmont Natural Gas, have announced that they are being acquired by large electric utility holding companies. These acquisitions make sense for the electric utilities as they desire to grow their source of regulated earnings while, at the same time, control the pipelines over which they expect to receive future deliveries of natural gas, which is expected to be the predominant power generation fuel choice of electric utilities for many years to come.

In my experience, I have found the difference between my recommendations and that of utility ROE witnesses is never about the choice of the proxy group. Instead, the difference is the manner in which the ROE models are applied. For this reason, and to sharpen the focus between myself and Mr. Hevert, I have chosen to use the companies used by Mr. Hevert in his proxy group.

V. Capital Structure

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

A. The term "capital structure" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments. For simplicity, there are three financing methods. The <u>first</u> method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Returns on common equity, which in part take the form of dividends to stockholders, are not tax deductible which, on a pre-tax basis alone, makes this form of financing about 28% more expensive than debt financing. The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock are not tax deductible. Corporate debt is the third major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in a year or less. Both long-term debt and short-term debt represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment

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

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

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. Yes, I have.

Q. WHAT CAPITAL STRUCTURE IS SEEKING IN THIS CASE?

A. According to the pre-filed Direct testimony of Company Witness Powers, Piedmont is seeking the following capital structure:

Table 2: Piedmont Requested Capital Structure

Component	Capital Structure Ratio (%)
Long-Term Debt	47.18%
Short-Term Debt	0.82%
Common Equity	52.00%
Total Capitalization	100.00%

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN YOUR PROXY GROUP?

A. Table 3 below shows the average common equity ratio of each company in the proxy group.

Table 3: Proxy Group Equity Ratio[6]

Company	2018E Ratio
Atmos Energy Corp	65.7%
Chesapeake UTIL	68.0%
New Jersey Res.	54.6%
N.W.Natural	52.5%
One Gas, Inc	61.5%
South Jersey INDS	50.0%
Southwest Gas	51.0%
Spire Inc	54.3%
Average	**57.2%**

As can be seen in the table above, the average common equity ratio in the proxy group is 57.2%, which is above the requested equity ratio in this case of 52.00%.

[6] *The Value Line Investment Survey*, Dec 14, 2018; Jan. 25, 2019; and Feb. 15, 2019.

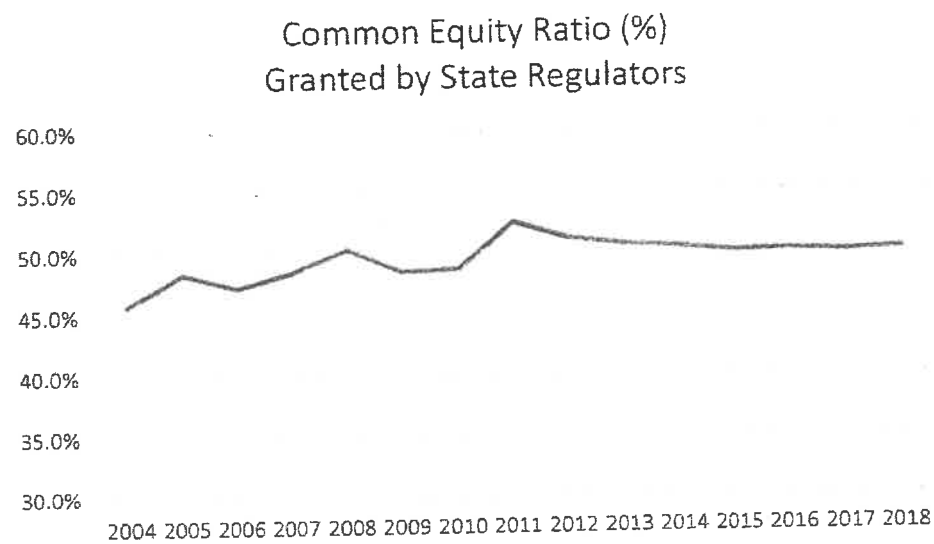
Q. **WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED BY UTIILTY REGULATORS ACROSS THE UNITED STATES IN 2018?**

A. The average common equity ratio granted by regulators in 2018 to gas utilities was 50.09%.[7]

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

A. State regulators have been quite consistent in their rulings in natural gas cases over the past 15 years. From 2004 through 2018, common equity ratios have ranged from roughly 45% to 52%. The average common equity ratio for each year over the past 15 years can be seen in Chart 3 below.

Chart 3: Common Equity Ratio Granted by State Regulators (2004-2018)



The data for Chart 3 is found in Table 4 below.

[7] S&P Global Market Intelligence, RRA Regulatory Focus Major Rate Case Decisions – January – December 2018, Jan. 31, 2019.

Table 4: Common Equity Ratios

Year	Common Equity (%)[8]
2004	45.81%
2005	48.40%
2006	47.24%
2007	48.47%
2008	50.35%
2009	48.49%
2010	48.70%
2011	52.49%
2012	51.13%
2013	50.60%
2014	50.35%
2015	49.93%
2016	50.06%
2017	49.88%
2018	50.09%
Average	**49.47%**

The average common equity ratio from 2004 through 2018 was slightly below 50%, at 49.47%.

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

A. Table 5 below provides a summary of how Piedmont's request in this case compares to the following equity ratios: the equity ratio requested by the Company, the equity ratio of the proxy group, and the average allowed equity ratio by state regulators across the country in 2018.

[8] Raw data from snl.com

Table 5: Common Equity Comparison	
Piedmont Request	52.00%
Proxy Group Average	57.20%
2018 Average Reg Eq Ratio	50.09%

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

A. Yes, for purposes of this case, I will accept the Company's proposed capital structure.

VI. Cost of Common Equity

Q. PLEASE EXPLAIN HOW THE ISSUE OF DETERMINING AN APPROPRIATE RETURN ON A UTILITY'S COMMON EQUITY INVESTMENT FITS INTO A REGULATORY AUTHORITY'S DETERMINATION OF JUST AND REASONABLE RATES FOR THE UTILITY.

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

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

A. Utilities obtain capital funding through a combination of borrowing (debt financing) and issuing stock (equity financing). Unless in the very rare event a company's borrowing is determined to be imprudent, the determination of ratepayer reimbursement for debt financing is generally uncontroversial, as the amount is simply the principal and interest repaid by the company to bondholders.

In contrast, the determination of the allowed ROE is where disputes most frequently arise. The allowed ROE is the amount that is determined to be appropriate for the utility's common stockholders to earn on the capital that they invest in the utility when they buy its stock. If the regulatory authority sets the ROE too low, the stockholders will not have the opportunity to earn a fair return and this may either cause existing shareholders to sell their shares or deter new investors from buying shares. If, on the other hand, the regulatory authority sets the ROE too high, the ratepayers will pay too much. Because ratepayers cannot choose a different utility due to the monopolistic service territory restrictions, countervailing competitive market forces are absent and the resulting rates will be unjust and unreasonable to the ratepayer.

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

A. The required equity return, which is based on the market value of a utility's stock, is combined with the cost of debt to produce the a company's "overall rate of return", which is then applied to the net book value of the utility's investment, otherwise known as the rate base. Under this procedure, the market price of a stock is used only to determine the return that investors expect from that stock. That expectation is then applied to the book value of the utility's investment to identify the level of earnings that regulation should allow the utility the opportunity to earn.

Q. WHAT IS THE "COMPARABLE EARNINGS" TEST AND HOW DOES THAT FACTOR IN TO DETERMINING THE APPROPRIATE RETURN ON EQUITY?

A. The "comparable earnings" standard, i.e., that the earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks," is derived from the Supreme Court's ruling in the *Hope Natural Gas* case to which I earlier referred. In my opinion, enterprises of "corresponding" or comparable risk are companies that are engaged in the same activities as Piedmont and are also regulated like Piedmont.

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

A. Regulatory commissions and boards, as well as financial industry analysts, institutional investors, and individual investors, use different analytical models and methodologies to estimate/calculate reasonable rates of return on equity. Among the measures used are Discounted Cash Flow analysis, the Capital Asset Pricing Model, and Comparable Earnings Analysis ("CEA"). I believe the most useful methodology is the DCF Analysis, but I am also presenting the CAPM and the Comparable Earnings Model as checks for my DCF results.

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

A. Yes. There is no direct, observable way to determine the rate of return required by equity investors in any company or group of companies. Investors must make do with indications from market data and analysts' predictions to estimate the appropriate price of a share. The principal and most reliable methodology for obtaining these indications is the Discounted Cash Flow procedure. Other procedures, such as the CAPM and the comparable earnings method, are less reliable than the DCF procedure.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE DCF MODEL IS SUPERIOR TO THE CAPM AND RISK PREMIUM APPROACHES.

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

The comparable earnings model is based on earned returns from book equity, not market equity. There is no direct and immediate stockholder input into the comparable earnings model and, as a fault, that model lacks a clear and unmistaken link to stockholder expectations.

The CAPM suffers, to a degree, from the same problem as the comparable earnings model in that there is not a direct and immediate link from stock market prices to the CAPM result. The beta in the CAPM can reflect changes in the ROE, but the delay can, sometimes, make the CAPM results meaningless.

A. DCF Model

Q. PLEASE EXPLAIN THE DISCOUNTED CASH FLOW MODEL.

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

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

Let D	=	dividends per share in the initial future period
g	=	expected growth rate in dividends
k	=	cost of equity capital
P	=	price of asset (or present value of a future stream of dividends)

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

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

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

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

Solving for k yields:

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

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

A. Yes, I believe that to be so. There are three primary reasons for my conclusion. First, there is much literature that supports the fact that, while emotional or so-called "irrational" behavior in the short term may affect (and has affected) share prices, over the long term a company's financial fundamentals drives the market.[9] Second, analysts give great weight to earnings, dividend, and book value growth in formulating their recommendations to clients. Finally, even a casual search on the internet produces hundreds of pages discussing the definition of the DCF methodology and how to apply it for investment decisions, from which I infer that general investor interest in DCF analysis is significant and widespread.

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

Q. IS THE DCF FORMULA EASY TO UNDERSTAND?

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[9] See, for example, "Valuation: Measuring and Managing the Value of Companies," 4th Edition, McKinsey & Company Inc., Tim Koller, Marc Goedhart, David Wessels ("Provided that a company's share price eventually returns to its intrinsic value in the long run, managers would benefit from using a discounted-cash-flow approach for strategic decisions. What should matter is the long-term behavior of the share price of a company, not whether it is undervalued by 5 or 10 percent at any given time." http://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/do-fundamentalsor-emotionsdrive-the-stock-market (accessed March 2, 2016). See also, for example, http://www.businessinsider.com/what-drives-the-stock-market-2012-8 (Accessed March 2, 2016).

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

Q. CAN YOU GIVE AN EXAMPLE?

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

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

A. I have calculated the appropriate dividend yield by averaging the dividend yield expected over the next 12 months for each proxy company, as reported by the Value Line Investment Survey. The period covered is from March 15, 2019 through June 7, 2019. To study the short-term as well as long-term movements in dividend yields, I examined the 13-week, 4-week, and 1-week dividend yields for the proxy group. My results appear in Exhibit KWO-1 and show a dividend yield range of 2.5% to 2.6% for the proxy group.

Q PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELD RANGES DISCUSSED ABOVE.

A. I developed the dividend yield range for the proxy group by averaging each Company's Value Line forecasted 12-month dividend yield over the above-stated 13-week, and 4-week periods as well as examining the most recent forecasted 12-month dividend yield reported by Value Line for each company. I averaged the dividend yield over multiple time periods in order to minimize the possibility of an isolated event skewing the DCF results.

Q. HOW DID YOU DERIVE THE EXPECTED GROWTH RATE?

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

$$g = \frac{br(2017) + br(2018) + br(2019E) + br(2022E\text{-}2024E\ Avg)}{4}$$

The plowback estimates for all companies in the proxy group can be obtained from The Value Line Investment Survey under the title "percent retained to common equity." Exhibit KWO-2 lists the plowback ratios for each company in the proxy group.

A key component in the DCF Method is the expected growth in dividends. In analyzing the proper dividend growth rate to use in the DCF Method, the analyst must consider how dividends are created. Since over the long term dividends cannot be paid out without a corporation first earning the funds paid out, earnings growth is a key element in analyzing what if any growth can be expected in dividends. Similarly, what remains in a corporation after it pays its dividend is reinvested, or "plowed back", into a corporation in order to generate future growth. As a result, book value growth is another element that, in my opinion, must be considered in analyzing a corporation's expected dividend growth. To analyze the expected growth in dividends, I believe the analyst should first examine the historical record of past earnings, dividends, and book value. Hence, the second method I used to estimate the expected growth rate was to analyze the historical 10-year and 5-year historical compound annual rates of change for earnings per share (EPS), dividends per share (DPS), and book value per share (BPS) as reported by Value Line for each of the relevant corporations.

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

Some analysts do not present historical growth rates in their DCF analyses. I believe analysts that do not present such available data fail to completely inform the respective regulatory bodies of the full extent of information on which investors base their expectations. In his analysis, Mr. Hevert presents historical data, but he opines that forecasted earnings should be provided more weight in the DCF analysis.[10]

[10] Direct Testimony of Robert Hevert, p. 61

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

The fourth method I used was the forecasted rate of change for earnings per share as recorded by CFRA, a publication of S&P Global Market Intelligence.

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

The details of my constant growth DCF analysis can be seen in Exhibit KWO-1.

Q. SHOULD THE RESULTS REFLECTED IN EXHIBIT KWO-1 BE VIEWED IN LIGHT OF FUNDAMENTAL DEVELOPMENTS IN THE NATURAL GAS UTILITY INDUSTRY THAT HAVE OCCURRED DURING THE PAST EIGHT YEARS?

A. Yes. As the Commission is well aware, natural gas prices have plummeted since 2008. As a result of the drastically lower natural gas prices, many electric utilities across the country are planning to meet their future electric load requirements through the use of natural gas. Distribution utilities that derive profits from the delivery of natural gas are now in high demand. In 2016, Piedmont Natural Gas, itself, was sold to Duke Energy for a very large premium. Remaining gas utilities are achieving solid growth as natural gas is in high demand across the country.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS?

A. As can be seen on Exhibit KWO-1, the dividend yield for each of the three timeframes studied ranges is equivalent to 2.6% for the proxy group.

In terms of the proper dividend growth rate to employ for the proxy group in the DCF analysis, it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future. An examination of the 10-year and 5-year historical growth rates for the proxy group show a change in the earnings and dividend growth rates. For the 10-year history, on first review, earnings per share grew faster than dividends per share. However, when the -10.5% growth rate for Northwest Natural Gas is omitted, the earnings per share (5.8%) over the past 10 years is close to the 10-year historical dividends per share (5.8%). The same situation is also evident in the 5-year historical growth rates. When the -18.0% for Northwest Natural Gas is omitted, the average for the proxy group changes from 2.1% to 5.5%, which is close to the 5-year average dividend growth rate of 5.9%. The forecast of the proxy group's various growth rates is consistent with the understanding that natural gas is growing in prominence in the energy industry around the country. The forecasted growth rates from Value Line range from 5.5% to 10.0%. However, the high end (10.0%) of the range is significantly influenced by the 27.0% forecasted earnings per share for Northwest Natural Gas from Value Line. Eliminating that one growth rate reduces the average Value Line forecasted earnings per share from 10.0% to 7.6%.

In addition to the above forecasted Value Line growth rates, the plowback growth rate for the proxy group is 4.3%, the CFRA forecasted EPS growth rate is 5.9%, and the Schwab forecasted earnings growth rate is 5.5%.

The fact that the proxy group forecasted growth rates are all between roughly 5% to 7% indicates that the natural gas utility industry is expecting solid and steady growth in earnings, dividends, and book value in the future.

Q. IN ESTIMATING THE COST OF EQUITY AT THE PRESENT MOMENT, SHOULD MORE WEIGHT BE PLACED ON FORECASTED GROWTH RATES OR HISTORICAL GROWTH RATES AND HOW DOES YOUR ANSWER AFFECT YOUR CONCLUSIONS AS TO THE PROPER GROWTH RATE RANGE FOR PROXY GROUP OF COMPANIES IN THE DCF ANALYSIS?

A. Due to the effects of the fundamental changes that have occurred in the natural gas utility industry over the past eight years that I mentioned previously, I believe that it is proper to place more weight on forecasted figures than historical figures in estimating the cost of equity for the proxy group. As a result, I believe that the proper growth rate range for the proxy group of companies to use in the DCF analysis is 5.0% to 7.0%. The lower end (5.0%) of the range is above the above the plowback growth rates and is slightly below the forecasted Value Line earnings growth rate whereas the upper end of the range (7.0%) is in the center of the Value Line forecasted growth rate range.

Q. SHOULD ONLY EARNINGS GROWTH RATES IN THE DCF METHODOLOGY BE USED? IF NOT, WHAT DID YOU DO TO MITIGATE THIS PROBLEM?

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

Q. PLEASE PROVIDE EXAMPLES OF ACADEMIC LITERATURE THAT CALLS INTO QUESTION THE ACCURACY OF ANALYST FORECASTS.

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

1. the accuracy of forecasts was extremely low; [11]
2. analyst forecasts are overly optimistic[12]; and
3. forecasts by analysts are inefficient.[13]

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

> …it is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic.[14]

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[11] "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," Journal of Business Finance & Accounting, (June/July 1999), p. 751;

[12] id

[13] id

[14] K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," Journal of Finance (2003), p. 683

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

> No executive would dispute that analysts' forecasts serve as an important benchmark of the current and future health of companies. To better understand their accuracy, we undertook research nearly a decade ago that produced sobering results. Analysts, we found, were typically overoptimistic, slow to revise their forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined. [15]

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

> We show that, on average, the difference between the estimate of the expected rate of return based on analysts' earnings forecasts and the estimate based on current earnings realizations is 2.84%. When estimates of the expected rate of return in the extant literature are adjusted to remove the effect of optimistic bias in analysts' forecasts, the equally weighted estimate of the equity risk premium appears to be close to zero. [16]

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

To mitigate the problems as cited above, I have presented EPS, DPS, and BPS figures to the Commission and systematically explained my rationale for

[15] "Equity Analysts, Still Too Bullish," McKinsey on Finance, (Spring, 2010), p. 14

[16] "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts", Journal of Accounting Research, December, 2007, p. 1012

arriving at the above stated growth rates. I believe it is incumbent upon every analyst presenting testimony in this case to present such a robust analysis to the Commission.

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

A. Combining the proxy group's dividend yield of 2.6% with the growth rate range of 5.0% to 7.0% produces a DCF range of 7.6% to 9.6%. Based on this analysis, the DCF results are in the range of 7.6% to 9.6%.

B. Comparable Earnings Analysis

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

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

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

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

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

Q. HOW DOES THE MARKET VALUE OF COMPANIES IN THE COMPARABLE GROUP COMPARE TO THE BOOK VALUE OF THESE SAME COMPANIES?

A. The market value of the companies in the comparable group far exceeds the book value. Table 6 below provides the results.

Table 6: Comparable Group Market-to-Book Ratios

Utility	Mkt Value	Book Value	MV/BV Ratio
Atmos	$97.30	$42.87	2.27
Chesapeake	$91.13	$31.80	2.87
New Jersey NG	$46.99	$16.18	2.90
Northwest NG	$64.18	$26.30	2.44
OneGas	$84.14	$38.85	2.17
South Jersey Ind.	$31.29	$15.15	2.07
Southwest Gas	$82.16	$42.40	1.94
Spire	$76.86	$44.51	1.73
		Average	2.30

As can be seen in the table above, market values are well in excess of book value. As a result, it is a mathematical fact that a return on book value will be far greater than a return on market value as the denominator in a return on market value will be greater than the denominator in a return on book value calculation.

Q. CAN YOU USE PROVIDE AN EXAMPLE OF A RETURN ON BOOK VALUE BEING IN EXCESS OF A RETURN ON MARKET VALUE?

A. Yes. Suppose a company had a net income in a particular year of $10 million and its book value was $100 million, but investors were willing to pay a total of $200 million in the current market valuation for the stock. The return on book equity would be 10% ($10 million/$100 million) whereas the return on market value would be 5% ($10 million/$200 million). Hence, when the market value of a stock is well in excess of its book value, the return on book value will be greater than the return on market value.

The above illustration provides an example of why I believe the stated returns on common equity should be used only as a guide to the DCF market-required estimates. Simply put, analysts can mistakenly equate the two returns and cause confusion for regulators.

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

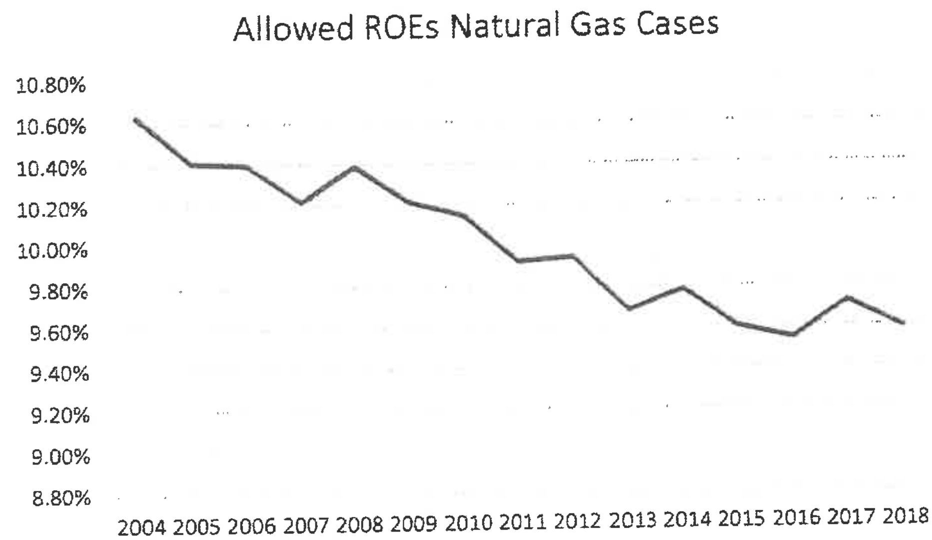
A. Exhibit KWO-3 presents a list of the earned returns on equity of the comparable group over the period of 2017 through 2024. I picked this range to provide the Commission with two years of historical returns and five years of forecasted returns. As can be seen in this exhibit, the average earned returns on equity for the proxy group are range from 9.3% to 10.6%.

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

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

As this Commission is likely aware, regulated ROEs have trended down over the past 15 years. In Chart 4 below, I have provided a chart that shows the allowed ROEs allowed for natural gas utilities by state regulators across the United States from 2004 through 2018.

Chart 4: Allowed ROEs 2004 – 2018



Source for raw data: S&P Global Market Intelligence, RRA Regulatory Focus Major Rate Case Decisions – January – December 2018, Jan. 31, 2019

As for the most recent year, 2018, the overall allowed ROE for gas utilities was 9.59%, which was down from the 9.72% allowed by state regulators for gas utilities in 2017.

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

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

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

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

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

A. Mr. Robert Hevert, who is also the witness for Piedmont in the current proceeding, was the witness for Otter Tail Power in the South Dakota proceeding. Mr. Hevert's recommendation in the South Dakota case was 10.3%.

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

A. As noted previously, gas utilities are expected to have strong growth in the future due to the abundance of natural gas now produced in the United States and the increasing demand for natural gas services. Electric utilities, for example, are turning almost entirely now to constructing natural gas generation plants as opposed to nuclear and coal units. Hence, the strength in the natural gas industry should continue unabated for several years to come.

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

Based on the above-stated findings, I believe the proper rate of return using a comparable earnings analysis is in the range of 9.0% to 10.0%. This lower end of this range represents the fact that regulators across the country are recognizing the lower cost of capital and setting ROEs at lower points. The high end of the range is at the midpoint between the Value Line forecasted earned return on common equity for the proxy group in 2019 and 2022/2024. This average allowed ROE for gas utilities, as reported by snl.com, is also in the midpoint of this range of 9.0% to 10.0%.

C. Capital Asset Pricing Model (CAPM)

Q. HAVE YOU PREVIOUSLY PRESENTED THE CAPM IN COST OF EQUITY TESTIMONIES?

A. Yes, but I have not given it much weight. I have long maintained the application of the CAPM can lead one to erroneous results when it is applied in an inaccurate manner, such as when "forecasted" risk premiums or "forecasted" interest rates are employed. For this reason, I have historically not used the CAPM in cost of equity analyses. However, I am aware that this Commission relies primarily on the DCF model, with consideration of other methods as a check. As a result, I am adding the CAPM in my analysis to supplement my DCF analysis as well as my Comparable Earnings analysis.

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL.

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

ROE = Rf + Beta [E(RM) – Rf]

where ROE is the return on equity;
Rf is the risk-free rate;
Beta is the risk of the studied company relative to the overall market; and
E(RM) is the expected return on the market.

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

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

ROE = Rf + (Beta * Risk Premium)

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

Q. HOW IS THE RISK-FREE RATE MEASURED?

A. The risk-free rate is designated as the yield on United States government bonds as the risk of default is seen as highly unlikely. Utility witnesses and consumer witnesses all use United States government bond yields as the risk-free rate in the CAPM. However, what is often debated in the risk-free portion of the CAPM is the term of those bonds. In my analysis for this case, I have developed risk premiums relative to the 30-year US Treasury bonds as this time period is the longest available in the marketplace, thereby affording consumers the longest protection at the risk-free rate. Chart 1, which I provided earlier in this testimony, provides the yield on 30-year US Treasury bonds over the past year.

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

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

> In a press conference after the Fed held policy steady, Yellen spoke of a sense that rates may be depressed by "factors that are not going to be rapidly disappearing, but will be part of the new normal."[17]

The statement above is confirmed by the fact that the Federal Reserve recently stated that it would not be increasing interest rates any further in 2019.[18]

Q. HOW IS BETA MEASURED IN THE CAPM?

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

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

A. The development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. To gauge the historical risk premium, I turned to the Ibbotson database published by Morningstar. The long-term geometric and arithmetic returns for both equities and fixed income securities and the resulting risk premiums are as follows:

[17] https://www.bloomberg.com/news/articles/2016-06-15/yellen-seems-to-sign-on-to-summers-view-of-lingering-low-rates

[18] https://www.cnbc.com/2019/03/20/fed-leaves-rates-unchanged.html

Table 7: Equity Risk Premium Calculations

Asset Class	Geometric Mean	Arithmetic Mean
Large Company Stocks	10.0%	12.0%
Long-Term Govt. Bonds	6.0%	6.3%
Resulting Risk Premium	4.0%	5.7%

Source: Exhibit 2.3, Ibbotson® SBBI®, 2017 Classic Yearbook: Stocks, Bonds, Bills, and Inflation, 1926-2016

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

A. On January 10, 2019, Morningstar.com published an article entitled "Experts Forecast Long-Term Stock and Bond Returns: 2019 Edition."[19] By future returns, these market experts are discussing total market returns, and not just the equity risk premium. Below are some of the market return forecasts from this article:

BlackRock Investment Institute
7% nominal (not inflation adjusted) return for US large caps over the next decade and 9% for non-US large caps.

John Bogle, Founder of Vanguard Group
4% - 5% nominal equity returns during the next decade

Grantham, Mayo, & van Otterloo ("GMO")
-4.1% real (inflation adjusted) returns for US large caps over the next 7 years

JP Morgan Asset Management
5.25% nominal return for US equities over a 10-15 year horizon

[19] https://www.morningstar.com/articles/907378/experts-forecast-longterm-stock-and-bond-returns-2.html

Morningstar Investment Management
1.8% 10-year nominal returns for US stocks

Research Affiliates
0.7% real (inflation adjusted) returns for US large caps furring the next 10 years

Vanguard
Nominal equity market returns of 3% to 5% during the next decade

The above-stated equity returns display a very large range. On the low side is GMO, which forecasts that US large caps will, after inflation, lose 4.1% of asset value annually over the next seven years. On the more positive side is BlackRock Investment that expects a nominal (before inflation adjustment) of 7% per year. Of the above-stated returns, Vanguard, John Bogle, JP Morgan, and BlackRock all forecast nominal (not inflation adjusted) returns in the range of 3% to 7%. A mid-range estimate is 4% to 6% for the group.

In 2018, Duke University finance professors published their annual equity risk premium estimates that stated the expected average risk premium exhibited by a survey of U.S. Chief Financial Officers around the country is 4.42%. [20] The article states as follows:

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

[20] "The Equity Risk Premium in 2018", John R. Graham and, Campbell R Harvey, Duke University, March 28, 2018, p. 3-4.

(=4.42%+2.37%) which is slightly below the overall average of 7.11%. The total return forecasts are presented in Fig. 1b.2 [21] (underline and bold added)

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

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

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

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

Q. WHAT WERE YOUR CAPM RESULTS?

A. The actual calculations for the CAPM can be seen in Schedule KWO-4. The yield on 30-year US Treasury yields (Rf) has ranged from 2.47% to 3.46% in the past year. The average beta for the proxy group is 0.69 which, when multiplied by the risk premium range of 4.0% to 6.0%, produces a beta-adjusted risk premium of 2.76% to 4.14%. The 30-year US Treasury yield (Rf) range of 2.53% to 3.46% is next added to the beta-adjusted risk premium range of 2.76% to 4.14% to arrive at the proxy group CAPM result range of 5.22% to 7.59%.

Based on this range of results for the CAPM, I find the proper ROE derived from the CAPM is in the range of 5.5% to 7.5%. The low-end (5.5%) of this range is at the low-end of the proxy group CAPM results using the 4.0% of the equity risk premium. The high end (7.5%) of the range is slightly lower than the high end of the proxy group CAPM results.

[21] Id, p. 3-4.

D. Return on Equity Summary

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

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

Table 8: ROE Method Results

	ROE Results	
Method	Low	High
DCF	7.60%	9.60%
Comparable Earnings	9.00%	10.00%
CAPM	5.50%	7.50%

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

A. My recommendation in this case is for the Commission to grant Piedmont Natural Gas a return on equity of 9.0% This 9.0% ROE is slightly above the midpoint of the DCF results for the proxy group, well above the CAPM results, and is at the low end of the Comparable Earnings results.

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

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

In making this recommendation, I am herein recognizing the strength of the stock market since Piedmont's last rate case in 2013, as evidenced in Chart 2 above, and I am actually recommending a ROE slightly higher than midpoint of the DCF results which, in my opinion, is the most indicative result of investor expectations for gas utilities.

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

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

A. The overall rate of return I am recommending is 6.85% and can be seen in the table below.

Table 9: Recommended Overall Rate of Return

Component	Capital Structure Ratio (%)	Cost Rate (%)	Wgtd. Cost Rate (%)
Long-Term Debt	47.18%	4.55%	2.15%
Short-Term Debt	0.82%	2.82%	0.02%
Common Equity	52.00%	9.00%	4.68%
Total Capitalization	100.00%		6.85%

VII. Consistency Matters – A review of Company Witness Hevert's History of Changing Cost of Equity Models

Q. WHAT RETURN ON EQUITY DID PIEDMONT ASK THE COMMISSION TO GRANT IT IN THIS PROCEEDING?

A. According to Company Witness Hevert, the return on equity that should be afforded the Company in this proceeding is 10.60%.

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

A. No. I disagree with Piedmont's requested ROE. The requested ROE is excessive and unwarranted given the current financial market conditions, and simply does not comport with the current economic reality facing investor-owned utilities.

Moreover, the models and inputs used by Company Witness Hevert to determine Piedmont's cost of equity are biased, in nearly every sense, to artificially inflate his ROE results. If the Commission were to accept Mr. Hevert's proposed ROE, Piedmont's customers would be forced to take on the burden of natural gas rates that encompass the highest allowed ROE for an investor-owned natural gas utility in recent years.

Taken together, these factors make it clear that Company Witness Hevert is recommending a ROE significantly exceeding the standards constituting a just and reasonable rate for an investor owned utility (IOU) in the state of North Carolina—and in virtually every other state in the country.

Q. **MR. O'DONNELL, SHOULD WITNESSES IN REGULATORY CASES BE CONSISTENT IN THEIR APPLICATIONS BEFORE COMMISSIONS?**

A. I certainly think so. A witness builds trust and respect amongst state regulators by being consistent in his or her appearances before regulatory bodies.

One of my favorite quotes is from Lincoln Chafee, who stated that "Trust is built with consistency."[22]

This Commission relies on expert witnesses to give it unbiased advice so it can make a determination in the best interests of consumers and the regulated utilities.

Q. **MR. O'DONNELL, HAS MR. HEVERT BEEN CONSISTENT IN HIS APPLICATION OF THE VARIOUS COST OF CAPITAL METHODS OVER THE YEARS THAT HE HAS BEEN PRESENTING TESTIMONY ON BEHALF OF HIS UTILITY CLIENTS?**

A. No. Mr. Hevert has changed the application of his cost of capital models over the years so that the results produce higher cost of capital results for his utility clients.

[22] https://www.brainyquote.com/quotes/lincoln_chafee_446309

A. Hevert CAPM Changes

Q. PLEASE EXPLAIN HOW MR. HEVERT APPLIES THE CAPITAL ASSET PRICING MODEL ("CAPM") IN THE CURRENT CASE.

A. In the current case, Mr. Hevert uses a forward-looking discount cash flow ("DCF") model to determine an expected market return. He then subtracts out the yield on 30-year Treasury bonds to determine a market risk premium for use in the CAPM. [23]

Q. IS MR. HEVERT'S APPLICATION OF THE CAPM IN THIS CASE CONSISTENT WITH THE WAY HE HAS APPLIED THE CAPM IN PAST CASES?

A. No, it is not.

Q. HOW IS MR. HEVERT'S CURRENT APPLICATION OF THE CAPM DIFFERENT FROM HIS PAST APPLICATIONS?

A. Mr. Hevert has changed his application of the CAPM in two very distinct ways:

1. he has changed the actual market risk premiums used in the CAPM; and
2. he has changed his reliance on historical data versus forecasted data as employed in the CAPM.

The result of these two changes is that Mr. Hevert's calculations lead to higher return on equity numbers for his clients.

Q. PLEASE EXPLAIN MR. HEVERT'S CHANGES IN THE MARKET

[23] Prefiled direct testimony of Robert Hevert, p. 70

RISK PREMIUMS USED IN THE CAPM.

A. Mr. Hevert has been presenting testimony on behalf of utilities for a number of years and has built up a history of cases in which he has used the CAPM. A review of prior cases shows Mr. Hevert has changed his risk premiums frequently throughout his tenure as an expert witness before various state regulatory bodies. As an example, Table 10 below shows Mr. Hevert's calculated risk premiums in eight cases since 2008.

Table 10: Historical Hevert Market Risk Premiums

Year	Implied Mkt. Premium
2008	7.10% [24]
2009	7.19% - 8.10% [25]
2014	8.71% - 10.31% [26]
2015	10.07% - 10.82% [27]
2016	9.99% - 11.81% [28]
2017	9.37% - 11.27% [29]
2018	11.21% - 11.38% [30]
2019	11.47% - 13.41% [31]

[24] Otter Tail Power Company, South Dakota Public Utilities Commission, Docket No. EL08-030, Schedule 4, 1.
[25] South Carolina Electric & Gas, South Carolina Public Service Commission, Docket No. 2009-489-E, Exhibit RBH-2, 1.
[26] Public Service of Colorado, Public Utilities Commission of Colorado, Docket No. 14AL-0660E, Attachment RBH-6, 1.
[27] Virginia Electric & Power, Virginia State Corporation Commission, Docket No. 2015-00027, Schedule 4, 1.
[28] Potomac Electric Power, District of Columbia Public Service Commission, Exhibit PEPCO (D)-5, 1.
[29] Duke Energy Progress, North Carolina Utilities Commission, Docket No. E-2, Sub 1142, Exhibit RBH-5, p. 1.
[30] South Carolina Electric and Gas, South Carolina Public Service Commission, Docket No. 2017-305-E, Exhibit RBH-5.
[31] Potomac Electric Power Company, Maryland Public Service Commission, Case No. 9602, Exhibit RBH-4, p. 1.

As shown in this table, in 2008, Mr. Hevert used a market risk premium of 7.10% in his CAPM calculations. In 2019, Mr. Hevert employed a risk premium as high as 13.41% in his CAPM. In his 2008 South Dakota testimony, Mr. Hevert states that the 30-day average yield on a 30-year U.S. Treasury bond was 4.22%.[32]

Even though the risk-free rate has fallen over 140 basis points since 2008[33], Mr. Hevert's risk premiums have increased 631 basis points during this same time period. With such continuous unsubstantiated increases in the risk premiums, Mr. Hevert's unique application of the CAPM will never result in a lower ROE for his client. Mr. Hevert's testimony, therefore, irrespective of the current interest rate environment, can and does produce high ROE values for Piedmont and Mr. Hevert's other utility clients. However, such analysis is suspect on many levels.

Mr. Hevert's Chart 13, which is found on p. 74 of his prefiled testimony, shows that Mr. Hevert's market premiums tend to increase when interest rates decrease.[34] In this case, Mr. Hevert is using a market risk premium of 10.65%[35] to 13.77%[36] at a time when 30-year Treasury bonds are yielding 3.37%. However, when one looks at Mr. Hevert's Chart 13, the risk premium for 30-year US Treasury bonds yielding 3.06% is approximately 7%, not the 10.65% to 13.77% as claimed by Mr. Hevert. In fact, a risk premium of anything over 8% is not even found on Mr. Hevert's Chart 13, thereby showing Mr. Hevert's own data prove his methods are biased to generate a high ROE for his utility clients.

[32] South Dakota Public Utilities Commission, Docket No. EL08-030, Schedule 4
[33] 30-year US Treasury yield on April 8, 2008 was 4.32%, same bond on April 4, 2008 was 2.92%. https://www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/TextView.aspx?data=yieldYear&year=2008, 2019.
[34] Prefiled direct testimony of Robert Hevert, p. 37.
[35] Prefiled direct testimony of Robert Hevert, Exhibit RBH-3, p. 1
[36] Prefiled direct testimony of Robert Hevert, Exhibit RBH-3, p. 8

Previously, I noted the importance of consistency in evaluating the integrity of a witness. My testimony speaks to the fact that Mr. Hevert has, over the years, changed his application of the Capital Asset Pricing Model so as to inflate his clients' risk premiums against, even, the counterweight of a falling risk-free rate and a favorable economy. He has made those changes, moreover, while failing to adequately explain the reasoning behind them. These facts show clearly that the models Mr. Hevert uses to power his own arguments are inconsistent and, in my opinion, very unreliable.

Q. HAS MR. HEVERT CHANGED ANY OTHER ASPECT OF HIS CAPM RISK PREMIUM CALCULATIONS OVER THE YEARS?

A. Yes. In 2008, Mr. Hevert advocated using historical returns from the Ibbotson data series to determine a risk premium of 7.1%. In 2019, however, Mr. Hevert abandoned his use of historical data and, instead, now advocates for the use of a forecasted DCF model to forecast a risk premium which, in this case, is a market premium of 10.65% to 13.77%. [37] Mr. Hevert did not provide any explanation as to why he has abandoned the use of historical premiums in favor of his current preference for forecasted risk premiums.

Historic data is proven data, while projections are just that - projections. It is a known truth in the financial community that investors and analysts rely on historic, proven data to make investment decisions at least as much as they rely on speculative projections. Earlier in this testimony, I provided citations to several articles that call into question analyst forecasts.

It stands to reason, then, that the sheer volume of historic data available to investors - both as annual reports from individual companies and as market-

[37] Prefiled direct testimony of Robert Hevert, Exhibit RBH-4

wide research released by trusted financial institutions - speaks to the flawed logic in depending almost solely on speculative, uncertain inputs for financial models. As such, Company Witness Hevert's abandonment of such a valuable investor resource as historic returns, while offering no justifiable defense of his reasoning, is yet more evidence of the inconsistency in his argument.

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

A. In his direct testimony in this case, Mr. Hevert uses expected market return estimates of 13.68%[38] to 16.81%[39] return on the market.

Q. DO YOU BELIEVE A 13.68% TO 16.81% RETURN ON THE MARKET IS A REASONABLE FORECAST?

A. No, not all. Such a return is simply unrealistic. As an example, the average market return for the period of 1926 through 2013, as reported by Morningstar, was 10.10% using a geometric mean calculation and 12.10% with an arithmetic mean. Mr. Hevert now wants this Commission to believe the future market return is going to be grossly in excess of the average market return over the past nearly 100 years. The reality is market forecasters are expecting returns to average approximately half of what Mr. Hevert is forecasting in this case.

B. Changes in Hevert's Risk Premium Models

Q. HAS MR. HEVERT CHANGED THE MANNER IN WHICH HE CALCULATES HIS RISK PREMIUM MODEL IN THE LAST YEARS?

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[38] Hevert direct testimony, Exhibit RBH-3, p. 1

[39] Id, p. 8

A. Yes. The inconsistencies that Mr. Hevert has exhibited in his application of the CAPM over the last several years also exist in his use of the Risk Premium model.

Q. PLEASE EXPLAIN THE INCONSISTENCIES THAT YOU FOUND IN MR. HEVERT'S RISK PREMIUM ANALYSES IN HIS PREVIOUS TESTIMONIES.

A. On p. 37, l. 4 of his prefiled testimony, Mr. Hevert states that the risk premium between ROEs granted by state regulators across the country and 30-year U.S. Treasury bond yields is 469 basis points. However, in his analysis in this case, Mr. Hevert increases that risk premium by another 216 basis points (685 as found in Exhibit RBH-6, p. 1 less 469). To be specific, on p. 74-75 of his pre-filed testimony, Mr. Hevert states the following:

> As Chart 13 illustrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.69 percent would significantly understate the Cost of Equity. Based on the regression coefficients in Chart 13, however, the implied ROE is between 9.89 percent and 10.11 percent (see Exhibit RBH-6 and Table 10, below).

Mr. Hevert did not provide a reason why he increased his risk premium nor did he provide any evidence. Hence, the Commission is left to wonder why he made such an unwarranted and unsubstantiated adjustment.

In his 2010 testimony before the South Carolina Public Service Commission in the general rate case of South Carolina Electric & Gas, Mr. Hevert performed the same regression analysis as noted in his testimony in this case and found a risk premium of 588 basis points to be appropriate.[40] In that 2010 case, Mr.

[40] *See* Hevert, p. 48 of SC PSC Docket 2009-489-E.

Hevert found a ROE in the range of 10.78% to 11.11%.[41] Mr. Hevert did not make any adjustments for "adders" in 2010 as he has done in the current case. This case comparison shows that Mr. Hevert has, again, changed his current testimony from his previous testimonies. This change is significant and leads to an unsubstantiated increase in Mr. Hevert's calculation of the cost of equity for Piedmont.

Q. HAS MR. HEVERT EVER USED ANY OTHER MODELS THAN THE CONSTANT GROWTH DCF, CAPM, AND RISK PREMIUM MODELS THAT HE PRESENTS IN THIS CASE?

