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DATE: Tuesday, August 20, 2019

TIME: 9:30 a.m. - 12:37 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: 5

Noteworthy
Reporting Services, LLC

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MR. JEFFRIES: And we would also ask that Ms. Powers' prefiled exhibits be identified as marked.

COMMISSIONER BROWN-BLAND: That motion is allowed as well.

MR. JEFFRIES: Thank you.

(Exhibits PKP 1 through PKP 8, PKP-1 Updated through PKP-8 Updated, and Settlement Exhibit PKP-1 were marked for identification.)

Q. Ms. Powers, have you prepared a summary of your testimony?

A. I have.

Q. Okay. Mr. Heslin is going to distribute that. Once he's done, could you go ahead and provide that?

A. I will.

(Summary handed out.)

A. Okay. My name is Pia Powers, and I am the director of gas rates and regulatory affairs for Piedmont Natural Gas Company. I prefiled direct testimony and exhibits in this docket on April 1, 2019, in support of Piedmont's application for a general rate increase. I also filed supplemental testimony and

AGO Powers Cross Examination .... 403/ -
Exhibit 4

AGO Powers Cross Examination .... 407/ -
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PROCEEDINGS

COMMISSIONER BROWN-BLAND: Good morning. Come back to order and go on the record, and I believe we are still in the applicant's case.

MR. JEFFRIES: We are. Madam Chair, I have got two administrative matters I would like to raise with the Commission before we resume our case. And I apologize, I should have dealt with one of these yesterday; and that is the subject of the admission of the prefiled testimony and exhibits of the witnesses that have been excused.

The active parties to the case have agreed that Mr. Yardley, Mr. Normand, Mr. Watson and Mr. Phillips' prefiled testimony and exhibits could be entered into the record; and, in fact, the Commission has already indicated in an order issued August 16th that they would be received into evidence at the hearing, and I would just formally move that out of an abundance of caution at this point.

COMMISSIONER BROWN-BLAND: All right. Name the witnesses again.

MR. JEFFRIES: Yes. Piedmont witness Daniel Yardley, Piedmont witness Paul Normand, Piedmont witness Dane Watson, and CIGFUR IV witness Nicholas Phillips.

COMMISSIONER BROWN-BLAND: There being no objection, that motion will be allowed and the testimony will be received as if given orally from the witness stand. The exhibits that were prefiled with those testimonies will be received into evidence and will be identified as they were marked when prefiled.

MR. JEFFRIES: Thank you, Madam Chair.

(Exhibits DPY-1 through DPY-5, PMN-1 through PMN-3, DAW-1 through DAW-3, and NP-1 through NP-6 were admitted into evidence.)

(Whereupon, the prefiled direct testimonies of Daniel P. Yardley, Paul M. Normand, Dane A. Watson, and Nicholas Phillips, Jr. were copied into the record as if given orally from the stand.)

BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET G-9, SUB 743

PREPARED DIRECT TESTIMONY
OF
DANIEL P. YARDLEY

ON BEHALF OF
PIEDMONT NATURAL GAS COMPANY, INC.

Q. Please state your name, affiliation and business address.

A. My name is Daniel P. Yardley. I am Principal, Yardley Associates and my business address is 2409 Providence Hills Drive, Matthews, North Carolina 28105.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company").

Q. Please provide a brief outline of your professional and educational background.

A. I have been employed as a consultant to the natural gas industry for the past 30 years. During this period, I have directed or participated in numerous consulting assignments on behalf of local distribution companies ("LDCs"). A number of these assignments involved the development of gas distribution company cost allocation, pricing, service unbundling, revenue decoupling and other tariff analyses. In addition to this work, I have performed interstate pipeline cost of service and rate design analyses, gas supply planning analyses, and financial evaluation analyses. I received a Bachelor of Science Degree in Electrical Engineering from the Massachusetts Institute of Technology in 1988.

Q. Have you previously testified before the North Carolina Utilities Commission ("NCUC")?

A. Yes. I testified in Piedmont's prior rate case before the NCUC in Docket No. G-9, Sub. 631. I have also testified on numerous occasions before other state utility commissions, the Federal Energy Regulatory Commission, and the National Energy Board of Canada on a variety of rate and regulatory topics. The subject matters addressed in these proceedings include cost allocation, service design, rate design, revenue decoupling, cost recovery mechanisms and tariff design. A list of my previous expert testimony is provided as Exhibit DPY-1 to my direct testimony.

Q. What is the purpose of your direct testimony?

A. I have been asked by Piedmont to evaluate the manner in which it recovers its base distribution revenue requirements from customers and to propose changes that are consistent with the nature of the services it provides as well as important policy objectives. In this regard, my testimony addresses two topics. First, I will present the results of an allocated cost of service study ("ACOSS") performed in a consistent manner with other elements of the Company's filing. Second, I will support the derivation of specific rates and charges for distribution service.

Q. Are you sponsoring any exhibits that accompany your prepared direct testimony?

A. Yes. I am sponsoring the following five exhibits, which will be explained later in my testimony:

Exhibit DPY-1: List of Prior Testimony
Exhibit DPY-2: Allocated Cost of Service Study
Exhibit DPY-3: Fixed Gas Cost Rates and Apportionment Factors
Exhibit DPY-4: Allocation of Proposed Revenue Adjustments to Customer Classes;
Exhibit DPY-5: Summary of Existing and Proposed Rates and Revenues.

ALLOCATED COST OF SERVICE STUDY

Q. Did you perform an ACOSS to support your rate design recommendations?

A. Yes. I believe that an ACOSS provides an important means of assessing the reasonableness of existing prices and to guide the development of price changes. In particular, the ACOSS that I performed for Piedmont examines all of the Company's common costs reflected in its base rate petition, and through appropriate cost assignments and allocations, establishes measures of investments, expenses and income by customer class. The ACOSS is an important tool because many of the Company's costs are common and are incurred to serve many classes of customers collectively.

The ACOSS calculates the total investment and operating costs incurred to serve each customer class, thereby establishing class-specific total revenue requirements. The class-specific revenue requirements are compared to class revenues in order to establish class income and class rate of return on investment. The class-specific rates of return are used to guide the apportionment of the revenue requirements among all of Piedmont's customer classes in conjunction with the development of proposed rates. Although the ACOSS is not the only factor relied upon to design rates, it is an important guide to ensuring that the process is fair and reasonable.

Q. Please describe the general costing methodology that is incorporated in the Piedmont ACOSS.

A. The most significant consideration in the development of an ACOSS is the methodological approach to allocating fixed demand costs. Various approaches may be employed to allocate fixed demand costs including approaches that are based on system design, system utilization or a blending of system design and system utilization. The ACOSS performed for Piedmont reflects a blended approach to the allocation of fixed demand costs that is consistent with previous studies. It is important to note that a system-utilization ACOSS typically reflects larger cost allocations to high load factor customers than a system-design ACOSS. A full description of the Piedmont ACOSS as well as the input data and detailed results are presented in Exhibit DPY-2.

Q. Please summarize the results of the ACOSS.

A. The primary results from the ACOSS are the rate of return by class. The results of the ACOSS indicate that the rate of return for the residential, firm large general and military classes are less than the system-average rate of return at present rates. The rate of return for the small general, medium general, interruptible large general are above the system average, to varying degrees. The rate of return indicated in the ACOSS for Piedmont's special contract customers is also slightly below the system average, however, the reasonableness of special contract prices are evaluated on the basis of marginal costs rather than through an embedded cost study.

PIEDMONT DISTRIBUTION RATE DESIGN

Q. Please describe the specific rate design goals for Piedmont that guided the development of the rate design you are recommending.

A. The rate design approach I am recommending seeks to achieve the following five goals:

(1) Fairness – Fairness is accomplished through pricing services based on the underlying cost. Fairness is important in many respects including between the Company and its customers, across the classes served by Piedmont, and among customers taking service under a common rate schedule.

(2) Revenue Stability – Revenue stability means that Piedmont's base rate revenues are more predictable in view of future uncertainties. As customer use patterns have become less certain, improved revenue stability through rate design takes on greater importance as a way of mitigating the increased risks to customers and the Company associated with such unpredictable consumption patterns.

(3) **Not Discriminatory** – Avoiding undue discrimination requires rates that do not grant an unreasonable preference or subject an unreasonable disadvantage to any customer or group of customers.

(4) **Rate Moderation** – Moderation ensures that customers are not exposed to dramatic price changes that could result in undesirable impacts including cost increases or economic decisions by existing customers to cease taking gas service from Piedmont.

(5) **Energy Efficiency** – Energy efficiency as a goal is the promotion of consumption decisions that support energy efficiency goals.

Q. Please describe the Company's existing rate schedules.

A. Piedmont's existing rate schedules are segregated by sector, nature of service (firm or interruptible), customer size and by end-use in some cases. Over 99 percent of the Company's customers are served under three bundled sales tariffs. The first of these, Rate Schedule 101, applies to all residential service customers. Rate Schedule 102 applies to small general service customers with average daily use less than 20 dekatherms ("Dt") per day, and Rate Schedule 152 applies to medium general customers with average daily use between 20 and 50 Dth per day.

Large general service customers with average use of 50 Dth per day or more have the option of taking either firm or interruptible service as well as either sales or transportation service. The four options are Rate Schedule 103 – Large General Sales Service, Rate Schedule 104 – Interruptible Sales Service, Rate Schedule 113 – Large

General Transportation Service and Rate Schedule 114 – Interruptible Transportation Service.

Piedmont also provides service under rate schedules applicable to three specific end-uses. Rate Schedule 142 applies to service to Natural Gas Vehicles at Piedmont-owned refueling stations. Rate Schedule 105 applies to service for outdoor lights and Rate Schedule T-10 applies to transportation service at military bases with use greater than 5,000 Dth per day. The Company also has two other rate schedules applicable to military bases, but these currently do not have any active customers.

Q. Does Piedmont provide service to any off-tariff customers?

A. Yes. There are a number of large electric generation, municipalities and other customers that receive service under long-term contracts rather than tariffs. Each contract service customer committed to pay rates over a multi-year period that results in an appropriate revenue stream to support the Company's associated investment in facilities to provide service. The rates and charges under each long-term contract reflect the unique attributes of the specific customer including the nature of the load and investment requirements. All off-tariff services are approved by the NCUC prior to the initiation of service to the customer.

Q. What rates and charges are incorporated into the residential, small general and medium general rate schedules?

A. The existing rate design for these customers is similar and includes two types of margin rate charges that are intended to recover Piedmont's non-gas revenue requirements or cost of service: a monthly fixed charge and a delivery charge or charges applicable to monthly volumes. Fixed monthly customer charges are applied per customer per month and delivery charges are applied to each customer's monthly usage. Under this rate structure, all residential customers pay a minimum monthly amount to Piedmont equal to the fixed customer charge, regardless of their monthly usage. The rate design also results in customers paying higher amounts as their consumption increases due to the per-therm delivery charge. The delivery charge is considered a variable charge because all of the associated revenues are linked to customer usage or throughput.

For Residential Service, Rate Schedule 101, the monthly fixed charge is $10.00 and the margin delivery charge is $4.6202 per Dth. The monthly fixed charge for Small General Service, Rate Schedule 102, is $22.00 and the corresponding margin delivery charge is $3.4437 per Dth. The monthly fixed charge for Medium General Service, Rate Schedule 152, is $75.00 and the margin delivery charge is $3.2319 during winter months (November through March) and $2.7134 during the summer months (April through October).

Q. Please describe the rates for Piedmont's large general customers.

A. The margin rates applicable to Large General Sales Service, Rate Schedule 103, and Large General Transportation Service, Rate Schedule 113, customers are the same and incorporate a demand charge in addition to a monthly fixed charge and delivery charges. The demand charge is an important means of recovering fixed peak-related costs from customers in an equitable manner. The margin rates for these two classes are a monthly fixed charge of $350.00 and a monthly demand charge of $2.00 per Dth of maximum demand. In addition, these rate schedules employ six block delivery charges that are seasonally-differentiated with the highest rate for the initial block of 0 to 1,500 Dth.

The margin rates for the Interruptible Sales Service, Rate Schedule 104, and Interruptible Transportation Service, Rate Schedule 114, also incorporate a monthly fixed charge of $350.00, but do not reflect any demand charge. The seasonally-differentiated delivery charges exhibit six seasonally-differentiated blocks with varying rates.

Q. Please describe the rates for Piedmont's remaining rate schedules?

A. The rates applicable to NGV Service at Piedmont-owned refueling stations, Rate Schedule 142, include a delivery charge of $2.7035 per Dth and an additional compression charge of $4.00 per Dth. The rates for Military Operations Transportation above 5,000 Dth per day, Rate Schedule T-10, include a delivery charge of $0.9645 during the winter months and $0.0545 during the summer months. The rates for Outdoor Gaslight Service, Rate Schedule 105, are $16.50 per month per fixture.

Q. Are there separate charges to recover the costs associated with various gas supply and capacity resources?

A. Yes. Piedmont employs separate fixed and variable charges to recover the costs of upstream capacity and commodity resources that are subject to a true-up mechanism through Piedmont's Purchased Gas Adjustment tariff rider. The variable cost of gas ("COG") charges recover the costs of gas supply and variable pipeline transportation costs. The current variable COG commodity charge for all sales customers is $2.8023 per Dth and for all transportation customers is $0.0523 per Dth. Transportation customers obtain their gas supply from a third party supplier that may offer competitive pricing or other terms.

The COG demand charges recover fixed costs associated with maintaining sufficient pipeline and storage capacity to reliably meet the firm requirements of its sales customers and the balancing requirements of its sales and transportation customers. The COG demand charges vary by class based on relative load factor and also by winter and summer. The demand gas costs are primarily recovered through volumetric charges that are higher for low load factor customers and lower for high load factor customers. COG demand charges are also lower for transportation customers. I will further explain the derivation of fixed gas charges later in my testimony.

Q. Please comment on the relationship between Piedmont's Margin Decoupling Tracker ("MDT") and the appropriate rate design in this proceeding.

A. The MDT represents an appropriate means of separating Piedmont's margin revenue recoveries from customer usage. The MDT is essential to aligning the interests of Piedmont and its customers with respect to energy consumption. Removing the link between throughput and margins through the MDT allows Piedmont to fully support increased energy efficiency and conservation, encouraging customers to reduce their gas bills and lower the environmental impacts of their gas consumption.

Moreover, the MDT is layered over the existing rate design, which provides significant flexibility in terms of the design of base rates. As a result of this flexibility, I am proposing to retain all monthly facility charges at the current levels and recover the increased revenue requirements primarily through delivery charges. The MDT enables the recovery of additional margin revenues through usage charges and is an integral component of Piedmont's overall rate structure.

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.

Q. What steps did you employ to establish the specific base rates you are proposing?

A. First, I determined the COG demand rates applicable to each class and each rate element. Next, I determined the total base revenue increase applicable to each class. Last, I established specific margin rates that recover the proposed base revenues for each rate class.

Q. Please describe the proposed changes to the COG demand rates.

A. Piedmont's fixed capacity and storage resources, net of applicable mitigation revenues, are allocated to rate classes on the basis of appropriate factors that reflect the load characteristics of each class. The total change in demand gas costs proposed in this proceeding is $1,665,536. Based on the results of the fixed demand gas cost allocations, I am proposing to increase the residential service COG demand rates to recover an additional $895,989 of costs, the small general service COG demand rates to recover an additional $554,176 of costs, the medium general service COG demand rates to recover an additional $68,151 of costs and the large general interruptible transportation COG demand rates to recover an additional $147,220 of costs. The COG demand rates for all other classes remain unchanged. The resulting COG demand rates and associated apportionment factors are presented in Exhibit DPY-3.

Q. How did you develop the class-by-class revenue requirements to be reflected in the new base margin rates?

A. I first calculated the level of existing base revenues from each customer class taking into account MDT and Integrity Management revenues. This calculation is provided in Exhibit DPY-4, Column (E). I am proposing to allocate the proposed base revenue increase of

$118.1 million to all rate classes in proportion to existing base revenues. The resulting base revenues by rate class for proposed rates are reflected in Exhibit DPY-4, Column (G).

Q. Please describe the proposed changes to Piedmont's base margin rates.

A. The remaining revenue increases are applied to the volumetric charges of each rate class and to the demand charge for the large general classes. The existing and proposed rates for each class are compared in Exhibit DPY-5. In addition, Exhibit DPY-5 also provides a proof of revenues demonstrating that the proposed charges yield the requested revenue requirements based on the Company's forecasts of sales and customers.

Q. What change do you propose to the Medium General Service rate structure?

A. Presently, the Medium General Service rate structure is similar to the Residential Service and Small General Service rate structures except that the Medium General Service rate structure incorporates higher winter rates. I am proposing to align the Medium General Service rate structure with these other classes by removing the winter-summer rate differential in base margin rates. The existing rate differential is not significant and the change increases simplicity.

Q. What changes do you propose to the large general firm and interruptible rate structures?

A. I am proposing to increase the fixed demand charge for firm large general customers to $2.50 per Dth per month. In terms of block charges, I am proposing to reintroduce the traditional seasonally-differentiated declining block rate structure that existed prior to the Company's last base rate case. In addition, the proposed sales and transportation rates are margin neutral.

Q. Please comment on the impact of the proposed rate changes on Piedmont's recovery of its overall costs of providing service to customers.

A. The proposed rates reflect an equal percentage increase to all customer classes, which generally leads to more equalized rates of return under the system-utilization ACOSS presented in Exhibit DPY-2. The estimated return on investment by class at existing and proposed rates is provided in Table 1.

Table 1

Estimated Return on Rate Base Investment

Rate Schedule	Present Rates	Proposed Rates
Residential Service	3.97%	7.70%
Small General Service	7.88%	12.43%
Medium General Service	19.11%	26.58%
Large Firm General Service	1.52%	3.42%
Large Interruptible General Service	30.58%	43.74%
Military Service	1.28%	2.30%
Special Contracts	3.74%	2.90%
Overall	4.96%	7.68%

In my view, the proposed rates in this proceeding result from a fair and reasonable rate design approach given revenue changes applied in recent base rate proceedings and the continuation of Piedmont's MDT mechanism. Development of future rate changes should also consider the impacts of revenue changes based upon a system design ACOSS.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

DIRECT TESTIMONY OF PAUL M. NORMAND

I. INTRODUCTION

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

A. My name is Paul M. Normand. I am a management consultant and President of Management Applications Consulting, Inc. ("MAC"), 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications are provided in Exhibit PMN-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I have been retained by and am testifying on behalf of Piedmont Natural Gas Company, Inc. for the natural gas operations in North Carolina ("Piedmont" or "the Company").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present and sponsor the cash working capital ("CWC") requirements of Piedmont. CWC is a component of rate base upon which investors are entitled to earn a fair rate of return. In order to quantify the CWC requirements, MAC prepared a lead-lag study for Piedmont's North Carolina natural gas operations. This study develops and documents Piedmont's cash flow patterns in accordance with generally accepted practices. The lead-lag study shows a lag of 19.78 days for cash working capital on a pro forma basis.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony consists of four sections. Section I introduces my background information. A description of my qualifications and experience is included in Exhibit PMN-1. Section II describes the purpose and organization of my testimony. Section III presents the lead-lag study prepared on behalf of Piedmont to determine the pro forma CWC. A summary exhibit detailing the lead and lag days by revenue and cost component on a pro forma basis is provided as Exhibit PMN-2. Detailed workpapers employed in developing the lag days are provided as Exhibit PMN-3. Finally, Section IV of my direct testimony summarizes my conclusions and recommendations.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring three Exhibits, labeled Exhibit PMN-1 through Exhibit PMN-3. The first Exhibit summarizes my qualifications and experience. The second Exhibit PMN-2 presents my recommended CWC calculation for Piedmont's North Carolina natural gas operations. Exhibit PMN-3 provides the workpapers that detail the various analyses and calculations employed in developing the lead days and lag days for each revenue and cost component of the Company's revenue requirement.