A. Yes. In at least one past case, Mr. Hevert used what he called the "Multi-Stage DCF" model.[42]

Q. DID MR. HEVERT PRESENT THE MULTI-STAGE DCF MODEL IN THIS CASE?

A. No, he did not.

Q. WHY DO YOU BELIEVE MR. HEVERT CHOSE NOT TO SUBMIT THE MULTI-STAGE DCF MODEL IN THIS CASE?

A. The Multi-Stage DCF model that Mr. Hevert presented in the past, such as in the 2017 Duke Energy Carolinas ("DEC") North Carolina rate case[43], required an assumption of GDP growth. In the 2017 DEC case, Mr. Hevert's forecasted GDP growth estimate was 5.38%.[44] However, in 2017, the US Congressional Budget Office was projecting GDP growth of 2.0% from 2017 through 2027.[45] The use of the Multi-Stage DCF simply does not work well when one cannot substantiate GDP forecasts that conflict with forecasts from independent

[42] Hevert Testimony in 2017 Duke Energy Carolinas rate case, NC Utilities Commission, Docket No. E-7, Sub 1146, p. 28
[43] Id.
[44] Id, p. 32.
[45] https://www.cbo.gov/publication/52370.

entities like the Congressional Budget Office. I am not surprised to see that Mr. Hevert stopped using the Multi-Stage DCF model.

C. Changes in Weighting of Hevert Cost of Capital Methods

Q. HAS MR. HEVERT BEEN CONSISTENT IN THE WEIGHTING OF THE RESULTS OF HIS COST OF CAPITAL METHODS FROM CASE TO CASE?

A. No. In comparison to past cases, in this case Mr. Hevert has changed the weights he places on the methods.

Q. CAN YOU PROVIDE US AN EXAMPLE OF THE CHANGE IN MR. HEVERT'S WEIGHTING OF HIS COST OF CAPITAL METHODS?

A. Yes. The following Q&A is from Mr. Hevert's 2010 South Carolina Electric & Gas testimony:

> **Q. DID YOU UNDERTAKE ANY ADDITIONAL ANALYSES TO SUPPORT YOUR DCF MODEL RESULTS?**
>
> A. Yes. As noted earlier, I also used the CAPM and the Risk Premium approach as a means of assessing the reasonableness of my [Constant Growth] DCF results.[46] (insertion added)

However, in the recent Potomac Electric Power Company (Pepco) rate case heard before the Maryland Public Service Commission in Formal Case No. 9602 filed on January 15, 2019, Mr. Hevert attempts to dismiss the Constant Growth DCF model. To be specific, he states:

> **Q38. Do you believe that the Constant Growth DCF model currently provides a reasonable estimate of the Company's Cost of Equity?**

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[46] South Carolina Public Service Commission Docket No. 2009-489-E, Hevert Testimony, 38.

> A38. No, I do not. As a practical matter, the period over which my analyses were performed included market data that were inconsistent with the model's fundamental assumptions. As such, the model produced results at odds with current observable capital market conditions. Regardless of the method employed, however, an authorized ROE that is well below returns authorized for other utilities (1) runs counter to the *Hope* and *Bluefield* "comparable risk" standard, (2) would place the Company at a competitive disadvantage, and (3) would make it difficult for the Company to compete for capital at reasonable terms. [47]

So, in the prior South Carolina case, Mr. Hevert stated that he used the CAPM and Risk Premium models to assess the reasonableness of his DCF models. However, since the 2010 case in South Carolina, Mr. Hevert has drastically changed his application of the CAPM and Risk Premium models such that the changes result in higher cost estimates. The very simple fact is that the cost of capital has gone down dramatically over the past several years, a fact that Mr. Hevert is simply unwilling to acknowledge.

Q. DO YOU AGREE WITH MR. HEVERT THAT THE CURRENT MARKET IS SO DIFFERENT FROM PAST MARKETS THAT ANALYSTS SHOULD CHANGE THEIR COST OF CAPITAL METHODOLOGIES FROM CASE-TO-CASE IN VARIOUS JURISDICTIONS?

A. No. In the investing community, many consider the four most dangerous words to be: "***this time is different***." There is no reason to doubt that a model that has worked well in the past should not work well in current times. Mr. Hevert's argument that the current financial times are different from the past ignores the fact that we have experienced "different" financial times in the past as well. Situations like the Great Depression, WWII, 9-11, the Great

[47] Hevert prefiled direct testimony, page 26-27.

Recession, and the multitude of other recessions experienced by this country have all been "different" in manners not unlike current market times. Mr. Hevert is attempting to convince state regulators that because a few economic elements in current times are unprecedented, the methods he used in the past are no longer valid. Such a position is not accurate. In reality, Mr. Hevert is simply choosing to forgo methods he used in the past because they no longer provide him the results that he needs – higher ROEs.

Q. HAVE OTHER STATE REGULATORY BODIES RECOGNIZED THE INCONSISTENCY OF MR. HEVERT'S TESTIMONY OVER THE YEARS?

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

1. Mr. Hevert's proposed cost of equity of 10.25% to 10.75% did not represent the actual cost of equity in the marketplace nor a reasonable ROE for DVP; [48]
2. Mr. Hevert's recommended ROE of 10.5% is not supported by reasonable growth rates, DCF methods or risk premium analyses; [49]
3. Mr. Hevert's application of the CAPM is flawed and his application of the Bond Yield Plus Risk Premium model contains similar flaws as his CAPM analysis; [50] and

[48] Virginia SCC Final Order in Case No. PUR-2017-0003, Nov. 29, 2017, at p. 4.
[49] Id.

4. Mr. Hevert's claim of Dominion deserving a 10.5% ROE due to certain business was summarily rejected because the majority of DVP's future cap-ex could be recovered through automatic revenue adjustment clauses (RACs).[51]

VIII. Cost of Service Study and Rate Design

Q. WHAT PIEDMONT WITNESS PRESENTED THE COMPANY'S COST OF SERVICE STUDY AND PROPOSED RATE DESIGN IN THIS CASE?

A. Piedmont retained the services of Mr. Daniel P. Yardley for the development of its cost of service study and its proposed rate design in this case.

Q. PLEASE EXPLAIN HOW MR. YARDLEY PERFORMED THE COSS PRESENTED IN THIS CASE.

A. In his prefiled direct testimony, Mr. Yardley presented an allocated cost of service study (ACOSS) in which he used various allocation factors to apportion Piedmont's costs and investments amongst its customer classes. The end result is, in essence, an income statement and rate base for each customer class from which a rate of return per class can be determined. Based on the results of the ACOSS, an analyst can design rates that will more accurately reflect the actual cost to serve a particular customer class.

Q. DO YOU AGREE WITH THE MANNER IN WHICH MR. YARDLEY CALCULATED HIS ACOSS?

A. No. Mr. Yardley used the peak and average allocation factor to apportion the fixed gas costs for Piedmont and, in doing so, skewed the results of the ACOSS.

[50] Id, 5.
[51] Id, 6.

Q. WHAT ARE FIXED GAS COSTS AND HOW DOES THE ALLOCATION OF THESE COSTS AFFECT THE RESULTS OF THE ACOSS?

A. Fixed gas costs represent the capacity costs associated with moving natural gas across the interstate pipelines and into North Carolina. These costs include firm transportation, incremental transportation, and peaking services transportation on the Transco pipeline as well as other similar costs on the Columbia, Cardinal, East Tennessee, Midwestern, and Texas Eastern Pipelines.

A data request [52] response provided by the Company shows that Piedmont incurred over $110 million in fixed gas costs during the test year. A slight change in the allocation of these costs can cause a wide change in the customer class rates of return in the ACOSS and, therein, should also cause a change in the rate design.

Q. HOW DID MR. YARDLEY ALLOCATE FIXED GAS COSTS WITHIN HIS ACOSS?

A. Mr. Yardley used the peak and average cost allocation method for allocating fixed gas costs in his ACOSS.

Q. PLEASE EXPLAIN THE PEAK AND AVERAGE ALLOCATION METHOD.

A. The peak and average allocation method apportions fixed gas costs at the ratio of 50% of the ratio of customer class usage at the time of the annual peak demand of the utility plus 50% of the ratio of the customer class usage (throughput) as compared to the total throughout for the entire year. Hence, the peak and average allocation factor gives equal weight to customer class usage

[52] Piedmont response 2-2Attachment.xlsx

at the time of the system peak and the customer class usage throughout the entire year.

Q. IS THERE ANY OTHER ALLOCATION METHOD THAT COULD BE USED TO ALLOCATE FIXED GAS COSTS?

A. Yes, the peak day allocation method is often used to allocate fixed gas costs.

Q. PLEASE EXPLAIN THE PEAK DAY ALLOCATION.

A. Piedmont's natural gas system is designed to meet the system peak day. Similarly, the Company purchases interstate pipeline capacity to meet its peak day demands. The peak day allocation method allocates fixed gas costs in the manner the utility purchases its needs to serve customers at its annual peak demand.

Q. HOW WOULD THE CHANGE IN ALLOCATION FACTORS FROM PEAK AND AVERAGE TO PEAK DAY AFFECT THE ACOSS?

A. A gas utility system's primary requirement at the time of the system peak is to serve its firm customers that absolutely must have their natural gas supplies met. These customers are called high priority gas customers and are, typically, residential and commercial consumers. However, Piedmont also has another set of customer(s) that have agreed to be interrupted at the time of the system peak so as to make room on the interstate pipeline for Piedmont's firm customers. These interruptible customers are typically manufacturers that are served at a lower rate with the expectation they will not be able to take natural gas service from Piedmont at the time of the system peak or on other high use days.

Based on the above, one can easily conclude that the use of the peak day demand allocation as opposed to the peak and average allocation will allocate more fixed gas costs to residential and small commercial customers and less to interruptible customers.

Q. WHAT ARE THE CUSTOMER CLASS RATES OF RETURN USING THE PEAK AND AVERAGE ALLOCATION FACTOR FOR FIXED GAS COSTS VERSUS USING THE PEAK DAY ALLOCATION FACTOR FOR FIXED GAS COSTS?

A. Table 11 below provides the customer class rates of return using these two different allocation factors for apportioning fixed gas costs.

Table 11: Customer Class Rates of Return Based on Fixed Gas Cost Allocation

Customer Class	Customer Class RORs (%)	
	Peak & Average	Peak Day
Residential Rate 101	4.55%	3.77%
Small GS Rate 102	8.09%	7.58%
Medium GS Rate 152	18.86%	19.50%
Large GS Sales Rate 103	-4.80%	-2.43%
Large GS Transport Rate 113	-3.31%	-2.01%
Interruptible Sales Rate 104	13.05%	54.02%
Int Trans Rate 114	29.64%	71.25%
Military Trans Rate T-10	-2.36%	-2.59%

As can be seen in the table above, with the exception of the interruptible sales and interruptible transportation classes, there is not much of a difference in the class rates per the ACOSS. The obvious reason for the huge increase in the class rate of return for the interruptible classes is that, with the peak day allocation factor, these two rate classes are not being allocated much, if any, fixed gas costs. As a result, their class rates of return jump when these costs are excluded.

Q. BASED ON THE RESULTS OF HIS ACOSS, HOW DID MR. YARDLEY DESIGN RATES TO BE APPROVED IN THIS CASE?

A. Mr. Yardley paid little mind to the customer class rates of return he developed in his ACOSS. Instead, Mr. Yardley applied an equal rate increase across all customer classes to arrive at his suggested rate increase. Mr. Yardley addresses how he developed the across-the-board rate increase in his direct testimony when he states:

> **Q. What factors guided your recommendation that the proposed revenue increase be applied on an equal percentage basis to all rate classes?**
>
> A. The results of the ACOSS are one consideration in the development of proposed rates. Another important consideration is the current rate structure including the MDT and the level of fixed and variable charges. In addition, the historic level of returns and existing rates for each class are important considerations as is the need to develop prices that are fair and not unduly discriminatory. Taking into account all of these factors, I believe that applying the revenue increase on an equal percentage basis to all rate classes is reasonable and appropriate in this case.[53]

In the above quote, Mr. Yardley states that the results of the ACOSS are a consideration in the development of the proposed rates. However, Mr. Yardley's ACOSS indicates interruptible transportation customers are paying a class rate of return of 29.64% but, yet, he recommends a rate increase of 16.4% for this class. Contrary to his statement about taking into account "all of these factors", Mr. Yardley took an easy path by applying an equal increase to all customer classes.

[53] Prefiled Direct Testimony of Daniel Yardley, p. 9

Q. WHAT ARE MR. YARDLEY'S PROPOSED CUSTOMER CLASS RATE INCREASES AND THE RESULTING CLASS RATES OF RETURN USING THE SWPA METHODOLOGY?

A. Table 12 below provides the requested customer class increases and the resulting class rates of return

Table12: Piedmont Proposed Class Rate Increases
and Class Rates of Return

Customer Class	Requested Rate Increase (%)	Cust Class Rate of Return(%)
Residential - Rate 101	14.70%	7.70%
Small GS - Rate 102	14.80%	12.43%
Medium GS - Rate 152	14.70%	26.58%
Large GS Sales - Rate 103	7.40%	12.93%
Large GS Trans. - Rate 113	17.80%	2.38%
Int. Sales - Rate 104	7.20%	**132.33%**
Int Trans - Rate 114	16.40%	**40.88%**
Military Trans	14.50%	2.30%
Special Contracts		14.35%
Municipal Contracts		-2.33%
Power Gen Contracts		3.16%

I have highlighted the Interruptible Sales (Rate 104) and Interruptible Transportation (Rate 114) class rates of return for the Commission's attention. Needless to say, such a high class rate of return is punitive and abusive. Manufacturers that use natural gas are already paying exorbitant rates and Mr. Yardley's proposal is to make these rates even more expensive and unfair.

Q. ARE YOU PRESENTING A RATE DESIGN AS PART OF YOUR ANALYSIS IN THIS CASE?

A. Yes, I am.

Q. **PLEASE EXPLAIN HOW YOU DEVELOPED YOUR RECOMMENDED RATE DESIGN.**

A. The basis of my rate design is the assumption that the sum of all my rate recommendations must allow Piedmont to earn my recommended overall cost of capital of 6.85%. I then made a second assumption that no customer class could sustain a rate increase or decrease of more than 10%. This last assumption is critical as, if we followed the details of the ACOSS results, interruptible sale and interruptible transportation customers would warrant a much greater rate reduction than 10%. My recommended rate change per customer class and the resulting class rates of return are found in Table 13 below.

Table 13: CUCA Recommended Rate Change and Resulting Class Rates of Return

Customer Class	CUCA Rec Rate Increase (%)	Cust Class Rate of Return(%)
Residential - Rate 101	9.5%	7.60%
Small GS - Rate 102	5.60%	10.26%
Medium GS - Rate 152	-5.00%	15.85%
Large GS Sales - Rate 103	6.00%	-1.00%
Large GS Trans. - Rate 113	8.00%	-2.13%
Int. Sales - Rate 104	0.00%	13.05%
Int Trans - Rate 114	-9.00%	21.59%
Military Trans	5.00%	-1.70%
Municipal Contracts	10.00%	-0.28%

In the above rate design, I attempted to balance the interests of all customer classes without allowing any one particular class to sustain excessive rate hikes while other classes enjoyed significant rate cuts. The customer class rates of return are still not cost-justified based on a risk/return basis, but the results are closer and more equitable than Mr. Yardley's results.

Q. DID YOU USE THE SWPA ACOSS OR THE PEAK DAY DEMAND ACOSS IN THE DEVELOPMENT OF THE ABOVE-STATED RATE CHANGES AND ACCOMPANYING CLASS RATES OF RETURN?

A. I used the SWPA ACOSS in the development of my recommended rate design. The reason is that use of the Peak Day ACOSS would not have altered my recommended rate design in any meaningful way. As noted in Table 13 above, the class rates of return for both the SWPA ACOSS and the Peak Day ACOSS are, with the exception of interruptible sales and interruptible transportation, very close to one other. Since I limited the rate change of any customer class to +/-10%, the resulting class rates of return could not change to a point of risk/return parity amongst the customer classes.

IX. Rate Case Fees

Q. WHAT ARE MR. YARDLEY'S FEES IN THIS CASE?

A. According to Piedmont's response to CUCA DR 1-13, Mr. Yardley is being paid $160,000 for his participation in this rate case. For $160,000, Mr. Yardley developed the ACOSS and then, in his rate design, ignored the ACOSS. The $160,000 fee charged by Mr. Yardley in this case alone is much greater than the annual compensation of members of this Commission as well as that of Public Staff Natural Gas engineers, who have similar experience and skills as Mr. Yardley. Ratepayers should not be required to pay such an excessive expense.

Q. WHAT ARE MR. HEVERT'S RATE CASE FEES IN THIS CASE?

A. In response to CUCA DR 1-13, Piedmont has indicated that Mr. Hevert's fees in this case are expected to total $120,000. These fees, like those of Mr. Yardley, are excessive and unwarranted.

Q. WHAT ARE THE LEGAL EXPENSES OF MR. JEFFRIES IN THIS CASE?

A. In response to CUCA DR 1-13, Piedmont has indicated that the McGuire Woods fees in this case are expected to total $900,000. As with the consulting fees, such legal fees are excessive and unwarranted.

Q. HAS THIS COMMISSION HISTORICALLY DISALLOWED RATE CASE EXPENSES IN THE PAST?

A. No. Historically, this Commission has not disallowed rate case-related fees. One reason, perhaps, is that rate case fees are generally amortized over 3-5 years and are only a small part of the overall revenue requirement in any rate case. While I understand this concept, I believe the Commission should take a longer look at this issue to see how it impacts the regulatory and legislative process in this State and how it increases customer rates.

Q. PLEASE EXPLAIN YOUR CONCERN ABOUT HOW UNCHECKED RATE CASE EXPENSES ARE AFFECTING THE REGULATORY AND LEGISLATIVE PROCESS IN NORTH CAROLINA.

A. As this Commission is aware, Piedmont's parent company, Duke Energy, is currently attempting to pass legislation that would change the fundamental nature of how the regulatory system operates in North Carolina. One of the stated reasons for the proposed change is the high cost of rate case expenses. I find it highly ironic that Duke Energy can make such a claim when one of its subsidiary companies, Piedmont in this case, is willing to pay its consultants excessive fees. I believe that if Duke/Piedmont had to pay these rate case expenses, instead of passing on these costs to ratepayers, the costs for these consultants would be much lower. However, a utility is allowed recovery of prudent rate case expenses and, as evidenced in this case, Piedmont has not shown constraint.

Another concern I have with these excessive rate case expenses is how these rate case expenses appear to consumer witnesses in North Carolina cases. If the Company is allowed rate case expenses of $120,000 (Mr. Hevert) to $900,000 (Mr. Jeffries) that are far in excess of the annual compensation of consumers' witnesses, such as employees of the Public Staff, it sends a poor regulatory message. I have known many of the Public Staff employees for well over 30 years and they are some of the best utility regulatory minds in the country. There is no basis or reason why Piedmont's witnesses should be compensated far more than Public Staff employees.

Similarly, put the McGuire Woods legal costs in perspective. The cost of $900,000 represents the annual cost of, probably, four or five or six Public Staff attorneys.

Q. WHAT IS YOUR RECOMMENDATION AS TO HOW THIS COMMISSION TREAT THE RATE CASE FEES OF MR. YARDLEY AND MR. HEVERT IN THIS RATE CASE?

A. The typical annual compensation, which includes salary and benefits, for a utilities rate engineer is approximately $150,000. I surmise that the development of the ACOSS would have taken Mr. Yardley, or any other experienced rate engineer, no more than 3 months to develop. As a result, I recommend Mr. Yardley's fees be cut 75% in this case. Specifically, I recommend the Commission disallow $120,000 of Mr. Yardley's fees in this case.

As to Mr. Hevert's fees, the Public Staff paid $50,000 for a ROE witness to present testimony in both the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) rate cases. The cost, therefore, for each case was $25,000. Based on what the Public Staff paid for its ROE consultant just last year, I recommend that Mr. Hevert's rate case expenses be cut by $95,000 so that the total allowed cost is equal to the same $25,000 the Public Staff paid for its outside consultant.

As for legal costs, I recommend these costs be reduced 67% so that ratepayers bear only $300,000 for these expenses. Such a fee would represent the annual cost of close to two Public Staff attorneys, counting salary and benefits.

A disallowance of a portion of the rate fee expenses in this case would send a clear message to Piedmont that the Commission does not believe that utility consultants' work products are any more valuable than that of Public Staff employees. Such a message would also let Piedmont and its sister subsidiaries, Duke Energy Progress and Duke Energy Carolinas, know there is a cap to the scope of acceptable rate case-related fees that will be funded by ratepayers.

Lastly, let me be clear that my recommendation pertains only to recovery of rate case fees that are part of the allowed revenue requirement in this case. Piedmont can pay whatever it chooses for its consultants. However, stockholders should pick up all disallowed rate case expenses. Again, this would send the clear signal that unlimited cost recovery for ratepayer-funded rate case expenses will no longer be approved.

X. Summary

Q. MR. O'DONNELL, PLEASE SUMMARIZE YOUR TESTIMONY.

A. Piedmont Natural Gas' requested rate increase in this case is excessive, unnecessary, and financially burdensome on the ratepayers of North Carolina. My specific recommendations in this case are as follows:

- Mr. Hevert's recommended rate of return is unreasonable, unnecessary, and excessive;
- Mr. Hevert's constantly changing application of the various cost of equity models underlies the fact that he is biased on behalf of his utility clients;
- the Company's allowed return on equity should be set at 9.0%
- the overall rate of return that Piedmont Natural Gas should be allowed to earn in this proceeding is 6.85%;
- rate design should be set such that the following changes occur to each customer class: 9.50% increase for residential consumers; 5.60% increase for small GS customers; -5.0% for medium GS customers; 6.0% for Large GS customers; 8.0% increase for Large GS Transportation customers; 0% change for Interruptible Sales customers; 9.0% cut for interruptible transportation customers; 5.0% increase for military customers; and a 10.0% increase for municipal customers
- Piedmont's requested rate case expenses should be slashed from $1.18 million to $365,000 as these costs are unreasonable and grossly excessive in comparison to consumer costs for the same work product.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

Kevin W. O'Donnell, CFA

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kodonnell@novaenergyconsultants.com

Kevin W. O'Donnell, is the founder of Nova Energy Consultants, Inc. in Cary, NC. Mr. O'Donnell's academic credentials include a B.S. in Civil Engineering - Construction Option from North Carolina State University as well as a MBA in Finance from Florida State University. Mr. O'Donnell is also a Chartered Financial Analyst (CFA).

Mr. O'Donnell has over thirty-three years of experience working in the electric, natural gas, and water/sewer industries. He is very active in municipal power projects and has assisted numerous southeastern U.S. municipalities cut their wholesale cost of power by as much as 67%. On Dec. 12, 1998, ***The Wilson Daily Times*** made the following statement about O'Donnell.

> **Although we were skeptical of O'Donnell's efforts at first, he has shown that he can deliver on promises to cut electrical rates.**

Through 2018, Mr. O'Donnell has completed close to 30 wholesale power projects for municipal and university-owned electric systems throughout North and South Carolina. In May of 1996 Mr. O'Donnell testified before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power regarding the restructuring of the electric utility industry.

Mr. O'Donnell has appeared as an expert witness in over 100 regulatory proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia Corporation Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Service Commission, Public Service Commission of the District of Columbia, the Maryland Public Service Commission, the Public Utility Commission of Texas, the Wisconsin Public Service Commission, the Oklahoma State Corporation Commission, and the Florida Public Service Commission. His area of expertise has included rate design, cost of service, rate of return, capital structure, creditworthiness issues, fuel adjustments, merger transactions, cogeneration studies, holding company applications, as well as numerous other accounting, financial, and utility rate-related issues.

Mr. O'Donnell is the author of the following two articles: "Aggregating Municipal Loads: The Future is Today" which was published in the Oct. 1, 1995 edition of *Public Utilities Fortnightly;* and "Worth the Wait, But Still at Risk" which was published in the May 1, 2000 edition of *Public Utilities Fortnightly.* Mr. O'Donnell is also the co-author of "Small Towns, Big Rate Cuts" which was published in the January, 1997 edition of *Energy Buyers Guide.* All of these articles discuss how rural electric systems can use the wholesale power markets to procure wholesale power supplies.

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
1985	Public Service Company of NC	NC	G-5, Sub 200	Public Staff of NCUC	Return on equity, capital structure
1985	Piedmont Natural Gas Company	NC	G-9, Sub 251	Public Staff of NCUC	Return on equity, capital structure
1986	General Telephone of the South	NC	P-19, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1987	Public Service Company of NC	NC	G-5, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1988	Piedmont Natural Gas Company	NC	G-9, Sub 278	Public Staff of NCUC	Return on equity, capital structure
1989	Public Service Company of NC	NC	G-5, Sub 246	Public Staff of NCUC	Return on equity, capital structure
1990	North Carolina Power	NC	E-22, Sub 314	Public Staff of NCUC	Return on equity, capital structure
1991	Duke Energy	NC	E-7, Sub 487	Public Staff of NCUC	Return on equity, capital structure
1992	North Carolina Natural Gas	NC	G-21, Sub 306	Public Staff of NCUC	Natural gas expansion fund
1992	North Carolina Natural Gas	NC	G-21, Sub 307	Public Staff of NCUC	Natural gas expansion fund
1995	Penn & Southern Gas Company	NC	G-3, Sub 186	Public Staff of NCUC	Return on equity, capital structure
1995	North Carolina Natural Gas	NC	G-21, Sub 334	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1995	Carolina Power & Light Company	NC	E-2, Sub 680	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1995	Duke Power	NC	E-7, Sub 559	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1996	Piedmont Natural Gas Company	NC	G-9, Sub 378	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Piedmont Natural Gas Company	NC	G-9, Sub 382	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Public Service Company of NC	NC	G-5, Sub 356	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Cardinal Extension Company	NC	G-39, Sub 0	Carolina Utility Customers Assoc.	Capital structure, cost of capital
1997	Public Service Company of NC	NC	G-5, Sub 327	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Natural gas transporation rates
1999	Public Service Company of NC/SCANA	NC	G-5, Sub 400	Carolina Utility Customers Assoc.	Merger case
1999	Public Service Company of NC/SCANA	NC	G-43	Carolina Utility Customers Assoc.	Merger Case
1999	Carolina Power & Light Company	NC	E-2, Sub 753	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	G-21, Sub 387	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	P-708, Sub 5	Carolina Utility Customers Assoc.	Holding company application
2000	Piedmont Natural Gas Company	NC	G-9, Sub 428	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2000	NUI Corporation	NC	G-3, Sub 224	Carolina Utility Customers Assoc.	Holding company application
2000	NUI Corporation/Virginia Gas Compan	NC	G-3, Sub 232	Carolina Utility Customers Assoc.	Merger application
2001	Duke Power	NC	E-7, Sub 685	Carolina Utility Customers Assoc.	Emission allowances and environmental compliance costs
2001	NUI Corporation	NC	G-3, Sub 235	Carolina Utility Customers Assoc.	Tariff change request.
2001	Carolina Power & Light Company/Prog	NC	E-2, Sub 778	Carolina Utility Customers Assoc.	Asset transfer case
2001	Duke Power	NC	E-7, Sub 694	Carolina Utility Customers Assoc.	Restructuring application
2002	Piedmont Natural Gas Company	NC	G-9, Sub 461	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2002	Cardinal Pipeline Company	NC	G-39, Sub 4	Carolina Utility Customers Assoc.	Cost of capital, capital structure
2002	South Carolina Public Service Commiss	SC	2002-63-G	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2003	Piedmont Natural Gas/North Carolina I	NC	G-9, Sub 470	Carolina Utility Customers Assoc.	Merger application

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Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2003	Piedmont Natural Gas/North Carolina ?	NC	G-9, Sub 430	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina ?	NC	E-2, Sub 825	Carolina Utility Customers Assoc.	Merger application
2003	Carolina Power & Light Company	NC	E-2, Sub 833	Carolina Utility Customers Assoc.	Fuel case
2004	South Carolina Electric & Gas	SC	2004-178-E	South Carolina Energy Users Committee	Return on equity, capital structure. rate design, cost of service
2005	Carolina Power & Light Company	NC	E-2, Sub 868	Carolina Utility Customers Assoc.	Fuel case
2005	Piedmont Natural Gas Company	NC	G-9, Sub 499	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2005	South Carolina Electric & Gas	SC	2005-2-E	South Carolina Energy Users Committee	Fuel application
2005	Carolina Power & Light Company	SC	2006-1-E	South Carolina Energy Users Committee	Fuel application
2006	IRP in North Carolina	NC	E-100, Sub 103	Carolina Utility Customers Assoc.	Submitted rebuttal testimony in investigation of IRP in NC.
2006	Piedmont Natural Gas Company	NC	G-9, Sub 519	Carolina Utility Customers Assoc.	Creditworthiness issue
2006	Public Service Company of NC	NC	G-5, Sub 481	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2006	Duke Power	NC	E-7, 751	Carolina Utility Customers Assoc.	App to share net revenues from certain wholesale pwr trans
2006	South Carolina Electric & Gas	SC	2006-192-E	South Carolina Energy Users Committee	Fuel application
2007	Duke Power	NC	E-7, Sub 790	Carolina Utility Customers Assoc.	Application to construct generation
2007	South Carolina Electric & Gas	SC	2007-229-E	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2008	South Carolina Electric & Gas	SC	2008-196-E	South Carolina Energy Users Committee	Base load review act proceeding
2009	Western Carolina University	NC	E-35, Sub 37	Western Carolina University	Rate of return, accounting, rate design, cost of service
2009	Duke Power	NC	E-7, Sub 909	Carolina Utility Customers Assoc.	Cost of service, rate design, return on equity, capital structure
2009	South Carolina Electric & Gas	SC	2009-261-E	South Carolina Energy Users Committee	DSM/EE rate filing
2009	Duke Power	SC	2009-226-E	South Carolina Energy Users Committee	Return on equity, capital structure. rate design, cost of service
2009	Tampa Electric	FL	080317-EI	Florida Retail Federation	Return on equity. capital structure
2010	Duke Power	SC	2010-3-E	South Carolina Energy Users Committee	Fuel application - assisted in settlement
2010	South Carolina Electric & Gas	SC	2009-489-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2010	Virginia Power	VA	PUE-2010-00006	Mead Westvaco	Rate design
2011	Duke Energy	SC	2011-20-E	South Carolina Energy Users Committee	Nuclear construction financing
2011	Northern States Power	MN	E002/GR-10-971	Xcel Large Industrials	Return on equity, capital structure
2011	Virginia Power	VA	PUE-2011-0027	Mead Westvaco	Capital structure, revenue requirement
2011	Duke Energy	NC	E-7, Sub 989	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2011	Duke Energy	SC	2011-271-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design. ROE, capital structure
2011	Dominion Virginia Power	VA	PUE-2011-00073	Mead Westvaco	Rate design
2012	Town of Smithfield/Partners Equity Gr	NC	ES-160, Sub 0	Partners Equity Group	Rate design, asset valuation
2012	Florida Power & Light	FL	120015-EI	Florida Office of Public Counsel	Capital structure
2012	South Carolina Electric & Gas	SC	2012-218-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Progress Energy Carolinas	NC	E-2, Sub 1023	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2013	Duke Energy Carolinas	NC	E-7, Sub 1026	Carolina Utility Customers Assoc.	Rate design
2013	Jersey Central Power & Light	NJ	BPU ER12111052	Gerdau Ameristeel	Return on equity, capital structure
2013	Duke Energy Carolinas	SC	2013-59-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design. ROE, capital structure

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Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2013	Tampa Electric	FL	130040-EI	Florida Office of Public Counsel	Capital structure and financial integrity
2013	Piedmont Natural Gas	NC	G-9, Sub 631	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2014	Dominion Virginia Power	VA	PUE-2014-00033	Mead Westvaco	Recoverable fuel costs, hedging strategies
2014	Public Service Company of Colorado	CO	14AL-0660E	Colorado Healthcare Electric Coordinating Council	Return on equity, capital structure
2015	WEC Acquisition of Integrys	WI	9400-YO-100	Staff of Wisconsin Public Service Commission	Merger analysis
2015	Dominion Virginia Power	VA	PUE-2015-00027	Federal Executive Agencies	Return on equity
2015	South Carolina Electric & Gas	SC	2015-103-E	South Carolina Energy Users Committee	Return on equity
2015	Western Carolina University	NC	E-35, Sub 45	Western Carolina University	Accounting, cost of service, rate design, ROE, capital structure
2016	Sandpiper Energy	MD	9410	Maryland Office of People's Counsel	Return on equity, capital structure
2016	Washington Gas Light	DC	FC 1137	Washington, DC Office of People's Counsel	Return on equity, capital structure
2016	Florida Power & Light	FL	160021-EI	Florida Office of Public Counsel	Capital Structure
2016	Jersey Central Power & Light	NJ	EM15060733	NJ Division of Rate Counsel	Asset valuation
2016	Rockland Electric Company	NJ	ER16050428	NJ Division of Rate Counsel	Rate design
2016	Dominion NC Power	NC	E-22, Sub 532	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2017	Potomac Electric Power	DC	FC 1139	Healthcare Council of the National Capitol Area (HCNCA)	ROE and capital structure
2017	Columbia Gas of Maryland	MD	FC 9447	Maryland Office of People's Counsel	ROE and capital structure
2017	Washington Gas Light	DC	FC 1142	Washington, DC Office of People's Counsel	Merger analysis
2017	Duke Energy Progress	NC	E-2, Sub 1142	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Public Service Electric & Gas	NJ	GR17070776	NJ Division of Rate Counsel	ROE and capital structure
2018	Duke Energy Carolinas	NC	E-7, Sub 1146	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Elkton Gas/SJI	MD	FC 9475	Maryland Office of People's Counsel	Merger analysis
2018	Entergy Texas	TX	PUC 48371	Public Utilities Commission of Texas	ROE
2018	Duke Energy Carolinas	SC	2018-3-E	South Carolina Energy Users Committee	Fuel case
2018	Elkton Gas Company	MD	FC 9488	Maryland Office of People's Counsel	Accounting, ROE, capital structure
2018	Baltimore Gas & Electric	MD	FC9484	Maryland Office of People's Counsel	ROE, capital structure
2018	South Carolina Electric & Gas	SC	2017-370-E	South Carolina Energy Users Committee	Creditworthiness issue
2018	Jersey Central Power & Light	NJ	EO18070728	NJ Division of Rate Counsel	ROE and capital structure
2019	Duke Energy Carolinas	SC	2018-319-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Duke Energy Progress	SC	2018-318-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Public Service Electric and Gas	NJ	EO18060629	NJ Division of Rate Counsel	ROE and capital structure
2019	Potomac Electric Power	MD	FC 9602	Maryland Office of People's Counsel	ROE, capital structure
2019	Oklahoma Gas and Electric	OK	PUD 201800140	Sierra Club	Creditworthiness issue
2019	Peoples Natural Gas	PA	R-2018-3006818	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	UGI Natural Gas	PA	R-2018-3006814	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	Dominion Virginia Power	VA	PUR-2019-00050	Federal Executive Agencies	Return on Equity

COMMISSIONER BROWN-BLAND: We are back for redirect.

MR. JEFFRIES: Thank you, Madam Chair.

Whereupon,

PIA POWERS,

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

REDIRECT EXAMINATION BY MR. JEFFRIES:

Q. Ms. Powers, do you have a copy of the Attorney General's Powers Cross Exhibit Number 2 up there?

A. Was it the long one?

Q. No. It was the -- actually, it was; you're right.

A. Yes, I do.

Q. Yeah. And this was a document you actually prepared originally and we provided to the Attorney General.

A. Yes.

Q. Okay. So, as I understand this, what it shows is, in the first column, under year one, you show a base margin revenue, and then you show certain other types of revenue that get combined with the base margin revenue, and then you end up with these end-of-period revenues, stipulate proposed revenues over on the right-hand side, and ultimately, a percentage by rate schedule and the impact of the stipulation, correct?

A. Yes.

Q. Okay. And then you start with year one, and then the other schedules behind that show year -- sequentially years two and three and years four and five?

A. Yes.

Q. And the reason it's broken down that way is because years two and three are the same based upon the roll-off of the initial deferral of the tax savings, and then, likewise, four and five are the same because, at the end of year three, other amortizations are complete, right?

A. Yes.

Q. Okay. So if you look -- let's just use as an example, the residential percent increase.

This shows, in year one, that there's a 3.5 percent increase, right?

A. Yes.

Q. Okay. And then, in year two, it's an 8.6 increase?

A. Yeah. A little bit more was later on in year two, such that the total increase compared to the end-of-period revenues is 8.6. I want to make sure it wasn't an additional 8.6.

Q. And that was the point of the question, is that these are cumulative increases from where we started in this case, right?

A. Yes.

Q. And the base rates we started at in this case were set in 2013?

A. Yes. That was our last general rate case when they were set.

Q. Okay. So by the time we get to an 11.1 percent increase in years four and five, we're, what, 10 years, close to 10 years out, maybe more than 10 years out from the last rate case; is that right?

A. Yeah. I didn't bring my cheat sheet. Hold on one second.

(Witness peruses document.)

Year one will begin November 2022; year five, 2023; last rate case was 2013. So yes, 10 years.

Q. And to your knowledge, has the inflation rate been higher than 1 percent per year?

A. To my knowledge, yes.

Q. Okay. Thanks. And I know Piedmont reserves the right to file rate cases when and as they need them, but has there been any discussion in this case between Piedmont and some of the other parties about their anticipation of the next general rate filing?

A. Of Piedmont's next general rate filing?

Q. Uh-huh.

A. Yes. We anticipate -- we've talked about that some additional plant investment in the coming years would drive the Company to likely need to file another general rate proceeding.

Q. And that's the -- specifically the Robeson Allen G project?

A. The Robeson Allen G Facility, yes.

Q. Okay. And that -- at least currently, we anticipate that that will occur before we ever get to the years four and five of the --

A. Yes.

Q. Is that right?

A. Yes.

Q. Okay. Thank you. Could you now turn to --

COMMISSIONER GRAY: Could you use that microphone a little better, please?

MR. JEFFRIES: I'm sorry?

COMMISSIONER GRAY: Speak into it.

MR. JEFFRIES: I'm sorry.

COMMISSIONER GRAY: Thank you.

MR. JEFFRIES: I should know better, because I have the same issue. So my sincere apologies.

Q. So Attorney General Cross Examination Exhibit Number 3, which is the order scheduling the investigation and providing the notice; do you have that?

A. (Witness peruses document.)

Give me a moment, I think I've misplaced it. Thank you.

Q. Ms. Powers, could you turn to page 2 of 5 of appendix A?

A. Yes.

Q. And that's the -- that's one page of the notice that the Commission required be given to customers, right?

A. Yes.

Q. Okay. And Ms. Force directed you toward the percentages over in the -- and the table at the top of that page. There are percentages that indicate the change in -- the proposed change in revenues by not exactly rate schedule, but by customer classes, right?

A. Yes.

Q. Okay. And is it your understanding -- and to be clear, that's -- those were the filed changes that we asked for in our application, right?

A. Yes, in our April 1st application filing.

Q. Okay. And those were allocated on, essentially, an across-the-board basis; is that right?

A. Yes. Their increase was.

Q. Okay. So what we did is we took -- you know, we had something like a 9 percent increase overall, and we just spread it across our various rate classes, right?

A. Yes.

Q. So everyone would receive the same -- essentially, the same increase?

A. Yes.

Q. We didn't prepare these percentages, though, did we?

A. We did not.

Q. Okay. So -- and these percentages -- Mr. Yardley performed an allocated cost of service study and testified to it, correct?

A. Yes.

Q. But that was more sanity check, it wasn't the way we proposed to allocate a rate increase?

A. Correct.

Q. Okay. And then Mr. O'Donnell and Ms. Patel, I believe, also performed allocated cost of service studies; is that right?

A. That's my understanding, yes.

Q. And is it your recollection that those cost of service studies, which were reflected in their testimony in this document, proposed or reflected a higher return for industrial customers than -- essentially, that industrial customers were paying a much higher return than residential customers and other customer classes?

A. Yes.

Q. Okay. And was that fact or were those conclusions part -- or did they inform the rate design that was ultimately agreed to?

A. For the stipulation, yes, they did.

Q. Okay.

MR. JEFFRIES: Last set of questions, I would like permission to approach the witness, Madam Chair.

COMMISSIONER BROWN-BLAND: You may.

MR. JEFFRIES: We had one redirect

exhibit, and we would -- Madam Chair, we would ask that this be marked for identification as Piedmont Powers Rebuttal Exhibit Number 1.

COMMISSIONER BROWN-BLAND: Rebuttal or redirect?

MR. JEFFRIES: I'm sorry, redirect.

COMMISSIONER BROWN-BLAND: It will be identified as Piedmont Powers Redirect Exhibit 1.

(Piedmont Powers Redirect Exhibit 1 was marked for identification.)

Q. Ms. Powers, can you can you tell the Commission what this is?

A. This chart shows Piedmont's residential billing rate and the bill impact over a period of time from December 2006 to -- well, the label in the chart goes to December '19, but it really only reflects the rates as of September, because that's what's known at this point. And so -- and the boxes, the call-out boxes there, are representing for the winter -- five-month winter period, what residential -- average North Carolina residential customer bill is at two points in time, at winter 2008/'09, and winter 2018/'19. So this is based on our actual billing rates for those two winter periods.

Q. So your average residential -- and to be clear, you prepared this exhibit, right?

A. Yes.

Q. And based on historical data that the Company maintains?

A. Yes.

Q. Okay. And so if I'm understanding your testimony, the box on the right, which is pointing to the blue line -- which at that point -- what is the significance of the red line?

A. It's average rate over this period of time.

Q. Okay. So the box on the right-hand side indicates that, for the winter of 2018/2019, that the average residential North Carolina customer bill was $532; is that right?

A. Yes. Based on normal customer usage for residential is approximately 45 and-a-half dekatherms in that five-month winter period, and that, based on the actual billing rates at that time, yield this amount.

Q. Okay. I notice on your exhibit you do not show -- there's not a marker for the results of the stipulation.

Could you -- have you calculated how the stipulation, what those results would be utilizing, I guess the most recent data that you have, which is 2018/2019, correct?

A. Yes. I have calculated it, although I did not put it onto this schedule. The rates that -- the year-one rates that would -- that are represented in the stipulation, if I couple that with our existing gas cost, our existing temporary rates, all the other components of our billing rate that are not part of this proceeding, that would yield, for this coming winter, an average North Carolina residential winter bill of $508.

Q. So $24 less in 2018/2019?

A. Yes. The cost of gas is lower than it was last winter.

Q. Okay. So if I'm understanding your testimony correctly, if the Commission approved the stipulation and there weren't any dramatic increases in the cost of gas between now and this coming winter, the average residential customer could reasonably expect to have a lower bill this coming winter; is that correct?

A. Than last, yes.

Q. Okay. Thank you.

MR. JEFFRIES: That's all the questions

we have of Ms. Powers.

COMMISSIONER BROWN-BLAND: All right. Questions from Commission?

Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Ms. Powers, referring to your redirect exhibit that you were just talking about, you gave us a number for the projected upcoming winter using year one of the stipulation. Suppose you use year six, and assumed that gas costs remained absolutely flat for six years, which they're probably not going to do, but let's just make the assumption. What then would be the average NC residential customer bill under the stipulation in year six?

A. I anticipated possibly getting that question.

Q. I'm sorry to be predictable.

A. No. So it would -- the way this -- as you know, we have the changes in the rates over the various years. So for year six, assuming all the other components of our rate, keeping months the same, it would yield about $550 -- $553 for the annual winter bill. That would be the comparable to the $532 and the $508 that I just mentioned.

Q. Okay. Thank you.

A. You're welcome.

Q. Going back to Attorney General's Powers Cross Examination Exhibit 3, that's the notice.

A. The notice.

Q. And you were asked some questions about page 2 of appendix A of that notice. I want to go back to that.

Did I understand you to say you did not prepare at least some portion of the information in the chart at the top of that page?

A. Yes. We did not prepare this table. Certainly, I recognize the 916267, those total amounts. And a member of my team has confirmed Ms. Couzens, prior witness, had gone through the exercise of checking the present and proposed revenue changes here. But with respect to what Mr. Jeffries was mentioning, the way that it bundles, some of the rate schedules doesn't show you -- it gives the appearance it was something other than an across-the-board increase, and so that is what we were referencing.

Q. Okay. Looking down toward the bottom of the page under the -- two-thirds of the way down there's a section titled "effective rates," and there's a chart there.

Do you know who prepared that chart?

A. I do not, but we are in agreement with these numbers.

Q. You don't know who prepared it, but you've taken a look at it and satisfied yourself that the chart is correct?

A. Yes.

Q. Okay. Thank you. I want to ask you a question here. In that section titled "effective rates" on the page, it says, "For existing residential customers, the proposed rates, including the effects of all riders, would change the average monthly bill, et cetera, according to the chart."

And so my question to you is, looking back at the chart on the top of the page, and understanding you don't -- can't validate the percentage change column, but the rest of the numbers perhaps are familiar with you, do the numbers in the rest of the chart at the top of the page, do those include the effects of all riders?

A. The chart at the top of the page would not.

Q. Does not. So if I'm reading this, where does it tell me that the information at the top of the page does not include the effect of the riders, and the information at the bottom of the page does include the effect of the riders? Where do I get that?

A. I'm not sure.

Q. Okay. I'll -- I think I probably ought to ask a later witness, but I'll ask you just to be sure you don't have an answer and save me a question later. Looking at Attorney General's Office Powers Cross Examination Exhibit 5.

A. I didn't label them when Ms. Force was speaking.

Q. This was the one that you were showed by Ms. Force that was given to you in response to a discovery request, and it's titled "Revised Patel Exhibit 3."

A. Got it.

Q. Do you remember that one?

A. Yes, I do.

Q. Okay. Do you have it there?

A. Yes, I do.

Q. This -- and again, I will ask a later witness, probably, but I'll ask you in case you know. This only shows calculations of the combined margin of flow-back of EDIT and the flow-back of EDIT for years one, two, and three.

Did you ever -- were you ever given anything for years four, five, and six?

A. Um --

Q. Did you see anything from anyone for years four, five, and six?

A. No. This was Public Staff Witness Patel's exhibit to an Attorney General data request.

Q. Right.

A. And so we answered a similar data request. So I have my own calculations of that for the other years.

Q. You have something similar to --

A. That was what -- I'm sorry, I don't remember how she labeled it, but the long schedule that --

Q. Exhibit 2? Cross Examination Exhibit 2?

A. Yes. So this is breaking it out by the individual rate schedules to yield the amounts.

Q. Thank you. You got me on track now.

A. Okay.

Q. Navigating through the paper sometimes is what we need help on, thank you.

A. My pleasure.

Q. That's all I have.

COMMISSIONER BROWN-BLAND: All right.

Ms. Powers, you are -- I believe you're it for the Company, so you and I have some cleanup work to do, primarily based on the questions that the Commission issued by order.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. So my first question is -- I think we heard a little bit about this earlier, but I'll go through it with you.

What is the benchmark commodity cost of the gas that was embedded in Piedmont's rates in the 2008 rate case?

A. At the time of the 2008 rate case, those rates took effect November 1, 2008, and our benchmark rate cost of gas rate, a/k/a the commodity benchmark cost of gas rate, was $8.75 a dekatherm. It was higher than that in several of the months leading up to the implementation, but it was at November 1, 2008, $8.75 a dekatherm.

Q. Do you recall its highest level?

A. The history that I looked at in preparation for this question went back to January 2004. So when I looked at that dataset, January 2004 rates to the present time, the highest benchmark rate that Piedmont had was in December and November of 2005, and it was

$13 per dekatherm at that time.

Q. Okay. And do you know what it was in the Company's 2013 rate case?

A. Yeah. That rate -- those rates took effect January 2014, and the benchmark was $4.25 per dekatherm then.

Q. All right. And in this case, is the embedded rate $2.75?

A. Yes, it is.

Q. All right. Yesterday, when I was asking some questions about LNG being trucked, I asked the question is that being done pursuant to tariff --

A. I'm ready to follow up on that.

Q. -- the tariff that covered it, and somebody pointed to you, so this is a follow up.

A. Sure. So we have trucking facilities at our two LNG sites in North Carolina, and so the trucking facilities kind of go both ways. A truck can bring liquefied natural gas to that facility for injection into the tank; it can also work in the other direction, that liquefied natural gas can be removed from the tank and put into the truck and trucked to a different location.

And those capabilities are very important to the Company. The Company uses it -- takes advantage of those capabilities for its own operations. I would say primarily for its own operations. That truck -- liquefied natural gas in one facility, such as the Huntersville facility, could be trucked to the Bentonville facility as needed, I think that has occurred on occasion. And another example of how we use those facilities would be in support of operations, that liquefied natural gas could be taken out, put into a truck, and brought to a specific point on our system and then put into the pipelines as needed. I believe that's actually used during -- supporting the inline inspection pinning operations of the Company is involved in. So I wanted to point that out that it has a very important operational use for the Company.

A third method or use for it is that, to the extent that another party needed LNG and that the Company would engage in transactions with them, it could support that sale. And I did check -- based on your follow-up questions yesterday, I did check with folks back at the office, and in 2018, we did not have any LNG sales, and there was some limited sales in 2019.

Just for order of magnitude, each of those

LNG facilities, as Witness Gaglio explained yesterday, one BCF tank. So think about it, there's a million dekatherms of natural gas that can be held in that capacity. And, in 2019 to date, about 500 dekatherms were sold. So that's less than a 10th of a percent of what it could hold. I just express that, in terms of order of magnitude to understand that that's not the primary use of the trucking facilities.

Q. And so when those sales occur, or if they were to occur, how is that billed? Is that pursuant to a tariff or some agreement with the --

A. It is not. It's treated -- it has been recorded by the Company as an off-system sale. And so, as with all of our off-system sales and other secondary marketing transactions, that the gains, 75 percent of it -- as long as the other party was not an affiliate, 75 percent of that goes to the benefit of customers via recognition or offset to the cost recorded in the all customers deferred account.

Q. Okay. Witness Yoho answered a question yesterday about secondary market transactions, and he gave us the numbers for the margin retained. And I asked how was the margin accountable. Again, you were --

A. Pointed to.

Q. -- offered up to that.

A. Secondary marketing. So the Company, again, when it's not an affiliate that is the counterparty to those transactions, gains from that are split; the Company customers receive 75 percent of the gain, the Company 25. And so those are recorded as an offset to the costs -- the demand fix cost of gas demand charges. So it's recorded to the all customers deferred account.

Let's say that deferred account were to have at any given point in time, reflect an amount due to the Company, it would then lower that amount due to the Company, hence it's going to the benefit of customers.

Q. So is it reflected in the 9.7 percent return on equity, the portion that's retained, the 25 percent?

A. So, in the general rate proceeding, this one, and consistent with our past proceedings, that the revenues there do not reflect secondary marketing revenues.

Q. Okay. And I think that Mr. Barkley indicated that you could tell us more about how weather normalization adjustment work, how that was accounted for.

A. I'll try. He gives me a little too much credit there. I started in the rates department in 2006, and it was coming out of the Piedmont's 2005 rate case. The rates from that took effect November 2005. That's when the margin decoupling mechanism, it actually had a different name at that time, customer utilization tracker, it took effect at that time. So my experience in the rates department was not during the -- was in a -- in the regime where we had the margin decoupling mechanism.

However, I do have some understanding I'm happy to share with you about the operation of the WNA in North Carolina prior to that date. So I, in general, look at margin decoupling as an evolution of weather normalization. Most of those mechanisms, I guess, nationally, out of LDCs and Commissions were adopting those mechanisms in the early 1990s, and Piedmont no different.

And those WNA mechanisms, customers would get their bill, and it would reflect an adjustment based on the fact that actual weather was almost always different than normalized weather, as used for setting rates. And my -- the formula looks complicated. In general, I think people found it very difficult to talk about margin -- to talk about WNA to customers in particular. And I have -- understand, through talking to other people, that there were a lot of -- that the Commission received a lot of complaints, or at least customers calling in not understanding their bill, and often it was driven by not understanding why that charge was showing up.

So weather -- excuse me, margin decoupling, like I said, it's an evolution of WNA, and it's a little bit broader in what it accomplishes. Both WNA and margin decoupling were meant to preserve the Commission's orders in a rate case, certain factors that were yielded by the order and implementation for rates. The margin decoupling is no different; it's just a little bit more -- like I say, it's a little more eloquent of a mechanism, and it's easier to understand and to use as deferred accounting. So it doesn't show up as its own individualized line item on a bill. Through deferred accounting, it's a much more smooth mechanism, and it's easier to explain and account for in schedules that we present to the Commission, let alone schedules that we look at internally. I guess that's what I have to explain it.

Q. Okay. And what is the net amount of interest earned or paid by Piedmont in the margin coupling tracker deferred account in 2018?

A. All right. In 2018, the interest that Piedmont has recorded related to the margin decoupling deferred account was $51,000. $50,898.

Q. All right. And what's the net amount of interest earned or paid in that deferred account since the Commission's order in the last general rate case?

A. $1.046 million, and that would be an amount -- interest income to the Company. In any given -- in those years, 2014 through 2018, in some years it was recorded as interest income, in other years it was recorded as interest expense, amounts due the Company. It's always going to depend on the cumulative effect of the deferred account balance at that time.

Q. Thank you for that. Just one minute.

(Pause.)

COMMISSIONER BROWN-BLAND: All right. Any other questions from the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: Questions on Commission's questions? Ms. Force?

RECROSS EXAMINATION BY MS. FORCE:

Q. Just a follow-up question so I understand one of the questions that was directed to you.

When you said that revenues are not reflected from secondary market transaction revenues, when you're reporting, I think, what you mean by that there is -- that the amount of profit that the Company gets does not reflect that too, right; it's just not included?

A. Yeah. It's not -- those revenues are not part of the books numbers for this rate proceeding.

Q. It's more like a bonus, essentially, isn't it, the 25 percent?

A. You know, I don't look at -- characterize it in that way, but I know what you're saying.

MS. FORCE: Okay. That's all. Thanks.

COMMISSIONER BROWN-BLAND: Mr. Jeffries?

MR. JEFFRIES: Thank you, Madam Chair.

FURTHER REDIRECT EXAMINATION BY MR. JEFFRIES:

Q. Are you more comfortable with the word "incentive"?

A. Yes.

Q. Thanks. On -- Commissioner Brown-Bland was asking you questions about margin decoupling, and I think she -- I think it was Commissioner Brown-Bland that asked you this, to sort of give the -- what's the result since the last rate case; is that right?

A. For the margin decoupling interest?

Q. Yes.

A. Yes.

Q. Okay. And do you have the figures for the entire period that that mechanism has been operating?

A. Not for the interest, but -- I don't have it for the interest piece.

Q. Okay.

A. But Mr. Barkley, in his direct testimony, he had Exhibit BPB-1, and that was showing from 2014 through the end of the test period the actual adjustments yielded before interest -- the actual adjustments yielded by the mechanism. And so, in that five-year period, it was a net $2.6 million amount due to the customers. So it was a benefit to the customer. It preserved -- by preserving the factors that came out of the 2014 rate case, the 2014 rate case, it yielded -- here's an amount you need to collect for residential customers annually to cover your cost of service for small and medium general customers.

By preserving that, it actually yielded an adjustment that, you know, had we not had the mechanism, customers would have received charges of $2.6 million more than they did in that five-year period.

MR. JEFFRIES: Thank you. That's the only questions I have, Madam Chair.

COMMISSIONER BROWN-BLAND: All right. Thank you. I will entertain your motions.

MR. JEFFRIES: Madam Chair, the Company would move that Ms. Powers' prefiled exhibits marked and identified as Exhibits PKP-1 through PKP-8, and the second set, PKP-1 Updated through PKP-8 Updated, and finally her settlement exhibit marked and identified as Settlement Exhibit PKP-1, we would move all of those into evidence.

COMMISSIONER BROWN-BLAND: All right. Without objection, those exhibits will be received into evidence.

(Exhibits PKP-1 through PKP-8, PKP-1 Updated through PKP-8 Updated, and Settlement Exhibit PKP-1 was admitted into evidence.)

MS. FORCE: And the Attorney General's office had six cross examination exhibits for Ms. Powers, and would like to move the admission of those as well.

COMMISSIONER BROWN-BLAND: Without

objection, those cross examination exhibits from the AGO Powers Cross Examinations 1 through 6 will be received into evidence.

(AGO Powers Cross Examination Exhibits 1 through 6 were received in evidence.)

MR. JEFFRIES: And, Madam Chair, we would also move Ms. Powers' Redirect Exhibit Number 1 into evidence.

COMMISSIONER BROWN-BLAND: All right. That Redirect Exhibit 1 is received into evidence.

(Piedmont Powers Redirect Exhibit 1 was admitted into evidence.)

MR. JEFFRIES: And as a formality, before Piedmont rests the presentation of its case, the Public Staff suggested, and I agree with them, that we would like to move the admission of the stipulation that's been filed with the Commission into the record in this proceeding.

CHAIRPERSON BROWN-BLAND: And the application?

MR. JEFFRIES: And the application. Thank you.

COMMISSIONER BROWN-BLAND: All right. The application from -- filed by Piedmont as well as the stipulation of the several parties that has been identified in this case will also be received into evidence.

MR. JEFFRIES: Thank you.

(Stipulation and Application was received into evidence.)

COMMISSIONER BROWN-BLAND: Does that have exhibits? The exhibits will also be received into evidence.

MR. JEFFRIES: That concludes the presentation of Piedmont's case, Madam Chairman.

COMMISSIONER BROWN-BLAND: All right. Thank you, Mr. Jeffries.

THE WITNESS: Am I excused?

COMMISSIONER BROWN-BLAND: I know you want to be, so yes, you are.

THE WITNESS: Thank you.

COMMISSIONER BROWN-BLAND: I was looking at Ms. Culpepper to see if we needed -- do we need any readjustment time, or are we ready? I think we were going to do some moving of microphones, I believe.

MS. CULPEPPER: Our panels are not up yet.

COMMISSIONER BROWN-BLAND: Okay. All right. So who are you calling?

MR. CREECH: May it please the Court, Commission, Chair Brown-Bland, public -- William E. Creech for the Public Staff. We would like to please call John R. Hinton as a witness.

JOHN R. HINTON,

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

DIRECT EXAMINATION BY MR. CREECH:

Q. Mr. Hinton, would you please state your name, business address, and present position for the record?

A. My name is John Robert Hinton. I work at 430 North Salisbury, Raleigh, North Carolina. I'm the director of economic research division for Public Staff.

Q. On July 19, 2019, did you prepare and cause to be filed in this docket, testimony consisting of 47 pages, appendices A and B and Hinton Exhibits 1 through 10?

A. Yes.

Q. On August 12, 2019, did you prepare and cause to be filed in this docket, your settlement testimony consisting of nine pages and a settlement exhibit?

A. Yes.

Q. Do you have any corrections to your testimony?

A. Yes. On my direct testimony, on page 15, line 10, the number reads 140; it should read 130, as in 130 basis points.

Q. So, again, that correction is from 140 to 130?

A. Correct. And that's my change.

Q. Line 10, page 15 of your July 19th testimony, correct?

A. Yes.

Q. Do you have any other corrections?

A. No, that's all.

Q. Okay. Except for the corrections -- the correction just made, if you were asked the same questions today as posed in your prefiled testimony, would your answers be the same?

A. Yes, they would.

MR. CREECH: I move that, as corrected, Mr. Hinton's prefiled testimony consisting of 47 pages and appendices A and B, and Mr. Hinton's settlement testimony consisting of 9 pages be copied into the record as if given orally from the stand, and that is prefiled exhibits to be identified as marked.

COMMISSIONER BROWN-BLAND: As corrected, Mr. Hinton's direct testimony will be received into evidence as if given orally from the stand, as well as his stipulation or settlement testimony will also be received into evidence, and the exhibits filed with each of those said testimony will be marked -- identified as they were marked when filed.

(JRH Exhibits 1 through 10 and Settlement Exhibit JRH 1 were admitted into evidence.)

(Whereupon, the prefiled direct testimony and settlement testimony of John R. Hinton was copied into the record as if given orally from the stand.)

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9 SUB 743

TESTIMONY OF JOHN R. HINTON ON BEHALF OF THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

July 19, 2019

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

A. My name is John R. Hinton and my business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Economic Research Division of the Public Staff – North Carolina Utilities Commission (Public Staff). My qualifications and experience are provided in Appendix A.

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

A. The purpose of my testimony is to present to the North Carolina Utilities Commission (Commission) the results of my analysis and my recommendations as to the fair rate of return to be used in establishing rates for natural gas distribution utility service provided by Piedmont Natural Gas Company, Inc. (Piedmont or the Company).

Q. WHAT IS THE CURRENTLY APPROVED COST OF CAPITAL FOR PIEDMONT?

A. In the last Piedmont general rate case in Docket No. G-9, Sub 631, the Commission approved an overall cost of capital of 7.51%, which is comprised of a capital structure ratio of 46.52% long-term debt, 2.82% short-term debt, and 50.66% common equity. The overall weighted cost rate includes 5.23% for long-term debt, 0.53% for short-term debt, and 10.00% cost of common equity.

Q. WHAT IS THE COST OF CAPITAL REQUESTED BY PIEDMONT IN THIS PROCEEDING?

A. Piedmont has requested an overall cost of capital or rate of return of 7.68%. This applied-for rate of return is based on a capital structure consisting of 47.18% long-term debt, 0.82% short-term debt, and 52.00% common equity as noted in the testimony of Company witness Sullivan. The overall weighted cost rate includes 4.55% for long-term debt, 2.82% for short-term debt, and 10.60% cost of common equity.

Q. HOW DOES PIEDMONT WITNESS HEVERT DEVELOP HIS RECOMMENDED 10.60% COST OF EQUITY?

A. Company witness Hevert utilizes four cost of equity methods: (1) the Discounted Cash Flow (DCF) model; (2) the Capital Asset Pricing

Model (CAPM); (3) the Risk Premium method; and (4) the Expected Earnings method. He applies these methodologies to a proxy group of eight publically-traded natural gas distribution companies. His first method relies on the DCF model which produces cost of equity results ranging from 9.60% to 12.03%. Company witness Hevert includes results from his CAPM results ranging from 9.26% to 13.52%. The witness includes results from his Risk Premium method ranging from 9.89% to 10.11%. The witness also includes the results of his Expected Earnings method ranging from 9.58% to 12.13%. Company witness Hevert also opines that the cost of equity should include the five basis point effect of flotation costs with an overall recommendation of a 10.60% cost rate for common equity.

Q. **WHAT IS THE OVERALL RATE OF RETURN RECOMMENDED BY THE PUBLIC STAFF?**

A. The Public Staff recommends an overall rate of return of 6.71%. This is based on a capital structure consisting of 49.94% long-term debt, 0.85% short-term debt, and 49.21% common equity. The overall weighted cost rate includes a 4.41% cost of long-term debt, 2.72% for short-term debt, and 9.13% cost of common equity.

Q. **HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?**

A. The remainder of my testimony is presented in the following five sections:

I. Legal and Economic Guidelines for Fair Rate of Return
II. Present Financial Market Conditions
III. Appropriate Capital Structure and Cost of Long-Term Debt
IV. The Cost of Common Equity Capital
V. Concerns with Company witness Hevert's testimony
VI. Summary and Recommendation

I. LEGAL AND ECONOMIC GUIDELINES FOR FAIR RATE OF RETURN

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND LEGAL FRAMEWORK OF YOUR ANALYSIS.

A. Public utilities possess certain characteristics of natural monopolies. For instance, it is more efficient for a single firm to provide a service such as natural gas utility service than for two or more firms to offer the same service in the same area. Therefore, regulatory bodies have assigned franchised territories to public utilities to provide services more efficiently and at a lower cost to consumers.

Q. WHAT IS THE ECONOMIC RELATIONSHIP BETWEEN RISK AND THE COST OF CAPITAL?

A. The cost of equity capital to a firm is equal to the rate of return investors expect to earn on the firm's securities given the securities' level of risk. An investment with a greater risk will require a higher expected return by investors. In Federal Power Com. v. Hope Natural Gas Co., 320 U.S. 591, 603, 64 S. Ct. 281, 288 (1944) (Hope), the United States Supreme Court stated:

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

> In Bluefield Waterworks & Improvement Co. v. Public Service Comm'n, 262 U.S. 679, 692-93, 43 S. Ct. 675, 679 (1923) (Bluefield) the United States Supreme Court stated: A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

These two decisions recognize that utilities are competing for the capital of investors and provide legal guidelines as to how the allowed rate of return should be set. The decisions specifically speak to the standards or criteria of capital attraction, financial integrity, and comparable earnings. The Hope decision, in particular, recognizes that the cost of common equity is commensurate with risk relative to investments in other enterprises. In competitive capital markets, the required return on common equity will be the expected return foregone by not investing in alternative stocks of comparable risk. Thus, in order for the utility to attract capital, possess financial integrity, and exhibit comparable earnings, the return allowed on a utility's common equity should be that return required by investors for stocks with comparable risk. As such, the return requirements of debt and equity investors, which is shaped by expected risk and return, is paramount in attracting capital.

It is widely recognized that a public utility should be allowed a rate of return on capital which will allow the utility, under prudent management, to attract capital under the criteria or standards referenced by the Hope and Bluefield decisions. If the allowed rate of return is set too high, consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. Likewise, customers will be charged prices that are greater than the true economic costs of providing these services. Consumers will consume too few of these services from a point of view of efficient resource allocation. If the return is set too low, then the utility stockholders will suffer because a declining value of the underlying property will be reflected in a declining value of the utility's equity shares. This could happen because the utility would not be earning enough to maintain and expand its facilities to meet customer demand for service, cover its operating costs, and attract capital on reasonable terms. Lenders will shy away from the company because of increased risk that the utility will default on its debt obligations. Because a public utility is capital intensive, the cost of capital is a very large part of its overall revenue requirement and is a crucial issue for a company and its ratepayers.

The Hope and Bluefield standards are embodied in N.C. Gen. Stat. § 62-133(b)(4), which requires that the allowed rate of return be sufficient to enable a utility by sound management

> to produce a fair return for its shareholders, considering changing economic conditions and other factors . . . to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and are fair to its customers and to its existing investors.

On April 12, 2013, the North Carolina Supreme Court decided State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) (Cooper). In that decision, the Supreme Court reversed and remanded the Commission's January 27, 2012 Order in Docket No. E-7, Sub 989, approving a stipulated return on equity of 10.50% for Duke Energy Carolinas, LLC. In its decision, the Supreme Court held (1) that the 10.50% return on equity was not supported by the Commission's own independent findings and analysis as required by State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 500 S.E.2d 693 (1988) (CUCA I), in cases involving nonunanimous stipulations, and (2) that the Commission must make findings of fact regarding the impact of changing economic conditions on consumers when determining the proper return on equity for a public utility. In Cooper, however, the Court's holding introduced a new factor to be considered by the Commission regardless of whether there is a stipulation.

In considering this new element, the Commission is guided by ratemaking principles laid down by statute and interpreted by a body of North Carolina case law developed over many years. According to these principles, the test of a fair rate of return is a return on equity that will provide a utility, by sound management, the opportunity to (1) produce a fair profit for its shareholders in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Tel. Co., 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972). Rates should be set as low as reasonably possible consistent with constitutional constraints. State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utilities Com., 323 N.C. 481, 490, 374 S.E.2d 361, 366 (1988). The exercise of subjective judgment is a necessary part of setting an appropriate return on equity. Id. Thus, in a particular case, the Commission must strike a balance that (1) avoids setting a return so low that it impairs the utility's ability to attract capital, (2) avoids setting a return any higher than needed to raise capital on reasonable terms, and (3) considers the impact of changing economic conditions on consumers.

Q. WHAT IS A FAIR RATE OF RETURN?

A. The fair rate of return is simply a percentage which, when multiplied by a utility's rate base investment, will yield the dollars of net operating income a utility should reasonably have the opportunity to earn. This dollar amount of net operating income is available to pay the interest cost on a utility's debt capital and a return to the common equity investor. The fair rate of return multiplied by the utility's rate base yields the dollars a utility needs to recover in order to earn for investors the cost of capital.

Q. HOW DID YOU DETERMINE THE FAIR RATE OF RETURN THAT YOU RECOMMEND IN THIS PROCEEDING?

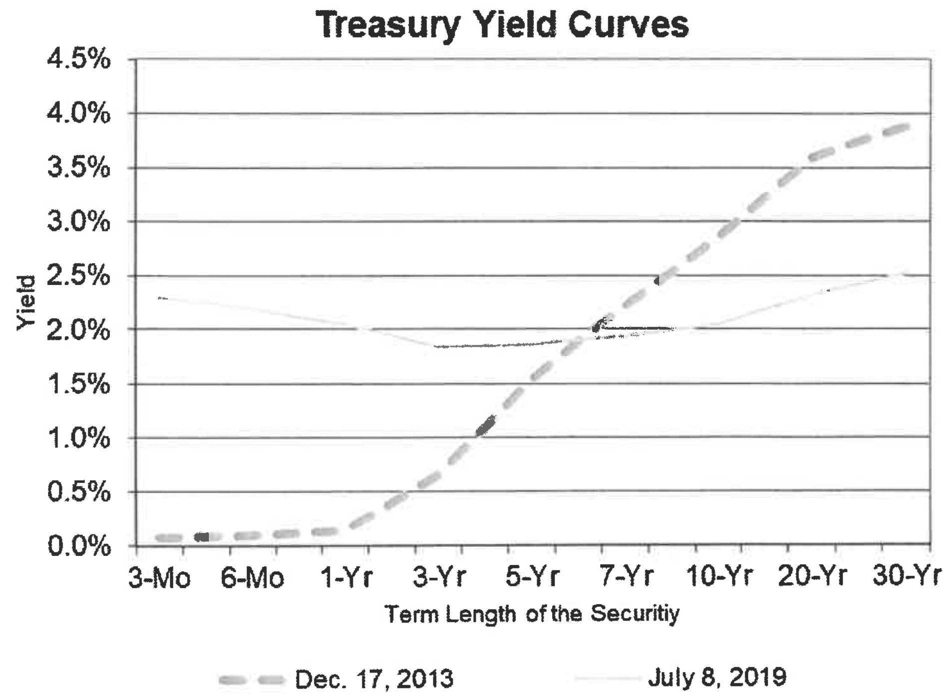
A. To determine the fair rate of return, I performed a cost of capital study consisting of three steps. First, I determined the appropriate capital structure for ratemaking purposes, i.e., the proper proportions of each form of capital. Utilities normally finance assets with debt and common equity. Because each of these forms of capital have different costs, especially after income tax considerations, the relative amounts of each form employed to finance the assets can have a significant influence on the overall cost of capital, revenue requirements, and rates. Thus, the determination of the appropriate capital structure for ratemaking purposes is important to the utility and to ratepayers. Second, I determined the cost rate of each form of capital. The individual debt issues have contractual agreements explicitly stating the cost of each issue. The embedded annual cost of debt may be calculated by simply considering these agreements and the utility's books and records over the life of the bond. The cost of common equity is more difficult to determine because it is based on the investor's opportunity cost of capital and there are no defined terms associated with the investment. Various economic and financial models or methods are available to measure the cost of common equity. Third, by combining the appropriate capital structure ratios for ratemaking purposes with the associated cost rates, I calculated an overall weighted cost of capital or fair rate of return.

II. PRESENT FINANCIAL MARKET CONDITIONS

Q. CAN YOU BRIEFLY DESCRIBE CURRENT FINANCIAL MARKET CONDITIONS?

A. Yes. The cost of financing is much lower today than in the more inflationary period of the 1990s. More recently, the continued low rates of inflation and expectations of future low inflation rates have contributed to even lower interest rates. According to Moody's Bond Survey, the yield on long-term "A" rated public utility bonds as of June 2019 are 3.82% as compared to 4.83% for December 2013, which is at the approximate date[1] of the Commission Order in the Company's last rate case. The overall decline in long-term interest rates over the last ten years is shown in Exhibit JRH-1. A similar observation is seen with the decline in the long end of the yield curve that indicates a significant lower cost of long-term financing.[2] However, there has been an increase in the cost of short-term financing, as indicated in the below graph, which has put upward pressure on the cost of short-term debt.

[1] The Commission issued its Order in Docket No. G-9, Sub 631, on December 17, 2013.
[2] See Federal Reserve, H15 Selected Interest Rates.



Q. HOW DO INTEREST RATES AFFECT THE FINANCING COSTS OF A COMPANY?

A. In simple terms, the current lower interest rates and stable inflationary environment indicate that borrowers are paying less for the time value of money. This is significant because utility stocks and utility capital costs are highly interest rate-sensitive relative to most industries within the securities markets. Furthermore, given that investors often view the purchase of common stocks of utilities as substitutes for fixed income investments, the reductions in interest rates observed over the past have paralleled the decreases in investor required rates of return on common equity, as evidenced by the reductions in allowed returns on common equity.

Q. DID YOU RELY ON INTEREST RATE FORECASTS IN YOUR INVESTIGATION?

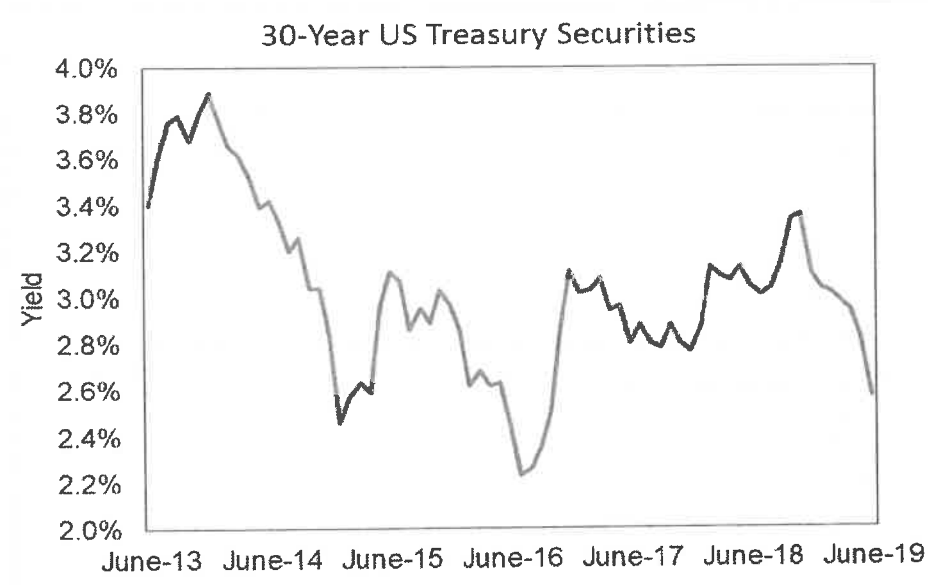
A. No. While I believe forecasts of earnings and dividends influence investor behavior, I generally do not believe interest rate forecasts to be reliable in determining the cost of equity. Rather, I believe that current interest rates, especially in relation to yields on long-term bonds, are more appropriate for ratemaking. This is because it is reasonable to expect that, as investors are pricing bonds, they are based on expectations on future interest rates, inflation rates, etc. To suggest the current bond yields do not reflect expectations of future interest rate levels suggests that investors don't have information on interest rate projections or the bond market is not efficient. I do not think either position is true.

While I'm confident in the market's ability to reasonably weight forecasts of future interest rates, I am less confident in the use interest rate forecasts for utility rate cases because I have seen numerous interest rate forecasts that do not materialize as expected. An example of this may be found in the testimony of Company witness Hevert in Duke Energy Progress' 2012 rate case, Docket No. E-2, Sub 1023. In that case, Company witness Hevert relied in part on predicted 30-year treasury yields published by the Blue Chip Financial Forecasts[3] in his CAPM and his Risk Premium analyses. The June 1, 2012 publication predicted that the 30-year treasury yields would rise to 4.2% in 2014 and 5.5% by 2018. However, these forecasts were approximately 200 to 300 basis points higher than the actual 30-year treasury yields observed from 2014 through 2018. In the more recent rate case involving Duke Energy Carolinas, Docket No. E-7, Sub 1146, the forecast errors associated with the 30-year treasury securities were smaller; however, the predicted yield for 2019 was over 140 basis points larger than the actual yields observed thus far in 2019.

Another example may be found in the interest rate prediction testified to by Aqua North Carolina, Inc.'s (Aqua) rate of return witness Pauline Ahern in the 2013 Aqua rate case, Docket No. W-218, Sub 363. In her testimony Ms. Ahearn testified[4] to several forecasts of 30-year Treasury bond yields that were predicted to rise to 4.3% in 2015, 4.7% in 2016, 5.2% in 2017, and 5.5% for 2020-2024. In 2013, Ms. Ahern was a Principal with AUS Consultants. She is currently Executive Director at ScottMadden, Inc., the same firm as Piedmont witness Hevert. As illustrated in the graph below, the forecasts Ms.

[3] See page 28, footnote 20 of witness Hevert's prefiled testimony in Docket No. E-7, Sub 1026.
[4] See page 13, lines 14-17 and page 14, lines 4-9 of Ms. Ahern's Prefiled Supplemental Direct Testimony in Docket No. W-218, Sub 363.

Ahearn testified to in the 2013 Aqua rate case significantly over-estimated actual interest rates for 30-year Treasury bonds.



The foregoing examples illustrate why I tend to place more weight in current market interest rates which are inherently forward looking as they reflect investor expectations of both current and future returns on bonds, and to an extent, future rates of inflation.

III. APPROPRIATE CAPITAL STRUCTURE AND COST OF LONG-TERM DEBT

Q. WHY IS THE APPROPRIATE CAPITAL STRUCTURE IMPORTANT FOR RATEMAKING PURPOSES?

A. For companies that do not have monopoly power, the price that an individual company charges for its products or services is set in a competitive market, and that price is generally not influenced by the company's capital structure. However, the capital structure that is determined to be appropriate for a regulated public utility has a direct bearing on the fair rate of return and revenue requirement, and, therefore, the prices charged to captive ratepayers.

Q. PLEASE EXPLAIN THE TERM CAPITAL STRUCTURE AND HOW THE CAPITAL STRUCTURE APPROVED FOR RATEMAKING PURPOSES AFFECTS RATES.

A. A local gas distribution company (LDC) obtains external capital from investors by borrowing debt and issuing common equity. The capital structure is simply a representation of how a utility's assets are financed. It is the relative proportions or ratios of debt and common equity to the total of these forms of capital, which have different costs. Common equity is far more expensive than debt for ratemaking purposes for two reasons. First, as mentioned earlier, there are income tax considerations. Interest on debt is deductible for purposes of calculating income taxes. The cost of common equity, on the other hand, must be "grossed up" to allow the utility sufficient revenue to pay income taxes and to earn its cost of common equity on a net or after-tax basis. Therefore, the amount of revenue the utility must collect from ratepayers to meet income tax obligations is directly related to both the common equity ratio in the capital structure and cost of common equity. A second reason for this cost difference is that the cost of common equity must be set at a marginal or current cost rate. Conversely, the cost of debt is set at an embedded rate because the utility is incurring costs that are previously established in contracts with security holders.

Because the Commission has the duty to promote economical utility service, it must decide whether or not a utility's requested capital structure is appropriate for ratemaking purposes. An example of the cost difference can be seen in the Company's filing. Based upon the Company's requested capital cost rates, each dollar of its common equity, and each dollar of its long-term debt that supports the retail rate base has the following approximate annual costs (including income tax and regulatory fee expense) to ratepayers:

1) each $1 of common equity costs ratepayers approximately 12 cents

2) each $1 of short-term debt costs ratepayers approximately 3 cents

3) each $1 of long-term debt costs ratepayers approximately 4 cents

Because of the capital cost differences, an appropriate capital structure for ratemaking purposes should be fair to both ratepayers and the utility's debt and equity investors. An appropriate capital structure should contain balances of debt and equity that provide capital cost and income tax savings without a corresponding increase in the overall cost of capital due to the increased financial risk. Therefore, a concern with the Company's capital structure is that the debt and equity ratios adopted in determining the overall rate of return on rate base investment should be no greater than required to allow Piedmont to qualify for reasonable credit ratings and to provide the ability to attract capital.

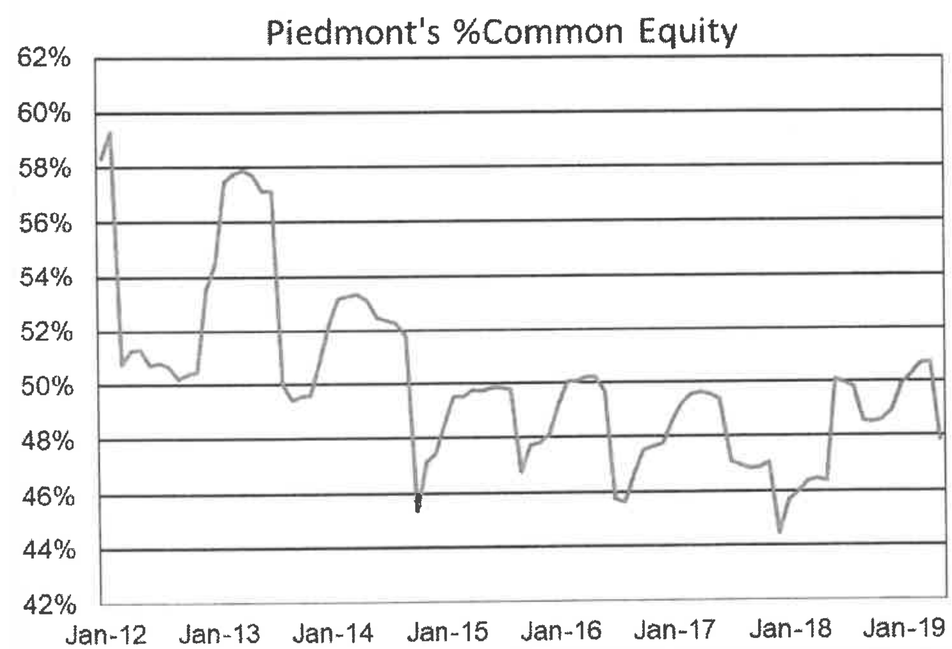
Q. WHAT CAPITAL STRUCTURE HAS THE COMPANY REQUESTED IN THIS CASE?

A. Company witness Sullivan has requested the use of a hypothetical capital structure of 47.18% long-term debt, 0.82% short-term debt, and 52.00% common equity as shown on Exhibit JLS-1 of the Company's Application. The exhibit contains the Company's capital structure as of December 31, 2018, containing 53.43% common equity. Company witness Sullivan's Exhibit JSL-1 also contains projected balances of long-term debt, short-term debt, and common equity for December 31, 2019, June 30, 2020, and December 31, 2020. The projected capital structures assume a certain amount of growth through retained earnings and external financing with the $600,000,000 debt issue in May 2019, the June 2018 infusion of

$300,000,000 common equity, and the expected infusion of $150,000,000 later in 2019 of common equity by its ultimate parent, Duke Energy Corporation (Duke Energy). Company witness Sullivan effectively averages these four capital structures to arrive at his recommended capital structure that reflects the Company's future plans to issue debt, generate future earnings from operations, and infuse equity capital from Duke Energy.

Q. DO YOU SUPPPORT THE HYPOTHETICAL CAPITAL STRUTURE PROPOSED BY COMPANY WITNESS SULLIVAN?

A. No. I have concerns with the heavy reliance on projected balances of debt and equity capital, as compared to the traditional use of a historical test year capital structure. Furthermore, I am concerned that the use of a 52.00% common equity ratio and 48% combined long-term debt and short-term debt ratio provides for an excessive degree of equity that is not reasonable, and it is not reflective of Piedmont's historical capitalization. Piedmont's historical capitalization ratio using North Carolina allotment of gas inventory as short-term debt is shown in the below graph. Since the issuance of the Commission's Order dated December 17, 2013, in Docket No. G-9, Sub 631, Piedmont's average common equity ratio is 48.97%, and the average equity ratio since the acquisition by Duke Energy on October 3, 2016, has averaged 48.21%. In order to observe average common equity ratios greater than 52.00%, one has to look back to 2014 and prior years. As indicated by the recent May 24, 2019 debt issuance of $600 million at 3.50%, Piedmont appears to have adequate access to capital with its "A-" rating, which does not lend support to the Company's request to raise its common equity levels back to the elevated levels that existed prior to 2014.



Q. WHAT APPROACH DO YOU RECOMMEND TO DETERMINE A REPRESENTATIVE AND REASONABLE CAPITAL STRUCTURE?

A. I recommend a capital structure for ratemaking purposes that is based on a 13-month average of long-term debt, short-term debt, and common equity. More specifically, to determine the capital structure, I averaged common equity, long-term debt, and short-term debt balances as of May 31, 2018, through May 31, 2019.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND THE COMMISISON EMPLOY FOR RATE MAKING PURPOSES?

A. I recommend that the following capital structure be employed for ratemaking purposes in this proceeding:

Piedmont Natural Gas Capital Structure
Thirteen Month Average as of May 31, 2019
($1,000)

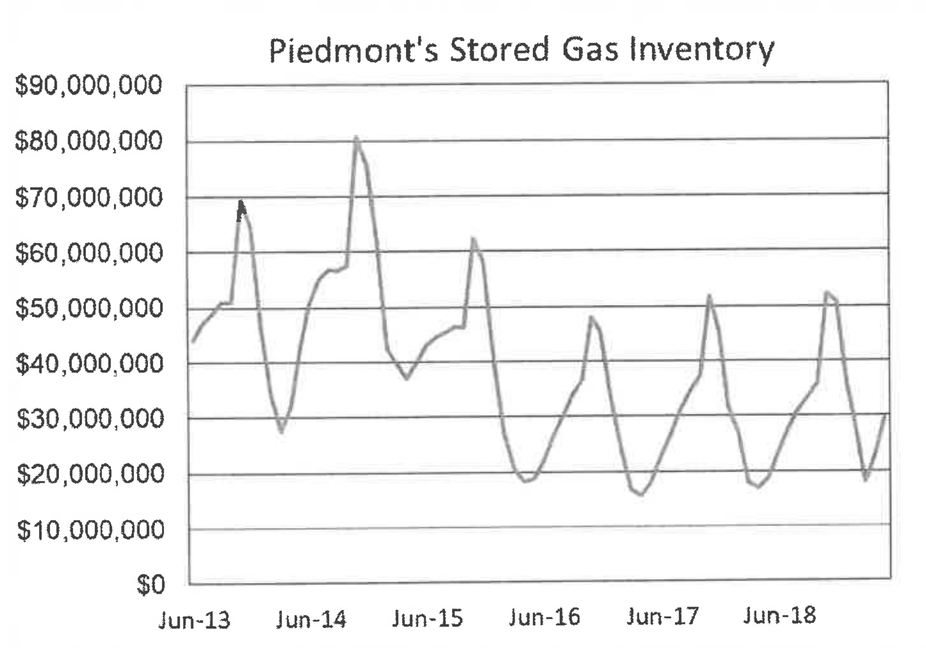
Capital Item	Amount	Ratios
Long-Term Debt	$ 2,121,868	49.94%
Short-Term Debt	36,170	0.85%
Common Equity	2,090,579	49.21%
Total Capital	$ 4,248,617	100.00%

Page 2 of Exhibit JRH-2 presents the balance(s) of long-term debt which are comprised of the outstanding long-term debt of $1,800,000,000 throughout the 13-month period from May 31, 2018, through May 31, 2019, and the current maturities of debt that ranged from $250,000,000 for the first four months and $350,000,000 for eight months up to May 2019, when the balance went to zero dollars. Each month there is a deduction to the debt balance for the unamortized debt issuance expense and May's debt balance includes an additional $600,000,000 from the May 24, 2019 issuance of a 10-year, 3.50% Senior Unsecured Note. The balance of common equity is comprised of $859,846,537 common stock, retained earnings which ranged from $883,752,309 to $1,059,443,975, other comprehensive income which ranged from $129,653 to $378,793, and a June 2018 $300,000,000 infusion from the parent company. The timing of the equity infusion from Duke Energy can be seen in the increase in the balance of equity from $1.8 billion in May, 2018 to $2.1 billion balance for June, 2018. During this 13-month period there were no dividends paid to Duke Energy.