III. CASH WORKING CAPITAL

1. Definition of CWC

Q. PLEASE DEFINE CASH WORKING CAPITAL.

A. CWC is the amount of investor-supplied capital required to fund the day-to-day operations of a company after accounting for the timing differences between booked and actual revenues and expenses. CWC represents amounts funded by investors to provide service prior to payment for such service by customers. As such, CWC is typically an addition to a company's rate base.

Q. DID YOU PERFORM A STUDY TO ESTIMATE THE CWC OF PIEDMONT FOR THE PRO FORMA PERIOD?

A. Yes. Exhibit PMN-2 summarizes the results of the lead-lag study conducted for Piedmont's North Carolina jurisdictional operations using the revenue requirements for the Pro Forma Period. As shown in this exhibit, the net lag is 19.78 days for cash working capital.

Q. WHAT IS A LEAD-LAG STUDY?

A. A lead-lag study is an analysis designed to determine the funding required to operate a company on a day-to-day basis. A lead-lag study compares (1) the timing difference between the receipt of service by customers and their subsequent payment for these services and (2) the timing difference between the incurrence of costs by Piedmont and its subsequent payment of these costs. Therefore, a lead-lag study must compute both a revenue lag (or lead) and an expense lead (or lag). Exhibit PMN-2 summarizes the lead-lag results for Piedmont. The CWC was developed using systematic reviews of cash flows for Piedmont's revenues and operations expenses. The lead-lag study we performed measured the actual lag days for Piedmont's day-to-day natural gas operations for the historic Test Period (the 12-month period ending December 31, 2018) and applies the resulting revenue lag and expense lag days to the revenue requirements for the Pro Forma Period (the 12-month period ending December 31, 2018, as adjusted for pro forma changes to revenue, operating expense and return).

Q. PLEASE DEFINE THE TERMS "LAG DAYS" AND "LEAD DAYS" AS USED IN YOUR TESTIMONY.

A. Revenue lag days are the number of days between delivery of service to Piedmont's customers and the subsequent receipt by Piedmont of payment for the service (revenue lag). Expense lag days are the number of days between the receipt of goods or services provided to Piedmont by vendors and the payment by Piedmont for those goods and services.

Because Piedmont's customers receive service prior to paying for it, Piedmont experiences a revenue lag in its daily operations. This revenue lag is computed based upon analysis of the time lag between the date when customers receive service and the date when the customers pay for such service. The longer the revenue lag, the greater the length of time that investor capital is employed to fund Piedmont's day-to-day operations. The revenue lag for Piedmont is 54.81 on a pro forma basis and is developed in Exhibit PMN-3.

Generally, expenses are paid by Piedmont after vendors have provided their goods or services, which results in an expense lag. On occasion, Piedmont pays for services before they are provided. In these instances, the expenses lead their service period. The expense lag is calculated as the number of days between the date when Piedmont receives goods or services from a vendor and the date when Piedmont pays for such goods or services. If the expenses are paid before the services are provided, then the expense lead is expressed as a negative. Consequently, any increase in the number of expense lag days results in a reduction of the amount of working capital required for ongoing Piedmont operations. The expense lag for Piedmont is 35.03 days on a pro forma basis and is developed in Exhibit PMN-3.

The arithmetic difference between the computed revenue lag and the computed expense lag is the net number of days that investors must provide funding for the utility's daily operations. As shown on Exhibit PMN-2, line 47, column 2, the Piedmont net lag days are 19.78 days.

2. <u>Lead-Lag Study General Approach</u>

Q. PLEASE DESCRIBE THE APPROACH YOU USED IN PREPARING YOUR LEAD-LAG STUDY.

The lead-lag study began with the selection of the actual per books revenues and expenses for the historic Test Period (the12-month period ended December 31, 2018) to form the basis for my analysis. The lag days in the recovery of revenue by type of revenue (i.e., sales and other revenues) were then determined. Lag days for each of several types of expenses (i.e., purchased gas, labor, incentive pays, employee pensions and benefits, fleet expenses, credit card expenses, regulatory expenses, and other O&M expenses) were developed for operation and maintenance ("O&M") expenses. In addition, lag days were developed for taxes, including payroll taxes, property taxes, other miscellaneous taxes, federal income tax, state income tax, and interest expense.

Once the lag days for the Test Period were established, they were applied to the revenue requirements for the Pro Forma Period. The lead or lag days for each of the items described above were multiplied by the Pro Forma Period corresponding amounts to determine the dollar-days of CWC. The dollar-days of revenue less the dollar-days of expenses and taxes were then divided by 365 days to obtain the average daily CWC.

3. Methods of Computation

Q. PLEASE DESCRIBE YOUR CALCULATION OF REVENUE LAGS.

A. The calculation of revenue lags is developed in Exhibit PMN-3 workpapers. As previously described, "revenue lag" is the length of time that occurs between Piedmont's providing service to its customers and the subsequent receipt of payment for those services. The existence of a revenue lag makes it necessary for investors to provide the funding for Piedmont to pay its operating costs during the lag period.

The measurement of revenue lag days typically consists of four components: (1) service lag, (2) billing lag, (3) collection lag and (4) revenue float. Since the time periods for these four components are mutually exclusive, revenue lag is computed by simply adding together the total number of days associated with each of the four revenue lag components. This total number of lag days represents the amount of time between the recorded delivery of service to customers and the receipt of the related revenues from customers.

Q. PLEASE DESCRIBE HOW YOU CALCULATE SERVICE LAG.

A. The service lag is the average time span between the midpoint of the customer's consumption interval, also known as the usage period, and the time that such usage is recorded by Piedmont for billing purposes. This service period determines the average length of time over which the billed services are provided and establishes a common point in time from which to measure (1) the time of reimbursement for the billed services, and (2) the time at which the accrued costs for the service period are actually paid. For virtually all utilities billing monthly, the service lag is one half of an average month or 15.22 days (365.25 / 24).

Q. PLEASE DESCRIBE YOUR CALCULATION OF BILLING LAG.

A. The billing lag is the time required to process and send out customer bills. The billing lag begins at the end of the service period when customer consumption is metered and it ends when the bills are rendered and billings are posted to accounts receivable. Piedmont utilizes an automated meter reading system and provides a window of dates for meter reading crews to post their meter reading data into the billing system. Billing is performed after the data is thoroughly checked and corrected, if necessary. Piedmont's billing lag was approximately 6.47 days after considering the delay for weekends, holidays, and the posting to accounts receivable. The details of this calculation can be found in the workpapers in Exhibit PMN-3.

Q. PLEASE DESCRIBE YOUR CALCULATION OF COLLECTION LAG.

The collection lag identifies the time delay between the issuance of customer bills and the receipt of the billed revenues. Collection lag begins with the posting of bills and ends with the receipt of payment. Collection lag may be influenced by payment arrangements, contract terms, postal delivery delays, customer inquiries, delinquent accounts, service termination practices, and other factors. MAC employed the accounts receivable turnover ratio method to determine the collection lags. Using this approach, the average daily accounts receivable balances were divided by the average daily revenues for the 12 months ended December 31, 2018. Using the accounts receivable turnover method, a collection lag of 33.00 days was computed. The details of this calculation can be found in the workpapers in Exhibit PMN-3.

Q. PLEASE DESCRIBE THE FINAL COMPONENT OF REVENUE LAG, REVENUE FLOAT.

A. Revenue float is the time difference between when funds are received from customers until customer payments clear the banks and are available to the Company. To clarify, there are two periods of float. The first is associated with the Company's payment of services from vendors. Expense float, or lag, is discussed later in my direct testimony. The second period of float is the delay in receipt of cash from customer payments. In this latter instance, Piedmont's cash requirements are increased by the delay in mailing and check processing. Many lead-lag studies assume that revenue float and check float are equal and offsetting and, therefore, can be removed. A closer examination reveals that the issue is much more complex. The majority of Piedmont's larger expense payments are made by wire transfer with a much shorter lag than a conventional mailed check. On the revenue side, a portion of customer payments are made by cash, credit card or bank transfer. Again, these payments have smaller lag times to clear than conventional checks. Since the dollar volume of utility payments exceed their receipts made by cash, credit card and bank transfer, the inclusion of check float in the lead-lag study should slightly increase CWC requirements. MAC chose to avoid this level of complexity with the knowledge that our simplifying assumption will slightly understate CWC and will not disadvantage customers. The inclusion of float would logically cause a slight increase to total net lag and a commensurate increase in cash working capital requirements, albeit with a significant level of additional complexity to quantify the actual impact. Therefore, float for revenues or expenses was not quantified in this study.

Q. TURNING OUR ATTENTION TO THE TIMING OF CASH FLOWS ASSOCIATED WITH EXPENSES, HOW DID YOU DETERMINE THE LAG ASSOCIATED WITH PURCHASED GAS EXPENSE?

A. The calculation of expense lags is developed in Exhibit PMN-3. Purchased gas expense is the largest category of expense in the Company's total revenue requirements. The purchased gas expense lag of 36.80 days is taken from the detailed calculations shown on Exhibit PMN-3. Each purchased gas invoice for the year was scrutinized in the preparation of this workpaper. Consistent with general industry practice, each invoice represents billings for the prior calendar month. The service period for each monthly invoice is defined as the 24-hour period ending at 10:00 AM. Consequently, each invoice is for the period beginning at 10:00 AM on the first day of the previous month and ending at the same time in the current month. Payments are made on approximately the 25th of the following month, depending on weekend and holiday schedules. The column labeled "Lag Days" shows the lag between the midpoint of the service period and the payment date. In order to compute the average lag, the individual invoices were weighted by the dollar amount of the invoice. The lead-lag study identifies the lag between receipt of gas and payment of invoices. The additional working capital required to support gas in fuel inventory is recognized through an addition to rate base, outside of the lead-lag study. Note that MAC's calculations do not address gas placed in storage.

Q. HOW DID YOU DETERMINE THE LAG FOR LABOR EXPENSE?

A. Piedmont's payroll stems from bi-weekly and semi-monthly payroll disbursements. Using payroll data, MAC measured the lag between the midpoint of the pay period and the pay date. However, not all labor costs earned by employees in the pay period are paid out as salary, the difference being payroll withholdings and deductions. In order to make an accurate calculation of total labor costs, MAC identified all labor-related costs and identified when the Company actually expended the cash. These labor-related costs include all salary including incentive compensation, payroll taxes including withholding taxes, and a wide range of benefits. The workpapers, provided as Exhibit PMN-3, summarize each component of labor-related costs. Each of the individual calculations is also shown. As this exhibit demonstrates, regular payroll costs are the largest component of labor costs and have the shortest payment lag. However, other components of labor costs have relatively long delays. For example, incentive compensation pay earned during the course of the fiscal period is paid in March of the next fiscal year, resulting in an expense lag of approximately 252 days. The Company also has a long term incentive compensation pay that is earned during the course of three fiscal periods which results in a much larger lag of approximately 622 days. In addition to direct labor expense, MAC examined other labor-related costs to the Company, including payroll taxes and pension and benefits expense as will be discussed below.

Q. PLEASE DESCRIBE THE CALCULATION OF LAG DAYS FOR PENSIONS AND BENEFIT EXPENSE.

A. The method for calculating pensions and benefit expense lag follows the same approach used for all other lag calculations. For each expense, the service period and its midpoint were determined. Then the payment date was established. The lag was then computed as the difference between the payment date and the midpoint of the service period. Next, a dollar-weighted average of each expense was computed to determine the overall average for this category. For those items that were included in Rate Base, such as Pensions and OPEB expenses, a zero lag was assigned. The workpapers in Exhibit PMN-3 show these calculations.

Q. WERE OTHER CATEGORIES OF O&M EXPENSE ANALYZED SEPARATELY AND INCLUDED IN THE EXPENSE LAG?

A. Yes. Fleet expenses, credit card and Regulatory Commission expenses in Account 928, were analyzed separately and included in the calculations of the expense lag. Again, the lags for each expense item were computed as the difference between the payment date and the mid-point of the service period. See the workpapers in Exhibit PMN-3 for these calculations.

Q. WHAT COSTS ARE REPRESENTED UNDER THE HEADING "OTHER O&M EXPENSE?"

A. So far, expense categories discussed consisted either of a relative few number of payments or payments representing large cash expenditures. For these categories, the individual payments and service period were determined and the lag days computed directly. In terms of total dollar expenditures, the majority of these expenses have already been identified and their lags computed. However, the remainder of Other O&M expenses was not accounted for in these calculations. Other O&M represents about twelve percent of the Company's revenue requirements but are the large majority of the number of cash disbursements. Different sampling approaches were therefore required to estimate the lags for Other O&M expense categories in the Company's revenue requirements for the 12 months ended December 31, 2018.

Q. HOW DID YOU CALCULATE THE EXPENSE LAG FOR OTHER O&M?

A. MAC requested a listing of all Company payments related to Other O&M. The Company provided a comprehensive list of all cash disbursements paid. The listing provided was separated into three major categories: accounts payable North Carolina charges, stores, and working stock payments. Payments related to other jurisdictions were eliminated, and payments made to multiple jurisdictions were allocated to the North Carolina jurisdiction based on the Company's allocation percentages. Each of the three categories were sampled separately. In each category, the largest dollar payments were selected, and for the remaining payments, a sequential sample was taken. In total, 158 payments were sampled that accounted for 29.5% of the total dollars in the population. Vendor invoices and payment date information were also examined for each of the payments sampled. The lags for each of the payments sampled were computed as the difference between the payment date and the mid-point of the service period. The lag days computed for the Company's accounts payable North Carolina charges was applied to the O&M expenses allocated to Piedmont from the service company. A weighted average of the samples was computed to estimate the composite lag of 59.41 days for Other O&M expense. The workpapers in Exhibit PMN-3 show these calculations.

Q. HOW WERE PREPAID EXPENSES THAT WERE INCLUDED IN RATE BASE TREATED IN THE LEAD-LAG STUDY?

A. Expenses that related to the prepayments included in rate base, such as insurance expenses, were assigned a zero lag. Normally, prepaid expenses have a negative expense lag and would increase working capital if they were not included in rate base.

Q. HOW IS UNCOLLECTIBLE ACCOUNTS EXPENSE INCLUDED IN THE LEAD-LAG STUDY?

A. Uncollectible Accounts expense for base revenues was not assigned lead or lag days in the study because it is a non-cash item. The lag for uncollectible accounts has been recognized in the calculation of the collection lag. The accounts receivable balance is reduced when uncollectible accounts are written off, thereby reducing the collection lag.

Q. HOW DID YOU DETERMINE THE LAG FOR THE ACCOUNTING ENTRIES APPEARING IN THE COMPANY'S REVENUE REQUIREMENT?

A. Piedmont's revenue requirements include a number of non-cash expenses or accrual accounting entries in addition to operating and maintenance expenses. These accounting entries recognize the accrual of expenses commensurate with the service rendered in the test period and the calculation of return. The most notable items in this category are depreciation and amortization, service company allocated depreciation expense, amortization of investment tax credits, provision for deferred income taxes, and Income for return after the deduction for short-term and long-term interest expense. Since these expenses require no current cash payments, a zero expense lag was assigned. Interest on customer deposits was also assigned a zero lag since both the amount of customer deposits and accrued interest on customer deposits were included as a deduction from working capital in rate base.

Q. DID YOU INCLUDE ANY OTHER EXPENSES BESIDES O&M EXPENSES IN THE CALCULATION OF THE EXPENSE LAG?

A. Yes. Since Property Taxes, Other Taxes, Payroll Taxes, Federal and State Income Taxes, and Interest on Long Term and Short Term Debt represent cash outlays, they were included in the calculation of CWC. All property tax payments made during the 12 months ended December 31, 2018 were analyzed and produced a 186-day lag. Other Taxes consist mostly of Payroll Taxes, Company Use Taxes, and Franchise Taxes. Each type of tax was analyzed separately and assigned a lag based on the service periods and payment dates. Federal and State Income Taxes were assigned lags based on Piedmont's statutory-required fiscal tax year equal tax payments. Interest on Long Term Debt and Short Term Debt was assigned lags based on the actual interest payments for the 12 months ended December 31, 2018. The details supporting these results are provided in the workpapers Exhibit PMN-3.

4. Results of Piedmont Pro Forma Lead-Lag Study

Q. WHERE HAVE YOU PRESENTED THE RESULTS OF THE CWC CALCULATIONS FOR THE PRO FORMA TEST YEAR ENDING DECEMBER 31, 2018?

A. The results of the lead-lag study are summarized on Exhibit PMN-2. This page summarizes the revenues and the expense lags from Exhibit PMN-3 and presents the Company's CWC for the pro forma test year.

Q. HAVE YOU IDENTIFIED THE NET LAG DAYS BETWEEN REVENUE AND EXPENSE FOR PIEDMONT'S GAS OPERATIONS FOR THE PRO FORMA TEST YEAR ENDING DECEMBER 31, 2018?

A. Yes. As indicated by the data in Exhibit PMN-2, page 1, the net lag for Piedmont's North Carolina operations as measured by the lead-lag study is 19.78 days. The positive lag indicates that the system requires investor capital to compensate for the fact that the lag in the recovery of revenues is greater than the lead in the payment of expenses. Piedmont's total CWC requirement for the December 31, 2018 pro forma test year is $54,375,609 as shown on Exhibit PMN-2.

Q. REFERRING TO EXHIBIT PMN-2, COULD YOU DISCUSS THE STRUCTURE OF YOUR PRO FORMA LEAD-LAG STUDY SUMMARY?

A. The summary of Piedmont's lead-lag study consists of three sections. Lines 1 through 3 summarize the revenue lag. Lines 5 through 45 detail the expense lag data. Lines 47 to 63 show CWC in total and segregated between Purchased Gas and all other.

The lag day calculations are based on per-books December 31, 2018 costs. Due to changes in revenue requirements and the resulting change in revenue and expense items, such as income taxes, the actual annual data is not indicative of the cash working capital requirements of Piedmont on an ongoing basis. Under normal conditions, the proposed rates are expected to allow Piedmont investors to earn a reasonable return on their investment, and the utility must pay income taxes on this return. Therefore, it is important to note the level of CWC computed on a per-books basis in Exhibit PMN-3 may understate the level of CWC required for normal operations. The importance of the per-books study is to determine the appropriate number of lag days applicable to revenue and expense items. Exhibit PMN-2 establishes the level of CWC on a pro forma basis using the lag days computed in the study and summarized in Exhibit PMN-3.

In order to compute subtotals and totals in Exhibit PMN-2, the rightmost working column, labeled "Day Weighted Amount," is shown. For those categories with known lag days, this column is the simple product of the annual expense and the lag days. For rows displaying subtotals and totals, this column is computed and then used along with the appropriate figure from the Proposed Amounts column to compute the average lag. Row 45 of Exhibit PMN-2 shows that the pro forma weighted average lag of all expenses is 35.03 days. Since revenues are received 54.81 days after the service is provided to customers and expenses are paid 35.03 days after service has been provided by vendors, there is a net lag of 19.78 days for revenues less expenses as shown on Row 47. Because the recovery of revenues lags the payment of expenses, investors must provide the funds to pay for the daily operations of the Company, and the CWC amount is a positive addition to rate base.

Q. DID YOU SEPARATELY DETERMINE THE NET LAG FOR PURCHASED GAS EXPENSE AS WELL AS THE REMAINDER OF PIEDMONT'S NORTH CAROLINA OPERATIONS?