To determine the amount of short-term debt, I recommend a balance of short-term debt equal to the Public Staff's recommended dollar value of stored gas inventory[5] included in the rate base of $36,169,890[6]. The graph below shows the seasonality of Piedmont's gas inventory, as recorded by the Company. Since short-term debt finances gas inventory, matching the amount of short-term debt included in the capital structure to the gas inventory in the rate base establishes a reasonable amount of short-term debt for ratemaking purposes. Furthermore, this approach better aligns the actual financing cost of the gas inventory in rate base.

[5] This use of gas inventory as a proxy for short-term debt was upheld by the North Carolina Supreme Court in State ex rel. Utilities Comm'n v. Carolina Util. Customers Ass'n, 351 N.C. 223, 524 S.E.2d 10 (2000). This Case involved a 1998 general rate case with Public Service Company of North Carolina, Inc., Docket No. G-5, Sub 495.

[6] Gas inventory per Public Staff witness Jayasheela, Exhibit I, Schedule 2-2.



Q. WHAT IS YOUR RECOMMENDED COST RATES OF LONG-TERM DEBT AND SHORT-TERM DEBT?

A. I recommend the use of the Company's updated 4.41% cost rate of long-term debt as of May 31, 2019, and I recommend a 2.72% cost rate of short-term debt. The short-term cost is based on the 13-month average spread between the prime rate and the Company's cost of short-term debt over the 13 months ending May 31, 2019, producing an average spread of 278 basis points. I then deducted 2.78% from the current 5.50% prime rate to produce the 2.72% cost rate of short-term debt.

IV. THE COST OF COMMON EQUITY CAPITAL

Q. HOW DO YOU DEFINE THE COST OF COMMON EQUITY CAPITAL?

A. The cost of equity capital for a firm is the expected rate of return on common equity that investors require in order to induce them to purchase shares of the firm's common stock. The return is expected or forward-looking because, when the investor buys a share of the firm's common stock, he does not know with certainty what his returns will be in the future.

Q. HOW DID YOU DETERMINE THE COST OF COMMON EQUITY CAPITAL FOR THE COMPANY?

A. I used the discounted cash flow (DCF) model and a regression analysis of approved returns for LDCs to determine the cost of equity. I have used the Comparable Earnings Analysis and the Capital Asset Pricing Model (CAPM) as a check on the results of my DCF analysis and my Regression Analysis of Approved Equity Returns.

A. DCF METHOD

Q. PLEASE DESCRIBE YOUR DCF ANALYSIS.

A. The DCF model is a method of evaluating the expected cash flows from an investment by giving appropriate consideration to the time value of money. The DCF model is based on the theory that the price of the investment will equal the discounted cash flows of returns. The model provides an estimate of the rate of return required to attract common equity financing as a function of the market price of a stock, the company's dividends, and investors' growth expectations. The return to an equity investor comes in the form of expected future dividends and price appreciation. However, as the new price will again be the sum of the discounted cash flows, price appreciation is ignored and attention is instead focused on the expected stream of dividends. Mathematically, this relationship may be expressed as follows:

Let D_1 = expected dividends per share over the next twelve months;

g = expected growth rate of dividends;

k = cost of equity capital; and

P = price of stock or present value of the future income stream.

Then,

$$P = \frac{D_1}{1+k} + \frac{D_1(1+g)}{(1+k)^2} + \frac{D_1(1+g)^2}{(1+k)^3} + \ldots + \frac{D_1(1+g)^{t-1}}{(1+k)^t}$$

This equation represents the amount an investor would be willing to pay for a share of common stock with a dividend stream over the future periods. Using the formula for a sum of an infinite geometric series, this equation may be reduced to:

$$P = \frac{D_1}{k-g}$$

Solving for k yields the DCF equation:

$$k = \frac{D_1 + g}{P}$$

Therefore, the rate of return on equity capital required by investors is the sum of the dividend yield (D_1/P) plus the expected long-term growth rate in dividends (g).

Q. HOW DID YOU APPLY THE DCF MODEL TO DETERMINE THE COST OF EQUITY?

A. Since Piedmont is a wholly owned subsidiary of Duke Energy, the Company does not have any publicly traded stock. Therefore, explicit market information cannot be obtained to show what investors would pay for the stock. For this reason, I could not apply the DCF method directly to Piedmont. However, the cost of equity capital is not unique to any particular firm. Rather, it is a cost shared by firms whose equity shares are considered by investors to be risk-comparable investments. In order to estimate the required rate of return, I have identified a group of comparable companies that will furnish market information which indicates the required investor return for Piedmont.

Q. HOW DID YOU IDENTIFY THE GROUPS OF COMPANIES COMPARABLE IN RISK TO PIEDMONT?

A. I began my analysis by reviewing ten companies that are identified by the Value Line Investment Survey Standard Edition (Value Line) as the natural gas utility industry. From this group of companies, I eliminated Nisource, Inc., due to a dividend cut in 2015.

Q. WHAT MEASURES OF RISK DID YOU REVIEW TO DETERMINE THE COMPARABILITY OF INVESTING IN PIEDMONT TO INVESTING IN OTHER NATURAL GAS DISTRIBUTION UTILITIES?

A. I reviewed standard risk measures that are widely available to investors that are considered by most investors when making investment decisions. The beta coefficient is a measure of the sensitivity of a stock's price to overall fluctuations in the market. The Value Line beta coefficient describes the relationship of a company's stock price with the New York Stock Exchange Composite. A beta value of less than 1.0 means that the stock's price is less volatile than the movement in the market;

conversely, a beta value greater than 1.0 indicates that the stock price is more volatile than the market.

I reviewed the <u>Value Line</u> Safety Rank, which is defined as a measure of the total risk of a stock. The Safety Rank is calculated by averaging two variables (1) the stock's index of price stability, and (2) the Financial Strength rating of the company.

I also reviewed the S&P and Moody's bond ratings, which are assessments of the creditworthiness of a company. Credit rating agencies focus on the creditworthiness of the particular bond issuer, which includes a detailed and thorough review of the potential areas of business risk and financial risk of the company. These and other risk measures I reviewed are shown in Exhibit JRH-3, and are further explained in Appendix B to my testimony.

Q. HOW DID YOU DETERMINE THE DIVIDEND YIELD COMPONENT OF THE DCF?

A. I calculated the dividend yield by using the <u>Value Line</u> estimate of dividends to be declared over the next 12 months, divided by the price of the stock as reported in the <u>Value Line</u> Summary and Index for each week of the 13-week period from April 12, 2019, through July 7, 2019. A 13-week averaging period tends to smooth out short-term variations in the stock prices. This process resulted in an average dividend yield of 2.5% for the comparable group of LDCs.

Q. HOW DID YOU DETERMINE THE EXPECTED GROWTH RATE COMPONENT OF THE DCF?

A. I employed the growth rates of the comparable group in earnings per share (EPS), dividend per share (DPS), and book value per share (BPS) as reported in Value Line over the past ten and five years. I also employed forecasts of future growth rates as reported in Value Line. The historical and forecasted growth rates are prepared by analysts of an independent advisory service that is widely available to investors and should also provide an estimate of investor expectations. I included both historical, known growth rates and forecast growth rates, because it is reasonable to expect that investors consider both sets of data in deriving their expectations. I should note that, in calculating an average or median growth rate, I did not include negative historical growth rates in EPS, DPS, and BPS. This is because, while negative growth rates are entirely possible, they are generally not the basis for investor expectations with utility investing.

Finally, I incorporated the consensus of various analysts' forecasts of five-year EPS growth rate projections as reported in Yahoo Finance. The dividend yields and growth rates for each of the companies and for the average for the comparable group are shown in Exhibit JRH-4.

Q. WHAT IS YOUR CONCLUSION REGARDING THE COST OF COMMON EQUITY TO THE COMPANY BASED ON THE DCF METHOD?

A. Based on my DCF analysis, I determined that a reasonable expected dividend yield is 2.5% with an expected growth rate of 5.60% to 6.60%. As such, the analysis produces a cost of common equity for the comparable group of LDCs of 8.1% to 9.1%.

B. REGRESSION ANALYSIS METHOD

Q. PLEASE DESCRIBE YOUR REGRESSION ANALYSIS METHOD.

A. I used a regression analysis to analyze the relationship between approved returns on equity for LDCs and Moody's Bond Yields for A-rated utility bonds, which is a form of the equity risk premium method that examines the risk premium associated with higher-risk investments. The differential between the two rates of return is indicative of the return investors require in order to compensate them for the additional risk. This method considers the return premium associated with an investment in a company's common stock over an investment in a company's bonds.

A strength of this approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. Thus, it is reasonable to conclude that the approved returns are good estimates for the cost of equity. The next step is to incorporate a contemporaneous cost of debt and the use of an ordinary least-squares regression model[7] that can be performed with spreadsheets that have basic statistical functionality.

Q. PLEASE DESCRIBE HOW YOU APPLIED A REGRESSION ANALYSIS TO APPROVED RETURNS ON EQUITY WITH NATURAL GAS UTILITY RATE CASES?

A. The method I used relies on approved returns on common equity for natural gas utility companies from various public utility commissions that are published by the Regulatory Research Associates, Inc. (RRA), within SNL Global Market Intelligence and Moody's "A" rated Utility Bond Yields. This method was relied upon by this Commission in Docket No. G-5, Sub 327, a 1994 general rate case of Public Service Company of North Carolina, Inc., and it is the method used in the formula rate plans for LDCs regulated by the

[7] The least squares model is a form of mathematical regression analysis that finds the line of best fit that quantifies the relationship between an independent variable(s) and a dependent variable.

Mississippi Public Service Commission.[8] The results from the regression analysis in this study and in other studies indicate that there is a high correlation between the cost of equity and utility bond yields.[9]

Q. WHAT WERE THE RESULTS OF YOUR REGRESSION ANALYSIS?

A. The results of the regression analysis shown on page 2 of 2 of Exhibit JRH-5, indicate that the predicted cost of equity is 9.64%. As noted, a statistical regression was performed in order to quantify the relationship of allowed equity returns and bond costs. The results of the regression analysis indicate a significant statistical relationship of the approved equity returns and bond costs, such that a reduction of 10 basis points in yields corresponds to a decrease of only 4 basis points in ROE.[10] As such, the regression analysis allows one to quantify the historical relationship of approved returns on equity and bond yields up through March 30, 2019, and then combine this relationship with current yields up through June 2019 to derive a predicted 9.64% cost rate for common equity.

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[8] See Mississippi Public Serve Commission, Mississippi Gas Co., Docket No. 18-UN-0139, Atmos Energy Corporation, Docket No. 05-UN-0503.
[9] See Brigham, E., Shome, D., and Vinson, S., 1985. "The Risk Premium Approach to Measuring a Utility's Cost of Equity." Financial Management, Spring 14: 33-45.
[10] The regression equation ROE=0.079857 + 0.40336, indicated a significant statistical relationship of Moody's utility bond yields and approved ROEs with an adjusted R^2=0.90860.

C. COMPARABLE EARNINGS METHOD

Q. PLEASE DESCRIBE YOUR COMPARABLE EARNINGS ANALYSIS.

A. My comparable earnings method analysis involves reviewing earned returns on equity for my comparable group of natural gas utilities.

This approach is based on the decision in the Hope case cited earlier in my testimony, which maintains that an investor should be able to earn a return comparable to the returns available on alternative investments with similar risks.

Q. WHAT ARE SOME OF THE STRENGTHS AND WEAKNESSES INHERENT IN THE COMPARABLE EARNINGS METHOD?

A. A strength of this method is that information on earned returns on common equity is widely available to investors and it is believed that investors use actual earned returns as a guide in determining their expected return on an investment. A weakness is that the earned return on equity may include non-utility income and increased earnings resulting from deferred income taxes. Furthermore, actual earned rates of return on equity can be impacted by factors outside a company's control, such as with weather and inflation. Such unforeseen developments can cause a company's earned rate of return on equity to exceed or fall short of its cost of capital during any certain period, which tends to make this method less reliable than other cost of capital methods. For this reason, I consider the results of this method as a check on the results of my DCF analysis and Regression Method analysis.

Q. HOW DID YOU APPLY THE COMPARABLE EARNINGS METHOD?

A. I examined the five historical earned returns and near term predicted returns of my comparable group of LDCs as reported in Value Line, as shown in Exhibit JRH-6.

Q. WHAT DID YOU CONCLUDE FROM YOUR COMPARABLE EARNINGS ANALYSIS OF THE GROUP OF COMPARABLE NATURAL GAS UTILITIES?

A. Based on the earned rates of return, I conclude that the cost of equity using the Comparable Earnings analysis provides a reasonable check on my results using the DCF model and the Regression Analysis of Approved ROEs method. However, I believe the historical earned returns are in excess of the Company's cost of equity and the predicted returns are more in line with investors' required returns on equity.

D. CAPM

Q. PLEASE DESCRIBE HOW YOU USED THE CAPM.

A. The CAPM is another version of the Risk Premium method. As with the Comparable Earnings method, I consider the results to provide a check on the results of my DCF and Regression Analysis methods. The CAPM incorporates the relationship between a security's investment risk and its market rate of return. The beta is an indicator of the relative volatility of the stock in question to the volatility of the market. The equation used to estimate the cost of equity is:

$$K = R_f + \beta(R_m - R_f)$$

Where, K = the cost of equity;

R_f = the risk free rate;

β = the beta coefficient; and

R_m = the expected return on the market.

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

A. The CAPM estimate was derived using the following inputs: the most recent six-month average 30-year treasury yield of 2.89% and the Value Line Betas for the comparable group of nine LDCs. For the expected return on the market, I relied on historical returns on the S&P 500 published by Duff and Phelps, LLC,[11] which have continued with the original data series by Ibbotson and Associates. The annual data of large company stock returns from 1926 through 2018 generated a 10.0% return using the geometric average, and 11.9% using the arithmetic return. These expected market returns produced a cost of equity of 9.10% using the arithmetic mean and 7.79% using the geometric mean shown in Exhibit JRH-7.

Q. **WHAT DO YOU CONCLUDE FROM YOUR CAPM?**

A. I conclude that the cost of equity arrived at using the CAPM provides a reasonable check on my results using the DCF model and the Regression Analysis of Approved ROEs. I believe the use of the geometric return, which measures the annualized rate of return compounded over time, is the more appropriate measure of investor expectations. This position is in step with the Security and Exchange Commission's requirements for publishing annualized compound total rates of return for mutual funds over 1, 5, and 10-year periods. However, I believe the 7.79% estimate is at the very low end, if not below, Piedmont's cost of equity. As such, these results provide a limited check on my recommended cost of equity.

Q. **WHAT IS YOUR RECOMMENDED COST OF EQUITY BASED ON YOUR STUDY?**

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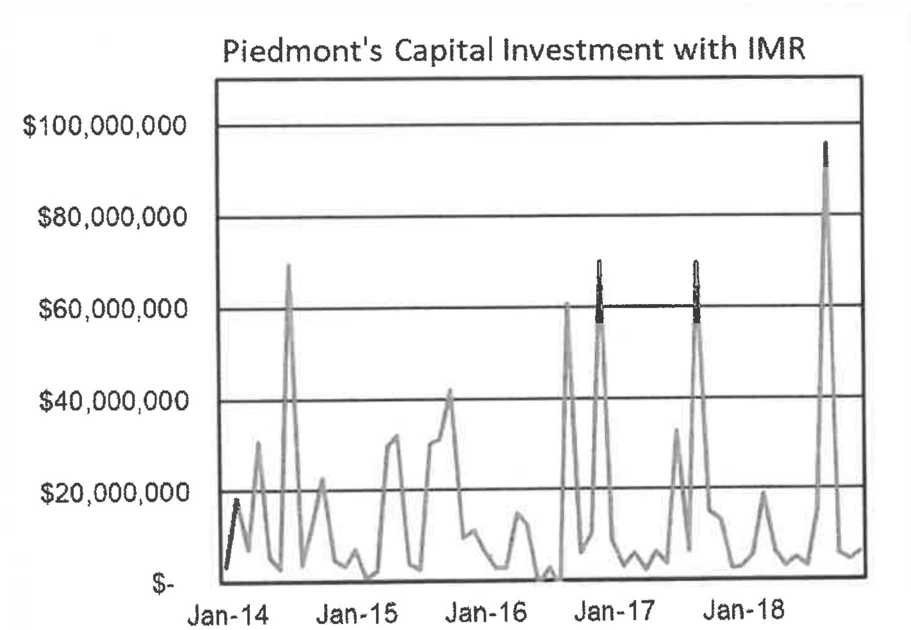
[11] 2019 SBBI Yearbook, Stock, Bonds Bills, and Inflation, 1926-2018, Exhibit 2.3.

A. The results of my DCF model indicate a cost of equity ranging from 9.25% using historical growth rates, to 8.63% using predicted growth rates, to 9.00% based on an average of all of the growth rates. I combined these results with a Regression Analysis result that indicates a cost of equity of 9.64%. The average of the four estimates produces an average cost of equity of 9.13%, which is central to a range of cost of equity estimates ranging from 8.63% to 9.64%. I further conclude that 9.13% is my single best estimate of the Company's cost of common equity, as summarized in Exhibit JRH-8.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN YOUR ASSESMENT OF THE REASONABLENESS OF YOUR RECOMMENDED RETURN?

A. In regard to reasonableness assessment, I considered the pre-tax interest coverage ratio produced by my cost of capital recommendation. Based on the recommended capital structure, cost of debt, and equity return of 9.13%, the pre-tax interest coverage ratio is approximately 3.6 times. These indicators of credit quality suggest that Piedmont has an adequate opportunity to continue to qualify for a single "A" bond rating.

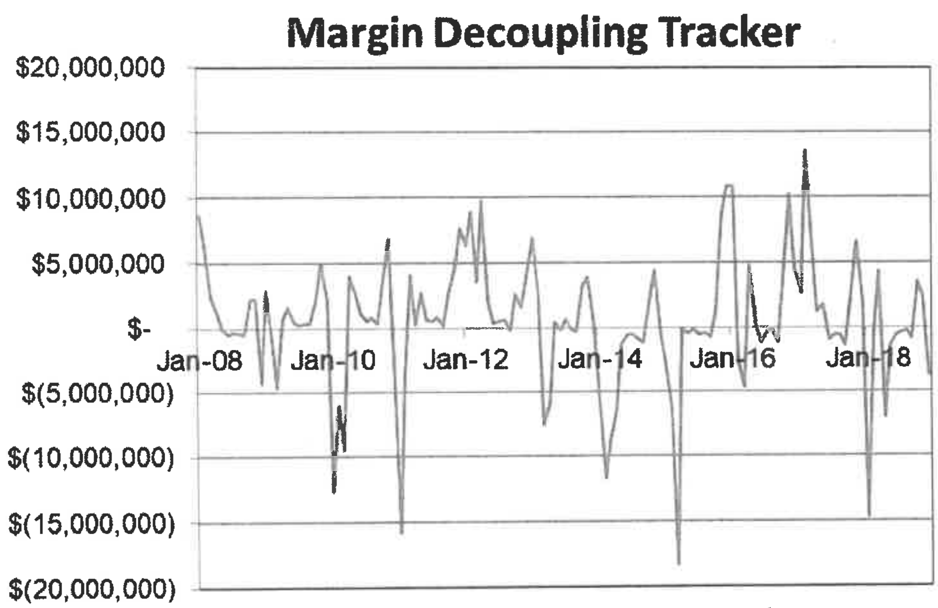
My reasonableness assessment acknowledges the continued role that the Integrity Management Rider (IMR) has in reducing regulatory lag which is seen as supportive regulatory policies by investors. The graph below shows the additional monthly revenue associated with the Company's IMR mechanism, which as of December 31, 2018 amounted to approximately $940 million in capital investment from the IMR.



I also considered the stabilizing impact on the residential and small commercial customers revenue and on the Company's earnings of the Company's Margin Decoupling Tracker (MDT) that was approved by the Commission in 2008 in Docket No. G-9, Sub 550.[12] In large part, the tracker was approved in view of the declining customer usage and to eliminate the Company's

[12] The Company had a similar mechanism named the Customer Utilization Tracker (CUT) that was approved in 2005 general rate case in Docket No. G-9, Sub 499.

disincentive to promote conservation. The Commission's Order[13] noted that the MDT would stabilize the Company's margin recovery and reduce the risk to Piedmont and its customers arising from potential variations in usage patterns. The graph below shows the historical impact of the revenue adjustments associated with the MDT.



Note: The MDT has produced an average annual increase in revenue of $ 5.7 million since 2008.

Q. TO WHAT EXTENT DOES YOUR RECOMMENDED RATE OF RETURN ON EQUITY TAKE INTO CONSIDERATION THE IMPACT OF CHANGING ECONOMIC CONDITIONS ON PIEDMONT'S CUSTOMERS?

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[13] See Commission's Order in Docket No. G-9, Sub 550, Finding of Fact No. 24, pages 18 and 19. The MDT affects rate schedules 101, 102, and 152.

A. I am aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate return on equity in setting rates for a public utility. Rather, the impact of changing economic conditions nationwide is inherent in the methods and data used in my study to determine the cost of equity for utilities that are comparable to Piedmont. I have reviewed certain information on the economic conditions in the areas served by Piedmont, specifically, the 2016 and 2017 data on the percent change in per capita personal income from the Bureau of Economic Analysis (BEA) and the Development Tier Designations published by the North Carolina Department of Commerce for Piedmont's service territory. The BEA data indicates that from 2016 to 2017, per capita total personal income grew at an annual growth rate of 3.9%, which is slightly higher than 3.5% for the whole state.

The North Carolina Department of Commerce annually ranks the State's 100 counties based on economic well-being and assigns each a Tier designation. The most distressed counties are rated a "1" and the most prosperous counties are rated a "3." The rankings examine several economic measures such as, household income, poverty rates, unemployment rates, population growth, and per capita property tax base. For 2019, the average Tier ranking for North Carolina counties in Piedmont's service territory was 1.8.

As discussed above, the Commission's duty is to set rates as low as reasonably possible consistent with constitutional constraints. This duty exists regardless of the customers' ability to pay. Moreover, the rate of return on common equity is only one component of the rates established by the Commission. N.C. Gen. Stat. § 62-133 sets out an intricate formula for the Commission to follow in determining a utility's overall revenue requirement. It is the combination of rate base, expenses, capital structure, cost rates for debt and equity capital, and capital structure that determines how much customers pay for utility service and how much investors receive in return for their investment. The Commission must exercise its best judgment in balancing the interests of both groups. My analysis indicates that my recommended rate of return on equity will allow the Company to properly maintain its facilities, provide adequate service to its customers, attract capital on terms that are fair and reasonable to its customers and investors, and will result in rates that are just and reasonable.

V. CONCERNS WITH COMPANY WITNESS HEVERT'S TESTIMONY

Q. HAVE YOU REVIEWED COMPANY WITNESS HEVERT'S TESTIMONY?

A. Yes. I disagree with his exclusive use of forecasted EPS in the DCF model, his estimate of the expected market return and the market premium used in his CAPM.

Q. WHY DO YOU DISAGREE WITH COMPANY WITNESS HEVERT'S EXCLUSIVE USE OF FORECASTED EARNINGS PER SHARE IN HIS DCF ANALYSIS?

A. Company Witness Hevert has focused entirely on five-year earnings per share (EPS) forecasted growth rates in estimating the long-term expected growth rate in dividends per share (DPS) for purposes of his DCF model. He has not given any weight to historical EPS growth rates. Nor has he given any weight to historical and forecasted DPS and BPS growth rates. While I have given primary weight to forecasted growth rates of EPS, DPS, and BPS, I have also given actual historical performance some weight in my recommendation. Consideration of DPS and BPS, along with EPS, provides a variety of growth measures instead of relying on just one measure. Given that at least one study has found that analysts' long-term earnings growth forecasts are no more accurate at forecasting future earnings than random walk forecasts of future earnings,[14] and that other studies have found that analyst's earnings forecasts tend to have an upward bias in their projections,

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[14] See Louis K.C. Chan, Jason Karceski, and Josef Lakonishok, "The Level and Persistence of Growth Rates, "Journal of Finance, April 2003.

I find it quite questionable that investors limit their investment decisions to forecasted growth rates in EPS. Company witness Hevert's DCF analysis is flawed because investors do not simply ignore the historical performance of stocks. While forecasts are generally based, in part, on a company's historical performance, it is quite a different argument to state that investors rely solely on forecasts of EPS and ignore past performance of dividends and book value.

In prior orders, this Commission has not been persuaded by rate of return witnesses who relied exclusively on forecasted growth rates in their use of the DCF model. The Commission's Order issued on December 30, 2003, in Docket No. P-100, Sub 133d, states on page 73, "The Commission is persuaded that investors consider a company's historical performance along with its forecasts when assessing its long-run growth potential." In that proceeding, BellSouth's witness Billingsley gave exclusive weight to security analysts' earnings per share forecasts compiled by Zacks Investment Research and the Institutional Brokers Estimate System, which is comparable to witness Hevert's use of earnings forecasts. This concern is applied to his DCF model and his CAPM's use of a market risk premium that relies on a results from DCF model on the 500 companies in the S&P500.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH COMPANY WITNESS HEVERT'S ESTIMATE OF THE EXPECTED MARKET RISK RETURN AND MARKET PREMIUM INCORPORATED IN HIS CAPM.

A. Company witness Hevert's CAPM model assumes that investors are currently requiring an expected risk premium of 10.65% that is based on an expected market return of 13.68%, as shown on Exhibit RBH-3, Page 1 of 14. Exhibit RBH-3, Page 8 of 14 shows an expected market return of 16.81% and a risk premium of 13.77%. These estimates of the expected market return are derived with earnings forecasts from Bloomberg Professional and Value Line as applied to the 500 firms that comprise the S&P 500.

In my opinion, Company witness Hevert's estimates of the expected returns on the S&P 500 of 13.68% and the 16.81% are unrealistic. The average growth rate for the 500 companies shown on Page 1 of his Exhibit calculates to a 10.81% growth rate. Similarly, the average growth rate for the 500 companies shown on Page 8 of his Exhibit calculates to a 13.68% growth rate. In my opinion, these growth rates of return are unsustainable within the long-term horizons of most investors. It stands to reason that no individual company within the S&P 500 could grow faster over the long-run than the growth of the general economy.[15] My opinion that Mr. Hevert's expected growth rates of the S&P500 is unsustainable is supported by commentaries from Christine Benz of Morningstar where she has collected forecasts of long-term rate of returns on stocks and bonds by BlackRock Investment Institute, John Bogle and J.P. Morgan: those well-known investment professionals are expecting a departure from history with lower future market returns on equity of 5% to 8%, as shown in Exhibit JRH-9.

VI. SUMMARY AND RECOMENDATION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING THE COST OF CAPITAL?

A. Based on the results of my study, it is my recommendation that the appropriate capital structure to employ for rate making purposes in this proceeding consists of 49.94% long-term debt, 0.85% short-term debt, and 49.21% common equity. The recommended cost of long-term debt is 4.41%, the cost of short-term debt is 2.72%, and the recommended cost of common equity of 9.13%. My recommended overall weighted cost of capital produced is 6.71%, as shown on Exhibit JRH-10.

[15] Id. at p. 649.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023 and the level of funding for nuclear decommissioning costs in Docket Nos. E-7, Sub 1026 and E-7, Sub 1146. I have filed testimony on the Integrated Resource Plans (IRPs) filed in Docket No. E-100, Subs 114 and 125, and I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual IRPs or IRP updates.

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings, filing testimony in Docket No. E-100, Subs 106, 136, 140, 148, and 158. I have filed a Statement of Position in the arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966.

I have filed testimony on the issuance of certificates of public convenience and necessity (CPCN) in Docket Nos. E-2, Sub 669, SP-132, Sub 0, E-7, Sub 790, E-7, Sub 791, and E-7, Sub 1134.

I have filed testimony on the issue of fair rate of return for electric utilities in Docket Nos. E-22, Sub 333; E-22, Sub 412; and E-22, Sub 532. I have filed testimony on credit metrics and the risk of a downgrade in Docket No. E-7, Sub 1146. The rate of return for telephone utilities in P-26, Sub 93; P-12, Sub 89; P-100, Sub 133b; and P-100, Sub 133d (1997 and 2002). The rate of return for natural gas utilities in G-21, Sub 293; P-31, Sub 125; G-5, Sub 327; G-5, Sub 386; G-9, Sub 351; and G-21, Sub 442. The rate of return for water utilities in W-778, Sub 31; W-218, Sub 319; W-354, Sub 360, and in several smaller water utility rate cases.

I have filed testimony on the hedging of natural gas prices in Docket No. E-2, Subs 1001 and 1018. I have filed testimony on the expansion of natural gas in Docket No. G-5, Subs 337 and 372. I performed the financial analysis in the two audit reports on Mid-South Water Systems, Inc., Docket No. W-100, Sub 21. I testified in the application to transfer of the CPCN from North Topsail Water and Sewer, Inc. to Utilities, Inc., in Docket No. W-1000, Sub 5. I have filed testimony on weather normalization of water sales in Docket No. W-274, Sub 160.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency. I have published an article in the National Regulatory Research Institute's Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

RISK MEASURES

SAFETY RANK[1]

Value Line's Safety Rank is a measure of the total risk of a stock. It includes factors unique to the company's business such as its financial condition, management competence, etc. The Safety Rank is derived by averaging two variables: the stock's Price Stability Index, and the Financial Strength Rating of the company. The Safety Rank ranges from 1 (Highest) to 5 (Lowest).

BETA[1] (ß)

The Value Line Beta is derived from a regression analysis between weekly percent changes in the price of a stock and weekly percent price changes in the New York Stock Exchange Composite Index over a period of five years.

There has been a tendency over the years for high Beta stocks to become lower and for low Beta stocks to become higher. This tendency can be measured by studying Betas of stocks in five consecutive intervals. The Betas published in the Value Line Investment Survey are adjusted for this tendency and hence are likely to be better predictors of future Betas than those based exclusively on the experience of the past five years.

The New York Stock Exchange Composite Index is used as the basis for calculating the Beta because this index is a good proxy for the complete equity portfolio. Since Beta's significance derives primarily from its usefulness in portfolios rather than individual stocks, it is best constructed by relating to an overall market portfolio. The Value Line Index, because it weights all stocks equally, would not serve as well.

The security's return is regressed against the return on the New York Stock Exchange Composite Index over the past five years, so that 259 observations of weekly price changes are used. Value Line adjusts its estimate of Beta (β_i) for regression described by Blume (1971). The estimated Beta is adjusted as follows:

$$\text{Adjusted } \beta_i = 0.35 + 0.67\beta$$

FINANCIAL STRENGTH RATING[1]

Value Line's Financial Strength Ratings are primarily a measure of the relative financial strength of a company. The rating considers key variables such as coverage of debt, variability of return, stock price stability, and company size. The Financial Strength Ratings range from the highest at A++ to the lowest at C.

PRICE STABILITY INDEX[1]

Value Line's Price Stability Index is based upon a ranking of the standard deviation of weekly percent changes in the price of a stock over the last five years. The top 5% carry a Price Stability Index of 100; the next 5%, 95; and so on down to an Index of 5.

EARNINGS PREDICTABILITY INDEX[1]

Value Line's Earnings Predictability Index is a measure of the reliability of an earnings forecast. The most reliable forecasts tend to be those with the highest rating (100); the least reliable (5).

S&P BETA[2] (ß)

The S&P Beta is derived from a regression analysis between 60 months of price changes in a company's stock price (plus corresponding dividend yield) and the monthly price changes in the S&P 500 Index (plus corresponding dividend yield). Prices and dividends are adjusted for all subsequent stock splits and stock dividends.

S&P BOND RATING[2]

The S&P Bond Ratings is an appraisal of the credit quality based on relevant risk factors. S&P reviews both the company's financial and business profiles. Shown below are the ratings:

AAA	An extremely strong capacity to pay interest and repay principal.
AA+	A very strong capacity to pay interest and repay principal.
AA	There is only a small degree of difference between "AAA" and "AA"
AA-	Debt issues.
A+	A strong capacity to pay interest and repay principal.

These A ratings indicate the obligor is more susceptible to changes in economic conditions than AAA" or "AA" debt issues.

BBB+ An adequate capacity to pay interest and repay principal.
BBB Economic conditions or changing circumstances are more likely to lead to a weakened capacity to pay interest and repay principal.
BB+ "BB" indicates less near-term vulnerability to default than other BB speculative issues.

However, these bonds face major ongoing BB uncertainties or exposure to adverse conditions that could lead to inadequate capacity to meet timely interest and principal payments.

S&P STOCK RANKING[2]

The S&P Stock Rankings is an appraisal of the growth and stability of the company's earnings and dividends over the past 10 years. The final score for each stock is measured against a scoring matrix determined by an analysis of the scores of a large and representative sample of stocks. Shown below are the rankings:

A+	Highest
A	High
A-	Above average
B+	Average
B	Below Average
B-	Lower
C	Lowest
D	In Reorganization
NR	Not rated

Moody's Bond Rating[3]

Moody's Bond Ratings is an appraisal of the credit quality based on relevant risk factors. Shown below are the ratings:

Aaa Obligations judged to be the highest quality and are subject to the very lowest level of credit risk

Aa Obligations judged to be the high quality and are subject to low level credit risk

A Obligations judged to be the upper medium grade and are subject to low credit risk

Baa Obligations judged to be the medium grade and are subject to moderate credit risk and may possess certain speculative characteristics

Ba Obligations judged to be speculative and subject to substantial credit risk

B Obligations are considered speculative and subject to high credit risk.

Sources:
[1.] Value Line Investment Analyzer, Version 3.3, New York, NY.
[2.] S&P Net Advantage and S&P Global Market Intelligence, July, 2019
[3.] Moody's Investor Service, Rating Symbols and Definitions, February, 2019

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

SETTLEMENT TESTIMONY OF JOHN R. HINTON
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

August 12, 2019

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

A. My name is John R. Hinton. My business address is 430 N. Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am Director of the Economic Research Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. **ARE YOU THE SAME JOHN R. HINTON THAT FILED DIRECT TESTIMONY AND EXHIBITS ON RATE OF RETURN ON JULY 19, 2019?**

A. Yes, I am.

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

A. The purpose of my settlement testimony is to support the stipulation between Piedmont Natural Gas Company, Inc. (Piedmont or the Company) and the Public Staff (Settlement), as it relates to the cost of capital to be used in setting rates in this proceeding.

Q. WHAT IS THE COST OF CAPITAL IN THE SETTLEMENT?

A. The Public Staff and the Company have agreed to a 7.14% cost of capital in this proceeding. The overall cost rate is comprised of a 9.70% rate of return on common equity (ROE), a 2.72% cost rate of short-term debt, a 4.41% cost rate of long-term debt which is combined with a capital structure consisting of 52.00% common equity, 0.85% short-term debt, and 47.15% long-term debt.

Q. WHAT IS YOUR EXPERIENCE WITH AND UNDERSTANDING OF SETTLEMENTS IN SIMILAR GENERAL RATE CASE PROCEEDINGS?

A. It has been my experience that settlements are generally the result of good faith "give and take" and compromise-related negotiations among the parties to utility rate proceedings. Settlements, as well as the individual components of the settlements, are often achieved by the respective parties' agreements to accept otherwise unacceptable individual aspects of individual issues in order to focus on other issues. Settlements sometimes result in a "global" resolution of all the issues that would otherwise be litigated in a rate proceeding, and are sometimes restricted to resolution of one or more individual issues. The Settlement in this proceeding is global with respect to the contested issues identified by the Public Staff.

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

A. Yes, I participated in the negotiations leading up to the Settlement.

Q. PLEASE COMMENT ON THE SETTLEMENT CAPITAL STRUCTURE AND HOW IT DIFFERS FROM YOUR ORIGINALLY FILED POSITION.

A. The Settlement recommendation of 52.00% for the equity ratio contains more equity than I recommended in my previously filed testimony. In large part, the difference between my recommended capital structure and that of the Company witnesses relates to the inclusion of current maturities of long-term debt that is retiring within 12 months. Another difference is that my recommended capital structure takes into account the impact of the $300 million equity infusion from Duke Energy Corporation which increased the monthly balances of common equity. While I believe the regularity of current maturities shown in Page 2 of Exhibit JRH-2, as well as, the Company's historical capitalization demonstrate that this form of capital should be considered as permanent capital for ratemaking, I maintain that the Settlement capitalization ratios are reasonable.

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

A. Yes I do. As with other settlements, the Settlement cost of capital components in this proceeding represent a compromise by both parties in an effort to reach agreement. Furthermore, the Settlement cost of capital components are the result of good faith negotiations and compromises.

I note that it remains my position that, should this be a fully litigated proceeding, I would continue to recommend a capital structure with 49.21% common equity, 0.85% short-term debt, and 49.94% long-term debt, a ROE of 9.13%, a cost of short-term debt of 2.72%, and a cost of long-term debt of 4.41%. However, given the benefits associated with entering into a settlement, it is my view that the cost of capital components of the Settlement are a reasonable resolution of otherwise contentious issues.

Q. PLEASE EXPLAIN WHY THE PROPOSED CAPITAL STRUCTURE RATIO IS REASONABLE.

A. The average common equity ratio for natural gas utilities approved from the start of January 1, 2016, to June 30, 2019, is 51.47%[1] which is supportive of the Settlement common equity ratio. The Settlement capitalization ratios include a 0.85% ratio of short-term debt capital

[1] This calculation excludes the decisions of four states – Arkansas, Florida, Indiana, and Michigan – because these jurisdictions include deferred taxes and other non-capital items in the approved capital structure. As such, the approved equity ratios are not comparable to North Carolina ratemaking and will bias the average equity ratio downward.

that is reflective of the Company's balance of gas inventory and a 47.15% ratio of long-term debt.

Q. DOES THE SETTLEMENT CAPITAL STRUCTURE COMPORT WITH CAPITAL STRUCTURES APPROVED BY THIS COMMISSION IN RECENT RATE CASES?

A. Yes, the last natural gas rate case was the 2016 Public Service Company of North Carolina, Inc. (PSNC), rate case where the North Carolina Utilities Commission (Commission) approved a capital structure containing 52.00% common equity. In addition, recent Commission-approved common equity ratios for other regulated utilities support the reasonableness of the Settlement common equity ratio, as shown below:

Company	Docket	Order Date	NCUC Approved Equity Ratio
PSNC	G-5, Sub 565	10/26/2016	52.00%
DENC	E-22, Sub 532	12/22/2016	51.75%
DEP	E-2, Sub 1142	2/23/2018	52.00%
DEC	E-7, Sub 1146	6/22/2018	52.00%

Q. PLEASE COMMENT ON THE SETTLEMENT, PARTICULARLY AS IT RELATES TO THE RATE OF ROE.

A. The Company and Public Staff have fundamentally different views of current market conditions and the current cost of capital. Neither party convinced the other to change its view of the cost of capital issues, but the Public Staff and Piedmont have found a way to bridge their differences which results in a reasonable Settlement ROE.

Q. HOW DOES THE SETTLEMENT 9.70% ROE COMPARE TO THE RESULTS OF THE ANALYTICAL MODELS USED BY YOU AND BY THE COMPANY?

A. The Settlement ROE of 9.70% is slightly higher than the upper end of my range of estimated cost rates for common equity of 8.63% to 9.64%, as shown in Exhibit JRH-8 to my originally filed testimony. Likewise, the Settlement 9.70% ROE is noticeably lower than the lower end of the Company's recommended range of 10.00% to 11.00%.[2] The impact of the compromises can be seen through the Company's revenue requirement which increases by $1.4 million when the ROE increases from 9.64% to 9.70%; as compared to a decrease of $7.1 million when the Company's original 10.00% ROE proposal is decreased to 9.70%.

Q. HOW DOES THE SETTLEMENT 9.70% ROE COMPARE WITH ROEs APPROVED BY OTHER PUBLIC UTILITY COMMISSIONS AND RECENT DECISIONS BY THIS COMMISSION?

A. The most recently published average ROE for natural gas utilities for the first half of 2019 is 9.63%[3], which is supportive of the Settlement. The approved median ROE in these same 2019 cases is 9.70%.

[2] Docket No. G-7, Sub 743, Prefiled Direct Testimony of Robert B. Hevert, page 4.
[3] S&P Global Market Intelligence, RRA Regulatory Focus, July 22, 2019.

However, one cannot make a simple comparison of approved ROEs with public utility commissions without consideration of the inherent risks within the type of utility, rates of returns available from other comparable risk investments, and other considerations that may warrant a ROE premium or discount. The following table contains ROEs recently approved by the Commission in natural gas and electric utility general rate cases in combination with the average ROEs as reported in RRA Regulatory Focus Major Rate Case Decisions. Given that the investor risk profiles of PSNC and Piedmont are very comparable, more weight should be ascribed to this decision. As such, the two basis point spread between the Commission's approved ROE with PSNC's 2016 rate case and the 2016 fourth quarter average ROE of 9.68% is close to the seven basis point spread from this Settlement 9.70% ROE and the 9.63% average natural gas utility ROE approved thus far in 2019.

Company	Docket	Order Date	NCUC-Approved ROE	RRA's Average ROE	Basis Point Spread
PSNC	G-5, Sub 565	10/26/2016	9.70%	9.68%[4]	2
DENC	E-22, Sub 532	12/22/2016	9.90%	9.77%[5]	13
DEP	E-2, Sub 1142	2/23/2018	9.90%	9.68%[5]	22
DEC	E-7, Sub 1146	6/22/2018	9.90%	9.68%[5]	22

[4] S&P Global Market Intelligence, RRA Regulatory Focus, July 29, 2019, average ROE for gas utilities for fourth quarter 2016.

[5] S&P Global Market Intelligence, RRA Regulatory Focus, January 31, 2019, annual average ROE for vertically electric utilities.

Q. IS THE 9.70% ROE AND THE 52.00% EQUITY RATIO A REASONABLE RESULT?

A. Yes. The Settlement 7.14% overall cost of capital is reasonable as shown in Settlement Exhibit JRH-1. The higher percentage of equity capital and the higher ROE contribute to increasing the pre-tax interest coverage ratio to 4.1. As previously noted, the Settlement overall cost of capital represents a reasonable middle ground between the original positions of the Public Staff and the Company. In addition, the agreement on the Settlement 9.70% ROE and on capital structure occurred in the context of various other compromises by both parties on other issues.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes, it does.

Q. Mr. Hinton, have you prepared a summary of your testimony?

A. Yes, I have.

Q. Would you please read it?

A. Yes. The purpose of my --

Q. Just one second, Mr. Hinton, my apologies.

(Summary handed out.

Q. Mr. Hinton, would you please read your testimony -- your summary, excuse me?

A. The purpose of my testimony in this proceeding is to present to the Commission my findings as to the reasonable cost of capital to be used as a basis for adjusting Piedmont's rates. As a result of my cost of capital study described in my direct testimony filed on July 19, 2019, and my settlement testimony filed on August 12, 2019, I conclude that the overall cost of capital to Piedmont is 7.14 percent.

My direct testimony recommended a capital structure compromise of 49.21 percent common equity, 0.85 percent short-term debt, and 49.94 percentage of long-term debt, where the balance of long-term debt included the amount of long-term debt that was coming due during the next 12 months. My testimony reveals the regularity of the Company's use of current maturities of long-term debt. As shown in my Exhibit JRH-2, 12 of the 13 months have a significant balance of current maturities and, in my opinion, this represents an ongoing use of debt capital and should be included for ratemaking purposes.

The stipulated capital structure is comprised of 52.00 percent common equity, 0.85 short-term debt, and 47.15 long-term debt. While this level of common equity is greater than I previously recommended, the stipulated level is reasonable when compared to recently approved common equity ratios for other local gas distribution companies. Furthermore, the 52 percent ratio is comparable to other common equity ratios approved by the North Carolina Utilities Commission.

In addition to the cost of rates for the long-term debt and the short-term debt, which were not controversial, the parties have stipulated to a 9.70 percent rate of return on common equity.

My direct testimony recommended a 9.13 percent cost of rate for common equity that was derived with the results from my DCF analysis, which ranged from 8.63 percent to 9.25 percent, and my regression analysis of approved ROE of 9.64 percent.

My settlement testimony notes the stipulated 9.7 ROE is slightly higher than my upper end of my estimated ROEs, and noticeably lower than the lower end of the cost of equity estimate by the Company's witness Robert Hevert. In support of the stipulated ROE, I cite a recent report that identifies that the average ROE for LDCs over the first half of 2019 is 9.63 percent. Furthermore, I note that the stipulated 9.7 percent ROE is similar to other ROEs recently approved by the NCUC and the rate is the product of compromise and good faith negotiations. This concludes my summary.

MR. CREECH: Chair, the witness is available for cross examination and questions from the Commission.

COMMISSIONER BROWN-BLAND: Okay. Any cross examination for this witness?

MR. JEFFRIES: No.

COMMISSIONER BROWN-BLAND: Questions from the Commission?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Hinton, I have just one. In terms of your recommended 9.13 --

A. 9.14, yeah.

Q. -- cost rate for common equity, your range was 8.63 to 9.25. If you could just summarize, briefly, the factors that led you to the 9.13.

A. Yes. In my testimony, there's an exhibit where I kind of summarize my results. Let me go to it real quick. I think it's Number 7. No, it's Exhibit GRH-8. In that exhibit there, I kind of lay out the math I used to come to that decision, where I lean heavily on the DCF method and the risk premium method, and I just took a raw average of that, which, to me, represented a reasonable -- a measure of central tendency. And I thought 9.13 was a reasonable number to use.

Q. How did you decide on that as the reasonable number, you know, in your professional opinion -- professional expertise and judgment, as opposed to somewhere else along the spectrum of your range?

A. Over the years I've put forth for the Commission, a DCF model and a risk premium analysis.

COURT REPORTER: I'm sorry, could you speak into the microphone?

THE WITNESS: Yes. Over the years, I've put forth -- this has been a core method that I've used. And it often is the case, not always the case, but the DCF numbers will be in this range, and the risk premium analysis would be slightly to the up end of that range. And I use a single-point estimate. The only difference between me and Mr. Verts' [sic] risk premium analysis, he uses -- leans on four interest rates, and he gets a much higher regression analysis.

My opinion is that current interest rates are the best predictor of short -- of forecast interest rates, as noted in my testimony. So I use those two methods to set the parameters. And then, within that, I just, again, took an average of it. But, I mean, I lean heavily on the DCF, but I also like to look at the risk premium, because that is the method that, in many ways, reflects decisions by Commissions. And these decisions are made, as the one here today, we have one side arguing for one ROE and the other side arguing for another ROE. And in the middle, or somewhere in between, there's usually truth.

And I find that, over time, you look at decisions by various DUCs, and on average, I think that's a true indicator of a true cost of equity. And when I say true, I mean that mystic source of knowledge that we're all searching for.

Q. Did you have a substantial difference of opinion in the methods used and explanations given by Witness Woolridge?

A. No. I had issues with his adjustment to reduce his ROE based on different composition ratios. I feel that method is somewhat tenuous, because relationship to a capital structure and ROE is -- I mean, obviously, if you have more equity in your capital structure, you have less risk, but it's not -- the relationship is not as granular as you might want to think it is. So when he made his transition to recommend the lower end of his ROE range, I could not accept that.

I mean, it's not unreasonable, because my lower number is 8.63, but that was has high number, that was his recommended number. So I have concerns with his range being in the lower end of the scale. I think it reflects -- he would determine it as the required return -- rate of return -- the minimum required rate of return. And there's reason within that range, parameters, have you've seen over the years before us, before you, of witnesses.

Q. Thank you, Mr. Hinton.

COMMISSIONER BROWN-BLAND: Any questions

on Commission's questions?

COMMISSIONER MITCHELL: I have a question.

COMMISSIONER BROWN-BLAND: Excuse me. Chair Mitchell.

EXAMINATION BY CHAIR MITCHELL:

Q. Good afternoon. Just one question for you.

You were in the room when Dr. Woolridge provided testimony, were you not?

A. Yes.

Q. Okay.

A. I stepped out for one moment to take care of an errand, but I think I was here for the majority of it.

Q. Okay. Well, he testified, as I understood, that historically low bond yields and high utility stock prices, at this moment in time, result in capital cost being at record lows for public utilities. That's the way I understood one of his -- that's how I understood one of his primary points.

Do you agree with that opinion? Can you --

A. I hate to ask you, say it one more time what you think he said.

Q. Historical low --

A. I think market-to-book ratio was real -- is high is what he was getting at, correct?

Q. Well, he said historically low bond yields -- and it's actually in his testimony summary if you want to refer to it, but it's -- he says historically low bond yields and high stock prices result in capital costs being at record lows for public utilities at this moment in time.

Do you agree with that?

A. Not necessarily, because to say it -- when you accent the word "this moment in time" --

Q. Those were my words. That's not in his, but that's how I understood it. The circumstances as we find ourselves in them right now.

A. I mean, obviously, if yields come down, the cost of capital come down -- and that is the heart of my risk premium analysis or regression analysis, because I base it on current -- what I believe is current cost of debt, which I use a six-month average. And if I updated my average today, it would go from 964 to 960.

So there is a relationship there between the cost of capital and the bond yields. There obviously is. They move in tandem. I think investors see utility stocks as a substitute for a bond, because they both have a lot of the risk -- lowering the risk from their perspective. But there's growth in utility stock, and so -- and the point I'm trying to say is that, there is a relationship there, but the art of the deal is how to quantify that relationship. So, in general, of course, I agree with him.

Q. Thank you.

CHAIRPERSON BROWN-BLAND: All right. Questions on Commission's questions?

Ms. Force?

MS. FORCE: I have a couple of clarifying questions, please.

CROSS EXAMINATION BY MS. FORCE:

Q. I think I heard you say that Dr. Woolridge's range is 7.60 to 8.70; is that right, in his analysis?

A. I don't know if I knew what his range was.

Q. Do you have his testimony?

A. No, I don't.

Q. On page 2 of his testimony --

A. I don't have his testimony. Just tell -- go ahead. I don't have his testimony on me.

Q. I'd submit to you that the results of Dr. Woolridge's DCF analysis was 8.70. The result of his capital asset pricing model was 7.60.

Does that sound right to you?

A. Yes, it does.

Q. And that was the basis for the range of calculation using his models?

A. Okay.

Q. I just want to clarify the record. You said that he had a different range than that?

A. I'll accept that.

Q. Okay. And one other question.

When you were talking about your risk premium analysis --

A. Yes.

Q. -- and you're talking about looking at the bond yield and using a different interest rate -- or, excuse me, a different measure than what Mr. Hevert used for that, because you used the current rate instead of forecasted, right?

A. Correct.

Q. And your comparison, though, my point is, is to the authorized rates of return when you do that; isn't that right?

A. That's what I used and so did Mr. Vert use that, too, as well.

Q. Thank you. That's all.

COMMISSIONER BROWN-BLAND: Okay. All right. I will entertain motions.

MR. CREECH: Thank you, Madam Chair. I'd move that prefiled exhibits of witness Hinton be entered into evidence.

COMMISSIONER BROWN-BLAND: That would be Exhibit JRH-1 through 10?

MR. CREECH: Correct.

COMMISSIONER BROWN-BLAND: And then his one exhibit that was filed with the settlement testimony, correct?

MR. CREECH: Correct, please.

COMMISSIONER BROWN-BLAND: All right. That motion will be allowed, and those exhibits will be received into evidence.

(Exhibits JRH-Plaintiff's through JRH-10 and Settlement Exhibit JRH-1 were admitted into evidence.)

COMMISSIONER BROWN-BLAND: Mr. Hinton, you may be excused. Thank you.

MS. CULPEPPER: Public Staff calls Julie G. Perry.

JULIE G. PERRY,

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

DIRECT EXAMINATION BY MS. CULPEPPER:

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

A. My name is Julie G. Perry. My business address is 430 North Salisbury Street, Raleigh, NC. My position is accounting manager of natural gas and transportation in the Public Staff county position.

Q. On July 19, 2019, did you prepare and cause to be filed in this docket testimony consisting of 25 pages, Perry Exhibits 1 and 2 and an appendix?

A. I did.

Q. On July 26, 2019, did you prepare and cause to be filed Revised Perry Exhibits 1 and 2?

A. I did.

Q. Do you have any corrections to your testimony?

A. I do.

Q. We're going to pass a handout. It's kind of a complicated correction.

A. On page 11 of my testimony -- I'll wait until you have it. I cited the wrong company and docket. So that makes a little difference.

Q. Okay. Would you go ahead and address your correction?

A. Yes, ma'am. On page 11 of my testimony, line 16, the sentence should read, "This amortization period is consistent with the amortization period recommended by the Public Staff in Duke Energy Carolina's most recent general rate case in Docket Number E-7, Sub 1146."

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

A. Yes, they would.

MS. CULPEPPER: I move that Ms. Perry's prefiled testimony as corrected consisting of 25 pages and one appendix be copied into the record as given orally from the stand, and that Revised Perry Exhibits 1 and 2 be identified as marked when filed.

COMMISSIONER BROWN-BLAND: That motion will be allowed, and the prefiled testimony will be received into the record as evidence, and the exhibits marked as they were when prefiled.

(Revised Perry Exhibits Plaintiff's and 2 were marked for identification.)

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

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF JULIE G. PERRY
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2019

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

A. My name is Julie G. Perry. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Accounting Manager for Natural Gas and Transportation with the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. PLEASE BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth 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 state Excess Deferred Income Taxes (EDIT), federal protected EDIT, federal unprotected EDIT, and the deferred revenues associated with the overcollection of taxes since January 1, 2018, due to changes in the federal tax rate applicable to Piedmont Natural Gas Company, Inc. (Piedmont or the Company).

I am also providing testimony regarding plant investment related to the Atlantic Coast Pipeline project (ACP), the Integrity Management Rider (IMR) mechanism and tariff, a special contract adjustment, the non-utility adjustment in this case, and my concerns regarding service company cost allocations.

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 Piedmont. The Public Staff has also conducted extensive discovery in this matter, performed an on-site audit, reviewed responses provided by the Company in response to the Public Staff's numerous data requests, and participated in conference calls with the Company.

Q. PLEASE DESCRIBE YOUR EXHIBITS.

A. My exhibits are as follows:

- Perry Exhibit I, Schedule 1 presents the tax adjustments to rate base for treatment as a Rider.

- Perry Exhibit I, Schedule 2 presents the calculation of the effects of federal protected EDIT on the Company's rate base and income statement.
- Perry Exhibit I, Schedule 3 sets forth the calculation of the federal unprotected EDIT Rider to be in effect for five years.
- Perry Exhibit I, Schedule 3(a) sets forth the calculation of the unprotected EDIT Rider annuity factor.
- Perry Exhibit I, Schedule 4 sets forth the calculation of the state EDIT Rider, which the Public Staff recommends be refunded in two years.
- Perry Exhibit I, Schedule 4(a) sets forth the calculation of the state EDIT Rider annuity factor.
- Perry Exhibit II, Schedule 1 sets forth the calculation of the non-utility adjustment for O&M expenses and general plant items.
- Perry Exhibit II, Schedule 2 sets forth the calculation of the Atlantic Coast Pipeline plant regulatory asset rate base and O&M expense impact.

TAX CUTS AND JOBS ACT EFFECTS

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSAL TO ADDRESS THE EFFECTS OF THE TAX CUTS AND JOBS ACT (TAX ACT)?

A. Yes.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSAL?

A. The Company has proposed an EDIT Rider to return to ratepayers (1) federal EDIT and (2) overcollected revenues that have accrued since January 1, 2018, both of which are related to the federal tax rate decrease provision of the Tax Act, and state EDIT resulting from various state income tax changes.

Q. WHAT ARE THE DIFFERENCES BETWEEN THE COMPANY'S AND THE PUBLIC STAFF'S PROPOSALS TO ADDRESS THE EFFECTS OF THE TAX ACT AND THE STATE TAX CHANGES?

A. The Company and the Public Staff differ as to (1) whether to remove protected federal EDIT from base rates and include them in a rider, (2) the rate at which unprotected federal EDIT should be flowed back to ratepayers, (3) the rate at which the overcollection (since January 1, 2018) of federal taxes due to the decrease in federal tax rates should be flowed back to ratepayers, (4) the rate at which state EDIT should be flowed back to ratepayers, and (5) which proposed federal EDIT Rider mechanism is appropriate.

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S GENERAL CONCERNS REGARDING PIEDMONT'S PROPOSED EDIT RIDER.

A. Piedmont has proposed an EDIT Rider that contains the following categories of refunds for customers:

(1) Federal EDIT – Protected

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

(3) State EDIT

(4) Deferred Revenue from Tax Act Overcollections

The Public Staff notes that Piedmont has not made an adjustment to exclude any EDIT from rate base, but instead proposes to handle each of the categories above in one, single Rider with rate changes occurring each year based on the proposed amortizations for these categories, which range from 52.9 years to 3 years. The Public Staff believes that the four categories of refunds listed above should be handled in separate Riders due to the differing natures of the amounts and the amortization periods. We believe that this provides a more transparent means of tracking the Tax Act and state tax-related refunds to customers for each year.

FEDERAL EDIT:

Q. PLEASE EXPLAIN WHAT IS MEANT BY PROTECTED AND UNPROTECTED FEDERAL EDIT.

A. The federal EDIT consist of two categories, protected and unprotected EDIT. 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 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 IRC Section 203(e).

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO PROTECTED FEDERAL EDIT?

A. The Company has calculated the known and measurable refund of protected EDIT based on Internal Revenue Service (IRS) normalization rules, as required by the Tax Act. The Company's proposed EDIT Rider would amortize its protected EDIT balance over a period of 52.9 years.

Q. PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT TO PROTECTED FEDERAL EDIT.

A. I have made an adjustment to remove the protected federal EDIT from the EDIT Rider proposed by the Company and to instead leave the amount in base rates. I did this because the Company's calculation of the net remaining life of the timing differences results in an extremely long life due to the timing differences that gave rise to the excess. The Public Staff proposes to amortize the protected EDIT balance over 52.91 years in base rates and to remove the first year of amortization from the deferral amount for purposes of this proceeding. Perry Exhibit I presents the impacts of including the protected federal EDIT in rate base and the income statement. Public Staff witness Jayasheela's Exhibit I depicts the impact of the adjusted protected federal EDIT as shown on Perry Exhibit I.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO UNPROTECTED FEDERAL EDIT?

A. The Company artificially created two categories of unprotected federal EDIT, namely, "unprotected, PP&E [Property, Plant, and Equipment] related" and "unprotected, non PP&E related." The Company asserts that because the "unprotected PP&E related" EDIT is similar in nature to protected EDIT (which is also related to PP&E), it is reasonable to return it to ratepayers over the same time period that it would have been paid to the IRS had the Tax Act not been enacted.

In its proposed EDIT Rider, the Company seeks to amortize its "unprotected, PP&E related" EDIT balance over 20 years, and its "unprotected, non PP&E related" balance over 5 years. The Company acknowledges, however, that the Commission has the discretion to flow back all of the unprotected EDIT over any time period it deems appropriate.

Q. DO YOU AGREE WITH THE COMPANY'S CHARACTERIZATION OF UNPROTECTED FEDERAL EDIT AND ITS PROPOSAL TO FLOW BACK THOSE FUNDS TO RATEPAYERS?

A. I do not agree with the Company's characterization of its unprotected federal EDIT as "unprotected, PP&E related" and "unprotected, non PP&E related." The IRS tax normalization rules are very clear – EDIT is either protected, or it is not. The EDIT that the Company designates as "unprotected, PP&E related" is clearly still unprotected under IRS rules, a fact conceded by the Company. The Company's assertion that it should return this "unprotected, PP&E related" EDIT over the same period of time it would have paid the funds to the IRS had the Tax Act not been passed is not supported by any accounting or ratemaking principle, and should not dictate the Commission's decision as to what is a reasonable amount of time over which to return these funds to ratepayers. These funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible. It should be noted that the Company will continue to collect accumulated deferred income taxes (ADIT) at a tax rate sufficient to meet its tax obligations.

Q. PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT TO UNPROTECTED FEDERAL EDIT.

A. I recommend removing the entire EDIT regulatory liability associated with the unprotected differences from rate base and placing it in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs.

The immediate removal of unprotected federal EDIT from rate base increases the Company's rate base and mitigates regulatory lag that might result from refunds of unprotected EDIT not being contemporaneously reflected in rate base. Furthermore, removing the total amount of the unprotected federal EDIT credit from rate base in the current case provides the Company with an increase in rates to moderate any cash flow issues that arise. The financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Q. WHY DOES THE PUBLIC STAFF RECOMMEND A FIVE-YEAR AMORTIZATION FOR UNPROTECTED EDIT?

A. The Public Staff believes that a five-year period would increase rate stability for ratepayers during the flowback period. While a shorter rider would flow the money back to ratepayers more quickly, it would also result in a larger de facto rate increase when the rider expired at the end of the amortization period. A five-year rider would smooth the rate impact and result in a significantly smaller increase after the rider expires. Additionally, the levelized rider would include a return, thus ensuring that ratepayers are made whole.

The Company has raised concerns regarding impact of the flowback on its cash flow, which it speculates could negatively impact its credit metrics. While the Public Staff does not agree that the Commission should allow those concerns to determine its actions in this case, given the lack of specific evidence of likely harm to the ratepayers presented by the Company, a five-year rider would give the Company additional time over which to manage any cash flow issues. This amortization period is consistent with the amortization period approved by the Commission in the most recent Carolina Water Service general rate case in Docket No. W-354, Sub 360.

<u>OVERCOLLECTION OF FEDERAL TAXES</u>:

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO ITS OVERCOLLECTION OF FEDERAL INCOME TAXES SINCE JANUARY 1, 2018?

A. The Company proposes to refund to ratepayers the overcollection of federal taxes (from January 1, 2018, through March 31, 2019), which resulted from the Tax Act's reduction of federal tax rates, over a three-year period. Piedmont has been accruing interest on these funds calculated at the net of tax overall rate of return since January 1, 2018.

Q. WHAT IS YOUR RECOMMENDATION REGARDING HOW THE COMPANY SHOULD REFUND THE OVERCOLLECTION OF FEDERAL TAXES DUE TO THE TAX ACT?

A. I recommend that Piedmont refund the amount plus interest as of November 1, 2018, the proposed effective date of rates in the current docket, over a one year period. The Public Staff has removed the Company's credit balance from the working capital schedules because we are recommending that the amount be refunded over one year.

Q. WHY DOES THE PUBLIC STAFF RECOMMEND A ONE YEAR AMORTIZATION PERIOD FOR THE OVERCOLLECTION OF REVENUE DUE TO THE FEDERAL INCOME TAX CHANGE?

A. The Public Staff's recommended amortization period is consistent with Commission Orders in both Cardinal Pipeline, Docket No. G-39, Sub 42, and Dominion Energy North Carolina, Docket No. E-22, Sub 560, [tax dockets], in which the Commission approved a one-year time period or a one-time bill credit over which to flow back the overcollection of revenues to ratepayers due to the federal income tax change. We believe that this amortization period represents a reasonable and consistent methodology and should be approved for Piedmont as well.

STATE EDIT:

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO STATE EDIT?

A. Piedmont has proposed to refund the state EDIT resulting from the various state income tax changes to ratepayers over a five-year period.

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO STATE EDIT.

A. I am recommending an adjustment to the amortization period proposed for the state EDIT in this case. Specifically, I recommend removing the entire EDIT regulatory liability associated with the state EDIT differences from rate base, and placing it in a rider to be refunded to ratepayers over a two- year period on a levelized basis, with carrying costs. The immediate removal of state EDIT from rate base increases the Company's rate base, and mitigates regulatory lag that might occur from refunds of state EDIT not being contemporaneously reflected in rate base. As with my proposed adjustment to unprotected federal EDIT, removing the total amount of the state EDIT credit from rate base in the current case provides the Company with an increase in rates to moderate any cash flow issues that may occur.

Q. WHY DID THE PUBLIC STAFF RECOMMEND A TWO-YEAR AMORTIZATION PERIOD FOR STATE EDIT?

A. The Public Staff's recommended amortization period is consistent the Commission orders in the most recent general rate case for both Public Service Company of North Carolina, Inc. (PSNC), Docket No. G-5, Sub 565 and Dominion Energy North Carolina, Docket No. E-22, Sub 532, in which the Commission approved a one year flowback and a two-year flowback of State EDIT to ratepayers, respectively. We believe that this amortization period represents a reasonable and consistent methodology and should be approved for Piedmont as well.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS REGARDING THE DEFERRED REVENUES WORKING CAPITAL ADJUSTMENT?

A. Yes. On March 25, 2019, the Commission issued its Order Approving Proposal and Application and Requiring Filing of Revised Tariffs in Docket Nos. M-100, Sub 148, G-9, Sub 731, and G-9, Sub 737 (Sub

148 Order). Regarding the deferral and refunding of the overcollection of revenues from the federal tax change. In the Sub 148 Order, the Commission stated:

> The Commission agrees with Piedmont that no legal justification has been presented to allow the Commission to require Piedmont to allocate tax savings attributable to special contract customer revenues to Piedmont's base rate customers. As Piedmont noted, the rates set for the special contracts are fixed and cannot be adjusted to reflect the tax savings attributable to the special contract revenues. Further as noted by Piedmont, under its proposal, its base rate customers will receive <u>all</u> of the tax savings associated with the revenues those customers generate but will not receive the tax savings associated with the revenues generated by special contracts.

(Sub 148 Order, p 9) (emphasis in original).

The Commission stated that its decision should not be considered precedential in any way, and that its decision was based solely on the comments filed by the parties in these specific dockets. The Commission found it appropriate to direct Piedmont to preserve any EDIT created by the reduction in the North Carolina corporate income tax rate in a regulatory liability account for disposition in this general rate case proceeding. Piedmont was, therefore, allowed to retain approximately $4.9 million of the overcollection from the federal income tax change attributable to the special contract customers. I have made an adjustment to reflect this amount as a cost-free capital item in working capital because Piedmont collected this money from ratepayers and has not been ordered to refund it.

IMR MECHANISM AND TARIFF

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE IMR MECHANISM?

A. In its 2018 Annual IMR Report in Docket No. G-9, Sub 734, the Public Staff stated that the spreadsheet model used to calculate the Integrity Management Revenue Requirement (IMRR) is unnecessarily complex, that further changes to the IMRR model may be advisable, and that any necessary changes should be addressed in Piedmont's next general rate case.

As discussed in both its 2017 and its 2018 Annual IMR Reports, the Public Staff stated that it had ongoing concerns about the Company's calculation of its IMR rate base components and the degree to which application of these methodologies may result in an overstatement of the Company's IMRR. The Public Staff stated that it intended to work with Piedmont to address the following areas during its upcoming general rate case:

(a) Accumulated Depreciation: The current model uses average balances, versus end-of-period balances, to calculate the rate base offset against IMR assets.

(b) Deferred Tax Liabilities: The current model uses average balances, versus end-of-period balances, to calculate the ADIT impact on IMR rate base. Furthermore, the Public Staff noted its continuing concern that the current model may not incorporate all integrity management-related ADIT that should be included in the Company's IMRR calculations.

(c) The Public Staff recommends that revisions be made to the IMR spreadsheet model so that it more closely mirrors the way plant, accumulated depreciation, and ADIT are handled in a general rate case, and is also consistent with the Integrity Management Tracker mechanism approved for PSNC in its last general rate case, Docket No. G-5, Sub 565. The Public Staff sent to Piedmont a template of our proposed modifications to the mechanism and plans to continue to work with the Company to implement these changes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE IMR TARIFF CHANGES PROPOSED BY THE COMPANY?

A. Company witness Barkley states that Piedmont is proposing to modify Appendix E to the Service Regulations to include updated percentages and throughput and eliminate the special contract credit provisions to the calculation of the annual IMRR. Company witness Barkley states that this crediting mechanism, which was agreed to by Piedmont and the Public Staff and approved by the Commission in Docket No. G-9, Sub 631, Piedmont's last general rate case, is not applicable subsequent to the effective date of rate changes approved by the Commission in this general rate case proceeding because Piedmont is including all special contract revenues in its revenue request.

The Public Staff disagrees with Company witness Barkley's statement concerning special contract credits because all special contract revenues were reflected in Piedmont's revenue request in the last proceeding when these credits were approved and therefore nothing has changed in the current rate case except that the Company does not want to implement the special contract credits in its tariffs in this proceeding. The special contract credits represent an amount attributable to special contract customers that should be contributing to the IMR for pipeline safety-related costs on the system as a whole. Because these special contracts are fixed in nature and cannot be re-opened for surcharges such as the IMR or a tax rate change as mentioned earlier in testimony, as was done when this IMR was implemented, we compute a credit amount to apply to the IMR revenues being surcharged to customers equal to the revenue requirement impact of the declining book value of the special contract investment included in the last rate case beginning a year after the new rates are put into effect. This credit reduces the amount of IMR revenues surcharged to all customers in order to recognize that all customers should be contributing to the pipeline safety costs on the system. Since these calculations are based on final returns and plant from the rate case order, the Public Staff proposes to provide the final special contract credits once the final order is out since we propose to add the special contract credits back into the IMR tariffs. This is consistent with the initial order approving the mechanism as well as the Revised IMR mechanism approved in 2015 by this Commission.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NON-UTILITY ADJUSTMENT?

A. The Company did not allocate a proportionate share of its general administrative costs to its merchandising and jobbing (M&J) operations and none to its equity investment affiliates. The Public Staff applied revised non-utility factors to certain A&G senior level salaries, other corporate O&M expense accounts, and general plant accounts. The revised factors incorporate investment, revenues, and payroll in equity companies at December 31, 2018. Based on data request responses, the Public Staff had a difficult time determining how certain charges from the service company were being handled as far as the equity investments owned by Piedmont. The Public Staff therefore included some but not all of the equity investments companies in my calculation of the non-utility factors.

The Company did not allocate any portion of its plant, accumulated depreciation, and depreciation expense to its M&J operations, nor did it allocate any portion of these items to its equity investment affiliates. The Public Staff has allocated a portion of the Company's plant, accumulated depreciation, and depreciation expense to the M&J operations using the revised three-factor formula method that was determined based on investment, revenues, and payroll.

Q. WHAT IS YOUR RECOMMENDATION REGARDING ATLANTIC COAST PIPELINE PLANT IN SERVICE AND RELATED ACCOUNTS THAT HAVE BEEN INCLUDED IN RATE BASE?

A. Piedmont had existing approved natural gas transportation/redelivery agreements in place with Duke Energy Progress, LLC (DEP) for the transportation/redelivery of natural gas from Piedmont's city gate receipt points on Transcontinental Gas Pipeline Company, LLC (Transco) to the following electric generation plants operated by DEP: Wayne/HF Lee (Docket No. G-9, Sub 572), Richmond/Sherwood Smith Energy Complex (Docket No. G-21, Sub 417), and Sutton (Docket No. G-9, Sub 579).

On September 8, 2014, Piedmont filed a petition in Docket No. G-9, Sub 655 (Petition), requesting that the Commission issue an order authorizing Piedmont to enter into and perform in accordance with the following: (1) a Precedent Agreement, Service Agreement, and Negotiated Rate Agreement (collectively, the Precedent Agreement) related to firm natural gas pipeline capacity on the Atlantic Coast Pipeline project (ACP), (2) amendments to the three preexisting transportation/redelivery agreements identified above (collectively, the DEP Amendments), and (3) a Transmission Capacity Lease between Piedmont and Atlantic Coast Pipeline, LLC.

The Petition stated that Duke Energy Carolinas, LLC (DEC) and DEP together are subscribing to 725,000 dekatherms per day of natural gas transportation capacity on ACP in order to provide service to existing and potential expanded gas-fired generation at their facilities. In order to allow for the redelivery of these volumes from ACP, all of which will be delivered by ACP to interconnect points between Piedmont and ACP in the eastern part of Piedmont's system, DEP requires additional transportation/redelivery rights from Piedmont. In order to provide these additional transportation/redelivery rights to DEP, Piedmont will be required to reconfigure portions of its system and in some cases construct limited new facilities. According to the Petition, DEP and Piedmont negotiated the DEP Amendments to enable Piedmont to provide the additional delivery rights requested by DEP at a reasonable cost.

On October 28, 2014, the Commission authorized Piedmont to enter into the Precedent Agreement and the Transmission Capacity Agreement and operate pursuant to their terms. The Commission also authorized Piedmont to provide natural gas service to DEP pursuant to the DEP Amendments.

ACP has met with major delays, and Piedmont stated in response to a Public Staff data request that ACP is targeting a partial in-service date of late 2020 and a full in-service date of late 2021. Based on data request responses provided by the Company, Piedmont completed a large majority of the planned plant enhancements and the project was closed to plant in service in 2018. Because our analysis indicates that the plant is used and useful for providing service, I have left the plant in rate base. However, as stated in the DEP Amendments, the cost of most of these assets will be paid by DEP, beginning as soon as ACP is in service and, therefore, in order to recognize that current ratepayers should not be paying for assets that will be paid for by DEP, I recommend crediting the revenue requirement in this case to remove the cost of a portion of the ACP-related facilities constructed by the Company, and establishing a regulatory asset to provide for the future collection of these costs from DEP. This regulatory asset should act like a receivable account from DEP. Once ACP comes online and DEP begins making payments to Piedmont, a portion of the revenue received should reduce the regulatory asset, which can be amortized over the life of the three transportation/redelivery agreements with DEP. In this manner, current ratepayers are insulated from paying for plant that will ultimately be paid for by DEP.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SPECIAL CONTRACTS.

A. I have removed the estimated plant, accumulated depreciation, depreciation expense, and ADIT associated with the Duke Lincoln contract because Duke previously paid Piedmont for the cost of the pipeline serving the Duke Lincoln plant. I have made this adjustment using prior rate case data but estimated the Duke Lincoln investment amounts since the Company stated the information was not available. In a data request, the Public Staff asked Piedmont to provide "[t]he amount of plant in service, accumulated depreciation, accumulated deferred income taxes, and depreciation expense as of December 31, 2018, that are included in rate base plant amounts" associated with each electric generation contract, each special contract (other than electric generation), and each minimum margin agreement. In response to the Public Staff's data request, Piedmont replied stating:

> Plant in service and depreciation expense details for certain projects are not available due to the age of the projects and/or limited system information.

> Furthermore, Piedmont does not track accumulated deferred income taxes by project.

OTHER PUBLIC STAFF CONCERNS

Q. PLEASE DESCRIBE YOUR CONCERNS ABOUT THE COST ALLOCATIONS FROM DUKE ENERGY BUSINESS SERVICES, LLC (DEBS) TO PIEDMONT IN THIS CASE.

A. During the course of the Public Staff's review of the cost allocations from DEBS to Piedmont, the information provided by the Company was not transparent enough for the Public Staff to determine (1) whether those costs should be assigned to Piedmont, and (2) if the costs should be assigned to Piedmont, whether the costs are being properly allocated to Piedmont.

For example, the Public Staff reviewed information about aviation costs and legal fees that were allocated from DEBS to Piedmont. The Public Staff was unable to "peel back" the information that was provided by the Company to determine if those costs even relate to Piedmont operations, and, furthermore, whether those costs should be allocated to Piedmont.

Although we understand this is a challenging process, it is imperative that the information provided by the service company be transparent so that the Public Staff can readily determine whether it is properly charged to Piedmont's customers.

One solution to this problem could be that the Commission order the Company to work with the Public Staff to implement processes so that any costs that are allocated from the service company to Piedmont (and other Duke Energy regulated affiliates) be transparent enough so that it is easily ascertainable to determine whether it is appropriate to charge ratepayers.

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

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JULIE G. PERRY

I graduated from North Carolina State University in 1989 with a Bachelor of Arts degree in Accounting and I am a Certified Public Accountant.

Prior to joining the Public Staff, I was employed by the North Carolina State Auditor's Office. My duties there involved the performance of financial and operational audits of various state agencies, community colleges, and Clerks of Court.

I joined the Public Staff in September 1990, and was promoted to Supervisor of the Natural Gas Section in the Accounting Division in September 2000. I was promoted to Accounting Manager – Natural Gas & Transportation effective December 1, 2016. I have performed numerous audits and/or presented testimony and exhibits before the Commission addressing a wide range of natural gas topics.

Additionally, I have filed testimony and exhibits in numerous water rate cases and performed investigations and analyses addressing a wide range of topics and issues related to the water, electric, transportation, and telephone industries.

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

A. Yes, I do.

Q. We're going to pass it out now.

(Summary handed out.)

Q. Would you please proceed with reading your summary?

A. Yes, ma'am. The purpose of my summary is to present the accounting and ratemaking adjustments I recommended regarding state excess deferred income taxes, federal directed EDIT, federal unprotected EDIT, and the deferred revenues associated with the overcollection of taxes since January 1, 2018, due to changes in the federal tax rate applicable to Piedmont.

I am also providing testimony regarding plant investment related to the Line 434 Project, the integrity management rider mechanism tariff to include special contract credits, the non-utility adjustment, and my concerns regarding the transparency of the service company cost allocations. In addition, after discussions with the Company, I updated my federal unprotected EDIT adjustment as well as my non-utility adjustment. All of these adjustments are reflected in the stipulation filed in this docket.

This concludes my summary.

MS. CULPEPPER: The witness is available for cross examination and questions by the Commission.

COMMISSIONER BROWN-BLAND: Is there cross examination for this witness?

MR. WEST: There is, but the AG has to work something out first.

COMMISSIONER BROWN-BLAND: Mr. West, let's gear up.

CROSS EXAMINATION BY MR. WEST:

Q. Good afternoon, Mr. Perry, how are you?

A. Good, thank you.

Q. In your position as the accounting manager for natural gas and transportation, is part of your role to review the special and electric generation contracts that are presented by Piedmont to the Commission for approval?

A. Yes, sir. For all special contracts, for all utilities in the state and electric generation contracts.

Q. And did you have a role in crafting paragraph 32 of the stipulation?

A. I did.

Q. So I would like to ask you some questions about paragraph 32 and some of the filings that have occurred at the Commission. Just as a caveat, primarily for Piedmont's benefit, I realize that the filings, themselves, are confidential except to the extent that something has been disclosed either in the application of the Commission's order. So I'm -- like, all of the questions is not to illicit any confidential information. If you feel like you have to provide confidential information, let me know, and we'll try to work around, it if that's okay?

A. Sure.

Q. Can you take a look at paragraph 32 and just summarize, in your own words, what it is designed -- what it does and it's designed to do?

A. Yeah. So the Public Staff has -- obviously, has responsibility of all special contracts, electric generation contracts to review, analyze for all the utilities of the state. And in doing so, I know all the contracts that are out there, how they're structured. All of them are somewhat structured differently.

And we have come to some -- we've had some concerns -- not concerns. Some issues come up about how certain contracts might be structured going forward. And we are trying to make sure that there is a system benefit to all contracts, that the customers would never be subsidizing any part of any contract, and that pretty much, now that we have so many mergers in the state where we have gas utilities owned by larger holding companies that have electric utilities in their -- as their sister affiliate, we want to make sure that the code of conduct, and the transfer pricing arrangements, and the market prices, although there aren't that many, but in the state would all be upheld. And in doing so, we believe that this approach we're trying to implement with Piedmont -- and it's something we're working together, and it is on a contract contract by basis -- basis to provide a system support to our, you know, type of charge, depending on the agreement. And we just feel that this is a very important part of moving forward and as contracts are negotiated in the state.

Q. Okay. Let's start with some basics, and then we'll break it down.

A. Okay.

Q. So, normally, if a customer wants to purchase gas from Piedmont, there are established rate schedules on which the customer can make a claim for service or make a request for service, correct?

A. If they are a new customer to Piedmont, then depending on if there needs to be a feasibility study done, most likely, if they're not right on the line, or depends on the -- if it's an industrial customer, special contract customer, there may be some plant investment involved.

Q. Well, so what I'm trying to get at is, the special contracts are an exception to the typical rate schedule, correct?

A. True.

Q. So an existing industrial customer -- we're just picking one type of customer at random -- the focus is not on industrial customers, but particular industrial customer that is a large consumer of gas is either selecting sales service or transportation service, and they're taking service on the tariff rate, correct?

A. Yes.

Q. Okay. Somebody who may be moving to North Carolina to build a plant might have needs that are a little bit different or opportunities that are a little bit different, and rather than taking service on an existing rate schedule, they may negotiate something with Piedmont and present that to you. And that's what we are referring to as a special contract, it's an exception to the existing rate schedule, correct?

A. Yes. And they would present to the Commission as well, but yes.

Q. Sure. But starting with you, and then ultimately going to the Commission, right?

A. Filed with the Commission, and then we do the investigation. So I'm not trying to split hairs there.

Q. No. It's an important clarification, so thank you. So can you -- with that in mind, can you describe the types of special contracts that you're being asked to review, or maybe the reasons for having a special contract?

A. Sure. There is a lot. But, you know, it could be -- if it's a new customer, it could be a customer that's sited further away from the line, and we have to have -- there's construction costs involved. And the level of volumes is high, or not high, and they need a sort of a levelized rate to maybe bridge the gap on the construction cost over time. And we do a net present value analysis to determine what a levelized payment would be to pay off the plant investment. Sort of like the old CIC calculations. Instead of paying the CIC up front, you do it over time.

We have agreements where it might be a customer that's upgrading its facility and wants to do the same thing, but they're already connected. It might not be as big a construction investment, but they want to pay -- a special contract might be where they want to pay something additional over five years, so they don't have to come out of pocket with the whole thing.

And we have now electric generators in the state, both CCs and CTs, that would be large volume users -- larger volume users -- and a lot of that is the plant investment. And then we need to make sure that the analysis is covering its cost. We have certain assumptions that we use to look at all of these. And similar to feasibility studies we do for residentials, but it's just on a larger scale with different assumptions, but we do the same thing for some other customers as well.

Q. Are any of the special contracts for potential bypasses? So somebody might be a customer of Piedmont, but they have the opportunity to interconnect directly with an interstate pipeline, and, therefore, they negotiate a special deal with Piedmont to stay on the system and defray deferred costs among -- or defray fixed costs among a larger group of customers?

A. Sure. I've been here since 1990, and we've probably hand a -- on one hand less than the number of bypasses that have actually -- but I think at that point, the Commission normally gets involved when it comes to their attention there is a bypass situation. Normally, the Commission will order the parties to work together as much as possible. They'll try to work out some deal with -- make the parties come to a deal.

If they can't, it comes back to the Commission. And yes, we've had a few. Some of them have just bypassed. One of them, in particular. A couple others have come out and worked out, like, sort of a volumetric or some sort of arrangement where it was a negotiated rate of some sort. But yes, we have that come up. And normally the Commission gets involved when it's actually a true bypass situation.

Q. Okay. And you mentioned identifying a cost and then levelizing the cost over a certain period of time?

A. Yes.

Q. Is that -- would that be a fixed contract, meaning we're going to charge this much per year to recover our cost?

A. There might be a fixed component to the contract to cover -- cover, and maybe a plant investment. There's different types of contracts structured different ways. I guess my problem is I know too much, so I'm trying to keep it very high level, as far as all the different contracts in the state.

Q. And I know too little, and I'm just trying to --

A. Okay. So there could be a fixed component to the contract, and that typically involves plant investment. And it's set up, you know, maybe similar to, like, whatever the return is at the time, the LDCs coming in signing the contract, they're allowed rate of returns. So we're making sure that they're covering their cost. And assumptions that we use in that are, you know, current tax rates and this, that, and the other that are going on.

And -- but a lot -- you know, there needs to be a contribution to the system as well, and I think that's what we're getting at, is that these -- we don't want there to be undue discrimination between somebody, you know, not paying enough for their part. And that's where all this is kind of coming from. So fixed may be there -- may be a piece of it, but there's got to be benefits coming back.

Q. So when we look at paragraph 32 of the stipulation, it requires Piedmont to, quote, implement a system report usage -- system support usage-based rate component.

Is that some kind of requirement to pay some amount of money based on the amount that you're consuming? Or what does that mean?

A. That's basically what it means. I think it's very normal, and most contracts are set up in that fashion anyway. I mean, you're paying -- the transportation customers are paying that type of rate. I mean, this is just going to be a negotiated type of rate, but you're paying something towards the system based on usage, yes.

Q. So is the implication of that requirement that there are some special contracts that are fixed and do not have a volumetric base or usage-based component?

A. No. I think what I'm trying to say is -- because all of that is confidential of anything is that -- is that every contract has a system benefit, but I think, because we are trying to make sure that those -- the way the contracts are structured, they're more -- there is no unfair advantage, and there's no way to unduly discriminate between different customers.

The fixed charges are, you know, typically held just for plant -- you know, for plant investment and feasible -- just like you would a CIC, just to connect any water customer with gas customer, and we've done that in the past. But we're -- we just want to make sure that, even though all these contracts that we've had so far do have a benefit built in, they're not all the same, and they're not all structured the same. And I'm sorry, I can't completely answer your question, because I'm getting confidential if I go too deep.