A. Yes. As indicated by the data in Exhibit PMN-2, line 55, the net lag for Piedmont's Purchased Gas expense is 17.89 days. The remainder of Piedmont's pro forma revenue requirements has a net lag of 20.73 days.

Q. PLEASE DESCRIBE EXHIBIT PMN-3.

A. Exhibit PMN-3 provides source information, service periods, payment dates, amounts, and other information with greater detail about the data and methodology employed in developing Piedmont's CWC requirements. These workpapers set forth the specific calculations and assumptions embodied in the lead/lag days set forth on Exhibit PMN-2.

IV. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The lead-lag study separately computes the lag days associated with revenue collection from customers and the lag days associated with the utility revenue requirements, segregated between purchased gas expense and all other. These lagged revenues and expenses are combined to determine the net lag days for Piedmont. The CWC net lag data is summarized in Exhibit PMN-2. Based upon the results of the lead-lag study, we recommend that the Company be allowed a CWC amount to be included in rate base and calculated using the revenue and expense lag days calculated in the lead-lag study.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DIRECT TESTIMONY OF DANE A. WATSON

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Dane A. Watson, and my business address is 101 E. Park Blvd., Suite 220, Plano, Texas 75074. I am a Partner of Alliance Consulting Group. Alliance Consulting Group provides consulting and expert services to the utility industry.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals ("the Society") has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I met all requirements and have become a Certified Depreciation Professional ("CDP").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University. Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation and certain other accounting-related studies for utilities in various regulated industries. My duties related to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management for its consideration, and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I also served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. No. However, I was responsible for the preparation of the last two depreciation studies for Piedmont Natural Gas Company ("Piedmont" or "Company"), the former one of which is the basis for Piedmont's current depreciation rates as authorized by this Commission in Docket No. G-9, Sub 631.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OTHER STATE AND/OR FEDERAL REGULATORY COMMISSIONS?

A. Yes. During my 31 year career in performing depreciation studies, I have testified before more than 30 separate state regulatory bodies and the Federal Energy Regulatory Commission ("FERC"). A complete list of the proceedings in which I have conducted depreciation studies, filed written testimony, and/or testified before various state and federal commissions is provided in Exhibit DAW-1.

II. PURPOSE OF DIRECT TESTIMONY

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

A. I sponsor and support the depreciation study performed for Piedmont of its wholly-dedicated North Carolina fixed assets and its wholly-dedicated South Carolina fixed assets (collectively referred to as "The Carolinas" fixed assets), and its multi-state dedicated fixed assets (referred to as "Corporate" fixed assets, which jointly support Piedmont's operations in North Carolina, South Carolina and Tennessee).

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring the following exhibits:

- DAW-1 – Dane A. Watson Testimony Appearances
- DAW-2 – Piedmont Natural Gas Company's Gas Depreciation Rate Study at September 30, 2018

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

A. Yes.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The study, which encompasses fixed assets for three of the four Piedmont jurisdictional entities (North Carolina, South Carolina and Corporate), results in an overall increase of $0.3 million in annual depreciation expense compared to the annualized current depreciation expense being recorded at September 30, 2018. In this proceeding, we only address the North Carolina and Corporate property, which resulted in a $9.5 million decrease and in a $10 million increase, respectively. The changes in removal cost experienced by the Company in several accounts, along with the increase of lives in several accounts and the historical reserve levels, are the primary drivers for the change in annual depreciation expense. The Piedmont depreciation rate study is attached to my testimony as Exhibit DAW–2. I recommend adoption of the proposed North Carolina and Corporate annual depreciation rates for each property group shown in Appendix B of the study, as well as adoption of the reallocated book reserves.

III. PIEDMONT NATURAL GAS COMPANY'S DEPRECIATION STUDY

Q. DID YOU PREPARE THE GAS DEPRECIATION STUDY?

A. Yes. The Piedmont Depreciation Study is attached to my testimony as Exhibit DAW–2. The depreciation study shown in Exhibit DAW-2 analyzes the life and net salvage percentage for the Company's gas assets operating in The Carolinas and Corporate at September 30, 2018. For the life and net salvage analysis for the three entities were combined, which results in one life and net salvage parameter recommendation for each account. Those parameters were then used to calculate annual depreciation accruals for each separate jurisdictional entity based on each entity's plant and reserves. While the study encompasses all three entities, my testimony herein addresses North Carolina and Corporate results specifically.

Q. WHAT PROPERTY IS INCLUDED IN THE DEPRECIATION STUDY?

A. There are five general classes, or functional groups, of depreciable property: Storage Plant, Transmission Plant, Distribution Plant property, General Plant and Intangible Plant property. The Storage Plant functional group primarily consists of facilities that store natural gas for use as needed. The Transmission Plant functional group primarily consists of high and intermediate pressure transmission assets that deliver gas to various receipt points or city gates. The Distribution Plant functional group primarily consists of lines and associated facilities used to distribute gas within the locale served by Piedmont. General Plant property is not location specific but is used to support the overall distribution of gas to its customers. Intangible Plant is also not location specific and consists of various software assets used to support overall operations.

Q. **WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR THE PURPOSES OF CONDUCTING A DEPRECIATION STUDY AND PREPARING YOUR TESTIMONY?**

A. The term "depreciation," as used herein, is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. The Company accrues depreciation based on the original cost of all property included in each depreciable plant account. On retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q. **PLEASE DESCRIBE YOUR DEPRECIATION STUDY APPROACH.**

A. I conducted the depreciation studies in four phases as shown in my Exhibit DAW-2. The four phases are: Data Collection, Analysis, Evaluation, and Calculation. During the initial phase of the study, I collected historical data to be used in the analysis. After the data was assembled, I performed analyses to determine the life and net salvage percentage for the different property groups being studied. Using the same methodology used in the prior study, the historical asset data for the Carolinas and Corporate were combined during life and net salvage analysis. However the annual depreciation rates were computed separately for North Carolina, South Carolina, and Corporate. As part of this process, I conferred with field personnel, engineers, and managers responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, engineers, and managerial personnel, combined with the study results, was then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans, should be applied. Using all of these resources, I then calculated separate depreciation rates for each account and function for North Carolina, South Carolina, and Corporate.

Q. WHAT DEPRECIATION METHODOLOGY DID YOU USE?

A. Consistent with the previously approved study, the straight-line, Average Life Group ("ALG") remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study.

Q. HOW ARE THE DEPRECIATION RATES DETERMINED USING THE ALG PROCEDURE?

A. In this system, the annual depreciation expense for each group was computed by dividing the original cost of the asset, less allocated depreciation reserve, less estimated net salvage, by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within an account were accumulated, and the total was divided by the original cost of all depreciable property within the account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual depreciation rates are shown in Appendix A of my Exhibit DAW-2.

Q. WHAT TIME PERIOD DID YOU USE TO DEVELOP THE PROPOSED DEPRECIATION RATES?

A. The account level depreciation rates were developed based on the depreciable property recorded on the Company's books at September 30, 2018.

Q. PLEASE SUMMARIZE THE DEPRECIATION STUDY RESULTS WITH RESPECT TO DEPRECIATION RATES.

A. Table 1 and Table 2 show the approved and recommended depreciation rates and annual accrual for each account for North Carolina and Corporate.

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Table 1 - Comparison of Existing versus Proposed North Carolina

			Existing		Recommended		
	Account	Plant Balance		Annual		Annual	Increase/
Number	Description	09/30/2018	Rate	Accrual	Rate	Accrual	Decrease
	INTANGIBLE PLANT						
23010	Organization	15,171	0.00%	-	0.00%	-	-
23020	Franchise and Consents	586,786	0.00%	-	0.00%	-	-
23030	Intangibles	2,486,925	0.00%	-	0.00%	-	-
	Total Intangible Plant	3,088,881	0.00%	-	0.00%	-	-
	TRANSMISSION PLANT						
26510	Land	12,685,647	0.00%	-	0.00%	-	-
26520	Land Rights	181,683,372	1.35%	2,452,726	1.25%	2,268,209	(184,517)
26610	Structures & Improvements - Compressor Stations	17,809,212	2.64%	470,163	2.10%	373,329	(96,834)
26620	Structures & Improvements - M&R Stations	11,248,093	2.14%	240,709	2.10%	235,753	(4,956)
26700	Mains & Cathodic Protection	1,886,162,936	1.70%	32,064,770	1.84%	34,753,806	2,689,036
26800	Compressor Station Equipment	177,215,141	2.64%	4,678,480	2.85%	5,043,287	364,807
26900	M&R Station Equipment	139,841,644	2.14%	2,992,611	2.33%	3,253,185	260,574
	Total Transmission (excludes land)	2,413,960,397	1.78%	42,899,459	1.90%	45,927,569	3,028,110
	DISTRIBUTION PLANT						
27400	Land	2,154,623	0.00%	-	0.00%	-	-
27401	Land Rights	38,509,644	1.52%	585,347	1.32%	509,644	(75,702)
27500	Structures & Improvements	576,403	2.11%	12,162	1.70%	9,781	(2,381)
27600	Mains	1,055,721,546	2.30%	24,281,596	1.71%	18,029,190	(6,252,405)
27800	M&R Station Equipment	32,452,491	2.57%	834,029	1.93%	626,885	(207,144)
27900	M&R City Gate Equipment	46,853,594	2.20%	1,030,779	1.90%	891,916	(138.863)
28000	Services	662,381,450	3.03%	20,070,158	2.78%	18,426,077	(1,644,081)
28100	Meters	81,039,613	3.16%	2,560,852	2.90%	2,350,980	(209,872)
28105	Meters - Meter Accessories & ERTs	29,577,780	6.52%	1,928,471	3.46%	1,024,842	(903,629)
28200	Meter Installations	40,428,037	3.28%	1,326,040	3.28%	1,326,181	141
28300	House Regulators	12,296,473	3.14%	386,109	2.96%	363.899	(22,210)
28400	House Regulator Installations	389,755	3.26%	12,706	3.40%	13,244	538
28500	Industrial M&R Station Equipment	43,053,116	2.28%	981,611	1.63%	702,272	(279,339)
28600	Property on Customer Premises	743,304	2.13%	15,832	1.50%	11,139	(4,693)
28700	Other Equipment	43,672	1.29%	563	2.29%	999	436
	Total Distribution (excludes land)	2,044,066,878	2.64%	54,026,255	2.17%	44,287,050	(9.739,205)
	GENERAL PLANT DEPRECIATED						
28900	Land	2,965,148	0.00%	-	0.00%	-	-
29000	Structures & Improvements	85,572,305	2.33%	1,993,835	2.00%	1,709,676	(284,159)
29200	Transportation 3 Year Meter Reading	256,646	14.89%	38.215	18.07%	46,367	8,152
29201	Transportation 5 Year Rural	10,205,385	14.89%	1,519,582	12.82%	1,308,807	(210.775)
29202	Transportation 7 Year Urban	29.041,348	14.89%	4,324.257	7.54%	2,188,397	(2,135,860)
29203	Transportation 10 Year Heavy Duty	13,978,891	7.36%	1,028.846	6.14%	858,373	(170,473)
29204	Transportation 15 Year Trailers & Other	1,530,169	5.51%	84,312	4.58%	70,037	(14,276)
29210	Passenger Cars & Station Wagons	151.250	14.89%	22,521	11.76%	17,785	(4,736)
29410	CNG Station Equipment	17,700,175	3.86%	683,227	3.90%	691,117	7,890
29600	Power Operated Equipment	12,183,401	3.03%	369,157	3.28%	399,124	29,966
	Total General Depreciated (excludes land)	170,619.571	5.90%	10,063,952	4.27%	7,289,682	(2,774,270)
	GENERAL PLANT AMORTIZED						
29100	Office Furniture & Equipment	8,902,996	4.35%	387,280	5.00%	397,913	10,632
29300	Stores Equipment	3,385	2.88%	97	5.00%	69	(29)
29400	Tools, Shop & Garage Equipment	12,504,508	3.86%	482,674	5.00%	527,324	44,650
29500	Laboratory Equipment	807,436	4.42%	35,689	5.00%	31,773	(3,916)
29700	Communications Equipment	5,373,011	4.83%	259,516	5.56%	211,620	(47.897)
29800	Miscellaneous Equipment	3,403,209	4.32%	147,019	5.00%	143,762	(3,257)
	Total General Amortized	30,994,545	4.23%	1,312,276	4.23%	1,312,459	184
	Total General Plant (excludes land)	201,614,115	5.64%	11,376,227	4.27%	8,602,141	(2,774,086)
	Total Plant excludes Land & Intangibles	4,680,535,690	2.32%	108,301,941	2.12%	98,816,760	(9,485,180)

Table 2 - Comparison of Existing versus Proposed Corporate

			Existing			Recommended		
Account		Plant Balance		Annual			Annual	Increase/
Number	Description	09/30/2018	Rate	Accrual		Rate	Accrual	Decrease
	INTANGIBLE PLANT							
20300	5 Year Software	21,815,616	7.49%	1,633,990		20.00%	4,363,123	2,729,134
20310	10 Year Software	140,536,818	7.49%	10,526,208		10.00%	14,053,682	3,527,474
	Total Intangible	162,352,435	7.49%	12,160,197		11.34%	18,416,805	6,256,608
	STORAGE PLANT							
26000	Land	3,711,022	0.00%	-		0.00%	-	0
26100	Structures & Improvements	33,679,450	1.83%	616,334		2.02%	678,938	62,604
26200	Gas Holders	10,708,928	1.56%	167,059		1.48%	158,843	(8,217)
26300	Purification Equipment	15,172,019	1.97%	298,889		2.46%	373,297	74,409
26310	Liquefaction Equipment	8,106,977	1.72%	139,440		2.06%	166,937	27,497
26320	Vaporizing Equipment	41,945,450	2.29%	960,551		3.43%	1,437,955	477,404
26330	Compressor Equipment	5,816,086	2.14%	124,464		2.51%	146,244	21,780
26340	M&R Equipment	293,884	1.80%	5,290		3.10%	9,096	3,806
26350	Other Equipment	11,063,494	2.21%	244,503		2.98%	329,940	85,437
	Total Storage (excludes land)	126,786,289	2.02%	2,556,530		2.60%	3,301,251	744,721
	DISTRIBUTION PLANT							
27400	Land	63,862	0.00%	-		0.00%	-	-
27500	Structures &Improvements	792,886	2.15%	17,047		4.60%	36,455	19,408
28100	Meters	13,630,871	3.14%	428,009		4.50%	613,423	185,414
28105	Meters - Meter Accessories & ERTs	13,119,799	6.89%	903,954		14.46%	1,897,644	993,690
	Total Distribution (excludes land)	27,543,556	4.90%	1,349,011		9.25%	2,547,522	1,198,511
	GENERAL PLANT DEPRECIATED							
29000	Structures & Improvements	3,218,829	2.35%	75,642		2.10%	67,439	(8,203)
29201	Transportation 5 Year Rural	29,000	14.84%	4,304		15.40%	-	(4,304)
29202	Transportation - 7 Year Urban	642,557	14.84%	95,355		8.83%	56,752	(38,604)
29203	Transportation - 10 Year Heavy Duty	590,263	7.33%	43,266		7.29%	43,002	(264)
29204	Transportation - 15 Year Trailers & Other	23,352	5.50%	1,284		4.94%	1,153	(131)
29410	CNG Station Equipment	2,908	3.93%	114		4.08%	119	4
29600	Power Operated Equipment	861,228	3.14%	27,043		3.71%	31,909	4,866
Total General Depreciated (excludes land)		5,368,136	4.60%	247,009		3.73%	200,374	(46,635)
	GENERAL PLANT AMORTIZED							
29001	Leasehold Improvements	6,907,269	10.00%	690,727		4.76%	317,130	(373,597)
29100	Office Furniture & Equipment	8,958,449	4.30%	385,213		5.00%	439,230	54,017
29102	Computer Processing Hardware	28,136,248	15.00%	4,220,437		20.00%	5,493,589	1,273,152
29103	Customer Information System	17,721,735	0.96%	170,129		5.00%	841,951	671,823
29400	Tools, Shop & Garage Equipment	3,327,640	3.93%	130,776		5.00%	164,422	33,646
29500	Laboratory Equipment	445,001	4.41%	19,625		5.00%	21,667	2,042
29700	Communications Equipment	28,736,506	4.69%	1,347,742		5.56%	1,550,286	202,544
29800	Miscellaneous Equipment	181,883	4.34%	7,894		5.00%	9,016	1,123
	Total General Amortized	94,414,732	7.39%	6,972,543		9.36%	8,837,293	1,864,750
	Total General Plant	99,782,868	7.24%	7,219,552		6.88%	9,037,667	1,818,115
Total Depreciated & Amortized (excludes land)		416,465,147	5.59%	23,285,290		8.00%	33,303,245	10,017,955
Total Plant with Land and Intangibles		$ 420,240,031						

Q. WHAT FACTORS INFLUENCE THE DEPRECIATION RATES FOR AN ACCOUNT?

A. The primary factors that influence the depreciation rate for an account are: 1. the remaining investment to be recovered in the account, 2. the depreciable life of the account, and 3. the net salvage for the account.

Q. WHICH OF THESE FACTORS INFLUENCED THE DEPRECIATION RATES FOR PIEDMONT NATURAL GAS?

A. All of these factors influenced the proposed depreciation rates for Piedmont. Adjustments in the average service lives and net salvage factors for various accounts combined with the historical book reserve level are what influenced the proposed depreciation rates.

Q. AS PART OF YOUR DEPRECIATION ANALYSIS, HAVE YOU TAKEN ANY ACTION TO PROPERLY ALIGN THE COMPANY'S DEPRECIATION RESERVE WITH THE LIFE CHARACTERISTICS OF THE ASSETS WITHIN EACH PLANT FUNCTION?

A. Yes. In the process of analyzing the Company's depreciation reserve, I observed that the depreciation reserve positions of the various accounts needed to be re-balanced based on my recommended service lives and net salvage ratios. To allow the relative reserve positions of each account within a function to mirror the life characteristics of the underlying assets, I reallocated the depreciation reserves for all accounts within each function.

Q. DOES THE REALLOCATION OF THE DEPRECIATION RESERVE CHANGE THE TOTAL RESERVE?

A. No. The depreciation reserve represents the amounts that customers have contributed to the return of the investment. The reallocation process does not change the total reserve for each function; it simply reallocates the reserve between accounts within each function.

Q. IS DEPRECIATION RESERVE REALLOCATION A SOUND DEPRECIATION PRACTICE?

A. Yes. The practice of depreciation reserve allocation is widely recognized and commonly practiced as part of a comprehensive depreciation study for the purposes of setting regulated rates where changes in services lives result in an imbalance between the theoretical and book reserve.[1]

Q. HOW WILL THE COMPANY IMPLEMENT THE REALLOCATION OF ITS DEPRECIATION RESERVE IF ITS PROPOSED RATES ARE APPROVED?

A. When the proposed depreciation rates are approved, the Company will reallocate the reserves on its books to match the allocation performed in this study.

Q. WHAT METHOD DID YOU USE TO ANALYZE HISTORICAL DATA TO DETERMINE LIFE CHARACTERISTICS?

A. All accounts were analyzed using actuarial analysis (retirement rate method) to estimate the life of property. In much the same manner as human mortality is analyzed by actuaries, depreciation analysts use models of property mortality characteristics that have been validated in research and empirical applications. Further detail is found in the life analysis section of Exhibit DAW-2.

Q. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIVES FOR EACH ASSET GROUP?

A. The establishment of appropriate average service lives for each account was determined by using actuarial analysis methods. Actuarial analysis combined vintage plant from the Carolinas and Corporate to determine one average service life and mortality curve for each account. Graphs and tables supporting the actuarial analysis and the chosen Iowa Curves used

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[1] *Public Utility Depreciation Practices*, NARUC (1968), p. 48; *Public Utility Depreciation Practices*, NARUC (1996), p. 188.

to determine the average service lives for analyzed accounts are found in the Life Analysis section of my Exhibit DAW-2. A summary of the proposed life parameters including average service life, mortality curve, and net salvage percent for each account is shown in Table 3.

Table 3 - Piedmont Natural Gas Proposed Life Parameters

Account	Description	Life	Curve	NS
	STORAGE PLANT			
26100	Structures & Improvements	54	R4	-10%
26200	Gas Holders	70	R5	-10%
26300	Purification Equipment	42	R4	-5%
26310	Liquefaction Equipment	50	R4	-5%
26320	Vaporizing Equipment	30	S6	-5%
26330	Compressor Equipment	40	R4	-5%
26340	M&R Equipment	30	R4	-5%
26350	Other Equipment	33	R4	0%
	TRANSMISSION PLANT			
26512	Land Rights	80	R4	0%
26610	Compressor Station Structures	50	R4	-5%
26620	M&R Station Structures	50	R4	-5%
26700	Mains	65	R4	-20%
26710	Cathodic Protection	25	SQ	0%
26800	Compressor Station Equipment	35	R4	0%
26900	M&R Station Equipment	45	R4	-5%
	DISTRIBUTION PLANT			
27420	Land Rights	75	R4	0%
27500	Structures & Improvements	50	R4	-5%
27600	Mains	65	R4	-20%
27800	M&R Station Equipment	55	R2	-10%
27900	M&R City Gate Equipment	55	R2	-10%
28000	Services	60	R2.5	-80%
28100	Meters	29	R1.5	0%
28104	Meter Accessories	16	R1.5	0%
28105	Meter Accessories, ERTs	15	R4	0%
28200	Meter Installations	29	R1.5	0%
28300	House Regulators	29	R1.5	0%
28400	House Regulator Installations	29	R1.5	0%
28500	Industrial M&R Station Equipment	55	R4	-5%
28600	Property on Customer Premises	40	R3	0%
28700	Other Equipment	41	S6	0%

Table 3 - Piedmont Natural Gas Proposed Life Parameters

Account	Description	Life	Curve	NS
GENERAL PLANT DEPRECIATED				
29000	Structures & Improvements	L1	50	-5%
29110/29101	Computer Hardware/Software (Electronic Data Processing)	5	SQ	0%
29130/29103	Customer Information System	30	SQ	0%
29140/29104	Client Server Applications	10	R3	0%
29401	CNG Station Equipment	25	R3	-2%
29600	Power Operated Equipment	22	S1	17%
GENERAL PLANT AMORTIZED				
29100	Office Furniture & Equipment	20	SQ	0%
29120/29102	PC Equipment	5	SQ	0%
29300	Stores Equipment	20	SQ	0%
29400	Tools, Shop & Garage Equipment	20	SQ	0%
29500	Laboratory Equipment	20	SQ	0%
29700	Communications Equipment	18	SQ	0%
29800	Miscellaneous Equipment	20	SQ	0%
TRANSPORTATION EQUIPMENT				
39200	3 Year-Meter Reading Trucks	3	SQ	30%
39201	5 Year-Rural 1 ton or less	5	SQ	23%
39202	7 Year-Urban 1 ton or less	7	SQ	30%
39203	10 Year-Heavy Duty	10	SQ	25%
39204	15 Year- Trailers & Other	15	SQ	25%
39210	Passenger Cars & Station Wagon	7	SQ	17%

Q. PLEASE DESCRIBE SOME OF THE CHANGES IN THE AVERAGE SERVICE LIVES FOR THE VARIOUS ACCOUNTS?

A. The detailed analysis of each account is described fully in Exhibit DAW-2. Examples of some of the changes in average service lives are:

- For North Carolina and Corporate lives increased in 16 accounts, lives decreased in 12 accounts, and lives stayed the same in 14 accounts. The largest change in life was Account 26200 – Gas Holders that increased from 38 years to 70 years.

Q. WHAT IS NET SALVAGE?

A. While discussed more fully in the study itself, net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Some plant assets can experience significant negative removal cost percentages due to the amount of removal cost and the timing of the addition versus the retirement. For example, a Distribution asset in FERC Account 276, Mains, with a current installed cost of $500 (2018) would have had an installed cost of $22.572 in 1953. A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a negative10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a negative 222 percent removal cost for that asset ($50/$22.57). Inflation from the time of installation of the asset until the time of its removal must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets.

Q. HOW DID YOU DETERMINE THE NET SALVAGE PERCENTAGES FOR EACH ASSET GROUP?

A. The establishment of appropriate net salvage percentages for each account was determined by analyzing retirements, gross salvage, and cost of removal data for each account from 1989-2018. The net salvage as a percent of retirements for various bands (i.e. groupings of years such as the five-year average) for each account is shown in Appendix D of my Exhibit DAW-2. Judgment was used to select a net salvage percentage that represents the future expectations for each account. The proposed net salvage percent for each account is shown above in Table 4.

Q. PLEASE DESCRIBE SOME OF THE CHANGES IN THE NET SALVAGE PERCENTAGES FOR THE VARIOUS ACCOUNTS?

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[2] Using the Handy-Whitman Bulletin No. 188, G-2, line 44, $22.57 = $500 x 38/842.

A. The detailed analysis of each account is described fully in Exhibit DAW-2. Examples of some of the changes in net salvage are:

- For North Carolina and Corporate net salvage increased (i.e. less negative) from negative 30 percent to negative 20 percent in Account 276 – Distribution Mains and decreased (i.e. more negative or less positive) from negative 70 percent to negative 80 percent in Account 28000 – Services.
- Net salvage also increased for all Transportation Equipment accounts (Accts 392.0-392.04) in the study.

V. CONCLUSION

Q. PLEASE SUMMARIZE THE CONCLUSIONS YOU HAVE REACHED AS A RESULT OF YOUR ANALYSIS.

A. The depreciation study and analysis fully support resetting annual depreciation rates for Piedmont at the level indicated in my testimony and in Exhibit DAW-2. In this way, all customers will be charged for their appropriate share of the capital expended for their benefit. The depreciation study for Piedmont's depreciable property in North Carolina, South Carolina, and Corporate as of September 30, 2018 describes the extensive analysis performed and the resulting rates that are now appropriate for its respective property classes. Therefore, I recommend that this Commission: 1) approve the updated North Carolina and Corporate annual depreciation rates for Piedmont from this study and analysis in order to recover the Company's total investment in property over the estimated remaining life of the assets, and 2) approve the recommended reallocation of the books reserves for Piedmont.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

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

Docket No. G-9, Sub 743

Direct Testimony of Nicholas Phillips, Jr.

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a managing principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants. Our firm and its predecessor firms have been in this field since 1937 and have participated in more than 1,000 proceedings in 40 states and in various provinces in Canada. We have experience with more than 350 utilities, including many electric utilities, gas pipelines, and local distribution companies. I have testified in many electric and gas rate proceedings on virtually all aspects of ratemaking. More details are provided in Appendix A of this testimony.

Q **ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am testifying on behalf of a group of intervenors designated as the Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR"), a group of large industrial customers that purchase gas delivery and associated service from Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company"). CIGFUR's members consist of customers served principally under Schedule 114 Large Interruptible Transportation Service and also under Schedule 113 Large General Transportation Service. Each CIGFUR member is a major employer in the county where it has a manufacturing plant, providing hundreds if not thousands of full-time jobs that are vital to the local economies in the Piedmont service area.

Q **HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?**

A Yes. I have been involved in many of prior proceedings before this Commission and have presented testimony in many of those proceedings. I have been involved with matters involving ratemaking issues in North Carolina for decades, including many cases involving Piedmont's parent Company, Duke Energy Corporation.

Q **WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**

A My testimony is directed toward Piedmont's natural gas cost of service study and the allocation of any allowed gas distribution rate increase to rate classes. I have examined the testimony and exhibits presented by Piedmont in this case with respect to cost of service, revenue allocation and rate design, and I will comment on the propriety of these proposals. I comment on Piedmont's Integrity Management Rider ("IMR") and the proposed charges associated with the IMR to Piedmont customers.

In addition, I comment on the excess deferred income tax ("EDIT") credit and the impact on Piedmont's requested increase. I also comment on Piedmont's proposed treatment of the Special Contract segment including the affiliate category within the Power Generation Contract class. Finally, I review Piedmont's requested rate of return on equity ("ROE").

Q DOES YOUR TESTIMONY ADDRESS PIEDMONT'S NEED FOR AN OVERALL INCREASE IN GAS SERVICE RATES?

A In order to make my presentation consistent with the revenue levels requested by Piedmont, I have, in many instances, used its proposed figures for rate base, operating income and rate of return. Use of these numbers should not be interpreted as an endorsement of them for purposes of determining the total dollar amount of rate increase to which Piedmont may be entitled. I focus my recommendations instead on the appropriate distribution to classes of any amount of rate increase allowed by the Commission.

Summary of Conclusions and Recommendations

Q PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING?

A The summary of my position and recommendations is listed below:

1. Piedmont's gas rates should be based on the cost of providing service to each customer class. They are not.
2. Piedmont's gas cost of service study is a form of a peak and average method and allocates excessive cost to high load factor customers on a throughput weighted allocation as compared to a peak demand cost of service study.
3. Piedmont's cost of service study shows extreme variances in class rates of return. Interruptible service rates currently provide a rate of return of 30.58% and the rate

of return under Piedmont's proposed rates would increase to 43.74%. In contrast, Piedmont's request is to earn an allowed overall rate of return of 7.68%.

4. Piedmont's proposed equal percentage method of distributing the requested increase to non-contract classes ignores cost of service, is fundamentally flawed and should not be implemented as proposed.

5. The Interruptible service class is paying rates for in excess of cost of service, and rates should actually be reduced. Certainly no rate increase is warranted for the Interruptible service rate.

6. Approximately 25% of Piedmont's rate base (investment) is dedicated to serving the Special Contract classes which do not receive any rate increase under Piedmont's structure. The largest Special Contract class is Power Generation which is almost entirely comprised of Piedmont affiliates. The second largest class is Municipal Contracts which according to Piedmont's cost of service produces a negative rate of return. Any revenue loss due to these contracts should not be borne by Piedmont's other customers.

7. The Special Contract customers are also not included in the Infrastructure Management Recovery Rider ("IMR") mechanism. Again, the entire IMR should not be borne by all other customers.

8. Piedmont's request to earn 10.6% ROE is excessive compared to the national average of authorized returns which is approximately 9.55%. Since Piedmont has rider mechanisms in place, the national average ROE of 9.55% should be considered as an upper limit on the ROE approved in this proceeding.

9. The rate design for Rate 113 and Rate 114 collects fixed cost in the initial usage blocks and has declining rates to reflect that once fixed costs are recovered, the higher usage blocks only need to recover variable costs. To the extent the Commission approves a lower increase than the $118 million requested by Piedmont, I recommend that the higher usage blocks be lowered even more to reflect only variable costs.

10. Piedmont's proposal to increase base rates by an equal percentage of revenue, credit excess deferred income taxes ("EDIT") by a net plant allocation and continue the IMR by a margin allocation all contribute to the significant rate inequities that currently exist. If the base rate increase is not modified to correct the overcharges, the EDIT credit and IMR should be modified to correct the inequities that currently exist.

11. Piedmont's parent company and affiliates have testified consistently before this and other commissions that rates should be within a 10 percent index band of the system average rate of return and that subsidies/excess rate levels should be decreased by 25% in distributing any allowed increase. Piedmont's existing rates deviate significantly from cost and many rate classes are hundreds of points outside the 10 percent band. It is recommended that Piedmont be ordered to follow the approach of Duke Energy, and move rates closer to cost in a meaningful manner.

Cost of Service and Rate Design Principles

Q COULD YOU PLEASE EXPLAIN THE RATEMAKING PROCESS AND THE DESIGN OF RATES?

A The ratemaking process has three steps. First, we must determine the utility's total revenue requirement and whether an increase or decrease in revenues is necessary. Second, we must determine how any alterations in the utility's costs and/or revenues should be distributed among the major customer classes. A determination of how many dollars of revenue should be produced by each class is essential for obtaining the appropriate level of rates. Finally, individual tariffs must be designed to produce the required amount of revenues for each class of service and to reflect the cost of serving customers within that class.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is universally agreed that the utility is entitled to an increase only to the extent that its actual cost of service has increased. If current rate levels exceed the utility's revenue requirement, a rate reduction is required. In short, overall rate revenues should equal actual cost of service. The same principle should apply in the next two steps. Each major customer class should produce revenues equal to the cost of serving that particular class, no more and no less. This may require a rate increase for some classes and a rate decrease for other classes. The standard tool for making this determination is a class cost of service study which shows the rates of return for each class of service. Rate levels should be modified so that each major class of service provides approximately the same rate of return. Finally, in designing individual tariffs, the goal should also be to relate the rate design of each class to the cost of service so that each customer's rate tracks, to the extent practicable, the utility's cost of providing service to that customer.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATEMAKING PROCESS?

A The basic reasons for using cost of service as the primary factor in the ratemaking process are equity and stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A When rates are based on cost, each customer (to the extent practicable) pays what it costs the utility to serve that customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenues by subsidizing service provided to other customers. This is inherently inequitable.

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the earnings impact on the utility associated with changes in customer usage patterns will be minimized as a result of rates being designed in the first instance to track changes in the level of costs. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for future rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of costs and also provide more accurate price signals. If rates are based on factors other than costs, it becomes much more difficult for customers to translate expected utility-wide cost changes (i.e., expected increases in overall revenue requirements) into changes in the rates charged to particular customer classes (and to customers within the class). Again, from the customer's perspective, this situation reduces the attractiveness of expansion, as well as of continued operations, because of the lessened ability to plan.

Q WHEN YOU SAY "COST," TO WHAT TYPE OF COST ARE YOU REFERRING?

A I am referring to the utility's "embedded" or actual accounting costs of rendering service; that is, those costs which are used by the Commission in establishing the utility's overall revenue requirement.

Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A COST OF SERVICE STUDY?

A After determining the overall cost of service or revenue requirement, a cost of service study is used to allocate the cost of service among customer classes. A cost of service study shows how each major customer class contributes to the total system cost. For example, when a class produces the same rate of return as the total system, it is returning to the utility revenues just sufficient to cover the costs incurred in serving it (including a reasonable return on investment). If a class produces a below-average rate of return, then the revenues are insufficient to cover all relevant costs. On the other hand, if a major class produces an above-average rate of return, it is paying revenues beyond sufficient to cover the cost attributable to it. In addition, it is subsidizing part of the cost attributable to other classes which produce a below-average rate of return. The class cost of service study is important because it demonstrates the various class revenue requirements, as well as the rates of return under current and proposed rates.

Q WOULD YOU PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A COST OF SERVICE STUDY?

A Yes. Cost of service is a basic and fundamental ingredient to proper ratemaking. In all class cost of service studies, certain fundamental concepts must be recognized. Of primary importance among these concepts is the functionalization, classification, and allocation of costs. Functionalization is the determination and arrangement of costs according to major functions, such as transmission, distribution and storage. Classification involves identifying the nature of these costs as to whether they vary with the quantity of gas consumed, the demand placed upon the system or the number of customers being served.

Fixed costs are those costs which tend to remain constant over the short run irrespective of changes in gas deliveries and are generally considered to be demand-related. Fixed costs include those costs which are a function of the size of the investment in utility facilities and those costs necessary to keep the facilities "on-line." Variable costs, on the other hand, are basically those costs which tend to vary with throughput and are generally considered to be commodity-related. Customer-related costs are those which are closely related to the number of customers served, rather than the quantity of gas consumed or the demands placed upon the system. A correct application of these concepts is essential to the proper development of a cost of service study, as well as appropriate rate design within the customer class.

With respect to allocation, fixed cost should be allocated on a peak demand factor, variable cost should be allocated on a throughput factor and customer related cost should be allocated on a per customer allocation factor.

Piedmont's Gas Cost of Service Study

Q HAVE YOU REVIEWED THE GAS COST OF SERVICE STUDIES PERFORMED BY PIEDMONT IN THIS PROCEEDING?

A Yes. Piedmont witness Daniel P. Yardley submitted a 2018 cost of service studies based on per book results, present rate adjusted results and under Piedmont's proposed rates. I will focus on the present rates adjusted or test year study.

Q DO YOU AGREE WITH THE ALLOCATION METHODS UTILIZED BY PIEDMONT IN ITS TEST YEAR 2018 GAS COST OF SERVICE STUDY?

A With the exception of the peak and average allocation method which Piedmont admits allocates more cost to high load factor customers, I basically agree with the Piedmont cost of service study. The 50% throughput weighting in the peak and average allocator is arbitrary and inconsistent with system design. The peak day demand method is more reflective of cost causation and with system design.

Q IS THE ALLOCATION OF FIXED DELIVERY COSTS BASED ON DESIGN DAY DEMAND DISCUSSED IN THE NATIONAL ASSOCIATION OF REGULATORY COMMISSIONERS ("NARUC") MANUAL?

A Yes. NARUC recognizes that distribution mains should be allocated to customer classes based on: (1) design peak day demands for the demand component; and (2) the number of customers for the customer component. In that regard, the NARUC <u>Gas Distribution Rate Design Manual</u> states the following:

> Demand or capacity costs vary with the size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers **or their annual usage**. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas;

> and most of the capital costs and expenses associated with that part of the distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size. (NARUC Manual, Gas Distribution Rate Design, June 1989, pp. 23-24; emphasis added)

Q **ARE YOU AWARE OF ANY OTHER AUTHORITATIVE AGENCY'S POSITION ON THE CLASSIFICATION AND ALLOCATION OF GAS DISTRIBUTION MAIN COSTS?**

A Yes. In Order 636, the Federal Energy Regulatory Commission ("FERC") endorsed the straight fixed-cost variable ("SFV") cost methodology, which allocates fixed pipeline cost 100% on a demand basis. In this regard, FERC states:

> The Commission believes that requiring SFV comports with and promotes Congress' goal of a national gas market as discussed above and goes hand-in-hand with the equity principle.
>
> ********
>
> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternative fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant natural gas over alternate fuels such as foreign oil. SFV is the best method for doing that. (FERC Order 636, Final Rate Issued April 8, 1992, pp. 127-129 (footnote omitted))

The FERC SFV allocation method appropriately treats fixed pipeline costs as demand-related costs. Similarly, transmission and distribution main costs not classified as customer-related on Piedmont's system should be treated as demand-related costs to achieve the goals and benefits outlined by FERC and in accordance with NARUC guidance.

Q HAS PIEDMONT PERFORMED A STUDY USING THE PEAK DEMAND TO ALLOCATE FIXED COSTS TO CLASSES?

A Yes. Piedmont performed a peak demand study in response to discovery from CIGFUR. In that study, peak demand data is used to allocate fixed demand-related delivery costs in place of the peak and average method.

While the peak demand study is a more correct representation of the cost of service associated with the various customer classes, I will use the Piedmont cost of service study to limit the issues of concern in this proceeding. The main issue is the amount of subsidy levels that currently exist in Piedmont's rates and how to correct the subsidies without harsh impacts to subsidized classes. The peak demand study will only show that certain subsidies are larger and make any corrective distribution of the requested increase even more difficult to manage in this case. The results of the peak demand study are shown on Exhibit NP-2.

Q HAS DUKE ENERGY PROGRESS LLC OFFERED TESTIMONY ON THIS SUBJECT BEFORE THE COMMISSION?