Q. Okay. Well, let me see if I can -- this might make the confidentiality issue worse, or it may alleviate it to some extent, but --

A. Sorry.

Q. -- in July 2009, in Docket G-9, Sub 568, the Commission issued an order allowing a transportation service agreement for gas between Piedmont and what was then Carolina Power and Light to go into effect. In other words, they accepted it. And what they explained in the order was that -- and I'm just going to read it. "Piedmont stated that the fixed price arrangement is based upon PECs," so it would be Progress Energy's, "estimated usage during the term of the arrangement at a preference or a fixed price option during the seasonal service. Piedmont further indicated that price terms are simply the fixed priced equivalent of the variable rates already approved by the Commission and that the service will be otherwise provided pursuant to the existing transportation service agreement."

Is that what you're trying to prohibit now by saying that there has to be a usage-based component?

A. Okay. That is confidential, but --

Q. Well, I'm reading from a Commission order.

A. Yeah. I get you. And my name is on that one, I think. I think I presented that one. If you read it, it says "seasonal," right?

Q. Yes.

A. So I think what you're looking at there, just in definition, it's for a limited amount of time. That my guess would be that that customer has not been using much gas, or they've worked out some deal with somebody or something, because it's seasonal. So I do know the specifics of that contract. I don't think it's all of what it says in the description, I think there's more to it and more along my position. It just doesn't say that. But that's confidential. It's really hard to answer your question.

COMMISSIONER BROWN-BLAND: Be sure you're speaking into the mic.

THE WITNESS: I'm so sorry. It's hard when I'm that way. I'll move the mic. I'm sorry.

Q. So just so people have an idea of the magnitude of the issue that we're discussing, in the last, let's say, 10 years, approximately how many special contracts and electric-generation contracts have been presented to the Commission for approval?

A. I'm going to have to use subject to check on that one. Do you have that number?

Q. Is it approximately 30?

A. Most likely. And I probably looked it all up. So let me -- can I just caveat one thing? In the last 10 years, the natural gas industry has changed dramatically. I mean, the contracts are changing, the gas industry's changed. I mean, it's just -- things are evolving, contracts are evolving, the models are evolving. You know, we're learning more, and the companies are coming back with different things, and we have different -- you know, obviously, we didn't have these electric generators. Those were some of the first ones that were coming in, as far as the combined-cycle ones. So it's been a learning curve getting the models straight.

We just believe this method is essential to protect ratepayers and to keep everyone on the same level playing field, which is something you've always been concerned about in mergers and such. And so we're just trying to keep everyone pretty much playing in the same ball game, you know, and not have an unfair advantage, now that we have affiliates to deal with all the time.

And other people that are siting in the territories. We just want to make sure that, if they're siting in public territory, if they're siting in Piedmont territory, everybody's getting the same -- you know, similar -- I mean, everybody's going to be different. Every -- every -- every customer is going to be different, but we're just trying to make sure we have the same rules in place, to some degree.

Q. Okay. But --

A. So yes, 30 contracts. I'm sure I probably approved most of them.

Q. And just to save a little bit of time, what I'm going to ask the Commission to do is to take judicial notice of the applications and the orders in the following dockets, that way I don't have to ask you about each of them: G-9, Sub 568, 572, 574, 578, 579, 588, 593, 597, 598, 603, 605, 613, 619, 620, 621, 624, 625, 628, 638, 640, 652, 654, 656, 657, 709, 711, 718 and 720.

A. I'm feeling old now.

Q. It just shows how much work you've done.

A. That's right.

COMMISSIONER BROWN-BLAND: No objection. The Commission will take judicial notice. Did you ask for the orders or the dockets?

MR. WEST: The -- I'm sorry?

COMMISSIONER BROWN-BLAND: What do you want us to take judicial notice of?

MR. WEST: Judicial notice of the Commission's order and the application that was filed in the docket.

COMMISSIONER BROWN-BLAND: All right. We will take -- in those docket numbers that

Mr. West called out, Commission will take notice of the applications and its orders.

Q. So a number of these orders identify a Duke gas-fired generation plant as the purchaser of gas pursuant to this special contract.

Is that consistent with your recollection?

A. I'm sure there are, uh-huh, yes.

Q. To your knowledge, are all or most of the Duke gas-fired plants covered by special contracts with Piedmont if the plants are in Piedmont's territory?

A. I was going to say, if they're in their territory. I'd say Duke Energy Progress instead of just saying Duke. Duke Energy Progress is in Piedmont's territory. Or maybe two of them are in Duke Energy Carolinas. It's both. Duke Energy Carolinas and Duke Energy Progress.

Q. Have plants in Piedmont's territory?

A. Yes. Yes.

Q. So, to your knowledge -- and we can go through the individual dockets if we need to, but to your knowledge, the generation plants of each of the two subsidiaries that are located within Piedmont's service territory have special contracts for gas delivery, correct?

A. Yes. Electric generation contract, yes.

Q. And electric generation contracts are just a special kind of special contract?

A. Yes. We seem to separate them out some, yes.

Q. Okay. With regard to the process for getting these things approved, you mentioned earlier that they go to the Commission, and then they're reviewed by the Public Staff.

A. Yes.

Q. It looks like, from the orders that I was citing and asking the Commission to take judicial notice of, that Piedmont will negotiate with a purchaser, whether it's an industrial, or an IOU, or any other third party, and then they file the contract under seal with a letter that provides some basic explanation of what the contract is. And then the contract gets reviewed by the Public Staff.

Is that generally correct?

A. Generally, yeah. We're charged with the investigation side of it, and then we present a recommendation to the Commission.

Q. Okay. And in the, roughly, 30 that were presented in the last 10 years, did the Public Staff object to any of them?

A. Yes, we did. I know for -- yeah. Well, let's see. Yes. And I'm trying to think what, what, what, what. Recently, Piedmont filed a revised agreement in G-9, Sub 722.

Q. Which docket?

A. G-9, Sub 722. And they state in their cover letter that, "The Public Staff had reviewed the proposed agreement, raised several concerns regarding the agreement, particularly with respect to the degree of system contribution provided for by the agreed rates set forth in the agreement. Based on these concerns, and discussions between Piedmont and the Public Staff, Piedmont and DEC have agreed to revise the rates and charges under the agreement, including a new usage-based incremental facilities volumetric charge designated to address the Public Staff's concerns."

We've had other issues with other utilities as well, you just would -- not in Piedmont's territory. That's why I was thinking for a minute that we sent other contracts back too, as well, but not for -- I'm trying to think if we've done it any more with them. I think we've had a lot of questions and discussions about -- we sent a lot of data requests to these guys. I mean, I guess I'm trying to think if we ever changed -- if we ever had them revised.

Seems like we have had some revisions, but I can't remember. It may just be some errors, you know, error correction too. Like, I know we had a -- I can't say that one. Okay. Confidential. Some of these things, just the names are confidential.

We did have one filed, it was probably four years ago, and it was just an error, and, you know, the way the analysis was done, I think we had them refile it. We do look at these, and if we see something that's wrong, we're going to ask them to refile. But, typically, they know what we're looking at now. They, sort of, got our assumptions down.

Q. Okay. So in other words, they file it with the Commission, they give it to you to review, you have an opportunity to ask for data requests and review their responses, and then you let them know whether the contract is or is not acceptable to you; is that correct?

A. Somewhat, yes. We get their analysis. They get -- they have -- you know, they have own, like, an Excel-type analysis that they do, and we do it -- I try to duplicate their analysis. So I know all their assumptions that they're using, you know, that type of thing. And if we see something that's out in left field, you know, we're going to ask them about it.

Q. And if you reach a conclusion that the contract is not fair or reasonable, whatever the standard is that you're applying, you have the opportunity to go back to them and say, we don't support this, you need to change these terms, or how does that work?

A. Well, I think so. I mean, that's -- we've done that. And the Company has the option of just sticking with what they filed before the Commission and pleading their case. So it's not just -- I mean, I'm not -- obviously, the Public Staff, not just myself, is not the last say. The Commission is the say in the matter, so.

Q. Okay. And that's where I wanted to go next.

So once you have finished your review process, if you either let them know that you agree with what they've done or you disagree and they don't deviate from their position, then the next step in the process is to get up in front of the Commission and present it for approval, correct?

A. Correct.

Q. So you would have the opportunity not just to let Piedmont know that you don't agree with the terms, but the Public Staff would have the opportunity to advise the Commission that they have some concerns about the economics of the transaction or other terms, correct?

A. Yes. But, typically -- let's just say if we have a controversial item like that, we're going to file a motion versus bringing it to the -- bring it downstairs to the Commission. Or if we have that big a concern, most of the time I think any company we work with is willing to go back and renegotiate or revise. Or, you know, they don't want -- they would rather be -- they would rather file something that we're going to think is reasonable than go against us.

But that definitely can happen. I mean, it can definitely happen. They have every right to file. And we have -- we've filed motions in the past with companies that just said, you know, we have problems with the agreement.

Q. Okay. So once the Commission gets the contract, historically -- and again, they've taken judicial notice of a lot of different dockets, but historically, if they accept the contract, meaning they allow the parties to proceed with the contract, they include a reservation in their order that says this is without prejudice to any party to challenge any aspect of this in the rate proceeding or elsewhere, correct?

A. They do.

Q. So if the Public Staff had an issue with an existing special contract in this rate proceeding or in any past or future rate proceeding, you could ask for an adjustment to be made based on the fact that you don't think that contract is contributing sufficiently to the system; is that correct?

A. I'm not going to play lawyer right now, but I'm going to say I don't -- I do not know that we can go back once the Commission has approved the agreement and reopen that back up, but I'm not --

Q. I'm not talking about the agreement, I'm talking about in a rate case. There were -- haven't there been adjustments in rate cases as a result of special contracts?

A. Sure. So we -- you know, how you account for special contracts in a rate case is -- right. Where do you put -- is the plant included, are the revenues included? You know, in the old days we had CIEC. When it came in they would credit -- credit plant. Right. That was kind of a done deal. It's not necessarily done that way anymore and, so we make sure all the revenues are included in the rate case so that there's a benefit coming back. Okay? We want to make sure the rate cases, the special contracts are providing a benefit to the system and based on the contracts that we approved. So I'm not sure I'm answering your question. Maybe you need to rephrase. Sorry.

Q. I think you are, and I think part of the problem is I don't remember the correct acronym, but there it was a -- I want to say there was a safety program or one of those things where, because contracts are fixed, they didn't have any kind of rate adjustment mechanism for them, and you-all in Piedmont seemed to have worked something out that essentially Piedmont was required to contribute a certain amount for its special contracts.

A. You're talking about IMR. You're talking about the IMR.

Q. That could be.

A. The temp program. So, basically -- and for, like, we've had an issue with the income tax, the changes. I'm sorry. We've also had -- yes, they -- they can't open the contracts back up, and things might change. When the IMR came up, we were saying all classes of customers should be providing some safety, and some portion of the IMR should be assigned to special contracts. Well, since you can't open the contracts back up, we have taken sort of a special contract approach, which I calculate in each rate case based on the contracts that are included in the rate case at the time, and we just -- not that we disallow IMR for the company, we just credit an amount each year so that they're sort of apportion -- so it basically assumes you're allocating a piece to the special contracts that they're not able to collect until the next rate case.

Q. Okay. So the point I was trying to get at is -- and thank you for providing that illustration -- is, it sounds like the Public Staff has what I would call multiple bites at the apple; you can let Piedmont know that you have objections to a specific contract when it's filed, you can let the Commission know that you have objections to the contract if Piedmont doesn't respond to the objections you expressed to it.

A. Uh-huh.

Q. The Commission has reserved rights to make adjustments in rate cases, and there have been instances where we actually have made adjustments in rate cases for special contracts.

So you have multiple bites of the apple to address any concerns you might have about special contracts, correct?

A. Yes. Can I but that, though?

Q. Absolutely.

A. Okay. Yes, but talking to, not just Piedmont, but companies in general, they don't want to be going back to their customer and having to renegotiate because they come in and say, oh, the Public Staff doesn't like this. Yeah, it's not good business for them, or for anyone, I guess, when they're doing the good faith negotiation. I'm sure you can identify with that with customers you've have, clients you've had.

So I think what we're trying to do here is sort of set the notion that -- that, you know, there needs to be a system contribution. It's fine to have some fixed part of the contract, and we think that there should be a system contribution, and we think it should be usage-based. If they bring something in and we say no, you know, and they have to go back to their customers and say, you know, Public Staff isn't going to support it, it's going to be this -- and it does get to be a long drawn out. We've done it, not necessarily with Piedmont, with other utilities, and sometimes it takes a year or so to get all this ironed out.

So yes, you're right, we do have a bite of the apple a few times, but I think to get these things done and be in good faith, we're trying to put it out there that this is going to be our position. And so herein lies the problem.

You know -- and we're not asking the Commission to do anything, just -- we will be doing this on a case-by-case basis. We're just letting them know that we are trying to get to an end resolve with this issue that we've had.

Q. Okay. And one of the concerns that I want to address is, I think where you were going, which is why does the Commission need to make a pronouncement in a general rate case about how you're going to be treating contracts that are negotiated on a one-off basis that are already the subject of a declaratory order. So maybe what we could do is talk about this paragraph in a little more detail so at least I understand it. So --

COMMISSIONER BROWN-BLAND: Mr. West, you've backed away from your mic.

MR. WEST: Oh, sorry.

Q. So this concept of the system support usage-based rate component, does that simply mean that it's the Public Staff's position, as of whenever these rates go into effect, that any special contract has to have a volumetric component, or what exactly does this mean?

A. That is basically what we're saying. Some -- and most likely a large user or any -- it's going to be a negotiated rate, but it is going to be volumetric, but that's not unlike most contracts. I mean, this is not anything unlike most of the -- I mean, most every contract sitting out there. I mean, there are some -- it's not a foreign -- this is not a foreign concept. This is pretty much how most contracts are set up.

Q. But if everybody's already doing it, why does the Commission need to issue an order?

A. Because we're seeing different -- we're seeing different types of structures coming in, and we want to make sure -- here we go confidential again, but we're seeing different structure -- I'm so sorry, but this thing is not -- we're seeing different contracts structured different ways. And we are just trying to make sure that we put the Commission on notice that we are working with Piedmont, and they are working with us, and they've been really good about it, and other utilities of the state, and are -- we're just making this a -- we feel strongly about it. We need to get this resolved, because I don't want to have to turn back contracts constantly. I don't want to have to get in that place where we're doing that.

Q. Why wouldn't it be enough, though, for you just to tell Piedmont, this is the Public Staff's position? Why does the Commission have to announce that?

A. Well, we have. We have told them. Sometimes it just needs to be able -- we just feel like we needed to state our position in this rate case. I think -- you know, rate cases are a time when we clean up, sorry, but messes that we have from rate -- between rate cases. And we might deal with interest rates, might deal with reporting requirements, and here is something that's been hanging out there with us for a little while, and we just felt like it was important to put the Commission on notice that we are trying to get a resolution to this. And it will be on a contract-by-contract basis, but we felt comfortable. We felt, like, strongly that we should put this in here.

Q. And you made some comments earlier about the need for a level playing field.

If a new customer were coming to Piedmont, whether it's a company building a gas generation plant or a manufacturer that might also have a cogen plant, and they look at this paragraph 32, is it conceivable that they would conclude that they're being treated differently than customers that have already negotiated their agreements because this applies only prospectively, this requirement for a system support usage-based rate component? And I'm looking at the fourth and fifth lines of the paragraph which says it applies only to contracts filed with the Commission after the effective date of rates in this proceeding.

A. Well, and that's because to today, we've gotten the contracts that are providing a benefit, they're providing a system support. The ones that are filed currently, based on our analysis. I think, going forward, if you think about it, you know, returns are going down, and tax rates are going down, and all these contracts are being negotiated at levels that we haven't seen in a long time, as far as that goes.

If things start turning around, we've got to make sure that the customers are covered, as far as that goes. That there is a system benefit. And I think any customer that locates in the state beyond -- if I'm a transportation customer, I'm going to expect to pay a system -- a volumetric rate to transport on Piedmont's system or public system. I mean, that is a normal requirement for most contracts.

Q. Except that, if you're building --

A. Or tariffs or whatever.

Q. If you're building a gas generation plant and you have to compete with Duke, and Duke has special contracts that are already in existence that may or may not have a system support usage-based rate component, you may be concerned that you would be not able to sell gas -- to sell electricity generated with gas at a competitive rate, correct?

A. Well, that's all confidential. But, I mean, all the contracts, including the Duke and the DEP cases, do have a system benefit and contribution into this. I'm not -- that's high level. Cut me off, Jim. But, I mean -- so I'm not -- -- I don't think it's anti-discriminatory. I think we're just trying to keep, I mean, your customer on the same level playing field as someone else as well. I mean, this is -- I think if you knew what I knew -- I'm trying to help you over here. I'm trying to help you or your customers or other customers coming in to -- I'm sorry, that's -- I'm trying to keep everyone non -- we did the G.S. 62-153 because of affiliates, we look at that, okay? We have to do 62-140 when we're looking at nonaffiliated because we have the nondiscrimination statute.

So we're really -- we have to look at these contracts in so many different arenas now, and we're just trying to make sure everyone is handled the same. And I don't think it would be nondiscriminatory for someone to site in this area with this language, because I think they would expect to pay it.

Q. It's not a question of what their expectation is, it's a question of whether they would be treated -- whether a new customer would be treated the same as an existing customer. And the language of the paragraph is, for a variety of reasons, including confidentiality, so vague that I think it would be very hard for somebody to make that determination.

Do you understand just --

A. I understand what you're saying. I understand what you're saying. But I don't think it --

I don't think it's -- now I'm thinking dollars in terms of, you know, returns, but I think that I understand what you're saying. I don't believe that it is anti-discriminatory, so that's why I'm having a hard time agreeing with that. Or I don't think -- I think we're just trying to keep people in the same playing field. I see that you think the volumetric charge would be in the future, but that's hard to answer when I can't answer.

Q. So Mr. Yoho testified earlier that the Atlantic Coast Pipeline was going to bring interstate gas to Eastern North Carolina and that Eastern North Carolina would finally be able to compete on a level playing field. I think Fayetteville is largely considered part of Eastern North Carolina. You could understand why we, and other folks in Eastern North Carolina, would be sensitive if a new rule is being put into place that does not allow manufacturers or electric generators to compete on the same basis as folks that were able to negotiate contracts prior to these rates going into effect and prior to the Atlantic Coast Pipeline being brought to Eastern North Carolina, correct? Recognizing that your goal is to help everybody, but you can understand the sensitivity, correct?

A. I do. But I just don't know how to answer that. The -- I believe that they will be on a level playing field regardless, and I can't really talk about any of those contracts. And I know that the language may, to you, appear as though it's changing something, but it's really not. I mean, there's got to be -- you've got to -- you've got to pay something to use utility system. I mean, otherwise, all customers are going to be subsidizing. We're not going to allow that. We're making sure that everyone is paying their own fair share. And sometimes that is structured differently, and we're just trying to get it more uniform.

Q. Okay. So let's talk about the second sentence of this paragraph, then. The second sentence says, "Such usage-based rate component shall be included in future special and electric generation contract arrangements unless and to the extent that Piedmont and the Public Staff agree and the Commission ultimately concludes that it is just and reasonable and not unduly discriminatory to exclude such rate component from a special or electric generation contract arrangement in discrete circumstances."

So, in essence, you are asking the Commission to adopt a rule, and at the same time adopt an exception to the rule that has no parameters that I can see that is basically equivalent in size to the rule.

Is that -- am I misreading that?

A. No. But I think what we're just acknowledging is the Commission does have the last decision in all this. I mean, they are the governing body. So, I mean, if -- if there's something that we don't agree with and Piedmont feels strongly about, then they're going to be able to come to the Commission and make their ruling on that. And I just think we're basically just trying to state that, that, you know, they are the ultimate decision-makers in all this. And so --

Q. Do we need them to say that in a rate case? I mean, don't they already know that?

A. I was being polite. I'm just kidding.

Q. And not to be argumentative, but it says to the extent Piedmont and the Public Staff agree.

So the way that I'm reading this is that you would have to agree that an exception applies before they can take that to the Commission; is that correct?

A. I think, on that part -- I think further down it may say that -- yeah, in the next sentence, it does say that -- they don't have to agree with us. We don't have to agree for them to bring anything to the Commission, first of all, okay? But I think they're trying to say if we agree. So if there's some -- if some -- I guess the gas industry changes so much you sometimes never know what's coming up, and so this is a sort of a catch-all. If there is a circumstance out there, I don't know what it is, okay? This is sort of a catch-all, then yes, we can agree to go to the Commission for an exception.

If you go further down, it says if we're unable to agree, the parties agree, you know, then they also can go to the Commission. And this is just making sure that each customer class is paying their fair share, and it's just very hard to talk about when these contracts are confidential. But, anyway, I'm sorry. Ask me again something. I'm sorry, I'm probably not answering your question.

Q. Well, I think for me, at least, one of the questions is what, if any, parameters exists for these exceptions? I mean, how would somebody know whether an exception applies and whether they're being treated fairly or nondiscriminatorily if the exception is as vague as it's written?

A. I think if I had a specific for the exception, I would have put it down there. I mean, I think that's just leaving us open. I mean, as you -- in my 29 years, I've seen so many things change over the course, and the contracts have changed, and the gas industry's changed, and I'm almost sure in the next five years something else is going to come up that's going to change, you know, some of these contracts. I just think that gives us an open -- you know, gives us an open to see what's out there. There may be something we haven't thought of that's an exception. I don't know.

The parameters that we set out for our special contracts, we feel very solid with, we feel like they cover their cost, and we're making sure -- we just want to make sure that there is a system contribution so the ratepayers are not ever harmed. And that's really what the whole point of this is.

Q. Okay. What about amendments? So this talks about contracts.

COMMISSIONER BROWN-BLAND: Mr. West, are you -- do you have much more left?

MR. WEST: I think this is my last

question.

COMMISSIONER BROWN-BLAND: Okay. Go ahead.

Q. You mentioned contracts that are filed after these rates go into effect. If Piedmont were to amend a special contract next year, would that have to -- would that be subject to this rule and exception, or what would be the rules for that, and where do you draw those lines?

A. Okay. So there's all kinds of amendments. I mean, there's -- there's -- you can have an amendment to expand your facility, increase your volumes. You can have an amendment to add units, do whatever. So I think they would cover. I think this would govern -- would govern that. If it's an amendment for an already-approved contract and there's nothing except they're trueing up construction costs, I think that would basically stay with whatever was originally filed.

Q. So in other words --

A. To the nature of the contract. I mean, if the nature of the contract hasn't changed, if the nature of the investment hasn't changed, it's just a true-up of construction costs -- I'm sorry, am I talking into the mic -- I think that would be -- that's a different type of amendment and just a whole new type of contract or a whole -- sorry.

Q. So if it's the Public Staff's judgment that it's a material amendment, then the new rules apply; if it's a nonmaterial amendment, the old rules apply?

A. No, sir. I think it's more about -- when you -- we do approve these contracts, there's usually a two to -- sometimes two- and three-year build-out period on these contracts. I think once we approve some of these contracts, if they're large, if they're large contract, you know, they're going to have to come back in and true-up to their construction cost, because the construction cost estimates are going to be old. And by the time you get that plant in service, you're going to have a new number.

And so those type of true-ups -- which I have a few sitting on my desk that have not been done yet, coming, and not for the other reason -- but, you know, just to true-up construction costs of these projects, I don't think that is in the realm of what we're talking about here.

MR. WEST: Thank you. I don't have any further questions.

COMMISSIONER BROWN-BLAND: All right. We're going to take a break and come back on the record, I am just going to say, at 4:00.

(At this time, a recess was taken from 3:42 p.m. to 4:01 p.m.)

COMMISSIONER BROWN-BLAND: Let's come back to order, go back on the record. And I believe the Attorney General has cross examination for this witness. Ms. Harrod?

MS. HARROD: Thank you. Just a few.

CROSS EXAMINATION BY MS. HARROD:

Q. Ms. Perry, I'm Jennifer Harrod on behalf of the AG. Good afternoon.

A. Good afternoon.

Q. I want to ask you a question about the correction to your testimony.

A. Sure.

Q. So this correction is on page 11 of your testimony -- your initial testimony in this matter, and it pertains to the flow-back of the federal unprotected EDIT, correct?

A. Correct.

Q. Okay. So your initial testimony stated that a five-year amortization period consistent with the amortization period approved by the Commission in the most recent Carolina Water Service general rate case, Docket Number W-354, Sub 360, correct?

A. That's what it said, but I've changed it.

Q. Right.

A. Yes.

Q. And that -- that order has been entered into evidence in this case and identified as Barkley Cross Examination Number 2; is that correct?

A. That is true. And just let me add, until I had to write my summary, I really hadn't even focused on that statement. But we got filed so quickly in this case, we lost a couple weeks, and I think that was just an oversight on my part. So we were basically just trying to cite what our proposal -- Public Staff's proposal had been in other cases. So that's what the intent was in that sentence.

Q. Okay. So am I correct that, since the 2017 change in the federal corporate income tax rate, this Commission has entered two orders in general rate cases in which it has ordered utilities to flow back federal unprotected EDIT?

A. On the unprotected?

Q. Unprotected, correct.

A. Unprotected. Yeah. As far as I -- yes. Because in the Duke Energy Carolinas case that we filed testimony in, it recommended the five years, they did not -- the Commission did not issue an order on that issue.

Q. Okay. So, in terms of orders that the Commission has entered, so far we have on the record the one that was by stipulation with Aqua in which they were ordered three years, and the one that was contested in which they were ordered four years?

A. That is true.

Q. So you have -- your testimony now states the amortization period is consistent with the amortization period recommended by the Public Staff in Duke Energy Carolinas' most recent general rate case, Docket Number E-7, Sub 1146?

A. Yes.

Q. Okay. And Peggy and I used the time to quickly pull up some information from that docket, and so it may not be complete, and I'm hoping maybe you could fill in the gaps a little bit.

A. Sure.

Q. What was the Public Staff's initial position in that docket?

A. Well, I think there was, like, a third revised -- I mean, there was a lot of revisions, so one minute. One minute. Let me find my sheet.

(Witness peruses document.)

So in the -- this is in the second supplemental testimony of Michelle M. Boswell for the Public Staff. And in her supplemental testimony, on page 7, she states that the Public Staff recommended EDIT unprotected be refunded to ratepayers on a two-year levelized rider including carrying costs. Then, subsequent, she updated her testimony to a five-year period.

Q. Okay. And what was the basis for the change?

A. So, just like in this case, I believe she's saying that -- talking about the concerns -- it's on page 9. She states the Company's raised concerns regarding the impact of flow-back on its cash flow. You know, you can read, but it's on page 9 of her supplemental testimony. And negatively impact the credit matrix, that type of thing.

The Public Staff, in our case, and I think it's important to note, we do -- we are looking -- and she testified in the Carolina Water Case as well and the Aqua case. And I think the Public Staff, in general, is just telling you that there is a range that we're looking at here. I think when you look -- she has, I guess, two-year initially, and then she went to five. I think we're looking in a three- to five-year range for the Public Staff's positions going forward.

Five -- in my case, if you look at -- I don't know if you can really look at the settlement exhibits and you've seen the rate impacts on the three different riders. I mean, we have three riders going in to refund money, which is wonderful for ratepayers, and we're trying to do it a lot faster than 20 years, which the Company had recommended. But if you look at how it's going back, you know, the increases year by year that the ratepayers are going to have to see is not a huge jump. And I think we're just -- I think we talked about it in my testimony. We're trying to smooth out -- we're trying to give it back. We're giving back with interest, a lot better interest rate than they're going to get in the bank right now.

But they're also smoothing out, so they're not going to see this huge jump up, you know, in year three at this point in time, like before if we did a two-year EDIT rider, which you guys have been crossing on. So we're just -- we're trying to show that we have a range. And we're also looking at impacts on the -- on the rates to customers.

As you saw, we have a $108 million base rate impact. Now, you wouldn't want to go from a low increase and then jump way up to, you know, a high one for ratepayers. I think they are very concerned about their bills, and that would be something that would be very upsetting to customers. So we're just trying to smooth out -- even the refunds. We do it with increases and we do it with refunds, just so they don't get a hit with their bills.

Q. Okay. So I think the question I asked you that --

A. I'm sorry.

Q. -- was what Ms. Boswell's initial position. So it was two years, correct?

A. And then hadn't you asked me why it was changed to five; that was your next question.

Q. It was not. I wasn't going to ask you that.

What I am going to ask you, though, in follow-up on your explanation there is, do you have a basis to say that customers would rather get this money back over a five-year period of time then, say, get it back on November 1st in order to help them pay for their Christmas presents? I mean, you said something about being upsetting to ratepayers. Didn't you think it would be upsetting to ratepayers to hear that their money is, essentially, in the nature of a forced loan to the Company?

A. I don't think that's a good characterization of this money, to be honest with you. I mean -- okay. So up until this point, there is a credit to rate base. So basically the customers are receiving a benefit. They've got a regulatory liability and rate based right now. Until the Company even filed with this credit in rate base, in the rates, okay, because of the rider mechanism that they were recommending at this point in time. So there are -- it's not -- it's -- and until the Commission issues -- I'm sorry, I'm having a characterization issue.

But the Commission has authority over all these monies, and they issued an order in January 3rd and October of '18 basically telling these companies to hold this money until their next general rate case. So I think, in a way -- I've been listening to the cross today, and I'm like, it's not Piedmont's fault that they've have had this money. They didn't make the rate change happen, they didn't -- they couldn't have refunded this money any earlier than the Commission allows for them to do.

Q. Of course.

A. So I think the characterizations that are being done today was a little bit over the top, as far as they're holding this money. But they're not doing it -- they're doing it by Commission order. You know, they recognize that the Commission has authority, they're going to issue an order in this case.

And all I'm saying is that we do smooth out rate increases, and we're trying to smooth out the refunds so that they don't see this 9 or whatever -- 3.1 percent in the first year, and I think goes to 7.2 in the second year. You know, if the riders were different than that, those ratepayers are going to see a lot higher jump in, say, year three than they're going to see now.

And I think we are just trying to -- like we do with all our rate case items, cost-of-service items, we're trying to smooth out the spikes and we're smoothing out the refunds so that it makes the ratepayers, you know, more levelized. And I think they do appreciate that. The companies I talked to, when those rates go up and they get calls on consumer services, we hear about it. I mean, you know -- so I'm -- I don't think the Christmas present gift is a good analogy, but. Anyway, I hope I answered that. Sorry.

MS. HARROD: If I may ask, since we didn't really have an opportunity to review the Public Staff's recommendations, Peggy and I are going by our memories from being involved in that rate case, may we ask that the Commission take judicial notice of the -- of Ms. Boswell's testimony? I think Witness Perry said that there were several filings that involved EDIT.

Q. I don't -- do you have a list of them?

A. No, I do not.

MS. HARROD: Can we just ask that the Commission take judicial notice of the Public Staff's position in that docket, as reflected in Ms. Boswell's various testimonies?

COMMISSIONER BROWN-BLAND: What is the docket number?

THE WITNESS: E-7, Sub 1146. Sorry, I need my glasses.

COMMISSIONER BROWN-BLAND: All right. Commission will take judicial notice of

Ms. Boswell's testimony in that docket.

MS. HARROD: Thank you, Chairman.

Q. And one more quick question for you, Ms. Perry.

Is the mechanism for the rider that is reflected in the stipulation the same mechanism that was used in the Carolina Water Service order?

A. As far as I know, it is. I have not looked at her calculations completely, but it's the annuity -- sounds like it's the annuity rider, and you're removing the balances from accumulated deferred income taxes and all of that, yes.

Q. Okay. Thank you.

MS. HARROD: And then, if the Commission will also take judicial notice of the orders that are cited in Ms. Perry's testimony, and I have them written down here somewhere, then we have no further questions of her, if that's acceptable. Those orders, in addition to the ones we've already entered into the record, are the order in Public Service Company of North Carolina, order approving rate increase and integrity management tracker, Docket Number G-5, Sub 565, and Virginia Electric and Power Company DBA Dominion NC Power, E-22, Sub 523, order approving rate increase and cost deferrals and revising PJM regulatory conditions.

COMMISSIONER BROWN-BLAND: All right. Commission will take judicial notice in those two dockets of its orders.

MS. HARROD: Thank you. Then I have no further questions of Ms. Perry. Thank you very much.

MS. CULPEPPER: I have some redirect.

COMMISSIONER BROWN-BLAND: Redirect?

REDIRECT EXAMINATION BY MS. CULPEPPER:

Q. Ms. Perry, I may have misunderstood you when Mr. West was asking you questions about paragraph 32 of the stipulation, but you may have said that it was not anti-discriminatory.

Did you mean that it was not discriminatory?

A. I did mean to say it was not discriminatory, I'm sorry if I said anti.

Q. Is every existing special contract an electric generation contract providing system support?

A. The current ones that are filed as of today, yes. Every system electric generation contract is providing system support, they are just structured somewhat differently, and we are just trying to fine tune the structure to be more consistent going forward.

MS. CULPEPPER: That's all.

COMMISSIONER BROWN-BLAND: All right. Are there any questions from the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: There are no questions from Commission, so.

MS. CULPEPPER: I move that Revised Perry Exhibits 1 and 2 be entered into evidence.

COMMISSIONER BROWN-BLAND: All right. Those exhibits are received into evidence and they are -- will remain identified as they were marked.

(Revised Perry Exhibits 1 and 2 were admitted into evidence.)

COMMISSIONER BROWN-BLAND: All right. You are excused, Ms. Perry.

MS. CULPEPPER: Can we just have one minute, please.

COMMISSIONER BROWN-BLAND: Yes.

(Pause.)

MS. JOST: I understand that there are no cross examination questions or Commission questions for Public Staff Witnesses Mary Coleman, Lynn Feasel, Jan Larsen, Geoff Gilbert and Zarka Naba, and therefore, I would move that the prefiled testimony of these witnesses be copied into the record as if given orally from the stand and that their exhibits be identified as prefiled and entered into evidence.

COMMISSIONER BROWN-BLAND: All right. That was Mary Coleman, Zarka Naba, Jan Larsen, and who else?

MS. JOST: Lynn Feasel.

COMMISSIONER BROWN-BLAND: Lynn Feasel.

MS. JOST: And Geoff Gilbert.

COMMISSIONER BROWN-BLAND: And Geoff Gilbert. Is there any objections? Anyone have cross-examination for these witnesses, and no questions from the Commission? So that motion will be allowed.

(Whereupon, the prefiled direct testimony of Mary A. Coleman, Lynn Feasel, Jan A. Larsen, Geoffrey M. Gilbert, and Zarka H. Naba were copied into the record as if given orally from the stand.)

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF MARY A. COLEMAN
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2019

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

A. My name is Mary A. Coleman. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Staff Accountant in the Accounting Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth 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 the Payroll, Employee Benefits, Executive Compensation, and Board of Directors (BOD) expenses in support of the application of Piedmont Natural Gas Company, Inc. (Piedmont or Company) for a rate increase.

Q. **MS. COLEMAN, 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 Piedmont. I have also conducted extensive discovery in this matter, including the review of numerous responses provided by the Company in response to Public Staff data requests, participation in conference calls with the Company, and an on-site visit to review information and obtain answers to additional questions regarding overtime, North Carolina (NC) allocations, executive compensation, BOD expenses, and employee benefits.

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

A. I am recommending adjustments in the following areas:

(1) Payroll Expense
(2) Overtime Expense
(3) Payroll Taxes
(4) Employee Benefits
(5) Executive Compensation
(6) Board of Directors' Expenses

Q. **PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.**

A. My adjustments are described below.

PAYROLL EXPENSE

Q. **PLEASE EXPLAIN YOUR PROPOSED PAYROLL EXPENSE ADJUSTMENT.**

A. I updated the annualized payroll expense to a level that reflects pay rates and employees as of May 31, 2019, which resulted in an adjustment of $298,058 to increase Piedmont NC-allocated Straight Time Payroll Expenses, an adjustment of ($85,524) to decrease Duke Energy Business Services (DEBS) Straight Time Payroll allocations to Piedmont (as allocated to NC), and an adjustment of ($22,102) to decrease the Other Duke Companies Straight Time Payroll allocation to Piedmont NC jurisdictional operations. As reflected in Coleman Exhibit I, Schedule 1, these adjustments resulted in a total increase to the Company's payroll expense of $190,432.

OVERTIME EXPENSE

Q. PLEASE EXPLAIN YOUR OVERTIME EXPENSE ADJUSTMENT.

A. I am recommending a $680,698 decrease to the Company's overtime expense. My investigation revealed that the test year overtime expense was unusually high compared to prior years' overtime charges. Therefore, I determined a reasonable ongoing overtime amount by computing a three-year average of overtime charged to Piedmont's NC jurisdiction, and comparing that to the amount proposed by Piedmont. Coleman Exhibit I, Schedule 2 presents the calculation of this adjustment.

PAYROLL TAXES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PAYROLL TAXES.

A. After reviewing all payroll tax data provided by the Company in response to Public Staff data requests, I found that during the test year the Company used the IRS rate of 7.65%. However, the Company used a Payroll tax rate of 8.62% in its payroll tax pro forma adjustment. I determined that the appropriate Payroll tax rate to use in my adjustment was 7.65%.

EMPLOYEE BENEFITS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO EMPLOYEE BENEFITS.

A. I have made an adjustment of $796,822 to decrease the Company's proposed Employee Benefits. Coleman Exhibit I, Schedule 3 presents the calculation where I divided the total test year Piedmont NC-allocated benefits incurred by the Company by the test year's payroll to determine the Public Staff's benefit percentage. This percentage was applied to the Public Staff's pro forma O&M payroll amount to determine a reasonable ongoing level of Employee Benefits.

EXECUTIVE COMPENSATION

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO EXECUTIVE COMPENSATION.

A. My adjustment to Executive Compensation includes the removal of 50% of the total compensation of the top five executives which is comprised of total annual salary, Short Term Incentive Plan (STIP), Long Term Incentive Plan (LTIP), and Benefits. The Public Staff has identified the top five executives who have charged the highest compensation to the Piedmont NC jurisdiction. In this case the top five are the Chief Executive Officer (CEO) of Duke Energy Corporation (Duke Energy) and four Piedmont executives, specifically the President, Natural Gas Business; Sr. Vice President and Chief Operations Officer, Natural Gas Business; Sr. Vice President, Corporate Development and Treasurer; and the Vice President, Regulatory and Community Relations. As presented on Coleman Exhibit I, Schedule 4, this adjustment is used to reflect the fact that the executives' duties and compensation encompass a substantial amount of activities that are closely linked to shareholder interests.

Q. IS YOUR RECOMMENDATION BASED ON THE PREMISE THAT THE COMPENSATION OF THE DUKE ENERGY CEO AND THE

PIEDMONT 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 very large natural gas and 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.

Q. WHAT IS THE PREMISE FOR REMOVING 50% OF THE TOP EXECUTIVES' COMPENSATION?

A. 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 Piedmont'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 compensation and pension should be borne by the shareholders.

The executive compensation for the four Piedmont executives and Duke Energy CEO includes STIP payments which are 50% based upon Duke Energy's earnings per share. The LTIP for Performance

Share Grants is based 50% on Duke Energy's cumulative adjusted earnings per share and 25% based on Duke Energy's total shareholder return, which consists of dividends to shareholders and the increase in the price of Duke Energy common stock.

For the four named Piedmont executives, the combined 2018 STIP and LTIP payments totaled 49.4% of their 2018 total compensation, including all benefits.

Duke Energy CEO's pay, as stated on page 40 of the Duke Energy 2019 Proxy Statement (Duke 19 Proxy), is

> 90% of CEO pay is performance and/or stock based (both short term and long term) which **creates strong alignment with our shareholders** and reinforces our pay for performance culture.

(emphasis added)

The Duke 19 Proxy describes on page 41 the overall design of Duke Energy's executive compensation program

> We design our program so that it motivates our executives to focus on our core business priorities **and aligns the interests of executives and shareholders**.

(emphasis added)

On page 41 of the Duke 19 Proxy it states

> In order to emphasize the importance of the EPS objective, the Compensation Committee

> established a performance floor or circuit-breaker providing that if an adjusted diluted EPS performance level of at least $4.15 was not achieved, our NEOs would not have received any payout under the 2018 STI plan.

An "NEO" is defined on page 80 of the Duke 19 Proxy as "named executive officers".

For the LTIP Compensation, the Duke 2018 Proxy states on page 44

> Our LTI program is designed to provide our NEOs with appropriate balance to the STI plan **and to align executive and shareholder interests in an effort to maximize shareholder value**.

(emphasis added)

As shown on Duke 19 Proxy page 52, the Long Term Performance Stock Awards for the Duke Energy CEO in 2018 were 71% of total compensation and in 2017 were 81% of total compensation. The STI Non-Equity Incentive Plan Compensation for the Duke Energy CEO in 2018 was 16% of total compensation and in 2017 was 10% of total compensation. For 2018 the combined performance percentage of the Duke Energy CEO total compensation was 87%, consisting of 71% LTIP plus 16% STIP. For 2017 the combined performance percentage of the Duke Energy CEO total compensation was 91%, consisting of 81% LTIP plus 10% STIP.

The compensation paid to these five executives is heavily based upon Duke Energy earnings per share and Duke Energy total shareholder return. These performance measures heavily benefit the Duke Energy shareholders. It is appropriate that 50% the total compensation including benefits to the five executive officers should be allocated to the Duke Energy shareholders.

Adjusting the compensation of the some of the top executives is consistent with the positions taken by the Public Staff in past general rate cases involving investor-owned utilities serving North Carolina retail customers. Some of these cases include Duke Energy Carolinas' (DEC) 2018 General Rate Case (Docket No. E-7, Sub 1146), Public Service Company of North Carolina's (PSNC) 2016 General Rate Case (Docket No. G-9, Sub 565), and Piedmont's 2013 General Rate Case (Docket No. G-9, Sub 631). DEC, DEP, and Dominion Energy North Carolina have all made executive compensation adjustments in their respective general rate cases to remove a portion of their top executives' total compensation. The Public Staff has consistently updated each utility's adjustments to reflect a 50% reduction of the top executives' total compensation in each of the general rate case proceedings.

The Public Staff has also consistently made executive compensation adjustments in Piedmont's prior North Carolina general rate cases, as well as in general rate cases of Public Service Company of North Carolina, Inc., all of which have been approved by the Commission.

In addition, now that Piedmont is owned by Duke Energy and receives service company expense allocations from Duke Energy's officers, the Public Staff believes that the same executive compensation adjustment is appropriate and consistent with how the Commission would expect this process to continue.

BOARD OF DIRECTORS EXPENSES

Q. PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENT TO BOD EXPENSES.

A. I have made an adjustment to remove 50% of the expenses associated with the Duke Energy BOD that have been allocated to the Piedmont NC jurisdiction, as presented on Coleman Exhibit I, Schedule 5. Piedmont does not have a separate BOD. The expenses allocated to the Piedmont NC jurisdiction encompass the BOD's compensation, Directors' and Officers' liability insurance, and other miscellaneous expenses. The Duke Energy Principles for Corporate Governance (Amended and Restated as of December 13, 2018), first sentence states:

> An effective Board of Directors (the "Board") **will positively influence shareholder value** and enhance the reputation of Duke Energy Corporation (the "Corporation") as a constructive resource in the communities where it does business.