A Yes. Laura A. Bateman recently presented testimony on behalf of Duke Energy Progress, LLC which stated:

> **"Q. HOW DO YOU PROPOSE TO ALLOCATE THIS ADDITIONAL REVENUE REQUIREMENT AMONG THE CLASSES?**
>
> A. Bateman Exhibit 2 shows how the additional revenue requirement is spread among the classes and how the target revenue requirements for rate design are established. The rate increase shown in the exhibit has been allocated to the rate classes on the basis of rate base, and then combined with an additional increase or decrease at the customer class level that results in a 25 percent reduction in each class's variance from the overall average rate of return. This additional increase or decrease at the customer class level nets to $0 for the North Carolina retail jurisdiction in total, but brings the customer classes closer to the average rate of return, and is an appropriate way to gradually bring rate classes closer to rate parity over time. This

> approach is consistent with the approaches in the last general rate proceedings for both DE Carolinas and DE Progress." (Docket No. E-2, Sub 1142, Bateman Direct, page 10, lines 4-17)

Q HAS DUKE ENERGY CAROLINAS, LLC PRESENTED A CONSISTENT POSITION REGARDING RATE PARITY AMONG THE VARIOUS RATE CLASSES?

A Yes. Mr. Michael J. Pirro presented testimony on behalf of Duke Energy Carolinas LLC which stated:

> "This historical subsidy has, in the past, been beyond the range of reasonableness, which we define as class rates of return within 10 percent of the total Company rate of return. The updated comparison through the test period year now shows significant convergence of the class rate of return over all classes towards the band of reasonableness demonstrating the success of the strategy of gradually reducing the subsidy/excess by 25 percent. Continuation of this trend would be encouraging and desirable.
>
> The Company remains committed to monitoring subsidy / excess levels and making improvements to ensure its rates are fair across the classes of customers served." (Docket No. E-7, Sub 1146, Pirro Direct, page 21, lines 12-22)

Q HAVE YOU EXAMINED THE CLASS RATES OF RETURN, INDEXES AND SUBSIDIES PRESENTED BY PIEDMONT?

A Yes. Exhibit NP-1 shows the results of Piedmont's peak and average cost of service, indexes and subsidies at both current rates and rates proposed by Piedmont.

Q WHAT DO YOU CONCLUDE?

A Piedmont's rates are not adequately based on cost of service, and Piedmont's proposed equal percentage increase to non-contract classes does not make a meaningful movement toward cost of service for most classes.

Q WHY ARE CONTRACT CLASSES NOT INCLUDED IN PIEDMONT'S REVENUE DISTRIBUTION?

A Piedmont has apparently entered into contracts that do not provide for increases in rate levels to the contract classes. This is problematic because Piedmont proposes to collect the entire claimed increase in system revenue requirement from all non-contract customer classes by basically increasing all rates for non-contract customers by approximately 14.5%. The contract classes represent approximately 25% of Piedmont's rate base, or investment, and the return associated with this investment requested by Piedmont in this proceeding would be borne by all other customers, based on the rates and class increases proposed by Piedmont.

Q IS THIS APPROACH REASONABLE?

A No. If Piedmont will not or cannot raise the rates to earn its requested return on 25% of its investment, the Commission should not allow Piedmont to increase the rates of other customers to make up the shortfall. Additionally, the Commission should be aware that the largest Special Contract class, Power Generation, involves contracts with affiliates of Piedmont making the Company's proposal even more problematic and self-serving.

Q WHAT OTHER CONTRACT CLASSES WOULD RECEIVE NO INCREASE UNDER PIEDMONT'S PROPOSAL?

A The Municipal Contract class is the second largest Special Contract class and shown to produce a negative rate of return. If Piedmont choses to earn a negative return on this class, other ratepayers should not make up the difference. The smallest Special Contract class, Special Contracts, does provide an above average return and under cost based ratemaking should not be increased by the system average amount, but the same is true of certain other non-contract classes, such as the Interruptible service class.

Q WHAT RATE OF RETURN IS PRODUCED BY THE INTERRUPTIBLE SERVICE CLASS?

A The Interruptible service class is shown to provide Piedmont a rate of return of 30.58% under current rates and that excessive return would increase to 43.74% under rates proposed by Piedmont. This is in contrast to Piedmont's request to earn a return of 7.68% on its entire rate base in this proceeding. The Commission should not approve any increase to a class that currently produces a rate of return of 30.58%.

Distribution of Increase

Q HAVE YOU REVIEWED PIEDMONT'S PROPOSED DISTRIBUTION OF ITS REQUESTED BASE RATE INCREASE?

A Yes. Piedmont's proposed distribution of its base rate increase is shown on Exhibit NP-3. Piedmont's proposed distribution increases base rates to all non-contract classes by 14.5% and proposed no increase in rates to Special Contract classes. Piedmont's proposal is not cost based, fair or reasonable and should be rejected.

If Piedmont refuses to or has agreed not to increase rates to contract classes that do not provide the requested rate of return, the solution should involve shareholders, not subsidies from all other ratepayers.

Q HAVE YOU PERFORMED A DISTRIBUTION SIMILAR TO PIEDMONT'S, BUT WITH NO INCREASE TO INTERRUPTIBLE SERVICE AND PARTICIPATION BY THE SPECIAL CONTRACT CLASS?

A Yes. Piedmont's equal percentage approach modified to include Special Contract customers and eliminate the increase to Interruptible service due to the excessive return provided to Piedmont by that class is shown on Exhibit NP-4.

Q THE APPROACH BY DUKE ENERGY AND DUKE PROGRESS YOU REFERENCED PREVIOUSLY INDICATED A RATE BASE ALLOCATION OF THE INCREASE. DID YOU PERFORM A DISTRIBUTION TO CLASSES ON THAT BASIS?

A Yes. An allocation of Piedmont's requested increase using rate base from the Company's cost of service study with no increase to Interruptible service is shown on Exhibit NP-5. This distribution of the $118 million requested increase basically keeps subsidy/excess that exist in rates at their current levels, without correction. Of particular concern is that the combined Special Contract classes require a $30.4 million or almost 30% rate increase just to keep the subsidy it receives from getting larger. Reducing subsidies by 25% as recommended by Duke witnesses in other proceedings is problematic due to the extremely large imbalances that currently exist in Piedmont's rates. One solution is to use the difference between Piedmont's requested increase and the ultimate amount authorized to reduce subsidy/excess levels by lowering the proposed increases to those classes providing above system average returns.

Q PLEASE COMMENT ON THE EDIT AS PROPOSED BY PIEDMONT.

A Piedmont proposes an approximate $36 million credit mechanism for excess deferred income taxes. The credit mechanism is an offset to the base rate increase but is not done on an equal percentage basis, similar to the proposed base rate increase, but on a net plant allocation to non-contract customer classes. While Piedmont's method has merit in isolation, it is inconsistent with the proposed increase and does not adequately move rates toward cost. The Commission should return EDIT to ratepayers in a manner that makes the overall net increase as cost based as possible.

Q HOW DOES PIEDMONT ALLOCATE THE IMR TO CLASSES?

A Piedmont allocates the IMR to classes on the basis of margin, but excludes the Special Contract customers. This allocation would cause all non-contract customers to bear the brunt of total system improvements covered by the IMR and exclude customers that are responsible for 25% of Piedmont's rate base investment. This allocation over time will exacerbate the subsidy/excess issue by forcing only non-contract customers to fund system improvements, which are significant. Customers paying margins in excess of cost are overcharged by this approach, in addition to paying for the shortfall of excluding the Special Contract classes.

Q HAVE YOU REVIEWED PIEDMONT'S PROPOSED RATE DESIGN FOR RATE 113 AND RATE 114?

A Yes. Piedmont's proposed rate design is shown on Exhibit NP-6. Piedmont is basically using the initial blocks for fixed cost recovery and the higher usage blocks are lowered in recognition of the initial fixed cost recovery. This rate design approach is reasonable. However, the significant subsidy (overpayment) by Interruptible Transportation would continue unless addressed in the distribution of the increase to classes, previously discussed.

Return on Equity

Q IS PIEDMONT'S PROPOSED 10.60% ROE REQUEST APPROPRIATE?

A No. Piedmont's requested ROE of 10.60% is excessive and should be rejected. The Company's current authorized ROE is 10.0%, which was authorized by approving a stipulation in the Commission's Final Order in Docket No. G-9, Sub 631, issued on December 17, 2013.

Every quarter, Regulatory Research Associates, an affiliate of SNL Financial, updates its *Major Rate Case Decisions* report that covers electric and natural gas utility rate case outcomes. Specifically, this report tracks the authorized ROEs resulting from utility rate cases. The most recent report has been updated through March 31, 2019 and shows that the national average authorized ROE for gas utilities in the first quarter of 2019 was 9.55%. This is 45 basis points below Piedmont's currently authorized ROE. The Commission also should consider the IMR, and any other mechanisms, which provide Piedmont with additional cost recovery outside of a base rate case in setting a reasonable ROE.

On that basis, the Company's current ROE, and definitely its requested ROE, are significantly above a reasonable cost of equity. I recommend that the Commission authorize a ROE that does not exceed the national average of 9.55%.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Nicholas Phillips, Jr.

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.**

A I graduated from Lawrence Institute of Technology in 1968 with a Bachelor of Science Degree in Electrical Engineering. I received a Master's of Business Administration Degree from Wayne State University in 1972. Since that time I have taken many Masters and Ph.D. level courses in the field of Economics at Wayne State University and the University of Missouri.

I was employed by The Detroit Edison Company in June of 1968 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included the overhead and underground design, construction, operation and specifications for transmission and distribution equipment; budgeting and cost control for operations and capital expenditures; equipment performance under field and laboratory conditions; and emergency service restoration. I also worked in various districts, planning system expansion and construction based on increased and changing loads.

Since 1973, I have been engaged in the preparation of studies involving revenue requirements based on the cost to serve electric, steam, water and other portions of utility operations.

Other responsibilities have included power plant studies; profitability of various segments of utility operations; administration and recovery of fuel and purchased power costs; sale of utility plant; rate investigations; depreciation accrual rates; economic investigations; the determination of rate base, operating income, rate of return; contract analysis; rate design and revenue requirements in general.

I held various positions at Detroit Edison, including Supervisor of Cost of Service, Supervisor of Economic studies and Depreciation, Assistant Director of Load Research, and was designated as Manager of various rate cases before the Michigan Public Service Commission and the Federal Energy Regulatory Commission. I was acting as Director of Revenue Requirements when I left Detroit Edison to accept a position at Drazen-Brubaker & Associates, Inc., in May of 1979.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff.

Our firm has prepared many studies involving original cost and annual depreciation accrual rates relating to electric, steam, gas and water properties, as well as cost of service studies in connection with rate cases and negotiation of contracts for substantial quantities of gas and electricity for industrial use. In these cases, it was necessary to analyze property records, depreciation accrual rates and reserves, rate base determinations, operating revenues, operating expenses, cost of capital and all other elements relating to cost of service.

In general, we are engaged in valuation and depreciation studies, rate work, feasibility, economic and cost of service studies and the design of rates for utility services. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q WHAT ADDITIONAL EDUCATIONAL, PROFESSIONAL EXPERIENCE AND AFFILIATIONS HAVE YOU HAD?

A I have completed various courses and attended many seminars concerned with rate design, load research, capital recovery, depreciation, and financial evaluation. I have served as an instructor of mathematics of finance at the Detroit College of Business located in Dearborn, Michigan. I have also lectured on rate and revenue requirement topics.

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A Yes. I have appeared before the public utility regulatory commissions of Arkansas, Delaware, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Montana, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Virginia, West Virginia, and Wisconsin, the Lansing Board of Water and Light, the District of Columbia, and the Council of the City of New Orleans in numerous proceedings concerning cost of service, rate base, unit costs, pro forma operating income, appropriate class rates of return, adjustments to the income statement, revenue requirements, rate design, integrated resource planning, power plant operations, fuel cost recovery, regulatory issues, rate-making issues, environmental compliance, avoided costs, cogeneration, cost recovery, economic dispatch, rate of return, demand-side management, regulatory accounting and various other items.

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MR. JEFFRIES: And one other matter. Yesterday, Ms. Force took Mr. Hevert through a series of portions of his testimony from prior proceedings. I don't feel the need to clutter the record with the full text of those testimonies which Ms. Force graciously provided to me yesterday, but I would ask the Commission to take administrative notice of them to avoid having to put them in the record in case we want to cite them in the proposed order.

COMMISSIONER BROWN-BLAND: Okay. If there is no objection to that, then the Commission will also receive those and take judicial notice.

MR. JEFFRIES: With that, we will return to our case. Piedmont will call Mr. Barkley to the stand.

COMMISSIONER BROWN-BLAND: For clarity, Mr. Jeffries, this is judicial notice of each one of those that was related to Exhibits 1 through 10.

MR. JEFFRIES: Correct.

COMMISSIONER BROWN-BLAND: From AG Hevert, Examination Exhibits 1 through 10.

MR. JEFFRIES: Exactly.

BRUCE P. BARKLEY,

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

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. Barkley, could you state your full name and business address for the record?

A. Bruce Barkley, 4720 Piedmont Road Drive, Charlotte, NC.

Q. And you work at Piedmont Natural Gas; is that right?

A. I do.

Q. And what is your title there?

A. Vice president regulatory and community relations.

Q. And what are your responsibilities in that position?

A. So I lead regulatory filings made before this Commission and also our group that provides support for communities throughout the Carolinas and Tennessee.

Q. Mr. Barkley, you prefiled direct testimony in this docket on April 1st consisting of 30 pages, and exhibits marked BPB-1 through BPB-3; is that correct?

A. Yes.

Q. Okay. And you also filed rebuttal testimony in this proceeding on August 29th -- or I'm sorry, August 9th consisting of 11 pages; is that correct?

A. Yes, I did.

Q. And that was prepared by you or under your direction?

A. Yes, sir.

Q. And do you have any corrections to your testimony or exhibits?

A. I did have one, Mr. Jeffries, I wanted to make to my prefiled testimony, Exhibit 3, page 62. And I do want to take a look at that and make a correction, if I may. And that is we listed some percentages on that particular page of my Exhibit 3.

Q. Is that the IMR?

A. It is. It is page 62 of 68. We listed percentages, and there are two Januarys in the list, and it was simply a typo, a clerical error, in that the second January should have been stricken and was not. So I just wanted to point that out that, you know, obviously a clerical error there that we wanted to just get straight for the record. And when we file the proposed tariffs in this docket, we'll, obviously, correct any clerical errors.

Q. Okay. Mr. Barkley, if I asked you the same questions that were set forth in your prefiled direct and prefiled rebuttal testimony while you were on the stand today, would your answers be the same?

A. Yes, sir.

MR. JEFFRIES: Madam Chair, Piedmont would ask that Mr. Barkley's prefiled direct and prefiled rebuttal testimony be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: There being no objection, that motion will be allowed.

MR. JEFFRIES: Thank you.

(Whereupon, the prefiled direct and prefiled rebuttal testimony of Bruce P. Barkley was copied into the record as if given orally from the stand.)

Q. Please state your name and business address.

A. My name is Bruce P. Barkley. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. By whom and in what capacity are you employed?

A. I am employed by Piedmont Natural Gas Company, Inc. ("Piedmont" or "the Company") as Vice President – Regulatory and Community Relations.

Q. Please describe your educational and professional background.

A. I obtained a Bachelor of Science Degree in Business Administration with a concentration in Accounting from the University of North Carolina at Chapel Hill in 1984 and an MBA Degree from Wake Forest University. I obtained my CPA license in 1987. From 1988 through 2001, I was employed by Public Service Company of North Carolina, Inc., where I was responsible for regulatory filings and reports submitted to the North Carolina Utilities Commission ("NCUC" or "Commission"). Prior to joining Piedmont, I held various positions with Progress Energy, Inc. and subsequently Duke Energy Corporation ("Duke Energy") in Regulatory Affairs, Fuels, and Regulatory Accounting. I joined Piedmont in 2015 and began serving in my current role in 2016.

Q. Mr. Barkley, have you previously testified before this Commission or any other regulatory authority?

A. Yes. I have previously testified before this Commission and the Public Service Commission of South Carolina.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support Piedmont's application in this proceeding. Specifically, my testimony addresses the following subjects: (1) the nature and scope of Piedmont's revenue request in this proceeding; (2) the impact of our requested revenue request on customers; (3) the public benefits inherent in the continued operation of our Integrity Management Rider ("IMR") mechanism; (4) the need for a Distribution Integrity Management Program ("DIMP") related operations and maintenance ("O&M") expense deferral mechanism; (5) the operation of our Margin Decoupling Tracker ("MDT") mechanism and the proposed expansion of conservation and energy efficiency spending; (6) our proposed implementation plans for the flow-through of benefits resulting from the federal Tax Cuts and Jobs Act of 2017 ("TCJA" or "Tax Act") and recent North Carolina state income tax rate reductions; and (7) proposed changes to our service regulations and tariffs.

Q. Do any exhibits accompany your testimony?

A. Yes. The following exhibits are part of my testimony:

Exhibit__(BPB-1)	MDT Performance
Exhibit__(BPB-2)	EDIT Calculations
Exhibit__(BPB-3)	Tariff and Service Regulation Changes

Q. Were these exhibits prepared by you or under your direction?

A. Yes.

Piedmont's Revenue Request

Q. What is Piedmont's revenue request in this proceeding?

A. As is reflected on Page 1 of Piedmont witness Powers' Exhibit__(PKP-7), we are requesting approval of an annual cost of service increase of $82.8 million in this proceeding. This amount includes an increase in fixed gas costs of approximately $1.7 million.

Q. Can you provide some context for this level of revenue request?

A. Yes. Our filed revenue request in this proceeding represents a 9% increase from our currently-effective revenues and incorporates the impact of the reduction in federal corporate income tax rates from 35% to 21% established under the federal Tax Cut and Jobs Act of 2017 along with associated amounts due to our customers as a result of the TCJA and recent North Carolina state income tax reductions. Piedmont proposes to manage the impacts of the TCJA and state income tax reductions through an EDIT Rider as fully explained subsequently in my testimony.

Impact of Revenue Request and Proposed Return on Common Equity on Piedmont's Customers

Q. What will be the impact on customers of Piedmont's revenue request and its proposed return on common equity in this docket?

A. Piedmont's revenue request in this docket, if granted without modification and including the impact of the tax impacts discussed below, will increase the average residential customer's bill by approximately $6.00 per month. Under our proposed rate increase, our average residential customer would pay approximately $778 per year for natural gas service. This compares with averages of $955 coming out of our 2008 rate case and $724 coming out of our 2013 rate case. The continuing stability and affordability of natural gas service reflected in these figures is primarily the result of beneficial impacts of low-cost shale gas production.

Q. Does this mean that all of Piedmont's customers will be free from any negative impacts of the requested rate increase?

A. No. We always have some percentage of our customers who struggle to pay our bills and any increase in rates will make that struggle more difficult. We work hard to provide options for customers who are experiencing difficulty in meeting their payment obligations, including establishment of deferred payment arrangements, coordination with social support agencies, and referrals to alternative sources of income that may be available to pay customer bills. We also scrupulously abide by the Commission's billing requirements and disconnection procedures in the thankfully small number of cases where termination of service for non-payment is required.

Q. What is the overall economic context to Piedmont's revenue

request and requested rate of return on common equity?

A. Our requested rate of return on common equity is relatively low by long-term historical standards and the state of the economy within our North Carolina service territory is generally strong. The State of North Carolina is currently enjoying unemployment rates that are at their lowest point since 2000 and is experiencing wage growth, both of which help our low-income customers be able to afford our services. In addition, and as noted above, our request in this docket is offset by several categories of tax-related regulatory liabilities that will be credited to customers upon approval of new rates in this proceeding and the continuing low level of natural gas commodity prices is allowing Piedmont to provide service at total costs that are lower than they were a decade ago.