(emphasis added)

Under the heading Responsibilities of Directors, the first responsibility stated is:

> The basic responsibility of the directors is to exercise their business judgment to act in what they reasonably believe to be **in the best interests of the Corporation and its shareholders**.

(emphasis added)

Another responsibility stated on page 1 is:

> A director should at all times discharge his or her responsibilities with the highest standards of ethical conduct, in conformity with applicable laws and regulations, and **act solely in the best interest of the Corporation's shareholders**.

(emphasis added)

Under the topic Director Nominations on page 2, it states that each director nominee should

> Have a genuine interest in the Corporation and a recognition that, as a member of the Board, **one is accountable to the shareholders of the Corporation**, not to any particular interest group.

(emphasis added)

The shareholders vote on the election of directors. The customers do not have a vote. It is clear the BOD is responsible to act in the best interests of the shareholders.

The average 2018 compensation to the 13 Duke Energy directors was $308,564 as shown on Duke 19 Proxy page 30. The CEO and BOD Chairwoman did not receive a separate director compensation. The test year BOD compensation allocation to Piedmont NC was $215,140 as shown on Coleman Exhibit 1 Schedule 5 Line 1.

The Public Staff believes that it is appropriate and reasonable for the shareholders of the larger electric and natural gas utilities to bear a reasonable share of the costs of compensating those individuals who have a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. The premise of this adjustment is closely linked to the premise of the adjustment made by the Public Staff related to executive compensation. Furthermore, Directors' and Officers' liability insurance, while a necessary expense for a corporation, has been utilized to defend the BOD in lawsuits brought by shareholders regarding issues such as coal ash in the electric industry and other types of lawsuits such as merger claims and shareholders' derivatives. Therefore, the Public Staff believes it is appropriate for both ratepayers and shareholders to share the cost of BOD expenses.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

Mary A. Coleman

I am a graduate of North Carolina State University with a Bachelor of Accountancy degree and a Bachelor of Arts degree in Business Management.

Prior to joining the Public Staff, I was a Financial Consultant focusing mainly on non-profit organizations from 2013 until 2017. I was employed as a Consultant in places such as UNC Chapel Hill, NC State University, City of Raleigh-Community Development Office, Neuro Community Care, and the Carolina Center for Medical Excellence. Before I became a Consultant, I was the Chief Financial Officer for several organizations including the North Carolina Justice Center where I worked for ten years.

I joined the Public Staff as a Staff Accountant in December 2017. Since joining the Public Staff I have assisted on natural gas, electric, and water proceedings.

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF LYNN FEASEL
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2018

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

A. My name is Lynn Feasel. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am a Staff Accountant with the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth in Appendix A.

Q. BRIEFLY EXPLAIN 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 regarding Piedmont Natural Gas Company, Inc.'s (Piedmont or the Company) plant in service, accumulated depreciation, depreciation expense, property tax, and miscellaneous general expense.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

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, a review of the Company's accounting end-of-period data and adjustments, and its after-period adjustments, to test year expenses and rate base, and a review of the Company's responses to the Public Staff's data requests.

The adjustments I am recommending be made to rate base and operating expenses are in the following areas:

(1) Plant In Service;
(2) Accumulated Depreciation;
(3) Depreciation Expense;
(4) Property Tax; and
(5) Miscellaneous General Expense.

PLANT IN SERVICE AND ACCUMULATED DEPRECIATION

Q. PLEASE EXPLAIN YOUR INVESTIGATION INTO PLANT IN SERVICE AND ACCUMULATED DEPRECIATION.

A. I have updated plant in service and accumulated depreciation for known and actual changes through May 31, 2019, the cutoff date for post-test year plant additions, and removed estimated additions through June 30, 2019, as calculated by the Company. I have also made an end-of-period depreciation adjustment to accumulated depreciation for the difference between the annual depreciation expense per the Public Staff and the book depreciation expense for 12 months ended May 31, 2019, per the Company. In summary, my adjustment reflects (1) a $79,594,683 decrease in plant in service, and (2) a $15,636,066 decrease in accumulated depreciation (which increases rate base). Feasel Exhibit I Schedule 1 and all of its backup schedules reflect the calculation of and adjustments to plant in service and accumulated depreciation by the Public Staff.

DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. I adjusted depreciation expense to reflect an annualized amount of expense, based on the actual plant in service as of May 31, 2019, with the proposed depreciation rates provided by the Company. I also made an adjustment to depreciation expense to reflect the impact of reallocation of the reserve account as shown on Appendix A - NC Calculation of Annual Depreciation Accrual Final in Company witness Watson's testimony and a spreadsheet entitled "PNG Corporate 9-30-18 Accrual Final" provided by the Company to the Public Staff on July 12, 2019. Feasel Exhibit I, Schedule 1 and all of its backup schedules reflect the calculation of and adjustments to depreciation expense by the Public Staff.

PROPERTY TAX

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPERTY TAX.

A. The property tax rate used to calculate property tax expense in this rate case proceeding is based on the actual property tax paid in 2018 divided by gross utility plant balances as of December 31, 2017. I applied this rate to the gross plant in service balance as of May 31, 2019, in order to calculate property tax expense. Feasel Exhibit I, Schedule 1 and all of its backup schedules reflect the calculation of and adjustments to property tax by the Public Staff.

MISCELLANEOUS GENERAL EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO MISCELLANEOUS GENERAL EXPENSE.

A. I made adjustments to miscellaneous expense to remove: (1) membership dues expense related to South Carolina that were allocated to North Carolina; (2) dues that are related to entertainment, electric, and unknown sources; (3) employee one-time moving and entertainment expense; and (4) tuition fees refunded to employees. Feasel Exhibit II, Schedule 1 and all of its backup schedules reflect the calculation of and adjustments to miscellaneous expense by the Public Staff.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

LYNN FEASEL

I am a graduate of Baldwin Wallace University with a Master of Business Administration degree in Accounting. I am a Certified Public Accountant licensed in the State of North Carolina. Prior to joining the Public Staff, I was employed by Franklin International in Columbus, Ohio until June 2013. Additionally, I worked for ABB Inc. from September 2013 until October 2016. I joined the Public Staff as a Staff Accountant in November 2016. Since joining the Public Staff, I have worked on rate cases involving water and sewer and natural gas companies, filed testimony and affidavits in various general rate cases, calculated quarterly earnings for Carolina Water Service, Inc. of North Carolina and Aqua North Carolina, Inc., calculated refunds to consumers from AH4R and Progress Residential and reviewed franchise and contiguous filings for multiple water and sewer companies.

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF JAN A. LARSEN
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2019

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

A. My name is Jan A. Larsen and my business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Natural Gas Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE NATURE OF THE APPLICATION IN THIS RATE CASE?

A. Piedmont Natural Gas Company, Inc. (Piedmont or the Company) filed an application with the Commission on April 1, 2019, in this docket seeking authority to increase its rates and charges for natural gas utility service in all of its service areas in North Carolina and other relief.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

A. My areas of investigation in this proceeding have been the review of: (1) Piedmont's proposal to continue its Commission approved Integrity Management Rider (IMR) mechanism, (2) Piedmont's proposed Distribution Integrity Management Program (DIMP) Operations and Maintenance (O&M) deferral as discussed by Company witnesses Gaglio and Barkley, (3) Piedmont's proposed changes to its current billing procedures concerning the conversion from cubic feet to therms as discussed by Company witness Barkley, and (4) the refund of various riders discussed in Public Staff witness Perry's testimony. Regarding Piedmont's proposed DIMP O&M deferral, my area of investigation focused on whether this mechanism is necessary while Public Staff witness Jayasheela discusses the regulatory asset treatment from an accounting perspective.

All other engineering matters that fall into the Natural Gas Division's responsibility are discussed by Public Staff witnesses Naba, Gilbert, and Patel.

IMR MECHANISM

Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING PIEDMONT'S REQUEST TO CONTINUE THE IMR MECHANISM.

A. The Commission first approved Piedmont's IMR mechanism in its Order Approving Partial Rate Increase and Allowing Integrity Management Rider issued December 17, 2013, in Docket No. G-9, Sub 631 (Sub 631 Order), Piedmont's prior general rate case. In Docket No. G-9, Subs 631 and 642, by order issued November 23, 2015, the Commission approved a stipulation between Piedmont and the Public Staff, which required that, among other things, the IMR mechanism be subject to further review by October 31, 2019. In the Sub 631 Order, the Commission concluded that adoption of the IMR mechanism was in the public interest in light of the uncontested evidence of the capital expenditures required of Piedmont for TIMP/DIMP compliance and its conclusion that the frequent general rate case proceedings that would be required to enable Piedmont to roll those expenditures into rate base would increase regulatory costs and burdens. The Commission further concluded that the adoption of the IMR mechanism would enhance the safety and reliability of utility infrastructure by enabling the Company to timely recover pipeline safety and integrity-related expenditures.

Piedmont has applied for and received Commission approval to implement rate increments to recover its Integrity Management Revenue Requirement (IMRR). There have been 11 of these rate changes, as they are implemented bi-annually. Since the Sub 642 Rate Case and through December 31, 2018, Piedmont has recorded $1.18 billion in pipeline safety spending and, as of April 2019, has recovered a total of $246 million from its rate payers through the IMR mechanism since it was first implemented in February 2014. The Public Staff consistently spends significant resources on auditing Piedmont's monthly IMR reports. We send data requests and follow up with conference calls to understand where and how what IMR activity is going on and the associated costs. We also file our comments to Piedmont's annual IMR report.

Currently the IMR increment in rates for residential customers is $1.3013/dekatherm (dt), which is an annual cost of $75 for the average residential customer, or approximately 10% of the current average bill ($752 annually).

Although Piedmont's initial estimate of $150 million annually for IMR-related costs was exceeded by over 50% ($230 million per year), I believe Piedmont's estimate in the instant docket of $173 million per year for the next three years is more accurate due to the six years of experience the Company has gathered since then.

Although the cost of pipeline safety will not go away anytime soon, I believe the burden on customers will remain at the current level or even lessen in the future as more of the IMR balance is recovered from rate payers.

Fortunately, the commodity (supply) cost of gas has remained very low (in the $2 to $4/dt level) in an historical view, and projections in the future continue to see low gas prices. Customer rates and bills are significantly lower than they were 15 years ago when commodity cost was very high after hurricanes Rita and Katrina hit the Gulf of Mexico. For example, Piedmont's benchmark commodity cost of gas is currently at $2.75/dt, and has been less than $5/dt since its 2013 general rate case. Piedmont's benchmark commodity cost of gas was $13/dt in the fall of 2005.

Based on the importance of pipeline safety and how it protects Piedmont's customers, employees, and the general public, coupled with the reasonableness of the overall bills, I recommend the IMR mechanism remain in place. Also, I agree with Company witness Barkley's proposed language changes to Piedmont's Appendix E – Integrity Management Rider.

DIMP PROPOSED FOR REGULATORY ASSET

Q. PLEASE EXPLAIN THE PROPOSED DIMP O&M MECHANISM.

A. An outline of the DIMP Proposed for Regulatory Asset Treatment (DIMP Proposal) is contained in Company witness Gaglio Exhibit_(VMG-3). The DIMP Proposal covers three areas of pipeline safety – damage prevention, records, and corrosion – and is comprised of five programs: (1) Legacy Cross Bore, (2) Watch & Protect, (3) Locatability Investigations/Repair Untoneable Assets, (4) Map Services in Geographic Information System (GIS) Mapping Technology, and (5) Close Interval Surveys on high pressure distribution lines.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR REVIEW.

A. I reviewed responses from data requests sent to the Company regarding the DIMP Proposal and followed up with discussions with various Piedmont personnel. The following is summary of my findings:

<u>Overview</u>:

These programs were developed to address non-leak based threats to Piedmont's distribution system which is approximately 16,000 miles in length. The programs are described below:

Legacy Cross Bore:

This involves the piercing of a sewer line from a home or business during the installation of a natural gas service or distribution line via horizontal directional drilling. This can often go unnoticed for a long time until the customer experiences a clogged sewer line. Problems typically arise when the customer hires a plumbing contractor who power augers the sewer line in order to clear the obstruction. This practice cuts the natural gas line, and gas can build up in the sewer line and eventually enter the home or business. This very dangerous situation can, and has in some instances, caused a natural gas-fueled explosion.

It is worth noting that, even when underground lines have been located prior to the installation of the natural gas line, the sewer line from the house or business to the main in the street is considered the customer's property and responsibility and is typically not located by the North Carolina 811 system. It is my understanding that the North Carolina 811 system only marks **publicly managed** underground utility lines and not customer "house" piping.

According to Piedmont representatives, the Company has located 142 cross bores in its North Carolina territory. In addition, Duke Energy Ohio and Kentucky natural gas operations have discovered over 300 cross bores.

Watch and Protect:

This program involves the evaluation of all underground location (811) tickets and computes a probability-risk factor based upon the past history of the third-party excavator in regards to damage to Piedmont's natural gas lines, the method of installation (direct drilling or open cut), the pipe material and density, and the consequence to the public if damage occurred to Piedmont's system based on population density. The riskiest tickets are assigned an on-site visit by a Piedmont employee or a contractor hired by Piedmont prior to excavation/installation to oversee the safety of the proposed work.

We have learned that Duke Energy Ohio's natural gas operations has implemented this program and has seen a 30-35% reduction in their natural gas lines being struck by a third party doing excavation work near their natural gas lines. Also, Duke Energy Ohio has represented to us that they have received positive response from contractors regarding this program.

Locatability Investigations/Repair Untoneable Assets:

This involves both locating all gas lines in advance of any proposed underground excavation and marking lines that were not locatable (untoneable).

<u>Geographic Information System (GIS):</u>

Piedmont is in the process of updating its GIS system in order to locate all of its facilities the GIS framework. It is my understanding that this project should be completed in approximately five years. GIS is a framework for gathering, managing, and analyzing data. Rooted in the science of geography, GIS integrates many types of data. It analyzes spatial location and organizes layers of information into visualizations using maps.

<u>Corrosion:</u>

Piedmont is proposing to place test stations every 500 to 1,000 feet along its high pressure distribution lines in order to test for voltage. This will enable Piedmont to pinpoint any voltage drops that may lead to pipe being compromised through corrosion. Piedmont has represented to us that this program has been successful in Duke Energy Ohio's natural gas operations. Also, it is listed by the American Gas Association as a "best practice."

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROPOSED DIMP DEFERRAL O&M EXPENSES?

A. Company witness Gaglio states that it is difficult to estimate these costs with much certainty and that doing so would be speculative. Based on the Company's responses to Public Staff data requests, some of these expenses are extrapolated from Duke Energy Corporation (Duke Energy) natural gas affiliates in other states with similar programs, some are third party estimates, and some are in-house estimates.

Company witness Barkley notes that Public Service Company of North Carolina, Incorporated was granted a DIMP O&M deferral by the Commission in 2016 in its last general rate case, Docket No. G-5, Sub 565.

The issue of pipeline safety and specifically the testing of local distribution companies' systems and the implementation of safety programs has come to the forefront in the past 10 to 15 years. The focus began on transmission systems and then moved to distribution systems. Significant expenditures have been made to address pipeline safety in order to remain compliant with regulations imposed by the Pipeline and Hazardous Materials Safety Administration (PHMSA). It is difficult to put a cost on pipeline safety and the prevention of property damage and personal injury or death that can occur from a natural gas incident.

Piedmont's proposed DIMP O&M deferral estimated at $11 million annually would result in the average residential customer paying about $0.87 more in their monthly bill, assuming that these expenses would be allocated to the various rate schedules in a similar manner as in the IMR Rider. This is only 1.4% of an existing average bill of $62.64/month. Some of these programs are on-going while others have a completion date within a few years.

Based upon the foregoing, I recommend that Piedmont be granted its requested DIMP O&M deferral with some reporting requirements. I recommend that Piedmont file annual reports beginning November 1, 2020, and continue until the Commission issues an order in Piedmont's next general rate case. The annual DIMP reports should include a listing of all DIMP O&M expenditures in Excel format and specify which DIMP program the expenditures relate to, and supporting documentation. The Public Staff should have the opportunity to examine the annual reports and, if the Public Staff deems it appropriate, comment on the expenditures.

CHANGES TO BILLING PROCEDURES

Q. WHAT IS YOUR RECOMMENDATION REGARDING PIEDMONT'S PROPOSED CHANGES TO ITS BILLLING PROCEDURES REGARDING THE CONVERSION FROM CUBIC FEET TO THERMS?

A. Natural gas is measured in cubic feet (volume) and is billed in therms (energy content). Piedmont currently links customers to 11 common gas areas (CGAs) to determine the proper energy (BTU) factor.

Piedmont is proposing to change this to two CGAs, one for its eastern operations and one for its western operations.

BTU factors remain fairly consistent at 1.034, and monthly Gas Utility Reports (meter reports) showed ranges from 1.027 to 1.043 when I analyzed them during 2016 and 2017 in a different proceeding. This is only a 1.5% difference in the lowest and highest BTU factors and is not significant to customers' bills. Also, this proposal appears to be administratively beneficial without harming customers. Therefore, I believe that Piedmont's proposal is reasonable and should be approved.

REFUND OF RIDERS

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE REFUNDING OF THE RIDERS DISCUSSED IN PUBLIC STAFF WITNESS PERRY'S TESTIMONY?

A. Since these riders are margin collected from customers and now being refunded back to customers, I recommend using the customer class apportionment percentages contained in the Company's existing Appendix E – Integrity Management Rider, Section 4. Computation of Adjustment of Biannual Integrity Management Adjustment. This is the same methodology ordered by the Commission in the merger of Duke Energy and Piedmont, Docket

Nos. G-9, Sub 682, E-2, Sub 1095, and E-7, Sub 1100, when implementing a bill credit. See Ordering Paragraph No. 4 of the Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued September 29, 2016.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JAN A. LARSEN

I graduated from North Carolina State University in 1983 with a Bachelor of Science degree in Civil Engineering. I was employed with Law Engineering Testing Company as a Materials Engineer from 1983 to 1984. From 1984 until 1986, I was employed by the North Carolina Department of Transportation as a Highway Engineer.

In 1986, I was employed by the Public Staff's Water Division as a Utilities Engineer I. In 1992, I was promoted to Utilities Engineer II with the Public Staff's Natural Gas Division and promoted to Utilities Engineer III in 2002.

In May of 2016, I was promoted to the Director of the Public Staff's Natural Gas Division. My most current work experience with the Public Staff includes the following topics:

1. Rate Design
2. Allocated Cost-of-Service Studies
3. Purchase Gas Cost Adjustment Procedures
4. Tariff Filings
5. Natural Gas Expansion Project Filings
6. Depreciation Rate Studies
7. Annual Review of Gas Costs
8. Weather Normalization Adjustments
9. Customer Utilization Trackers / Margin Decoupling Trackers
10. Feasibility Studies / Line Extension Policies
11. Pipeline Integrity Management Riders
12. Biogas Injection into Natural Gas Systems
13. Mergers and Acquisitions

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF GEOFFREY M. GILBERT
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2019

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

A. My name is Geoffrey M. Gilbert and my business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Public Utilities Engineer in the Natural Gas Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE NATURE OF THE APPLICATION IN THIS RATE CASE?

A. Piedmont Natural Gas Company, Inc. (Piedmont or the Company), is applying for an adjustment of rates, charges, and tariffs applicable to its service in North Carolina. It is also applying for continuation of its Integrity Management Rider (IMR) mechanism, adoption of an

Excess Deferred Income Taxes (EDIT) Rider mechanism, and other relief.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS APPLICATION.

A. My areas of investigation in this proceeding have been (1) determining the service quality provided by Piedmont, (2) evaluating whether an increase in spending is appropriate for Piedmont's energy efficiency (conservation) program(s), (3) evaluating the Company's depreciation study and determining if new depreciation rates should be implemented, and (4) other engineering matters.

Q. HOW WOULD YOU RATE THE SERVICE QUALITY OF PIEDMONT?

A. Based on my investigation, I believe Piedmont has met or exceeded every service quality requirement.

I reviewed the monthly call center reports for the test year which show that Piedmont exceeded the goal of answering 80% of incoming calls within twenty seconds for the overall year.

In response to a Public Staff data request, Piedmont stated that it uses a proprietary survey, CX Monitor, to measure customer satisfaction utilizing a Net Promoter Score (NPS) that ranges from

-100 to +100. Piedmont's NPS is up over the course of the study (12 months ended May 2019) and has stabilized in the mid-50+ range.

The Director of the Public Staff's Consumer Services Division, Vickie Debnam, advised me that Piedmont's service quality is very good and that Piedmont responds and resolves complaint investigations in a professional and timely manner. Ms. Debnam also added there has been no noticeable change in Piedmont's service quality since the merger of Piedmont and Duke Energy Corporation (Duke Energy) in 2016 (Merger), which was approved by the Commission in Docket Nos. G-9, Sub 682, E-2, Sub 1095, and E-7, Sub 1100.

Piedmont has made several changes to its service centers and/or service center protocols since the Merger, which include the following:

- Piedmont integrated the Duke Achieving Customer Excellence (ACE) quality monitoring form as part of its overall Quality Monitoring Program for contact center agents. The Quality Monitoring Program is designed to help maintain quality standards, improve the customer experience, and improve performance.
- Piedmont changed its holiday schedule to be consistent with that of Duke Energy.

- Duke Energy affiliates, including Piedmont, established mutual storm support.
- Piedmont incorporated Duke Energy's quarterly incentive program for call center agents that offers financial rewards to agents who meet targeted goals for attendance, schedule adherence, customer satisfaction, and quality assurance.
- Piedmont moved to the same process for recruiting call center agents as Duke Energy.

The foregoing evidence supports the testimony Company witness Yoho who states in his testimony on page 15, lines 7-9, that "Piedmont has continued to receive customer satisfaction and trusted brand scores from J.D. Power and Cogent Reports that exceed or closely approximate top quartile and top decile respectively."

Q. PLEASE EXPLAIN YOUR INVESTIGATION OF PIEDMONT'S CUSTOMER CONSERVATION PROGRAM AND THE REQUESTED $1,225,000 ANNUAL INCREASE IN SPENDING?

A. Piedmont's current Commission-approved funding level for its conservation program is $1,275,000. The Company is requesting an increase of $1,225,000, nearly doubling the current amount to $2.5 million.

Q. PLEASE PROVIDE A HISTORY OF PIEDMONT'S CONSERVATION PROGRAM FUNDING.

On November 3, 2005, the Commission issued its Order Approving Partial Rate Increase and Requiring Conservation Initiative in Docket No. G-9, Sub 499 (Sub 499 Order). In that case, the Commission approved a Customer Utilization Tracker (CUT) mechanism, as an experimental, provisional tariff for a period of no more than three years from the effective date of rates therein, and ordered that, during the life of the CUT, Piedmont contribute $500,000 per year toward conservation programs and work with the Attorney General and the Public Staff to develop appropriate and effective conservation programs to assist residential and commercial customers. The Sub 499 Order stated that "[t]he Commission believes in order for the CUT to be fair to both the Company and customers, approval of the CUT must be associated with a substantial and effective conservation initiative by Piedmont to assist its customers with the high natural gas prices that they face today." (Sub 499 Order, p 24) The Attorney General filed notices of appeal regarding approval of the CUT in Sub 499 and implementation of Piedmont's first semi-annual rate increment under the CUT in Docket No. G-9, Sub 521. Following docketing of the appeals, Piedmont and the Attorney General undertook negotiations and ultimately agreed to a settlement in which the Attorney General agreed to dismiss its appeals and Piedmont committed to an additional $750,000 in annual conservation program funding.[1] By Order Approving Requested Relief issued September 14, 2006, the Commission approved the proposed annual accounting adjustment to Piedmont's CUT deferred account utilizing the formula described in the settlement agreement for each of the three years of its experimental period.

On March 31, 2008, in Docket No. G-9, Sub 550, Piedmont filed a petition seeking, among other things, an increase in and revisions to its rates and charges, permanent extension of its margin decoupling mechanism, and approval of conservation and energy efficiency programs and recovery of associated costs. Piedmont requested an increase in its conservation program spending to $3 million. All of the parties to the docket, except the Attorney General, entered into a stipulation which provided that Piedmont will be allowed to recover $1,275,000 of conservation program expenditures through the cost

[1] Piedmont agreed that for each of the three years that the experimental CUT is in effect, and to the extent that the total deferral under the CUT for that year exceeds the sum of the weather-related deferrals during November through March, Piedmont will make a credit entry to the CUT deferred account partially reducing the amount to be collected from customers through future rate increments. The amount of this credit entry will be equal to twenty-five per cent (25%) of the amounts deferred in excess of weather-related deferrals for that period, subject to an annual cap of $750,000 plus the related accumulated interest on the amount of such credit. Further, Piedmont agreed that for each of the three years that the experimental CUT is in effect, and to the extent that the total deferral under the CUT mechanism for that year exceeds the sum of weather-related deferrals during November through March, Piedmont shall contribute additional amounts to fund conservation programs. The amount of such additional contributions shall equal twenty-five per cent (25%) of the amounts in excess of weather-related deferrals for that annual period, subject to a cap for each respective annual period of $750,000.

of service in the proceeding. As authorized by N.C. Gen. Stat. § 62-133.7, which was enacted in 2007, the stipulating parties agreed that it was appropriate to continue the Company's proposed Margin Decoupling Tracker (MDT) mechanism, which was originally known as the CUT. On October 24, 2008, the Commission issued an Order Approving Partial Rate Increase and Requiring Conservation Program Filing and Reporting in Docket No. G-9, Sub 550, approving the stipulation, and thus the $1,275,000 in conservation spending. The Commission also found that the MDT was in the public interest and should be approved. The Commission's approval of the MDT was not tied to conservation spending.

In Piedmont's last general rate proceeding, Docket No. G-9, Sub 631, Piedmont did not request a change to its conservation program spending. Thus, Piedmont's conservation program spending has remained steady at $1,275,000 for over ten years.

I also examined Piedmont's Annual Conservation Program Reports and the resultant effects of energy savings from the programs.

Piedmont's current conservation programs include:

- Equipment Rebate Program – Provides rebates to Piedmont's current residential and commercial customers who replace their existing natural gas water and space heating equipment with qualifying high-efficiency equipment, including tankless water heaters.

- Residential Low Income Energy Efficiency Program – Provides energy efficiency measures and weatherization assistance through a third-party energy contractor to low-income residential customers that are intended to create a more energy-efficient and comfortable home environment for the customers.

- School Conservation Education Program – Consisting of a school-based education program that provides interactive, engaging performances by The National Theater for Children and includes lessons and take-home activities for Kindergarten through 5th grade students on the importance of natural gas conservation and safety.

In this docket, Company witness Barkley states in his testimony on page 14, line 22, that specific conservation program proposals are "not yet ready." I interpret this to mean that no specific programs have been generated/created for the use of or demonstrate the need for Piedmont's proposed conservation program funding increase. Also, Piedmont's most recent Annual Conservation Program Report filed in Docket No. G-9, Sub 631A, on June 14, 2019, does not list any recommended changes to any of Piedmont's programs.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING PIEDMONT'S PROPOSED INCREASE IN CONSERVATION PROGRAM FUNDING?

A. Based on my investigation and evaluation, I conclude that the programs are working well at their current funding levels and that no further funding is warranted at this time. If the Company wishes to increase spending for its conservation programs, I recommend that Piedmont identify specific programs and provide an explanation as to how they will benefit ratepayers. The Public Staff should be given the opportunity to examine any proposed new programs and make recommendations to the Commission regarding such programs before they are implemented.

I would also note that approval of increased spending for conservation would impact customers' bills not only directly, as a result of the increased conservation spending, but also as a result of rate increases through the Company's MDT mechanism to recover any lost revenue resulting from the reduction in usage triggered by the conservation programs.

Q. WHAT IS THE PUBLIC STAFF'S POSITION ON CHANGING DEPRECIATION EXPENSE TO THE LEVEL RECOMMENDED BY COMPANY WITNESS WATSON?

A. In this docket, Piedmont submitted its five-year depreciation study in compliance with Commission Rule R6-80. Company witness Watson of Alliance Consulting Group conducted the depreciation study of Piedmont North Carolina, South Carolina (together "the Carolinas"), and Corporate depreciable assets as of September 30, 2018.

The study recommends a change in depreciation rates, which results in an overall increase of $0.3 million in annual depreciation expense compared to the annual depreciation expense being recorded as of September 30, 2018. This overall increase is comprised of a decrease of $9.5 million for North Carolina, a decrease of $0.2 million for South Carolina, and an increase of $10 million for Corporate. Overall, the primary driver of the change is in the Distribution function and Intangible Software. In addition, depreciation expense is impacted by the reserve position.

I have reviewed the depreciation study and responses to Public Staff data requests related to the depreciation study. I recommend that the depreciation study as filed be accepted as being in compliance with Commission Rule R6-80. Public Staff witness Feasel has implemented in the depreciation expense adjustments in her testimony.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS?

A. Yes. Piedmont is proposing to eliminate the winter only standby sales service, which is currently available to customers on Rate Schedules 113, T-12, and ST-1. According to Company witness Barkley, subscription to this service is essentially a back-up supply source for customers during the winter heating period, and customers are required to pay demand charges in order to reserve this service. Company witness Barkley states that customers have not needed this service in recent years, he does not anticipate customers will have need for it in the future, and proposes to eliminate it. Since eliminating the service will simplify Piedmont's gas cost acquisition planning and strategies and will not inconvenience customers, I agree with Piedmont's proposal to eliminate it.

Another change being proposed by Piedmont to its tariffs involves changes in tolerances used in Piedmont's annual customer classification process under Sections 34 and 35 of the Company's Service Regulations. Piedmont's proposal will allow a 10% buffer (customers moving "up" in rate schedule qualification will have to exceed 110% of the threshold amount and customers moving "down" in rate schedule qualification will have to be below 90% of the threshold amount in order to move). Piedmont states that this method has been approved for its South Carolina natural gas operations. This change does not appear to harm North Carolina customers, and I agree with the proposal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

GEOFFREY M. GILBERT

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Environmental Engineering.

Prior to joining the Public Staff, I worked in the environmental field for TRC Solutions beginning in October 2008. At TRC, I specialized in air emissions testing and monitoring. Beginning in May 2015, I worked for Geo-Technology Associates, Inc., where I was responsible for completing Transaction Screens, Phase I and II Environmental Site Assessments for a variety of sites, including residential, commercial, industrial, and brownfield.

I joined the Public Staff in August 2017 as a Public Utilities Engineer with the Natural Gas Division. My work to date includes Purchased Gas Cost Adjustment Procedures, Customer Utilization Trackers, Integrity Management Riders, Annual Review of Gas Costs Proceedings, Peak Day Demand and Capacity Calculations, and Customer Complaint Resolutions.

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF ZARKA H. NABA
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2019

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

A. My name is Zarka H. Naba. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Public Utilities Engineer with the Natural Gas Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE NATURE OF THE APPLICATION IN THIS RATE CASE?

A. Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed an application with the Commission on April 1, 2019, in this docket seeking authority to increase its rates and charges for natural gas utility service in all of its service areas in North Carolina and other relief.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING PIEDMONT'S APPLICATION.

A. My areas of investigation in this proceeding have been: (1) determining the appropriate volume and customer levels, (2) evaluating the weather normalization for the test period, (3) calculating end-of-period revenues, and (4) reviewing the Company's terms and conditions.

The main purpose of my investigation was to normalize the Company's volume of gas for weather and to evaluate and update the customer growth as of May 31, 2019, the update period recommended by the Public Staff.[1] To do this, I calculated weather normalization and customer growth adjustments to the per books number of bills and volumes of each rate schedule to determine the appropriate end-of-period levels of sales and transportation bills and volume. I then used the adjusted sales and transportation levels to complete the end-of-period revenue calculations.

WEATHER NORMALIZATION AND CUSTOMER GROWTH

Weather normalization measures the impact of weather on energy consumption. When evaluating a natural gas general rate case, the

[1] Piedmont's application uses an update period as of June 30, 2019, as discussed later in this testimony.

Public Staff runs its own weather normalization model and compares the results to those produced by local distribution company.

Q. PLEASE EXPLAIN HOW YOU CALCULATED YOUR WEATHER NORMALIZATION ADJUSTMENT.

A. The Public Staff calculates the weather normalization by taking the test year customer data (i.e., the number of bills and consumption by month) and comparing it with the monthly actual Heating Degree Days (HDDs) to develop a mathematical model that computes a Base Load and a Heat-Sensitive Factor (HSF). These Base Load and HSF components are then applied to the normal HDDs for the test year, resulting in a volume level that would have been expected if the weather had been normal during the test year.

Q. PLEASE EXPLAIN HEATING DEGREE DAYS AND HOW THEY ARE UTILIZED IN YOUR MATHEMATICAL MODEL.

A. HDD is a measurement used to quantify the demand for energy needed to for space heating. HDDs are calculated by subtracting the average daily temperature from a base or standard temperature of 65 degrees Fahrenheit.[2] For example, a low of 20 degrees and a high of 40 degrees would yield an average of 30 degrees and an

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[2] The use of 65 degrees Fahrenheit is based on an assumption that heating is not needed to be comfortable when the outside temperature is 65 degrees or more.

HDD of 35 degrees (65-(20+40)/2). The normal HDDs are based on a 30-year average.

A mathematical model in the form of a linear regression is used to compare the average usage to the actual HDD. The accuracy of this model can be determined by examining the R^2 (R Squared) value that the model produces. The closer the R Squared value is to 1.000, the more accurate the model is in predicting the calculated volume from the HDD input. The Public Staff's model resulted in an R Squared value of 0.977. Generally speaking, an R Squared value of 0.900 or above indicates a very good correlation between usage and HDDs.

Q. WHAT DATA SOURCES DID YOU USE FOR YOUR HEATING DEGREE DAY CALCULATIONS?

A. The temperatures used to calculate the HDDs were obtained from the State Climate Office of North Carolina – North Carolina State University. The Company has historically used weather data obtained on an hourly basis, whereas the Public Staff uses a daily average (high temperature+low temperature/2). Because Piedmont's service territory is so geographically dispersed, temperature data from multiple weather stations are used. Weighting percentages for the weather stations provided by the Company through a response to a data request were applied to the normal and actual degree days. The weighting percentages are determined by heat-sensitive customer population, i.e., residential and commercial customers who need more security of service during peak (cold) days than do non-heat-sensitive customers. The final numbers for the normal HDDs and actual HDDs are the combined weighted normal HDDs and actual HDDs used to perform the linear regression analysis for the test period of the 12 months ended December 31, 2018.

Q. DOES THE COMPANY'S WEATHER NORMALIZATION ADJUSTMENT AGREE WITH THAT OF PUBLIC STAFF?

A. The results do not agree exactly, but they are very similar. The difference in the adjustments is likely due to the fact that the Company uses hourly weather data, whereas the Public Staff uses daily averages, as explained above. Based on my review of the Company's weather normalization analysis, I believe it is accurate and should be used in this case.

Q. WHAT DATE DID YOU USE TO ADJUST FOR CUSTOMER GROWTH?

A. Due to the Public Staff's need to update plant in service and expenses and comply with its deadline to file its testimony, the Public Staff reflected customer growth through May 31, 2019, in its adjustment, whereas the Company reflected growth through June 30, 2019.

END OF PERIOD VOLUME AND CUSTOMER DETERMINATION

Q. WHAT ARE THE TOTAL SALES AND TRANSPORTATION BILLS AND VOLUME THAT YOU HAVE USED TO CALCULATE END-OF-PERIOD REVENUES?

A. I have determined that the appropriate end-of-period level of sales and transportation bills is 8,970,571 and volume is 483,296,485 dekatherms (dts). The derivation of this volume level, made to arrive at the Public Staff's total adjusted end-of-period level, is shown in Naba Exhibit 1.

Q. PLEASE PROVIDE AN EXPLANATION FOR YOUR ADJUSTMENTS SHOWN IN NABA EXHIBIT 1?

A. Columns (4) and (5) of Naba Exhibit 1 show the per books number of bills and the per books sales and transportation volume level segmented by rate schedule for the test year ended December 31, 2018. Adjustment for the effect of weather normalization, which is shown in Column (6), adjusts the volumes for the heat-sensitive market (Rate Schedules 101, 102, and 152) by (2,733,638). The Public Staff and the Company are in agreement on the weather normalization calculation methodology. Due to the similarity of the adjustments of the Public Staff and the Company, the Public Staff is not proposing an adjustment to pro forma revenue.

END-OF-PERIOD REVENUE CALCULATIONS

Q. WHAT RATES DID YOU USE FOR PURPOSES OF CALCULATING THE END-OF-PERIOD PRO FORMA REVENUE LEVEL?

A. I used the April 1, 2019 rates approved by the Commission in Docket No. G-9, Sub 746, Piedmont's Application for Approval of Bi-Annual Adjustment of Rates Under Appendix C of its Service Regulations, to calculate the end-of-period pro forma revenue level. These rates exclude any temporary increments or decrements (temporaries) which were included in rates at that point in time. This calculation produces what are known as "clean rates."

Q. WHY ARE TEMPORARIES REMOVED FROM RATES FOR RATE CASE ANALYSIS?

A. Temporaries are usually associated with deferred account activities and are not related to revenue generation for the Company. The margins associated with various rate schedules are not affected by temporaries, except when temporaries are associated with fixed gas costs. Temporaries are removed when calculating end-of-period rates and proposed rates to achieve consistency and for ease of understanding. After the Commission determines the proper rates in this case, the new billing rates will be adjusted for the then current temporaries.

Q. WHAT IS YOUR END-OF-PERIOD REVENUE CALCULATION FOR THE COMPANY?

A. The total revenue level for the sale and transportation of gas, including other operating revenues, is $899,592,143.

Q. HOW DID YOU CALCULATE THIS END-OF-PERIOD REVENUE FOR THE COMPANY?

A. This figure was calculated by multiplying the number of bills, by the facilities charge per bill, to arrive at the total facilities charges. Similarly, the demand (for certain rate schedules) was multiplied by the demand charge per bill, to arrive at the total demand charges. Likewise, the volume is multiplied by end-of-period rates to arrive at the energy charges. The total facilities charge for a particular rate schedule, plus any demand charge for that rate schedule, plus the energy charge for that rate schedule, plus Integrity Management Rider revenues for that rate schedule, plus any Minimum Margin Agreement payments or Compression Charges for that rate schedule equals the total revenue received from that class of customer. The addition of all these rate schedule totals calculates to the total end-of-period revenue level.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

ZARKA H. NABA

I am a graduate of The City University of New York with a Bachelor of Engineering degree in Environmental Engineering.

I began working in the environmental field in June 2016 as an Environmental Engineering Intern. I've worked with the New York City Department of Sanitation's Vehicle Acquisition Warranty Division (DSNY) to assist in several fuel usage tracking projects installed in their fleet vehicles. While employed at DSNY, I was responsible for reporting installation projects, as well as researching environmental and safety impacts of various new technologies introduced.

I joined the Public Staff in September of 2017 as a member of the Natural Gas Division. My work to date includes Purchased Gas Cost Adjustment Procedures, Tariff Amendments, Fuel Tracker & Power Cost Adjustments, CNG Contracts, Annual Review of Gas Costs, Margin Decoupling Trackers, Peak Day Demand and Capacity Calculations, and Customer Complaint Resolutions.

MS. JOST: Thank you. The Public Staff has three other witnesses who would like to make corrections to their testimony who I would like to call at this time.

COMMISSIONER BROWN-BLAND: All right. And if you will -- before that, just for the record, testimony of those witnesses just -- whose testimonies were just moved and admitted, they are received into evidence as well as their exhibits filed, the prefiled testimony, and those are identified as they were marked when prefiled.

(Coleman Exhibit Plaintiff's, Revised Feasel Exhibits 1 and 2, and Naba Exhibit 1 were admitted into evidence.)

COMMISSIONER BROWN-BLAND: With regard to the other three that you wish to call, will you call them one at a time so we don't have to reorganize?

MS. JOST: Sure.

MS. CULPEPPER: May I ask for clarification? Some of the witnesses filed revised exhibits as well, we would ask that those be admitted.

COMMISSIONER BROWN-BLAND: And that was

part of the motion that she just made, correct?

MS. CULPEPPER: Okay. I wanted to make sure that you had admitted those as well.

COMMISSIONER BROWN-BLAND: All right. Yes.

MS. CULPEPPER: Okay. Thank you.

COMMISSIONER BROWN-BLAND: They will be received, same as the others.

MS. JOST: Thank you. The Public Staff calls R. Tyler Allison.

R. TYLER ALLISON,

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

DIRECT EXAMINATION BY MS. JOST:

Q. Mr. Allison, could you please state your name, business address, and present position for the record.

A. My name is R. Tyler Allison. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. And I'm a staff accountant with the accounting division with the Public Staff.

COMMISSIONER BROWN-BLAND: Mr. Allison, stay near your microphone for us.

COMMISSIONER GRAY: Move it towards you,

might help.

Q. All right. On July 19, 2019, did you prepare and cause to be filed in this docket, testimony consisting of 14 pages, two exhibits, and an appendix?

A. Yes.

Q. Was that filing subsequently withdrawn?

A. Yes.

Q. And on July 29, 2019, did you prepare and cause to be filed in this docket, confidential and public versions of your testimony, each consisting of 14 pages, two exhibits, and an appendix?

A. Yes.

Q. Do you have any corrections to your testimony?

A. Yes, I do.

Q. Go ahead and make those, please.

A. On page 10, line 6, remove the word "advertisements." And on page 12, line 21, change Allison Exhibit 2 to Allison Exhibit 1.

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

A. Yes.

MS. JOST: I move that Mr. Allison's

prefiled direct testimony as corrected consisting of 14 pages and one appendix be copied into the record as if given orally from the stand, and that has exhibits be identified as marked when filed and entered into evidence.

COMMISSIONER BROWN-BLAND: All right. That motion will be allowed, and is it revised direct testimony; is that correct, Michelle?

MS. JOST: That's correct.

COMMISSIONER BROWN-BLAND: Will be received into evidence treated as if given orally from the stand along with the exhibits which will be identified as they were marked when prefiled. The information -- they will continue to be in the confidential and in the public form and confidential will remain confidential.

MS. JOST: Thank you.

(Allison Exhibit I Schedule 1, Allison Confidential Schedule 2 through 6, Allison Exhibit II Schedule 1, and Allison Schedule 1-1 through 1-7 were admitted into evidence.)

(Whereupon, the prefiled revised direct testimony of R. Tyler Allison was copied

into the record as if given orally from
the stand.)

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF R. TYLER ALLISON
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2019

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

A. My name is R. Tyler Allison. 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 (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth in Appendix A.

Q. WHAT IS THE NATURE OF THE APPLICATION IN THIS RATE CASE?

A. Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed an application with the Commission on April 1, 2019, in Docket No. G-9, Sub 743, seeking authority to increase rates for natural gas utility service in all of its service areas in North Carolina.

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 certain expenses presented by Piedmont in support of its application.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

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, an on-site audit, and a review of the Company's accounting, end-of-period, and after-period adjustments. It also included a review of the Company's responses to the Public Staff's data requests.