Q. Based on this context do you believe that economic conditions support Piedmont's requested rate of return on common equity and its requested rate increase?

A. Yes. I also note that Piedmont witness Hevert reached the same conclusion in Section VIII of his direct testimony.

Continuation of Piedmont's IMR Mechanism

Q. What is the status of Piedmont's Integrity Management Rider mechanism?

A. In its Order issued November 23, 2015 and amended October 4, 2016 in Docket No. G-9, Sub 642, the Commission approved a stipulation and settlement agreement between Piedmont and the Public Staff that provided for a continuation of Piedmont's IMR mechanism subject to further review of the mechanism by October 31, 2019. Piedmont is including, as part of this proceeding, a proposal to continue operation of this mechanism for an additional four-year period.

Q. Can you provide an overview of why you believe that a continuation of the IMR mechanism is in the public interest?

A. Yes. As the Commission is well aware and as is supported in the testimony of Piedmont witness Gaglio, Piedmont has made capital investments in its system of more than a billion dollars in the last five years in its efforts to comply with the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") Transportation Integrity Management Plan ("TIMP") and Distribution Integrity Management Plan ("DIMP") requirements. Without the mitigating effect of Piedmont's IMR mechanism, which permitted Piedmont an opportunity to begin earning a return on a significant portion of its PHMSA compliance-related capital investment during this timeframe, Piedmont would have filed multiple rate cases during that period, probably with a frequency of every 12-18 months. Each one of these rate cases would have resulted in a proposed rate increase that would include not only earnings on PHMSA compliance-related capital investment but also earnings on all capital investment and recovery of any other increases in Piedmont's cost of service. They would have also come at a significant cost, in excess of a million dollars each, in rate case expense – not to mention the time and administrative burden on all parties (including the Commission) associated with preparing, prosecuting, and resolving each such case. Instead, of "death by rate case" over the last six years, Piedmont's customers have experienced stable base rates and have only been exposed to rate increases, through the IMR mechanism, associated with investments required in order to comply with standards set by PHMSA. I believe that the public interest inherent in this result is obvious and compelling.

Q. Does Piedmont expect to continue to experience significant amounts of capital investment in PHMSA compliance going forward?

A. Yes. As is reflected in Exhibit__(VMG-2), attached to Mr. Gaglio's testimony, we expect ongoing levels of integrity management capital additions in the range of approximately $173 million per year. And these estimates are conservative inasmuch as they do not include any increased spending that may be required by the pending PHMSA Mega-Rule, which is anticipated to increase TIMP compliance requirements. Based upon these projections, we believe that the same factors that supported the operation of the IMR over the last five years continue to support its operation over the next four years and respectfully request that the Commission approve such continuation in this docket.

Q. Do similar mechanisms exist in other states to address requirements to upgrade transmission and distribution facilities of natural gas local distribution companies in accordance with federal mandates and prevailing best practices in the industry?

A. Yes. Based on information provided to me by the American Gas Association, natural gas companies in forty-one states operate under similar approved regulatory mechanisms that facilitate the efficient recovery of required capital expenditures as Piedmont seeks to extend in this proceeding.

Q. Do you have anything else to add to your testimony regarding the IMR mechanism?

A. Yes. In order to update our existing IMR mechanism, we have proposed certain updates to the IMR rider. This item is Appendix E of the proposed Service Regulations presented as Exhibit__(BPB-3) which is attached to my testimony. These updates are necessary for the IMR to properly function prospectively.

TIMP and DIMP O&M Expense Deferral

Q. Is Piedmont proposing any new mechanisms to address the extraordinary costs it is incurring in response to PHMSA regulatory requirements?

A. Yes. For some time now, Piedmont has been able to defer O&M expenses related to TIMP compliance to be amortized in the Company's subsequent general rate case proceedings. This regulatory asset treatment was initially approved by the Commission in Docket No. G-9, Sub 495. In this proceeding, Piedmont seeks similar treatment for O&M expenses associated with certain DIMP compliance efforts. Mr. Gaglio explains the specific DIMP activities included in Piedmont's request in his direct testimony.

Q. Why is this important for the Company?

A. At the time Piedmont was granted regulatory asset treatment for TIMP related O&M expenses, PHMSA was developing its guidance for TIMP compliance and had not yet begun to seriously address distribution integrity measures. Early transmission integrity activities tended to focus on inspections and assessments – which are O&M intensive activities. This led Piedmont to seek and the Commission to approve regulatory asset treatment for TIMP-related O&M expenses. As PHMSA developed more comprehensive guidance for TIMP compliance, however, the efforts of Piedmont and other transmission providers to abide by that guidance became more capital intensive. This led to the approval of Piedmont's IMR. The focus of Piedmont's DIMP compliance will prospectively include significant amounts of O&M. As a result of these increasing O&M expenses, Piedmont is requesting regulatory asset treatment for O&M expenses related to DIMP compliance.

Q. Does the lack of regulatory asset treatment for these expenses create an issue for Piedmont?

A. Yes. Because the expenses are both unpredictable and material, they threaten the stability of Piedmont's rates and could place increased pressure on Piedmont's need to file for rate relief. If approved for treatment as a regulatory asset, they will not impact the stability of Piedmont's rates.

Q. Has the Commission previously approved regulatory asset treatment for DIMP related O&M costs?

A. Yes. The Commission granted such treatment for Public Service Company of North Carolina, Inc. ("PSNC") in Docket No. G-5, Sub 565. Piedmont simply asks that it be afforded the same treatment as was previously granted to PSNC with respect to these costs. Consistent with its existing TIMP deferral, Piedmont does not seek carrying costs associated with its proposed DIMP deferral at this time. Further, we have not included any of the incremental expenses we seek to defer in the adjusted test year cost of service presented by Ms. Powers on Page 1 of Exhibit_(PKP-7). The amounts expected to be incurred over the next five years are presented by Mr. Gaglio in his Exhibit_(VMG-3).

The Operation of Piedmont's MDT Mechanism and the Proposed Expansion of Piedmont Sponsored Energy Efficiency Programs

Q. Is Piedmont's MDT mechanism up for review before the Commission in this proceeding?

A. Not specifically, however, because the mechanism has been in use for a number of years and because Piedmont is proposing to increase economic support for customer conservation efforts and related programs, Piedmont believes that it is appropriate to review the performance of this mechanism in this case.

Q. Can you describe the purpose of the MDT?

A. The purpose of the MDT mechanism is to normalize variations in actual per customer usage that can result from any cause, including weather and customer conservation, to the levels underlying Piedmont's approved rates in a general rate case.

Q. How does the mechanism work?

A. In this rate case proceeding, the Commission will set Piedmont's rates by applying the final approved cost of service to certain usage presumptions in order to establish billing rates for the Company. This exercise is premised on assumptions about what individual customer usage will be within each of Piedmont's rate schedules on a monthly basis. We know from experience, however, that actual customer usage during any month will vary from the assumed levels of usage used to set rates. This variance is particularly significant when the impacts of changes in the weather/temperature from "normal" occur during the winter heating season, but some variance occurs at lower usage levels year-round. Over time, Piedmont also experiences variations in customer usage attributable to customer conservation which is the natural result of ever-tightening housing envelopes, increased appliance efficiency, and customer conservation efforts. Because Piedmont recovers a significant portion of its fixed costs through usage-based rates, variations in usage can pose a significant risk of either under-recovery or over-recovery of its costs to serve customers. Our MDT mechanism eliminates this risk by normalizing monthly customer usage to historic norms. The mechanism applies to residential, small general service and medium general service customers and is set forth in Appendix C to the Company's Service Regulations.

Q. Is this beneficial?

A. Yes, it is highly beneficial to both Piedmont and its customers. It is beneficial to Piedmont primarily because it ensures that Piedmont recovers the costs of providing natural gas service to its customers consistent with the assumptions that were used to set its usage-based rates in Commission-issued general rate case orders. It also puts downward pressure on Piedmont's need to file additional general rate cases as a result of declining per customer usage resulting from conservation. It is beneficial to customers because it smooths monthly bills by eliminating the impact of variations in usage and it also ensures that Piedmont does not reap a windfall (at customer expense) when extremely cold weather hits Piedmont's service territory.

Q. Are there any other advantages to the MDT mechanism?

A. Yes. Because Piedmont recovers a significant portion of its costs through usage-based rates, Piedmont is incentivized to promote maximum customer usage of natural gas. Without the MDT, the promotion of conservation by Piedmont would be problematic because of the Company's obligation to reasonably maximize profits. The MDT mechanism renders Piedmont neutral on the issue of variations in customer usage by aligning customer interests (economic and otherwise) with the Company's interests. This allows Piedmont to support and promote customer conservation efforts without being economically punished for that support.

Q. Do you believe that the mechanism has operated effectively during the past several years?

A. Yes. Exhibit__(BPB-1) attached to this testimony shows the practical impacts of the MDT over the last five years which is the period since the effective date of Piedmont's last general rate case through the end of the test period in this proceeding. In reviewing this Exhibit, it is important to recognize that MDT adjustments have operated bi-directionally (favoring both the Company and customers at different times) and that each MDT adjustment represents an avoided shortfall or windfall in customer billings. Over these five years, the mechanism was slightly favorable to customers.

Q. Do you have anything else to add to your testimony regarding Piedmont's MDT mechanism?

A. Yes. In order to update our existing MDT mechanism, we have calculated new base, heat and "R" factors which are presented by Piedmont witness Couzens on Exhibit__(KAC-4). These new factors are necessary for the MDT to function properly on a going forward basis.

Q. Is Piedmont proposing any changes in funding for customer conservation support in this case?

A. Yes. We are proposing to increase authorized expenditures for conservation funding from $1.275 million a year to $2.5 million a year.

Q. Are you proposing specific programs under which these additional funds would be spent?

A. Not at this time. Piedmont's existing conservation programs are supervised by the Commission under Docket No. G-9, Sub 631A. Piedmont proposes that any change in programs or additional programs through which Piedmont would utilize the proposed additional $1.225 million in conservation spending be submitted for approval in a new subdocket independent of the revenue increase request presented in this docket. Pending such approvals, Piedmont recommends that the additional $1.225 million in conservation spending sought hereunder be placed in a regulatory liability account in order to segregate those funds from Piedmont's earnings.

While specific program proposals are not yet ready, one option under consideration for presentation to the Commission is a collaborative effort with other NC regulated utilities to encourage homebuilders to install high-efficiency equipment in new single-family homes. Further, Piedmont is investigating opportunities to increase its efforts to benefit low-income customers through increased funding of weatherization assistance.

Implementation of the Flow-Through to Customers of the TCJA

Q. Please provide an overview of the Tax Act and its impact on Piedmont.

A. While the headline change brought by the Tax Act is a reduction of the statutory corporate tax rate from 35 to 21 percent, this reduction in rate is accompanied by many other provisions. The varying impacts of the Tax Act on Piedmont all must be taken into account, as the Company has done in its proposal for how best to address this matter for the benefit of customers in North Carolina. Customers should – and will through the Company's proposal in this case – benefit from the overall reduction in the revenue requirement, but it is appropriate to also consider other, non-tax impacts of the legislation, particularly as it relates to cash flow and credit quality. Piedmont, consistent with the natural gas industry as a whole, is a very capital intensive operation. Piedmont makes capital investments in new infrastructure because they are necessary to provide critical energy to the State of North Carolina, and to ensure that its pipeline systems continue to maintain the highest level of safety and reliability, not because of federal tax policy. Piedmont's obligation to serve the public requires that Piedmont maintain the financial ability to support such service at all times.

Some aspects of the TCJA will negatively impact Piedmont's cash flow and credit metrics. Evidence of the detrimental impact of the Tax Act arrived in the form of a downgrade to Piedmont's credit rating by Moody's Investors Services ("Moody's") in the summer of 2018 as described in the testimony of Piedmont witness Jack Sullivan. The ratings downgrade was partially driven by the negative cash flow consequences of the reduction in the corporate tax rates and the loss of bonus depreciation associated with the Tax Act. Under bonus depreciation, Piedmont could depreciate more that 50% of utility plant additions during the first year of service. These cash flow and credit rating impacts must be taken into account, and make sound and balanced regulatory treatment critical. Inasmuch as credit quality drives access to affordable capital, it is also important, and in the best interest of customers, to prevent weakening of the Company's cash flow and credit quality.

The Tax Act represents a unique opportunity to deliver savings to customers, but as with all ratemaking actions, the long-term and short-term interests of customers should be balanced. Piedmont's proposal as presented in my testimony to incorporate benefits of the Tax Act in our customers' rates simultaneous with the effective date of this rate case is balanced, appropriate, and consistent with the Commission's Order issued October 5, 2018, in Docket No. M-100, Sub 148.

Q. What are the key provisions of the Tax Act as it relates to Piedmont?

A. For utilities in general, and Piedmont specifically, the key provisions of the Tax Act that will affect customer rates are as follows: (1) reduction of the corporate income tax rate from 35 percent to 21 percent; (2) retention of net interest expense deductibility; (3) elimination of bonus depreciation; and (4) normalization of excess Accumulated Deferred Income Taxes ("ADIT") resulting from the Tax Act.

Q. Please summarize how these key provisions could impact Piedmont and customer rates.

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

INTEREST EXPENSE DEDUCTIBILITY: The Tax Act generally provides that net interest expense is deductible only to the extent it does not exceed a stated percentage of an adjusted taxable income calculation, a calculation that becomes even more restrictive four years hence. However, regulated utilities are exempt from this limitation provision and may deduct their interest expense without limitation.

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

EXCESS DEFERRED INCOME TAXES: At the end of 2018, Piedmont had a significant net deferred tax liability, booked at a 35 percent corporate tax rate and driven overwhelmingly by accelerated and bonus depreciation utilized for tax purposes. Because a deferred tax liability represents taxes collected from customers but not yet paid to taxing authorities, and because the ultimate payment of these taxes will now occur at a 21 percent corporate tax rate, the balance of the deferred tax liability was remeasured. The resulting "excess" deferred tax balance becomes a regulatory liability. The Tax Act requires that excess deferred taxes generally associated with property, and specifically connected to the accelerated depreciation of property, must be normalized into customers rates in a highly-prescribed manner that mimics the remaining life of the underlying assets. These are known as "protected" excess deferred taxes. All other excess deferred taxes may be treated by the Commission like any other regulatory liability in the rate-setting process.

Because the Company has use of the cash until it has to pay the IRS, ADIT reduces rate base and is basically used as a source of financing for investments that benefit customers such as pipeline extensions and compliance with federal safety standards. With the change in the federal tax rate, the amount that the Company must pay to the IRS in the future for these ADIT obligations has been reduced. At the end of 2018, the Company calculated this reduction and the difference was carved out and remained on the balance sheet, and in rate base, as Excess Deferred Income Taxes ("EDIT"). Instead of having an obligation to pay this money to the IRS in the future, the

Company now has an obligation to pay it to customers. However, since the money is currently being used to finance investments benefitting customers, as the Company pays the money to customers, it must find other sources of financing for these investments. If the money is returned to customers too quickly, it can put pressure on the Company's credit metrics and create rate volatility for customers.

Q. Please describe the three buckets of federal EDIT.

A. As of the end of 2018, Piedmont had approximately $378 million in EDIT on its books, in three different "buckets." One bucket amount contains approximately $279 million. This bucket is called "protected EDIT" and is related to the Company's investment in property, plant and equipment whose flowback treatment is expressly made subject to IRS normalization rules by the Tax Act. The normalization rules – specifically, Section 13001(d)(3)(B) of the Tax Act – require protected EDIT to be flowed back over the remaining lives of the property giving rise to the deferred tax balance. The method used by Piedmont to refund this amount to customers is fully compliant with IRS regulations and is known as the Average Rate Assumption Method ("ARAM"). Under this method, during the time period in which the timing differences for the property reverse, the amount of the adjustment to the reserve for the deferred taxes is calculated by multiplying the ratio of the aggregate deferred taxes for the property to the aggregate timing differences for the property as of the beginning of the period in question by the amount of the timing differences which reverse during such period. This equals 1.89% at this time.

The remaining two buckets of EDIT, totaling approximately $99.0 million, as of the end of 2018, are "unprotected" under IRS rules, and, therefore, subject to flow back in a timeframe open to discretionary action by the Commission. The majority of unprotected EDIT, totaling more than $74 million, relates to the Company's investment in property, plant, and equipment. The assets represented in this bucket have an average life estimated to be approximately 20 years and the Company therefore proposes a 20-year period over which to accomplish this flowback. Normalization, or the gradual return of EDIT over the life of the asset being depreciated, balances the customer and the Company's interests. It protects the Company's cash flow and credit ratings by lowering the need to raise funds from investors. It also protects the customer against rate volatility because the deferred balance acts as an offset to rate base, and, therefore reduces rates.

The third and final bucket, totaling approximately $25 million, as of the end of 2018, is unprotected EDIT that is not related to the Company's investment in property, plant, and equipment. The assets in this bucket include a variety of things such as pension-related excess deferred taxes. Their average life is estimated to be approximately five years and the Company therefore proposes to return these items to customers over a five-year period.

Q. Please explain the Company's proposed EDIT rider.

A. My Exhibit_(BPB-2) shows the Year 1 calculation of this rider, and then shows for illustrative purposes how the rider would be calculated in future years. The actual proposed rider language is included in Exhibit_(BPB-3) as new proposed Appendix G to Piedmont's Service Regulations. The rider contains the following five categories of benefits for customers:

1. Federal EDIT – Protected (first bucket)
2. Federal EDIT – Unprotected, PP&E related (second bucket)
3. Federal EDIT – Unprotected, non PP&E related (third bucket)
4. Revenue Deferred from Tax Act Overcollections
5. NC State EDIT

The proposed treatment of the federal EDIT, identified in items 1-3 above, has already been discussed.

Q. What about items 4 and 5?

A. My proposals for items 4 and 5 are as follows:

<u>Deferred Revenue (item 4)</u>

As directed by Commission Order issued January 3, 2018 in Docket No. M-100, Sub 148, the Company began deferring the impact of the reduction in the federal corporate income tax rate on January 1, 2018. Line 3 of Barkley Exhibit__(BPB-2), page 3, shows the projected balance of this liability as of October 31, 2019 to be $36,761,711. The Company requests that the amount of Tax Act deferred revenue be amortized over a period of three years and be returned to customers through the operation of the rider proposed herein.

NC State EDIT (item 5)

Similar to the EDIT that results from the reduction in the federal corporate income tax rate, there are EDIT balances that resulted from the several recent reductions in the North Carolina state corporate tax rate. The Company is proposing to return this amount ($56,190,417) to customers over a 5-year period.

Q. Please explain how these five categories of benefits will be incorporated into the EDIT rider.

A. The proposed rider will contain the amortization for each of these five categories of benefits. These amounts can be seen in Columns B through E and column M of Barkley Exhibit __(BPB-2), page 2. As EDIT-related amounts are refunded to customers, rate base will increase. As such, the rider also calculates the return on the increased rate base since the last rate case. This is shown in Column K of Barkley Exhibit__(BPB-2), page 2. Column L shows the sum of the amortization and return for the EDIT amortization, Column M shows the amortization of the estimated overcollection due to the tax rate decrease, Column N shows the total of EDIT and overcollection amounts, and Column O shows the total revenue impact for the rider grossed up for uncollectibles and the regulatory fee. The amount in the Year 1 row on Barkley Exhibit__(BPB-2), page 2, is approximately $37 million proposed to be returned to customers during the first full year of operations under the rider as proposed in this case. Years 2 and 3 are also shown for illustrative purposes and respectively amount to projected credits to customers of $35.1 million and $33.3 million respectively.