Based on my investigation, I have made adjustments to and recommendations regarding the following expense items:

(1) Uncollectibles
(2) Advertising
(3) Lobbying
(4) Sponsorships and Donations
(5) Line Locates
(6) Inflation
(7) Rents
(8) Customer Growth

UNCOLLECTIBLES EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UNCOLLECTIBLES EXPENSES.

A. The Company made an adjustment to increase uncollectibles expenses by $1,020,327 for the test period ended December 31, 2018. I recommend instead that test year uncollectibles expenses be adjusted as shown in Jayasheela Exhibit I, Schedule 3-4.

Pursuant to its Purchased Gas Adjustment procedures, Piedmont recovers the gas cost portion of uncollectible account write-offs by charging the actual amounts to its Gas Cost Deferred Account. Therefore, the only portion of uncollectibles that should be included in operations and maintenance (O&M) expenses in a rate case proceeding is the non-gas cost, also known as "margin," portion of customer bills.

The Company computed its uncollectibles expense by calculating the ratio of net accounts charged off to total company NC operating revenues, and then applied this ratio to the proposed pro forma operating revenues to determine the pro forma provision for uncollectible accounts. The Company then applied a ratio of pro forma margin to the pro forma operating revenue to determine the non-gas portion of pro forma uncollectible accounts expense of $6,264,395.

My calculation of uncollectibles expense differs from the Company's in three ways. First, I used the NC charge offs, rather than using total company charge offs as the Company did, to calculate the new uncollectibles percentage. Second, I used a three-year average of Net NC Charge-offs and sales and transportation revenues. I used a three year average because the test year reflected a higher-than-average uncollectibles due to an usually cold winter in 2018. Third, I netted the gas cost deferrals for each year with the net NC charge-offs used to determine the ratio. The ratio of net accounts charged off to revenue that I have calculated in the current proceeding is 0.4871%, as compared to the Company's ratio of 1.07405%.

To determine the accurate uncollectible expense I recalculated a three-year average of net NC Charge-offs less the gas cost deferral, and I used a three-year average of sales & transportation revenues. I then divided the average of net NC Charge-offs by the averaged of Sales & Transportation revenues to determine the uncollectible percentage per Public Staff.

When I applied my uncollectibles ratios to the sales and transportation revenues proposed by the Public Staff in this proceeding, it results in a decrease in uncollectibles expense as shown in Jayasheela Exhibit I, Schedule 3-4.

ADVERTISING EXPENSES

Q. PLEASE DESCRIBE HOW YOU CONDUCTED YOUR INVESTIGATION OF ADVERTISING EXPENSES.

A. I first requested a detailed listing of all advertising expenses for the test period. From this listing, I reviewed expenses from each advertising account and also requested documentation to support the expenses. The Company allocated the advertising expenses into the following categories: Sales, Energy Efficiency, Employment Advertisements, Safety, Third Party Notifications, Billing, and Community Relations. In addition, the Company produced ads, audio recordings, video recordings, bill inserts, mailings, and/or transcripts of the advertisements.

I reviewed each advertisement to determine if the content was in compliance with Commission Rule R12-13 and also otherwise appropriate for inclusion as an expense recoverable from ratepayers.

Q. PLEASE DESCRIBE THE DIFFERENT TYPES OF ADVERTISING YOU REVIEWED.

A. Image advertising is designed to enhance the image, or brand name, of a company. An example of image advertising would be an advertisement that promotes the community service of the utility or the utility's name. Image advertising also includes advertising classified for accounting purposes as institutional/goodwill advertising. Institutional/goodwill advertisements are ads placed in brochures, programs, or yearbooks for non-profit or charitable organizations such as high schools, colleges, newspapers, or churches. These advertisements have nothing to do with the actual provision of utility service to the customers, and therefore, are not a true cost of providing utility service. They should not be paid for by ratepayers.

Promotional advertising is designed to increase the sale of a company's product. Advertisements that encourage customers to expand their level of service or that solicit new customers are examples. This type of advertising is not a necessary cost of providing utility service, and should not be paid for by ratepayers.

Competitive advertising is designed to increase a company's sales by encouraging customers of other energy sources to switch to the company's product. Competitive advertising could also be used to encourage first time subscribers to select the advertised energy source over the alternative energy choices. Competitive advertisements often compare the savings a customer would enjoy if appliances using one energy source were converted to appliances using the promoted energy source. The cost of this type of advertisement is also not a legitimate cost of providing utility service, and should not be paid for by ratepayers.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ADVERTISING EXPENSES.

A. The Company included $670,022 of advertising expenses in O&M expenses in this test period. I recommend that test year advertising expenses be adjusted as shown in Allison Exhibit II, Schedule 1.

I recommend that competitive, promotional, image, and some other advertising expenses be excluded from recoverable utility expenses because the advertisements are closely-aligned with shareholder interests and are not necessary for Piedmont to provide natural gas utility service. If a utility believes that it is in its best interest to pursue these types of advertising programs, the costs of these programs should be borne by the utility's shareholders.

The adjustment I recommend is in accordance with Commission Rule R12-13 and the Commission's treatment of advertisements in all of Piedmont's previous general rate case proceedings, including Docket No. G-9, Sub 631.

LOBBYING EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LOBBYING EXPENSES.

A. The Company included $434,291 of lobbying expenses in O&M expenses in this test period. I recommend that test year lobbying expenses be adjusted as shown in Allison Exhibit I, Schedule 1.

The Company did not remove any lobbying expenses from its test period O&M expenses. I have adjusted O&M expenses to remove lobbying activities charged to Piedmont during the test period. In determining what costs should be removed, I applied the "but for" test for reporting lobbying costs as applied in a Formal Advisory Opinion of the State Ethics Commission, AO-L-10-001, dated February 12, 2010. The Commission recognized in its Order Granting General Rate Increase issued December 21, 2012, in Docket No. E-22, Sub 479, at pages 70-71, that lobbying included not only employees' direct contact with legislators, but also other activities preparing for or surrounding lobbying that would not have been conducted but for the lobbying itself. In applying this test, I adjusted lobbying expenses to remove $310,952 in O&M expenses associated with Stakeholder Strategy and Federal Government Affairs that were recorded above the line during the test period.

SPONSORSHIPS AND DONATIONS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR SPONSORSHIPS AND DONATIONS

A. The Company included $122,747 of sponsorships and donations expenses in O&M expenses in this test period. I recommend that test year advertisement expenses be adjusted as shown in Allison Exhibit I, Schedule 2.

I have decreased O&M expenses by $118,345 to remove amounts charged to O&M expenses for sponsorships and donations. All of these expenses should be disallowed because they were not incurred in order to provide natural gas service to Piedmont's customers

LINE LOCATES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR LINE LOCATES.

A. Line locate requests are requests from external parties to locate Piedmont's underground natural gas pipelines. Company witness Gaglio states, on page 16, lines 4-13, of his testimony, that due primarily to increased activity by cable, internet, and telecommunications providers, Piedmont is receiving and expects to continue to receive an increased number of locate requests, and that this activity is expected to increase Piedmont's going-level annual O&M expense amount by approximately $1.7 million.

Piedmont made a pro forma adjustment to increase the test year level of line locates, based on a growth rate of 17.28% that represents the change in line locate requests for only two months of 2018 and two months of 2019, January and February of 2019 as compared to January and February 2018. Piedmont applied this growth factor to the test year level of outside services, representing that a majority of line located have been performed by third parties.

I determined that a longer period of time should be used to determine the growth in line located expense. After reviewing the Company's data, it became apparent that January and February 2018 were some of the lowest months for line locates and January and February of 2019 were some of the highest months for line locates. I determined a new growth rate of 12.11% using the change in line locate requests for 12-month period ended May 31, 2018 as compared to the 12-month period ended May 31, 2019. I believe this growth rate is much more representative level of growth than the level used by the Company. I then applied this new growth factor to the same test year level of outside services expenses as the Company. This resulted in a decrease to line locates expense of $505,974.

INFLATION

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR INFLATION.

A. The Company made an adjustment to test period non-labor, non-fuel O&M costs to reflect an increase in O&M expenses from the test year that have not been adjusted elsewhere in the Company's filing. I made an adjustment to inflation by first adjusting the base level of O&M expenses used in the calculation to remove test year customer growth-related expense accounts that the Company had adjusted elsewhere in its application. Next, I have removed the test year expenses for additional adjustments that the Public Staff is recommending, such as advertising, lobbying, and sponsorship and donation. Lastly, I have reflected an updated inflation factor recommended to me by Public Staff witness Hinton that is applied to the remaining base level of O&M expenses. These adjustments resulted in a Public Staff inflation adjustment of ($631,524).

RENTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR RENTS.

A. The Company made an adjustment to increase rents expenses by $228,686 during the test period ended December 31, 2018. I recommend that test year rents expenses be adjusted as shown in Allison Exhibit II, Schedule 5 to reduce rents by ($912,462).

Each month the Company allocates a portion of the PTC Lease and the PTC Common Area Maintenance (CAM) Lease to Duke Energy Business Services, LLC (DEBS). The Company calculated a ratio of the number of DEBS employees occupying Piedmont leased buildings to total company employees (including the DEBS employees and contingent workers, who are also referred to as contractor employees) and applied it to the PTC Lease and the PTC CAM Lease to determine the portion of lease expenses that should be allocated to DEBS.

During the test period, the Public Staff determined that Piedmont had not allocated the full 12 months of rents to DEBS. The Public Staff also found that the ratio included contingent workers. Based on my review of the data request responses, contingent workers include temporary consultants and contractors. Therefore, the Public Staff removed the contingent workers as a component of this ratio, and then recalculated the ratio and applied it to the PTC Lease and the PTC CAM Lease test year amounts to determine the appropriate annual amount to allocate to DEBS to determine the Piedmont NC jurisdictional rent amount for these leases.

CUSTOMER GROWTH

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO CUSTOMER GROWTH.

A. I have presented the customer growth adjustment using the same methodology as the Company but updated our adjustment for the number of end of period bills provided by the Public Staff witness Naba. My adjustment results in a decrease of ($21,499) to the customer growth adjustment proposed by the Company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

R. TYLER ALLISON

I am a graduate of North Carolina State University with a Master of Accounting degree. After graduating, I accumulated more than three years of auditing experience, one year of general accounting experience, and became a Certified Public Accountant (CPA License #35859). I was employed as an auditor with a regional public accounting firm, a consultant with a national public accounting firm, and an internal auditor with a federal agency. While in public accounting, I worked with clients in a variety of industries including banking, healthcare, manufacturing, and non-profits, and assisted these clients in becoming compliant with Sarbanes-Oxley Act Section 404 controls and with other control-related audits.

I joined the Public Staff Accounting Division on October 2, 2017. Since joining the Public Staff, I have been involved with various electric, natural gas, and water utility proceedings. I have worked on several rider proceedings including the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) demand side management and energy efficiency cost reviews, and Piedmont IMR review. In addition, I have worked on a water-utility rate case.

MS. JOST: I don't have anything further for this witness.

COMMISSIONER BROWN-BLAND: All right. There being no questions from the Commission and no further cross examination, Mr. Allison, you may be excused.

THE WITNESS: Thank you.

MS. JOST: The Public Staff next calls Poornima Jayasheela.

POORNIMA JAYASHEELA,

having first been duly sworn, was examined

and testified as follows:

DIRECT EXAMINATION BY MS. JOST:

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

A. I'm Poornima Jayasheela. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I'm a staff accountant with the accounting division of the Public Staff.

Q. On July 19, 2019, did you prepare and cause to be file indeed this docket testimony consisting of 21 pages, Jayasheela Exhibit 1 and an appendix?

A. Yes.

Q. On July 26, 2019, did you prepare and cause to be filed, revised Jayasheela Exhibit 1?

A. Yes.

Q. Do you have any corrections to your testimony?

A. Yes, I do.

Q. Please go ahead and provide that.

A. On page 8 of my direct testimony, line 12 should read as "deferred Eastern NC cost" instead of "deferred Eastern NCNG costs."

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

A. Yes, they would.

MS. JOST: I move that Ms. Jayasheela's prefiled testimony as corrected consisting of 21 pages and an appendix be copied into the record as if given orally from the stand, and that Revised Jayasheela Exhibit 1 be identified as marked when filed and entered into evidence.

COMMISSIONER BROWN-BLAND: That motion is allowed, and the testimony is received, and the exhibit will be received into evidence.

(Revised Jayasheela Exhibit 1 was admitted into evidence.)

(Whereupon, the prefiled direct

testimony of Poornima Jayasheela was copied into the record as if given orally from the stand.)

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF POORNIMA JAYASHEELA
ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2019

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

A. My name is Poornima Jayasheela. 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 (Public Staff).

Q. **BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.**

A. My qualifications and duties are set forth in Appendix A.

Q. **WHAT IS THE NATURE OF THE APPLICATION IN THIS RATE CASE?**

A. Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed an application with the Commission on April 1, 2019, in Docket No. G-9, Sub 743, with a test period ended December 31, 2018, seeking authority for: (i) a general increase in and revisions to the rates and charges for customers served by the Company; (ii) continuation of Piedmont's Integrity Management Rider (IMR) mechanism; (iii) regulatory asset treatment for certain incremental Distribution Integrity Management Program (DIMP) operations and maintenance (O&M) expenses; (iv) adoption of revised and updated depreciation rates for the Company's North Carolina and joint property assets; (v) updates and revisions to Piedmont's rate schedules and service regulations; (vi) revised and updated amortizations and recovery of certain regulatory assets accrued since Piedmont's last general rate case proceeding; (vii) approval of expanded energy efficiency and conservation program spending; and (viii) adoption of an Excess Deferred Income Taxes (EDIT) Rider mechanism to manage the flowback to customers of deferrals and excess deferred income taxes created by changes to state and federal income tax rates.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's accounting and ratemaking adjustments and to incorporate the adjustments recommended by other Public Staff witnesses who work in the Accounting, Engineering, and Economic Research Divisions. The Public Staff has made its adjustments based on its investigation of the revenue, expenses, and rate base presented by the Company in support of its request for an annual cost of service increase of $82.8 million in this proceeding. This amount includes an increase in the margin revenue requirement of $118.1 million, an increase in fixed gas costs of approximately $1.7 million, and a decrease of $36.9 million dollars for an EDIT rider.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

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

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

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

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

A. Schedule 1 of Jayasheela Exhibit I presents a reconciliation of the difference between the Company's requested margin revenue increase of $118,116,597 and the Public Staff's recommended increase of $63,877,506. In addition, the Public Staff has recommended several temporary decreases to the revenue requirement associated with the refund of various income tax-related amounts, which differ somewhat from the EDIT rider proposed by the Company.

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

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. Schedules 3A and 3B summarize the Public Staff's adjustments, which are detailed on backup schedules.

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

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

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 Hinton regarding the overall cost of capital, capital structure, embedded cost of long-term debt, and return on common equity.

(2) The recommendation of Public Staff witness Patel regarding Commodity Cost of Gas.

(3) The recommendation of Public Staff witness Gilbert regarding the Customer Conservation Program.

(4) The recommendations of Public Staff witness Naba regarding the following items:

(a) Customer Growth
(b) End-of-Period Revenues and Bills

(5) The recommendations of Public Staff witness Feasel regarding the following items:

(a) Plant in Service
(b) Accumulated Depreciation
(c) Depreciation Expense
(d) Property Tax
(e) Miscellaneous - General Expense

(6) The recommendations of Public Staff witness Coleman regarding the following items:

(a) Payroll Expense
(b) Overtime Expense
(c) Payroll Taxes
(d) Employee Benefits
(e) Executive Compensation
(f) Board of Directors' Expenses

(7) The recommendations of Public Staff witness Allison regarding the following expenses:

(a) Uncollectibles
(b) Advertising
(c) Lobbying
(d) Sponsorship and Donations
(e) Line Locates
(f) Inflation
(g) Rents
(h) Customer Growth

(8) The recommendations of Public Staff witness Perry regarding the following items:

(a) State Excess Deferred Income Taxes (EDIT)
(b) Federal protected EDIT
(c) Federal unprotected EDIT
(d) Deferred revenues associated with the overcollection due to the federal tax change since January 1, 2018
(e) Regulatory asset treatment of Atlantic Coast Pipeline Plant
(f) Non-utility adjustment

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.

A. The accounting and ratemaking adjustments that I will discuss relate to the following items:

(1) Other Operating Revenues
(2) Short-Term and Long-Term Incentive Plans (STIP and LTIP)
(3) Pension Expense
(4) Deferred Rate Case Costs
(5) Deferred Transmission Pipeline Integrity Costs
(6) Deferred Environmental Costs
(7) Deferred NCNG OPEB Liability
(8) Deferred Eastern NCNG Costs
(9) Regulatory Fee Expense
(10) Deferred Regulatory Fee
(11) Aviation Expense
(12) GTI Expenses
(13) Distribution Integrity Management Program Accounting Treatment

OTHER OPERATING REVENUES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO OTHER OPERATING REVENUES.

A. I have applied a growth factor, as recommended by Public Staff witness Naba, to Late Payment Revenues and Miscellaneous Service Revenues.

INCENTIVE PLANS

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

A. The Company offers two incentive plans to its employees: the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). The STIP is offered to all employees, including executives. The LTIP is comprised of two programs: the Executive LTI Plan and the Restricted Stock Units (RSU) Plan. Employees that are members of the Executive Leadership Team (ELT) participate in the Executive LTI Plan. Generally, eligibility for the RSU Plan is reserved for management positions with a salary midpoint of $195,000 or above.

The STIP consists of goals set and approved by the Board of Directors (BOD) of Duke Energy Corporation (Duke Energy) for a one-year term. In 2018, the test year in this case, the goals consisted of Earnings per Share (EPS), Operational Excellence, Customer Satisfaction, as well as team and individual goals. The LTIP consist of Performance Shares, which are further categorized between EPS 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 STIP is based on the achievement of targets at minimum, target, and maximum levels. I have adjusted the allowable costs of STIP to exclude the incentive accruals that were based on the EPS metric. The Public Staff believes that the incentives related to EPS should be excluded because they provide a direct benefit to shareholders, rather than to ratepayers. It should be further noted that the EPS portion of the STIP only accounts for 30% of the non-executive level employees accrual and 50% of the executive level employees accrual.

I have adjusted the allowable LTIP costs to exclude the Performance Shares, which include the EPS and TSR metrics. The Public Staff believes that the incentives related to EPS and TSR should be excluded because they provide a direct benefit to shareholders, rather than to ratepayers. Therefore, these costs should be borne by shareholders. My adjustment is shown on Jayasheela Exhibit I, Schedule 3-2.

PENSION EXPENSE

Q. PLEASE EXPLAIN PUBLIC STAFF'S ADJUSTMENT TO THE COMPANY'S PENSION EXPENSE.

A. In the current rate case filing, the Company proposed a reduction of $2,028,528 to its ongoing annual pension expense based on the Company's 2019 projection. The Public Staff has instead determined an annualized on-going pension expense amount that results in a further reduction of $1,456,933, based on the actual 2019 pension accruals on Piedmont's books from January 31, 2019, to May 31, 2019.

DEFERRED RATE CASE EXPENSE

Q. PLEASE EXPLAIN PUBLIC STAFF'S ADJUSTMENT TO DEFERRED RATE CASE EXPENSE.

A. The Company proposed that estimated rate case expenses of $1,742,292 be amortized over a three year period. The Public Staff has reviewed the actual invoices paid as of July 11, 2019, and the contracts related to the various consultants. The Public Staff summed up fifty percent of the difference between the Company proposed amount and actual payments as of July 11, 2019 to determine the rate case expense. The Public Staff did not apply the same approach to Regulatory Notices since the actual payments as of July 11, 2019 have exceeded the Company's estimate. Therefore, the Public Staff has allowed the amount recorded as actual payments for Regulatory Notices.

In its filing, the Company requested that rate case expenses be given deferred accounting treatment and the unamortized balance be included in rate base. The Public Staff disagrees with the Company's proposal of deferred treatment for rate case expenses and is removing the deferred rate case expense amount from rate base. The Company has not been allowed deferred accounting treatment on rate case expenses in the past and the Commission has never allowed deferred rate case expenses in rate base for a gas utility.

DEFERRED TRANSMISSION PIPELINE INTEGRITY COSTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEFERRED TRANSMISSION PIPELINE INTEGRITY COSTS.

A. The Company's adjustment for Pipeline Integrity Management Transmission (PIM-Transmission) costs is composed of the amounts paid to outside vendors in connection with the PIM-Transmission program between September 1, 2013 and December 31, 2018. The Public Staff has updated the Company's balance of deferred PIM-Transmission costs to reflect the actual amount deferred as of May 31, 2019. The Public Staff has also reflected the existing amortization from the prior rate case through November 1, 2019, the effective date of rates in the current case. The total deferred PIM-Transmission costs per Public Staff is $51,718,363 as compared to the Company's amount of $47,017,636. The Public Staff recommends that the balance of the deferred PIM-Transmission costs, net of prior amortizations, be amortized over a five-year period.

The Public Staff also recommends that the deferred balance, less one full year of amortization, be allowed to earn a return by being included in rate base. In addition, the Public Staff believes that it is appropriate to continue regulatory asset treatment for PIM-Transmission costs and to defer and treat such costs as a regulatory asset until the resolution of the Company's next general rate proceeding. In making this recommendation, the Public Staff does not intend to indicate that it believes these deferred costs to constitute used and useful property; instead, the Public Staff has included the costs in rate base as a convenient and efficient way of providing for a return on the deferred costs. The Public Staff considers the provision for a return to be reasonable in this case, but believes that the Commission's provision of such is discretionary, not obligatory, in nature.

DEFERRED ENVIRONMENTAL COSTS

Q. PLEASE EXPLAIN PUBLIC STAFF'S ADJUSTMENT TO DEFERRED ENVIRONMENTAL COSTS.

A. On December 23, 1992, in Docket No. G-9, Sub 333, the Commission issued an Order Granting Request regarding Piedmont's request to defer certain environmental assessment and clean-up costs relating to various state and federal environmental control requirements for air emissions, wastewater discharges, and solid, toxic and hazardous waste management. In its filing in the current case, the Company has proposed a three-year amortization of an unamortized credit balance of ($576,988). The Company calculated amortized expenses from September 1, 2013, to October 31, 2019, whereas the Public Staff included the amortization expense from January 1, 2014, to October 31, 2019. The Public Staff calculated the amortization expense from January 1, 2014, the date when rates were effective in Docket No. G-9, Sub 631, Piedmont's prior general rate case. The Public Staff has also updated deferred environmental expenses to May 31, 2019, and applied a five-year amortization period.

The Public Staff recommends that the deferred balance less one full year of amortization be allowed to earn a return by being included in rate base. The Public Staff also recommends that it is appropriate to continue regulatory asset treatment for environmental costs and to defer and treat such costs as a regulatory asset until the resolution of the Company's next general rate proceeding. In making this recommendation, the Public Staff does not intend to indicate that it believes these deferred costs to constitute used and useful property; instead, the Public Staff has included the costs in rate base as a convenient and efficient way of providing for a return on the deferred costs. The Public Staff considers the provision for a return to be reasonable in this case, but believes that the Commission's provision of such is discretionary, not obligatory, in nature.

DEFERRED NCNG OPEB LIABILITY

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEFERRED NCNG OPEB LIABILITY.

A. The Company removed the amortization related to the deferred NCNG OPEB liability from O&M expenses since the deferred asset has been fully recovered. The Company inadvertently left a deferred balance in working capital. The Public Staff has made an adjustment to remove the NCNG OPEB liability deferred balance from the working capital.

EASTERN NC DEFERRED O&M EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO EASTERN NC DEFERRED O&M EXPENSES.

A. As of January 1, 2014, the effective date of rates in Piedmont's previous rate case, Docket No. G-9, Sub 631, the Eastern NC Deferred O&M expenses had 82 months or seven years remaining to be fully recovered. As of November 1, 2019, the expected date of rates in the current general rate case, the amortization will have run for seventy months leaving 12 months remaining to collect the balance. The Company proposed to leave the amortization amount in the cost of service while the Public Staff recommends that the principal and interest balances be amortized over the Public Staff's proposed five-year amortization period in this case at the net of tax overall rate of return approved in the current case.

ADJUSTMENT TO REGULATORY FEE EXPENSE

Q. PLEASE EXPLAIN PUBLIC STAFF'S ADJUSTMENT TO THE NCUC REGULATORY FEE.

A. When the current rate case was filed on April 1, 2019, the Commission's regulatory fee for noncompetitive jurisdictional revenues was 0.14%. In its Order Decreasing Regulatory Fee Effective July 1, 2019 (issued June 18, 2019, in Docket No. M-100, Sub 142), the Commission ordered that the regulatory fee for noncompetitive jurisdictional revenues shall be set at 0.13% effective July 1, 2019. Since the rates in the current case will likely be effective on November 1, 2019, Public Staff made an adjustment to change the regulatory fee rate from 0.14% to 0.13%.

REGULATORY FEE EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEFERRED UNDERCOLLECTION OF NCUC REGULATORY FEE EXPENSE.

A. The Public Staff reviewed the Company's calculation of the undercollection of the NCUC regulatory fee, and found that the Company had inadvertently not reflected the change in the regulatory fee from 0.135% to 0.13% from July 1, 2014, to June 30, 2015. The Public Staff updated this change and also reflected deferred expenses through May 31, 2019. I have amortized the projected balance over five years.

The Public Staff recommends that the deferred balance less one full year of amortization be allowed to earn a return in rate base. In making this recommendation, the Public Staff does not intend to indicate that it believes these deferred costs to constitute used and useful property; instead, the Public Staff has included the costs in rate base as a convenient and efficient way of providing for a return on the deferred costs. The Public Staff considers the provision for a return to be reasonable in this case, but believes that the Commission's provision of such is discretionary, not obligatory, in nature.

AVIATION EXPENSES

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

A. The Company did not make an aviation expenses adjustment; however, the Public Staff made an adjustment after investigating the aviation expenses charged to Piedmont's North Carolina (NC) jurisdiction during the test year. Aviation expenses are allocated to Piedmont through Duke Energy's service company, Duke Energy Business Services, LLC (DEBS), and then are apportioned to

Piedmont's NC operations through a North Carolina jurisdictional allocation factor. Since corporate aircraft are available for use by Duke Energy's officers, I reviewed the flight logs to determine whether the flights charged to Piedmont should be recoverable from ratepayers. Based on this review, I recommend that certain expenses allocated to Piedmont's NC jurisdiction be removed due to fact that most of the flights do not appear to have anything to do with providing natural gas utility service. I also recommend that fifty percent of expenses related to Board of Directors (BOD) flights be disallowed consistent with the BOD expense adjustment recommended by the Public Staff My adjustment is shown on Jayasheela Exhibit I, Schedule 3-12.

GTI EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO GAS TECHNOLOGY INSTITUTE EXPENSES.

A. The Company has proposed to increase the funding for two programs offered by the Gas Technology Institute (GTI): (1) the Operations Technology Development (OTD) Program, and (2) the Utilization Technology Development (UTD) Program. The OTD Program focuses its technology development efforts on distribution and transmission activities identified by the members of GTI. The current OTD projects are divided into the following six project categories:

(1) Pipe and Leak Location

(2) Pipe Materials, Repair and Rehabilitation

(3) Excavation and Site Restoration

(4) Pipeline Integrity Management and Automation

(5) Operations Infrastructure Support

(6) Environmental, Renewables and Gas Quality

The Public Staff agrees with the Company proposed increase for the OTD Program expense because the OTD projects are designed mainly to enhance safety, increase operating efficiency, reduce operating costs and help maintain system reliability and integrity.

The UTD Program is a wide-ranging program to enhance the use, reliability, and efficiency of natural gas appliances and technologies. In response to a Public Staff data request, the Company provided the GTI prospectus, which explicitly states that the UTD Program is at the forefront of research, development, and deployment for end-use equipment and appliances. Since the Company is a regulated utility engaged in the natural gas distribution business, the Public Staff does not believe that ratepayers should be required to fund a program which is targeted towards research and development for natural gas appliances.

The Public Staff's adjustment on Jayasheela Exhibit I reflects the Public Staff's agreement to accept the Company's proposal for the OTD Program and also shows the removal of the UTD Program. This results in a decrease of $350,000 to GTI expenses, as shown on Jayasheela Exhibit I, Schedule 3-13.

DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S PROPOSAL FOR DIMP ACCOUNTING TREATMENT.

A. Piedmont proposes regulatory asset accounting treatment for certain O&M expenses incurred due to the Company's DIMP program, i.e., to treat such costs as regulatory assets and to defer such costs and reflect the approved annual amortization of DIMP costs until the resolution of the Company's next general rate case proceeding. Company witness Barkley states in his testimony that Piedmont does not seek any carrying costs associated with its proposed DIMP deferral at this time. The Public Staff agrees with the Company's proposal.

The Public Staff also recommends an annual filing requirement as recommended by Public Staff witness Larsen.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

POORNIMA JAYASHEELA

I received a Bachelor of Science degree and a Master of Business Administration degree from Osmania University, Hyderabad, India. I was employed by the Michigan Public Service Commission (MPSC) from July 2004 to August 2015. During my employment with the MPSC, I participated in contested rate cases, Times Interest Earned Ratio (TIER) case audits for regulated co-operatives, Power Supply Cost Recovery reconciliation audits, reconciliations of uncollectible expense tracking mechanism and revenue decoupling mechanism, and any special audits required by the MPSC.

I started employment with the Public Staff – North Carolina Utilities Commission in August 2015 as a staff accountant. I have presented testimony and exhibits or assisted with the following general rate case audits: Docket No. E-35, Sub 45, Western Carolina University; Docket No. W-1058, Sub 7, Elk River Utilities, Inc.; and Docket No E-34, Sub 46, New River Light and Power Company. I have also presented testimony and exhibits in Piedmont Natural Gas Company's annual gas cost reviews in 2016 (Docket No. G-9, Sub 690), 2017 (Docket No. G-9, Sub 710) and 2018 (Docket No. G-9, Sub 727).

MS. JOST: Thank you. I don't have anything further.

COMMISSIONER BROWN-BLAND: All right. We don't have any questions for you, Ms. Jayasheela, so you may be excused.

THE WITNESS: Thank you.

COMMISSIONER BROWN-BLAND: Thank you.

MS. JOST: All right. Finally, I would like to -- the Public Staff calls Neha Patel to the stand.

NEHA PATEL,

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

DIRECT EXAMINATION BY MS. JOST:

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

A. My name is Neha Patel, I'm a public utilities engineer with the natural gas division. And my address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. On July 19, 2019, did you prepare and cause to be filed in this docket, testimony consisting of 10 pages, an appendix -- I'm sorry, strike that.

On July 19, 2019, did you prepare and cause to be filed in this docket, testimony consisting of 10 pages, appendix A, and Patel Exhibits 1, 2, and 3?

A. Yes, I did.

Q. Do you have any corrections to your testimony?

A. Yes, I do.

Q. Please go ahead and make the correction.

A. Page 10, line 9 should read a bill decrease of $1.32 per month or $15.84 in year one, instead of 15.84 percentage in year one.

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

A. Yes, they would.

MS. JOST: I move that, as corrected, Ms. Patel's prefiled testimony consisting of 10 pages, one appendix -- and one appendix be copied into the record as if given orally from the stand and that her exhibits be identified as prefiled and entered into evidence.

COMMISSIONER BROWN-BLAND: Before I rule on that, Ms. Patel, can you repeat your correction for us?

THE WITNESS: Sure. The line 9 should read as bill decrease of $1.32 per month, or $15.84 in year one. It initially was 15.84 percentage in year one. So instead of percentage, it's just a dollar sign.

COMMISSIONER BROWN-BLAND: Okay. Thank you.

THE WITNESS: You're welcome.

COMMISSIONER BROWN-BLAND: With that, motion made by Ms. Jost will be allowed and the prefiled testimony of Witness Patel will be received into evidence along with appendix A, and the three exhibits will be identified as they were prefiled and received into evidence as well.

(Patel Exhibits Plaintiff's through 3 were admitted into evidence.)

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

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 743

TESTIMONY OF NEHA PATEL ON BEHALF OF THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

JULY 19, 2019

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

A. My name is Neha Patel. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Public Utilities Engineer with the Natural Gas Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE NATURE OF THE APPLICATION IN THIS RATE CASE?

A. Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed an application with the Commission on April 1, 2019, in this docket seeking authority to increase rates for natural gas utility service in all of its service areas in North Carolina and for other relief.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

A. My areas of investigation in this case have been: (1) performing an Allocated Cost of Service Study (ACOSS), (2) adjusting the Cost of Gas to the going level basis, (3) review of the Margin Decoupling Tracker (MDT) as discussed by Company witnesses Couzens and Yardley, and (4) recommending an appropriate rate design.

I performed a billing analysis to determine the level of revenues produced at present and proposed rates utilizing the data updated through May 31, 2019, and developed a recommended rate design to recover the revenue requirement set forth in the pre-filed testimony of Public Staff witness Jayasheela.

ALLOCATED COST OF SERVICE STUDIES

Q. HAVE YOU PERFORMED AN ALLOCATED COST OF SERVICE STUDY TO SUPPORT YOUR RATE DESIGN?

A. Yes. I utilized the Public Staff's recommended levels for volumes, customer numbers, revenues, expenses, and investments and prepared a fully allocated ACOSS under Piedmont's existing rates with pro forma adjustments (end of period) and arrived at several allocation factors. This study assigns each class specific costs based on Company records to determine the proper cost to serve the respective customer classes taking into account Company expenses, operating revenues, and net investments. This allocated cost of service study is only a ratemaking guide and not the only factor to be used in designing utility rates.

Q. WHAT COST OF SERVICE METHODOLOGY DID YOU USE?

A. I used the Peak and Average or "Seaboard" Method, which properly allocates fixed costs between annual use and peak day utilization. This method was determined by the Commission to be the "best cost-of service study method available" in its Order Granting Partial Rate Increase issued October 30, 1998, in Docket No. G-5, Sub 386. (PSNC Sub 386 Rate Order)[1]

Q. WHAT GENERAL COSTING PRINCIPLE DID YOU USE IN YOUR ACOSS?

A. The two main costing principles utilized in developing an ACOSS are System Utilization and Cost Causation. The Public Staff has historically supported the System Utilization principle because the allocation of demand and storage charges accurately depicts the utilization of these services associated with the costs. The Cost Causation principle, on the other hand, makes an assumption that

[1] The Commission's decision was appealed to the North Carolina Supreme Court which affirmed the Commission in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 351 N.C. 223, 524 S.E.2d 10 (2000).

costs are caused by certain classes of customers, regardless of whether they actually use the services in question. The Commission upheld the use of the System Utilization principle in the PSNC Sub 386 Order.

Q. **HOW DID YOU ALLOCATE SERVICES AND MAINS?**

A. I calculated the customer and demand components by employing the Zero-intercept method, which uses a regression analysis to calculate the unit cost per foot that a theoretical zero-inch diameter pipe would cost to install. Customers would pay these costs regardless of whether they received any gas through the pipe. This constant is then multiplied by the total length of mains or services to calculate a customer cost component. The demand cost component is the dollar amount for the particular account less the customer cost component. Based on my calculations, the customer component for the distribution mains account was 43.37% and the customer component for the services mains account was 46.82%.

Q. **WHAT IS THE RESULT OF YOUR ACOSS?**

A. Patel Exhibit I is a summary of my ACOSS under the existing rates. Patel Exhibit II is a summary of my ACOSS under the Public Staff's recommended rates.

COST OF GAS

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED LEVEL OF COST OF GAS?

A. The Public Staff's calculation of the commodity cost of gas differs from the Company's level by a very small amount. The Public Staff's updated volumes are 75,113,869 dekatherms (dts) for sales and 2,608,533 dts for Company Use and Lost and Unaccounted Gas. This number differs from the Company's number by about 4,829 dts. Therefore, the Public Staff's recommended commodity cost of gas is $215,113,340 versus the Company's level of $215,168,222. The Public Staff accepts Piedmont's fixed gas cost as our calculation is very similar to that of the Company.

MARGIN DECOUPLING TRACKER (MDT) MECHANISM

Q. PLEASE EXPLAIN ANY ADJUSTMENTS REGARDING THE MDT MECHANISM.

A. In this proceeding, the Company filed MDT adjustments to the Residential, Small General and Medium General Service rate schedules. The Public Staff calculated the normalized usage for heat sensitive customers on a monthly basis and determined that there is not a significant difference between the Public Staff's MDT revenue adjustments and the Company's adjustments and the "R" factors using data through May 31, 2019. As stated in Piedmont witness Couzens' testimony, there is a total Residential pro forma revenue increase and decreases in total Small and Medium General pro forma revenues.

RATE DESIGN

Q. HOW DO YOU RECOMMEND THE COMPANY RECOVER THE PUBLIC STAFF'S RECOMMENDED REVENUE REQUIREMENT?

A. The Public Staff is recommending an increase of $63,031,608 as set forth in the pre-filed testimony of Public Staff witness Jayasheela. A number of factors may be considered in designing rates to allow the Company to recover the annual levels of revenue. These factors include value and type of service, quantity of use, time of use, manner of service, competitive conditions relating to the acquisition of new customers, historical rate design, the Company's revenue stability, economic policy, administrative ease, and ACOSS.

Value of service is an important consideration because it recognizes that the price paid for natural gas service cannot be significantly greater than a satisfactory alternative. The fact that natural gas is cleaner burning (i.e., produces less emissions) and easier to use also affects its value for some customers. Consideration of value of service is the reason rates for some rate classes are designed to allow for negotiations based on alternative fuel pricing and transportation of gas procured by end-users.

The type of service, quantity used, time of use, and manner of service are evaluated by reviewing customer characteristics. Different types of customers have different needs. For example, heat-sensitive residential and commercial customers need more security of service during peak (cold) winter days than do non-heat sensitive customers, and they pay for this enhanced service by contributing more margin in the form of higher rates. Within the industrial class, some customers require a firm (guaranteed) gas supply in their manufacturing process, whereas others use gas only as boiler fuel. Some may choose to have an alternate fuel available, and some may not. Rate design should reflect all these differences among customers.

Rates should be attractive to new customers. Some industrial customers are energy intensive and are very conscious of their choice of fuels. Residential and small commercial customers are also concerned with their long-term commitment to their energy choice. Rates should be set in a manner that appeals to all classes of customers so as to ensure both the financial health of the utility and the welfare of its customers.

Historical rate design is also considered both in evaluating the results of past rate design and in anticipating the response to the recommended rate design.

In reviewing the revenue stability of the Company, I considered whether rates would enable it to attract new customers and keep its current customers. Dramatic changes in rate design can result in unpredictable revenue shifts and should generally be avoided.

Economic policy includes rate design that encourages economic growth in the Company's territory for all rate classes. Proper rate design can facilitate growth by enabling the Company to add new load in a cost-effective manner.

Administrative ease involves the reasonable classification of customers into various groups or classes where they share similarities. If customers are separated into too many rate categories, the utility incurs excessive administrative costs that provide little benefit to customers.

Finally, rates of return resulting from an ACOSS are considered in determining rate design and are used as a guide in determining the direction of rate changes for the various customer classes.

EFFECT OF RATE CHANGES

Q. WHAT EFFECT WILL YOUR RECOMMENDED RATES HAVE ON EXISTING BILLING RATES?

A. Patel Exhibit No. III shows the effect of my recommended margin change for each rate schedule and the associated rate change from the implementation of the flowback of Excess Deferred Income Taxes (EDIT) for Year 1 (Nov'19 - Oct'20) and Year 2 (Nov'20 - Oct'21). Residential customers will experience an average bill decrease of $1.32 per month or 15.84% in Year 1. Most other rate classes will see similar decreases in Year 1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

NEHA PATEL

I graduated from University Of Mumbai in 1995 with a Degree of Bachelor of Science in Electronic Engineering. I began working as a Utilities Engineer with the Natural Gas Division of the Public Staff in February of 2014.

My most current work experience with the Natural Gas Division includes the following topics:

1. Purchase Gas Cost Adjustment Procedures;
2. Tariff Filings;
3. Customer Utilization Trackers;
4. Margin Decoupling Trackers;
5. Special Contract Review and Analysis;
6. Integrity Management Riders;
7. Integrity Management Trackers;
8. Weather Normalization Adjustments;
9. Franchise Exchange Filings;
10. Annual Review of Gas Costs;
11. Cost Of Service Studies;
12. Peak Day Demand and Capacity Calculations; and
13. Fuel and Electric Usage Trackers.

MS. JOST: Thank you. I have nothing further.

COMMISSIONER BROWN-BLAND: Ms. Patel, we have no further -- you almost got out.

Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Ms. Patel, earlier today there was some testimony from Ms. Powers about a document that was an exhibit to your testimony, Revised Exhibit 3.

A. Yes.

Q. And I have only one question for you. That shows a calculation for years one, two, and three.

Did you extend that to years four, five, and six in any of your work?

A. We can file it as a late-filed exhibit.

Q. But you didn't do so? You haven't done so up to this point?

A. For year six, no.

Q. No, you have not. Could you do that as a late-filed exhibit for years four, five, and six, just carry Exhibit 3 on out?

A. Yes.

Q. I would ask for that.

COMMISSIONER BROWN-BLAND: All right.

COMMISSIONER CLODFELTER: That's all.

COMMISSIONER BROWN-BLAND: All right. So we will be sure to receive that as a late-filed exhibit, and when it comes in, it will be received into the record. All right.

Now, no questions from the Commission? And no cross examination?

Ms. Patel, thank you. You are excused and you may step down.

MS. CULPEPPER: That concludes the Public Staff's case.

COMMISSIONER BROWN-BLAND: By my account, all the prefiled testimony has already been received into evidence. We have the application and stipulation into evidence. Any other matters that we might be overlooking?

(No response.)

COMMISSIONER BROWN-BLAND: All right.

MS. HARROD: I'm sorry, Madam Chair.

COMMISSIONER BROWN-BLAND: Yes, Ms. Harrod.

MS. HARROD: Mr. Mannus was kind enough to let me know that, when I asked the Commission to take judicial notice of the Dominion rate case order, that I misspoke and gave the wrong docket number. And I think that the correct docket number there should have been E-2, Sub 532. Sorry, E-22, Sub 532. But my intent is for the Commission to take judicial notice of the order that's cited in Ms. Perry's testimony. If -- I'm reading from the testimony. If that docket number is incorrect, I hope that's clear enough for the record.

COMMISSIONER BROWN-BLAND: And one more time, your understanding right now, the correct docket is E-22, Sub --

MS. CULPEPPER: 532.

COMMISSIONER BROWN-BLAND: All right. Commission will take judicial notice, but it will be based on that testimony that is -- that order that is cited in Ms. Perry's testimony.

MS. HARROD: Thank you, Chair. I'm sorry for my confusion on that.

COMMISSIONER BROWN-BLAND: All right. It's a little bit late. We'll overlook it. So the proposed orders or any briefs that the parties may wish to file will be due 30 days from the availability and posting of the transcript.

Anything else?

(No response.)

COMMISSIONER BROWN-BLAND: There being nothing else, thank you, everyone, for helping this to go smoothly, and we will be adjourned.

(Whereupon, the hearing was adjourned at 4:40 p.m.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly sworn; that the testimony of said witnesses were taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 22nd day of August, 2019.

Joann Bunze

JOANN BUNZE, RPR

Notary Public #200707300112