The actual rider amounts for those years may change based on several factors including adjustments to any of the balances presented on this exhibit, changes in the ARAM rate, the impact of future general rate cases, and changes to the retention factor

The Company proposes to file with the Commission the rider amounts, along with the allocation to customer classes and rate derivations, for each year after Year 1 by August 31, for rider rates effective November 1.

The Year 1 EDIT rider revenue reduction, shown in Barkley Exhibit__(BPB-2), was provided to witnesses Powers and Couzens for inclusion in the proposed revenue requirement and rates.

Rate Schedule and Service Regulation Changes

Q. Is Piedmont proposing any changes to its Rate Schedules and Service Regulations in this case?

A. Yes. We are proposing revisions to a number of our Rate Schedules and also to our Service Regulations.

Q. Could you briefly describe the nature and types of revisions being proposed by the Company?

A. Yes. Piedmont is proposing to eliminate one category of optional standby sales service currently offered to its customers under Rate Schedules 113, T-12, and ST-1 and also proposes to make minor corrective adjustments to a number of other provisions of its Rate Schedules and Service Regulations.

Q. Could you please describe Piedmont's proposal to eliminate Standby Sales service from Rate Schedules 113, T-12, and ST-1?

A. Yes. Under these rate schedules, Piedmont currently offers customers the right to subscribe to a winter only standby sales service. Subscription to this service is essentially a back-up supply source for customers during the winter heating period but customers are required to pay demand charges in order to reserve the service. Piedmont's experience in recent years, in the face of abundant sources of supply feeding into the interstate pipeline systems that serve North Carolina, is that customers have no need of and are not subscribing to standby sales service. Piedmont does not anticipate that customers will have need of this service in the future and proposes to eliminate it. Eliminating the service will simplify Piedmont's gas cost acquisition planning and strategies and will not inconvenience customers.

Q. What other changes are you proposing to Piedmont's tariffs?

A. We are proposing minor changes in the tolerances used in our annual customer classification process under Sections 34 and 35 of our Service Regulations. These changes provide a buffer before necessitating rate schedule reclassifications and are consistent with amounts set forth in Piedmont's tariffs in South Carolina. Adoption of these standards in North Carolina will make the administration of Piedmont's tariffs across the Carolinas consistent and equal. Our anticipation is that these changes will be to the benefit of our North Carolina customers.

We are also proposing to modify Appendix E to our Service Regulations to include updated percentages and throughput and eliminate the special contract credit provisions to the calculation of our annual Integrity Management Revenue Requirement. This crediting mechanism, which was agreed to by Piedmont and the Public Staff and approved by the Commission in 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 in this proceeding.

Q. Is Piedmont proposing any additional rider provisions to its tariffs?

A. Yes. As is discussed earlier in my testimony, we are proposing to implement an EDIT Rider as Appendix G to our Service Regulations. The rationale for this rider is discussed above and the text of the proposed rider is included in my Exhibit__(BPB-3).

Q. Is Piedmont proposing changes to its current billing procedures concerning the conversion of cubic feet to therms?

A. Yes. Piedmont currently converts gas measured in cubic feet to therms in North Carolina using conversion factors based on linking customers to one of eleven groups known as common gas areas ("CGAs"). In Section 27(b) of the attached Service Regulations, Piedmont proposes to codify its request to utilize two CGAs prospectively. These two areas will be divided between the eastern and western portions of our NC service territory.

Q. Why is Piedmont proposing this change?

A. Piedmont has reexamined its current practice and believes the current number of CGAs causes administrative burden without a demonstrable improvement in the accuracy of customer billing. Piedmont currently has twenty-four interconnection points with its interstate suppliers in North Carolina. These are mapped to the eleven CGAs. However, physical flow of natural gas on Piedmont's system does not map directly from the twenty-four interconnection points to customers contained in the judgmentally-determined CGAs. Given the lack of precision that exists in the current process, Piedmont believes it beneficial to streamline the process.

Q. Please provide an example of future efficiency benefits.

A. Maintenance and utilization of two conversion factors within

Piedmont's billing system is obviously more easily administered than having eleven such factors. In situations in which manual billing is required for customers experiencing meter or communication issues, Company personnel must determine the appropriate CGA. This process will obviously be more efficient with two options as opposed to current state of eleven. Also, if Piedmont is unable to receive information from one of the twenty-four city gate meters due to malfunction, the impact of such individual meter on one of two zones will be reduced as compared to the current state.

Q. Did Piedmont review the impact on customers before making this proposal?

A. Yes. Another reason for recommending this change is that the conversion factor does not vary greatly throughout Piedmont's NC service territory. Our analysis indicated that residential customer impacts did not exceed one dekatherm per year. One dekatherm represents less than 2% of annual usage for an average Piedmont residential customer in North Carolina.

Q. Will Piedmont realize greater or less profit as a result of this recommended change?

A. No. While each individual customer may experience an immaterial difference, these differences are expected to offset and therefore not materially change the amount of therms billed by Piedmont. Further, all impacts will be fully included in test period revenues included in future general rate case applications.

Q. What other changes is Piedmont proposing to its tariffs?

A. We have addressed changes related to the implementation of the Commission's Order issued April 6, 2018 in Docket No. GR-100, Sub 0 in the definition of "Customer" and in Section 19 of our Service Regulations. We are also proposing to make some technical corrective changes such as replacing the word "redelivery" with the defined term "Transportation" in a number of places in our tariffs and in updating several provisions of our tariffs consistent with current realities of our business operations. Further, we have included a reference to Piedmont's approved Appendix F concerning alternative gas quality standards in Section 8 of the Service Regulations. Finally, we are proposing some changes to the titles of certain Piedmont Rate Schedules in order to ensure accuracy and consistency in those Rate Schedule titles. All of our proposed tariff changes are shown, in red-line format, on Exhibit__(BPB-3) attached to my testimony.

Q. Are any of these other changes material in your view?

A. No. They simply clarify the language of Piedmont's existing tariff or update that language based upon changes in the market, regulations, and/or customer practices. The nature of each of these proposed changes is evident on the face of the revised tariffs.

Q. Do you believe that Piedmont's proposed tariff changes are reasonable and appropriate?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Bruce P. Barkley. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. By whom and in what capacity are you employed?

A. I am employed by Piedmont Natural Gas Company, Inc. ("Piedmont" or "the Company") as Vice President – Regulatory and Community Relations.

Q. Please describe your educational and professional background.

A. I obtained a Bachelor of Science Degree in Business Administration with a concentration in Accounting from the University of North Carolina at Chapel Hill in 1984 and an MBA Degree from Wake Forest University. I obtained my CPA license in 1987. From 1988 through 2001, I was employed by Public Service Company of North Carolina, Inc., where I was responsible for regulatory filings and reports submitted to the North Carolina Utilities Commission ("NCUC" or "Commission"). Prior to joining Piedmont, I held various positions with Progress Energy, Inc. and subsequently Duke Energy Corporation ("Duke Energy") in Regulatory Affairs, Fuels, and Regulatory Accounting. I joined Piedmont in 2015 and began serving in my current role in 2016.

Q. Mr. Barkley, have you previously filed testimony in this case?

A. Yes. I prefiled direct testimony in this proceeding on April 1, 2019.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to address matters raised by the testimony of public witnesses and to address the public interest inherent in the potential impact of the stipulated revenue requirement on our customers in light of changing economic conditions. In the latter regard, I also address the economic conditions testimony of Attorney General witness Woolridge.

Q. Can you comment on the public's response to Piedmont's rate filing in this case?

A. Yes. Several public witnesses appeared and testified at the public hearings set by the Commission in this case. The issues raised by the witnesses generally fell into five categories: 1) the proposed rate increase will have a disproportionate impact on low income customers; 2) environmental concerns associated with fossil fuel infrastructure and how Piedmont should be focusing on renewable energy; 3) belief that the rate increase is unjustified; 4) safety concerns associated with natural gas; and 5) a purported lack of need/demand for additional fossil fuel infrastructure.

Q. What is Piedmont's response to each of these issues?

A. Regarding the contention that the proposed rate increase will have a disproportionate impact on the low-income population, it is a reality of our society that some customers are better able to afford their utility services than others. Piedmont undertakes many efforts on a continuous basis to assist low-income customers who are having difficulty paying their bills including working out payment plans, advising such customers on steps they can take to save energy/money, and referring customers to outside agencies that can assist them in paying their utility bills. Piedmont is also aware that many charitable organizations also will help low-income customers in situations where they cannot pay their utility bills and Piedmont frequently directs customers to these organizations. Notwithstanding all of this, it will remain true that some portion of Piedmont's customers will struggle to pay increased rates but it is also true that even at increased levels, the total costs paid by Piedmont's customers for natural gas service have remained flat or been reduced for the last decade. In fact, the Company projects lower rates for the upcoming winter compared with the prior winter, even after the impact of this general rate proceeding is considered. There is no other essential service that I can think of that can make the same statement.

Regarding public witnesses' environmental concerns associated with fossil fuel infrastructure and how Piedmont should be focusing on renewable energy, I note that the use and reliance on clean and low cost natural gas has permitted electric utilities to move away from, and, in some instances, discontinue burning coal, a higher-emitting energy source than natural gas. More to the point though, this proceeding is not the proper forum to address the policy issues of how to react to global warming and whether and how to promote renewable energy sources. I believe the Commission's attention in this proceeding should be focused on deriving just and reasonable rates for Piedmont's customers and approving a fair rate of return for the Company. In short, environmental concerns and climate change are not issues before the Commission in this proceeding and are not matters the Commission has the authority to resolve.

Regarding witnesses who contend that Piedmont's proposed rate increase is unjustified, they did not appear to understand the utility ratemaking process or the dynamics of Piedmont's ongoing costs to provide service. This lack of comprehension by public witnesses is not surprising given the relative complexity of utility ratemaking but it stands in stark contrast to the position of the Public Staff who engaged in an exhaustive investigation of Piedmont's costs and concluded that a rate increase was required as reflected in the Stipulation.

Regarding witness safety concerns associated with natural gas, I would note that natural gas is inherently safe and that the vast majority of incidents involving natural gas explosions occur as a result of third-party negligence or damage to utility pipelines. I would also note that these concerns were raised primarily in the context of statements regarding Atlantic Coast Pipeline or the Robeson LNG project, neither of which are properly before the Commission in this proceeding.

Regarding witness statements that contend that North Carolina does not need additional fossil fuel infrastructure, such as the Robeson LNG facility or ACP, I would point out that both of these projects are supported by demonstrable and growing demand from North Carolina customers who need additional gas supplies (and the infrastructure necessary to provide those supplies).

Q. Do you have anything else to add to your response to public witness testimony?

A. Yes. At the Wilmington Public Hearing, a witness testified that Piedmont's construction of Line 434 exacerbated flooding associated with Hurricane Florence in Robeson County. We have investigated this claim and cannot substantiate it. We can confirm that the Line 434 project was underway at the time Hurricane Florence impacted North Carolina and that a significant amount of rainfall from that storm caused widespread flooding throughout most of the eastern part of the State. Our project manager for this project has indicated that the Line 434 project did not increase the amount of impervious surfaces in the vicinity of the pipeline and did not alter the existing hydrology. As such, we are unable to confirm the existence of any negative impact on Hurricane Florence related flooding caused by our Line 434 project.

Q. How does the current economic situation compare to what customers have seen since 2013?

A. I would say that the current economic environment in which our customers operate is sound and has continued to improve over the course of this proceeding. All indications are that economies of this State and the Nation are positive.

Q. Can you please explain the basis for this assessment?

A. Yes. As the Commission is aware, there are a myriad of broad ranging factors that are regularly evaluated and reported on in assessing the economic health of North Carolina and the United States. In the past several years, since the filing of Piedmont's last rate case, many of these indicators reveal a steadily improving economy.

Q. Can you provide some examples?

A. Yes, there are many indicators that the economy is improved and improving, including the following:

- As reported by the NC Dept. of Commerce in July of this year, North Carolina employers continue to add jobs in our state. The number of employed North Carolinians has risen over the year for the past 111 straight months.
- As reported by the US Bureau of Labor Statistics, in July 2019, total employment in the United States grew by 0.2% (more than 247,000 new jobs), compared to 0.3% for North Carolina (16,068 new jobs).
- According to the same source, North Carolina's job postings have increased by 10.4% over the year.
- Real gross domestic product (GDP) increased in all 50 states and the District of Columbia in the first quarter of 2019, and increased at an annual rate of 2.1% in the second quarter of 2019 according to the Bureau of Economic Analysis ("BEA").
- Individual real disposable personal income (DPI) increased $69.7 billion (0.4 percent) and personal consumption expenditures (PCE) increased

$41.0 billion (0.3 percent) in June 2019 according to estimates released July 30, 2019 by the BEA.

- As reported by the same source, wages and salaries, the largest component of personal income, increased 0.5 percent in June 2019 after increasing 0.2 percent in May.
- According to BEA, personal savings as a percentage of disposable income remain higher in both the 1st and 2nd quarters of 2019, compared to all four quarters in 2018.
- According to the United States Census Bureau, North Carolina exports increased .4% in 2018, compared to 2017.
- According to the same source, privately-owned housing starts in June 2019 were at a seasonally adjusted annual rate of 1,253,000, 6.2 % above the June 2018 rate of 1,180,000.
- The Census Bureau also reported that new orders for manufactured goods in June increased $3.1 billion (or 0.6 percent) to $493.8 billion.
- Business investment increased in the second quarter of 2019 according to BEA. BEA also reports that in 2018, expenditures by foreign direct investors to acquire, establish, or expand U.S. businesses totaled $296.4 billion, up 8.7 percent from $272.8 billion in 2017.
- North Carolina continues to rank as one of the best states for business by Chief Executive Magazine.
- On October 24, 2018, Forbes Magazine ranked Raleigh, Charlotte and Durham as the 2nd, 5th and 13th Best Places for Business and Careers in the

Nation and on November 28. 2018, Forbes selected North Carolina as having the best business climate in the U.S. The publication noted that North Carolina's labor, energy and tax costs are all well below the national average and rank as the second lowest in the U.S. overall, per Moody's Analytics.

- North Carolina has experienced a significant number of new business project announcements in the last 24 months. For example, on July 25, 2019, WFAE, Charlotte's NPR News Source, reported that financial software company AvidXchange is planning to build a second in Charlotte and increase its workforce by 1,200. This follows an announcement from Lowe's in June that it plans to build a tech center in Charlotte's South End and add 1,600 positions.

Q. What is your conclusion based upon these statistics?

A. In my opinion, they provide substantial grounds upon which to be optimistic that the economy continues to be strong. This is shown in everything from construction starts, new projects coming into the state, personal disposable income growth, better employment rates, growth in GDP, and greater confidence among consumers and the business community.

This positive economic outlook supports the reasonableness of the settled return on equity in this proceeding and provides support for the notion that such return will not be unreasonably harmful to customers.

Q. Are you aware of any published economist reports that support your conclusions as they relate to the prospects for the North Carolina economy?

A. Yes. On May 30, 2019, Professor John Connaughton, an economist from the University of North Carolina at Charlotte, presented the economic report for 2018 and his forecast for the next 18 months. According to Professor Connaughton, the country is in the second-longest economic expansion since 1854. Connaughton said that consumer confidence remains strong and that "[d]espite what is likely to be the short-lived spike in GSP growth during 2018, the longer-term outlook, at a more modest rate of growth, is fairly optimistic." He noted that in April, the Consumer Confidence Index was at 129.2, up from the March index of 124.2. Connaughton predicts that it will take a considerable negative event to slow the economy during 2019 or into 2020 in light of the national unemployment rate consistently below 4.0 percent, more job openings than job seekers, modest interest rates, and continued consumer optimism.

Q. How does this evidence comport with Dr. Woolridge's testimony on economic conditions?

A. Dr. Woolridge makes essentially three points regarding current economic conditions in North Carolina in his direct testimony: (1) the unemployment rate in Piedmont's service territory is allegedly somewhat higher than the State average: (2) the median household income in North Carolina is 10% below the US norm; and (3) natural gas rates in North Carolina are more than 15% higher than the national average. While Dr. Woolridge does not identify the source of these statistics, I am not challenging them in my rebuttal testimony.

Q. Do you have any comments on these statistics?

A. Yes. It is not clear to me how Dr. Woolridge calculated the unemployment rate within Piedmont's service territory because our service territory covers a broad and economically diverse portion of the State. Assuming his figures are accurate, the unemployment rate he cites for Piedmont's service territory is extremely low by historic standards. With respect to his citation to median household income, it is unclear to me how that relates to the impact analysis for our customers. Every jurisdiction in the United States has different costs of living and different median household incomes. The fact that median household income is somewhat lower in North Carolina than in other locations in the United States is neither particularly surprising nor particularly meaningful without an examination of a host of other factors that would reveal how North Carolina households fare overall when costs of living and incomes are compared. Even if that examination showed that North Carolina households are more economically challenged than in some places in the United States – which they undoubtedly are in some cases – that analysis says nothing about the relative impact of the stipulated annual revenue requirement on those households. As stated previously in my testimony, costs in North Carolina are among the lowest in the nation. Finally, the mere fact that natural gas rates are higher in a state that has no native gas production capacity, which is located a great distance from any such production capacity, and which has populations spread across large rural areas does not provide meaningful information as to whether the annual revenue requirement set forth in the Stipulation is just and reasonable and otherwise fair to customers in light of changing economic conditions.

Q. Does this conclude your testimony?

A. Yes.

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

A. Yes.

Q. Once Mr. --

COMMISSIONER BROWN-BLAND: Mr. Jeffries, the exhibits, they will be identified as they were prefiled.

MR. JEFFRIES: Thank you. Thank you.

(Summary handed out.)

(Exhibits BPB-1 through BPB-3 were marked for identification.)

Q. You may proceed, Mr. Barkley.

A. Good morning. My name is Bruce Barkley. I'm vice president of regulatory community relations for Piedmont Natural Gas Company. I prefiled direct testimony in this docket on April 1, 2019, in support of Piedmont's application for a general rate increase. I also submitted prefiled rebuttal testimony on August 9, 2019.

My prefiled direct testimony addresses the following seven subjects: the nature and scope of Piedmont's revenue request in this proceeding, the impact of Piedmont's requested revenue request on customers, the public benefits inherent in the continued operation of the Company's integrity management rider mechanism, the need for a distribution integrity management program related to Piedmont's operations and maintenance expense deferral mechanism, the operation of Piedmont's margin decoupling tracker mechanism and the proposed expansion of conservation and energy efficiency spending, Piedmont's proposed implementation for the flow-through of benefits resulting from the Federal Tax Cuts and Jobs Act of 2017 and recent North Carolina state income tax reductions, and proposed changes to the Company's service regulations and tariffs.

My direct testimony is supported by the following three exhibits: number one, data demonstrating that Piedmont's margin decoupling tracker benefitted customers over the five-year period ended December 31, 2018; EDIT calculations, excess deferred income tax calculations; and Piedmont's proposed tariff and service regulation changes.

For my rebuttal, I prefiled rebuttal testimony to address and respond to the matters raised by the testimony of public witnesses which included concerns that a rate increase would have a disproportionate impact on low income customers, environmental concerns associated with fossil fuel infrastructure, a belief that rate increase is unjustified, safety concerns associated with natural gas, and a purported lack of need or demand for additional fossil fuel infrastructure.

In addition, my rebuttal testimony responds to the economic conditions testimony of Attorney General Witness Dr. J Randall Woolridge. I explain how the current economic environment in which our customers operate is sound and has continued to improve over the course of this proceeding, and I provide examples of economic indicators that support this contention.

Q. Thank you, Mr. Barkley.

MR. JEFFRIES: Mr. Barkley's available for cross-examination and questions by the Commission.

COMMISSIONER BROWN-BLAND: All right. Cross-examination for this witness, Ms. Harrod?

MS. HARROD: Yes, Chair.

CROSS-EXAMINATION BY MS. HARROD:

Q. Mr. Barkley, good morning. I'm Jennifer Harrod. I represent the Attorney General of North Carolina.

A. Good morning.

Q. Good morning. I am going to limit my questions to the EDIT aspects of your testimony. And just to, you know, ask a few preliminary questions just so we all share an understanding, can you please define EDIT or excess deferred income taxes?

A. Sure. The excess income -- deferred income taxes were a result of the Federal Tax and Job Cuts Act, as I referenced in my summary, when the federal government lowered the income tax rate for corporations by beginning 1/1/18 from 35 percent to 21 percent. Piedmont, along with every other company and certainly utility, has deferred income taxes. Deferred income taxes are caused by the difference between how you recognize income on your books and records and how they -- that is recognized on tax returns. Two different methodologies with, typically, items of plan being amortized much more quickly for income tax purposes than on the books and records of the company.

When the rate was reduced from 35 to 21, the inevitable turn in these timing differences that I just referenced would not fully occur as if -- if the rate would have remained at 35 percent, everything that was amortized more quickly on the tax return would -- had a turnaround, and it would have been amortized more quickly on the books after it had been fully amortized for tax. The books' life is much longer, but eventually it would catch up. If you're trying to amortize $100, you could do it over five years, that would be $20; you could do it over 10 years, it would be $10 per year. So it would eventually come to that amount. It would turn around.

When you lower the tax rate, it does not fully turn around, therefore, creating, instead of accumulated deferred income tax, the E in that acronym, excess deferred income tax to that amount will never turn around, and, therefore, it is excess. And in normal businesses, that amount was a windfall; for utilities, that amount is typically refunded to customers, as proposed in my testimony.

Q. Thank you. So, in your testimony, you speak of that EDIT as being in several buckets, correct?

A. I do; yes, ma'am.

Q. Okay. So one bucket that doesn't get a lot of testimony because it's not controversial is the protected EDIT. And as I understand that, and you can tell me if I'm right, that's a category of EDIT as to which the IRS has mandated how that will be treated, and this Commission does not have discretion because the IRS already states how that would be handled, correct?

A. I think that's generally correct. I would always hate to testify that the Commission doesn't have discretion, but I think this Commission would typically follow clear guidance from the Internal Revenue Service. So I think we're on the same page; yes, ma'am.

Q. Thank you. I appreciate that.

So, of the total federal EDIT that's on Piedmont's books right now, that's $378 million at least as of the time you filed your initial testimony, correct?

A. Yes.

Q. Okay. And the protected bucket is $279 million as of the time you filed your initial testimony?

A. Yes. And that amount, just for clarity, it has been grossed up. And so you need to -- if the number is $10, you basically need to gross it up to $13 for refund purposes. That may not be all that important for our conversation here, but the amount of the actual excess, you take that amount and you increase it before you refund it to customers to take into account the impact of refunding that on the Company's income taxes.

So the amount that was in my exhibit is exactly what you said, and those amounts were grossed up as if ready to refund to our customers.

Q. Okay. And that protected EDIT, the 300 -- sorry, the $278 million, will be returned to ratepayers over 52.9 years; is -- that was your initial testimony, the proposal?

A. It does. And I think that 52.9 tends to vary. It's not something that's a locked-in to where you could absolutely say it, but I think you could say that it would be in the range of 50 years.

Q. Thank you. And that's consistent -- that's also what the stipulation provides, I take it?

A. It does.

Q. Okay. So primarily what's at issue here is the treatment of the unprotected EDIT, E-D-I-T, which is $99 million as of the time of your initial testimony, correct?

A. Yes.

Q. All right. And, in your initial testimony, you propose that -- that that be provided into two buckets, and that $74 million of that would be returned to ratepayers over 20 years, and that $25 million would be returned to ratepayers over 5 years, correct?

A. Yes.

Q. Okay. And now, under the stipulation, if that were to be accepted by the Commission, all of that unprotected EDIT, E-D-I-T, would be returned to ratepayers over five years, correct?

A. Yes.

Q. And then there's some additional buckets. There's the overcollection that was -- that results from the change in the tax rates that -- where the company, beginning on 1/1/18, was still collecting at the old authorized tax rate but, in fact, the tax rate had gone down, correct?

A. Yes. Yes.

Q. So that amount is $36 million?

A. Approximately, yes.

Q. Okay. And your initial testimony was to return that to ratepayers over three years, correct?

A. It was.

Q. Okay. And now, if the stipulation were to be accepted, that would be returned to ratepayers over one year, correct?

A. Yes.

Q. Okay. And then there is the North Carolina EDIT.

A. Yes.

Q. And that reflects changes in the North Carolina corporate income tax rate which dropped since your last rate case and caused you to have excess deferred North Carolina corporate income taxes.

And those are in the amount -- at least as of your initial testimony -- in the amount of $56 million and some change, correct?

A. I think so, but let me check just to make sure we're on the same page.

Q. Sure. Page 23, line 6 through 10 of your testimony.

A. It must be right.

Q. I try to bring the receipts.

A. (Witness peruses document.)

56; yes, ma'am.

Q. Okay. And, initially, in your testimony, the Company's proposal was to return that to North Carolina ratepayers over five years; and, in the stipulation, the Company has agreed to return that over three years, correct?

A. Yes.

Q. All right. So thank you for that background.

So did you participate in the Company's decision-making process for how to treat the EDIT in its application?

A. I did.

Q. Okay. And in that thought process, did you review prior positions of the Public Staff and the Attorney General's office and prior orders of this Commission?

A. I was aware of some precedent in -- yes, I was, yes.

Q. Okay. All right.

MS. HARROD: Chair, we would ask to circulate exhibits at this time, if we can approach the witness.

COMMISSIONER BROWN-BLAND: Go ahead.

MS. HARROD: Okay. Doing them all in a bunch, so they're bulky, but we only have to do it once.

(Exhibits handed out.)

Q. All right. Mr. Barkley, I've handed you three exhibits. The one on the top is the Commission's order approving joint partial settlement agreement and stipulation granting partial rate increase and requiring customer notice in -- oh, sorry, I got my own exhibits out of order.

The one on the top, rather, is the Commission's order in the general rate case of Aqua North Carolina, Docket Number W-218, Sub 497; do you see that?

A. I do.

Q. Okay. Is that -- were you familiar -- were you aware of this order when you prepared the Company's position for the application with respect to EDIT?

A. Generally familiar with it. Certainly not with every detail in the Aqua order.

Q. I'm not going to ask you about every detail related here. So --

MS. HARROD: Chair Brown-Bland, may we -- may I ask to have this identified as Attorney General's Office Cross Examination Barkley Exhibit 1?

COMMISSIONER BROWN-BLAND: It will be so identified.

MS. HARROD: Thank you.

(Attorney General's Office Cross Examination Barkley Exhibit 1 was marked for identification.)

Q. So this -- with respect to the return of the federal unprotected EDIT, the position that was -- the Public Staff and Aqua reached a stipulation on that exhibit -- on that issue, and the Commission accepted that stipulation; is that correct?

A. I will accept that.

Q. And so if you look at, actually, page 22 of the order, the result of that stipulation being accepted was that the EDIT was returned over a three-year period, correct? If you look at -- if you look at paragraph 103 of the order, page 22.

A. Page 22 of the order. Finding of fact 103.

(Witness peruses document.)

That's what it says, yes.

Q. Okay. And if we go all the way to the date the order was entered, which is -- you can find -- I believe that is on page 187, this order was entered on December 18, 2018.

So, at that point, the lower rates had been in effect for virtually all of a year?

A. Yes.

Q. Okay. And Aqua was ordered to return those, then, over a subsequent three years for a total of four years since the -- since the tax rates have been in effect, correct, roughly?

A. Yes, sure.

Q. Okay. Then the next exhibit that we have there for you is the order in the general rate case for Carolina Water Service that is Docket Number W-354, Sub 360; do you see that?

A. I do.

Q. Okay.

MS. HARROD: Chair Brown-Bland, may we have this marked as Attorney General's Office Cross Exhibit Barkley 2.

COMMISSIONER BROWN-BLAND: Yes, it will be so marked.

MS. HARROD: Thank you.

(Attorney General's Office Cross Exhibit Barkley 2 was marked for identification.)

Q. Okay. In the Carolina Water Service issue, are you aware that this was actually a contested issue, it was not stipulated by the parties?

A. I accept that, yes.

Q. Okay. So if we go to page 12, finding of fact 49, in that case, the Commission ordered that the federal unprotected EDIT should be returned to ratepayers over four years; do you see that?

A. I do.

Q. Okay. And if we turn to page 52 of that order, it's the one, two, three, fourth full paragraph reflects the Commission is summarizing the position of the Attorney General's office in that paragraph.

Are you with me?

A. Yes.

Q. All right. So I wanted to call to your attention that it was the position of the Attorney General's office in that proceeding that the EDIT should be returned over a period of no greater than two years, two years or less, as reflected in the first sentence of that paragraph.

A. (Witness peruses document.)

Okay.

Q. Do you see that?

A. The specific paragraph citation, again, please. I'm on page 52.

Q. It's the fourth full paragraph. So it says, "The AGO noted that it recommended a return of the federal unprotected EDIT over a period of two years or less in the" -- oh, I'm sorry, I see your confusion -- "in the recent Duke Energy Carolinas rate case," and then it gives a docket, "so the ratepayers benefit as soon as possible from the amounts they are owed." And it's actually the last sentence of that paragraph where it says, "The Attorney General's office asserted that, with the adoption of the two-year time frame to return the federal unprotected EDIT, ratepayers would benefit immediately from the use of the amounts that are owed."

A. Right.

Q. Okay. The middle of that paragraph, it's -- I'll just read it. "The AGO noted that Public Staff Witness Boswell testified that, although the Public Staff has proposed a three-year period in this proceeding, a two-year time frame is feasible and is within the range that the Public Staff has proposed in other cases."

Do you see that?

A. Yes.

Q. Okay. Does that comport with your own recollection and analysis when you have reviewed the various possibilities for EDIT in this matter?

A. Sure. I mean, the statements here, I think, basically speak for themselves, so I wouldn't quarrel with the Public Staff's ability to state their belief and their position. Ms. Boswell's an experienced member of the Public Staff, and so I wouldn't quarrel if she expressed whatever opinion she felt was appropriate.

Q. Okay. So if we would turn, then, to the third exhibit in the packet, we have prepared a demonstrative exhibit; do you see that?

A. (Indicating.)

Q. Yes, that's it.

A. I do.

MS. HARROD: Chair Brown-Bland, may we have this marked as Attorney General Barkley Cross Exhibit 3?

COMMISSIONER BROWN-BLAND: Yes, it will be so marked.

(Attorney General Barkley Cross
Exhibit 3 was marked for
identification.)

Q. So, Mr. Barkley, the purpose of this exhibit is just to provide sort of a visual representation of the facts we just went over there, that all of the bars begin at the beginning of 2018 because that's when the change in the tax rates took place. And so if we carry out for Aqua, there was an agreement which the Commission accepted to return the unprotected EDIT over three years, which means that Aqua had full use of that taxpayer money for approximately a year, and then returned it subsequently over a period of three years which was completed approximately the end of 2021.

Do you agree with that?

A. That would be -- if you begin something at the beginning of '19 and run it for three years, it would conclude at the end of 2021; yes, ma'am.

Q. Okay. And then, in the contested case of Carolina Water, that order was a little bit later. So there was a longer period of time where Carolina Water had full use of the unprotected EDIT, and then returned it -- it was directed to return it over a subsequent four years.

So that -- that order -- that gives them, you know, five years and a little bit to have full or partial use of that EDIT, correct?

A. It would be refunded at the end of four years, as stated on your exhibit, yes.

Q. Okay. So if the stipulation were accepted in this case, the Company has asked for rates to go into effect November 1st -- or no later than November 1st, I believe; is that correct?

A. That's correct.

Q. Okay. So we don't know when that may happen, but likely to be sometime in the fourth quarter of this year?

A. We certainly hope that we will have an order in this case on November 1, 2019, or prior to that date, so that we can have rates effective for the winter heating season.

Q. Okay. So then that would -- if that were the case, and if the Commission were to accept the stipulation with respect to this particular issue, that would mean that Piedmont would have the full use of that EDIT for almost two years, and then it would have partial use of it as it returns it over a subsequent five years, causing Piedmont to have the use of that money in full or in part for a seven-year period of time, correct? Or nearly seven years, not quite.

A. That would be -- I guess if you say -- part of your supposition in building that -- certainly -- certainly two plus five would be seven, I would not argue with that. That would be the arithmetic of when it would go back to customers. But I think you're characterizing this as an overcollection and also as something that could have gone back day one. And I don't think, in any company in this state, or in any company across the nation, was there an order to give back the excess deferred income taxes day one.

So that's certainly the effect and the answer to your direct question, but as far as holding this money for seven years as if Piedmont were holding onto something it shouldn't have, certainly, an immediate refund of these excess deferred taxes -- the Commission actually gave us an immediate order on January 3, 2018, providing some instruction. But they -- I think for them to decide in a couple of days what to do with a complex issue like EDIT would not have been possible.

So I think there's a clarification around how long this thing is being held. It's being held until the Commission feels that it needs to be returned to customers, which they didn't feel immediate was appropriate, nor did any other Commission or the federal government.

Q. Okay. The question was, but the Company's had the -- has had the use of the money and is asking to continue to have the use of the money for five additional years. That was the -- that was the question I asked you.

A. And that is -- that is the effect of a five-year amortization as approved -- as agreed to by the stipulating parties in this. That if you don't fully return it until the end of the five years, then you do have use of some portion of the money until the five years has concluded.

Q. Okay. And then, just to close the loop on this, if the -- if the final bar on the -- on Attorney General Barkley Cross Exhibit Number 3 shows the position of the Attorney General's office for the return of the EDIT over two years, and do you agree with me that the Company, having had full use of the EDIT from the beginning of 2018 to whenever new rates go into effect, if from that point in time it then had to return the EDIT over two years, it would have had full or partial use of that money for approximately four-year period of time?

A. From --

Q. A little bit less.

A. From -- yeah. From the beginning of 2018 when the federal taxes were lowered until the conclusion of 2021 would be four years; yes, ma'am.

Q. And that would be somewhere between the amount of time that Aqua and Carolina Water had full or partial use of the EDIT of their customers?

A. That looks like to be the amount that is shown here. I would like to -- so yes is the answer to your question.

Q. Thank you.

A. But I would like to expand on my answer, that I don't feel that the Commission is obligated in this case to follow what was done in water cases, especially one that was settled. And I believe, in the second case you handed to me associated with Carolina Water, I'm not sure they had any protected EDIT, and that's the category that we are really concerned with. So I think there is a distinction there.

There's also many distinctions. They're not obligated to give us a 9.75 ROE. They could. That's what was awarded by this Commission to Carolina Water. So I think that it needs to be -- the decision on excess deferred income taxes needs to be situational. I don't even know the amount of money that was at stake for Carolina Water or for Aqua, for that matter. I'm not sure about the amounts. But the amounts that we are looking at here are almost $500 million.

And I think the point of my testimony and the point of both prefiled and my testimony here today is that this Commission can order us to return that under any -- except for the caveat around the IRS violation around the protected, but for the remainder, they can order that to be returned as fast as they feel is prudent.

But I believe five years reaches a good balance for the purpose of settlement and that this Commission is aware that cash flow is important to utilities. Poor cash flow leads to poor credit ratings, and poor credit ratings make it difficult to borrow money, to finance economically, that leads to higher rates.

So it's in our testimony that they have the ability, the jurisdiction on these -- everything other than the protected -- to do whatever they want. But what I would ask is that they approve the stipulation, because it's a prudent compromise between the 20 years for the plant-related unprotected, that we felt and still feel is appropriate based on the nature of those assets, and the five years that was agreed to based on give-and-take, primarily with the Public Staff but also accepted by CUCA and CIGFUR.

Q. So you're aware that, in the initial testimony of Public Staff Witness Perry, she said that there is unprotected federal EDIT and there is protected federal EDIT, and there is no basis in law or accounting for the Company to then take that unprotected EDIT and divide it into subsequent buckets, correct?

A. I am aware of that, and I have talked with Ms. Perry about that. I understand her perspective, and I think you said law or accounting. I would agree on both parts there, but there is also room for judgment as well. And I think those assets -- I talked about, in response to your very first question, about how these things turn around. It's timing between book and tax. And those assets -- those deferred tax liabilities tend to have a very long turnaround period primarily related to repairs that are made.

And so if there had never been a reduction in federal taxes, these amounts would have gone back to customers by the fact that our -- by the impact that it has on deferred taxes and the impact that has on rate base. So they were going back to customers regardless, these timing differences. And so now we need to look at what is a prudent time. Since the rate dropped, I understand that changes the equation, but the nature of those long-lived assets make our prefiled position of 20 years very reasonable, in my opinion, because it matches what would have happened as those assets had the difference between book and tax laws to reverse.

Q. In Ms. -- in Witness Perry's initial testimony, she stated, on page 10, lines 1 through 3, "These funds rightfully belong to ratepayers and should be returned to them as soon as reasonably possible."

Do you agree that these funds belong to the ratepayers?

A. They will be -- right now they are in the -- they belong to the Company. The Commission has the ability, on the unprotected, to determine when they are refunded to customers. And all across the -- the conversation we're having now is happening in many jurisdictions across the country. And just to cite a few examples, this thing is happening over 10 years in Indiana, 10 years in Florida, 20 years in South Carolina.

Q. I didn't ask you that question.

A. I have a chance, though, in response to your question, to expand upon my answer.

Q. The question was, do these funds rightfully belong to customers? That's just a yes or no answer.

A. And I think I said yes, but I also would say -- I believe that the Commission's practice has been the witness can expand on his answer, and my answer is the -- who it belongs to and the time that that cash changes hands is up to the Commission. It doesn't -- it doesn't belong to customers today. It will be refunded under both our proposal and under what's in the stipulation. I think everybody's in agreement to refund those dollars to customers at the appropriate time. And the appropriate time is in the stipulation, not on this exhibit.

Q. And so are we in agreement that the Commission has complete discretion about the time to flow back these unprotected federal EDIT to customers?

A. They certainly do, yes.

Q. Okay.

A. And I trust them to recognize what I was speaking about a little while ago. Cash flow affects credit ratings; credit ratings affect our ability to finance; high cost of financing is bad for customers.

Q. And so we heard yesterday -- I don't know if you were -- were you in the room yesterday?

A. Yes, ma'am.

Q. Okay. So did you hear Piedmont Witness Sullivan testify about the Company recently had an historic debt offering of $600 million this spring?

A. I did.

Q. Okay. And has had large equity investments from its parent company, Duke energy, both in 2018 and in 2019?

A. I did; yes, ma'am.

Q. Okay. And so another category of EDIT that's at issue here is the state EDIT. And, in your testimony, you refer to that as recent reductions in the North Carolina corporate tax rates.

Do you know when those reductions were?

A. I don't know all of them by heart, but, basically, we were at 6.9 percent when we came out, or in the fall of 2013 when Piedmont prosecuted its last general rate case, and it dropped from 6.9 to 6 to 5 to 4 to 3 to 2.5. So, basically, every year. Maybe not literally every year, but almost every year between '14 and '19, there was an additional drop of a point or so as legislated by the General Assembly, finally concluding with 2-and-a-half percent effective 1/1/19.

Q. Okay. And so Piedmont has -- is a sophisticated corporation, has had a significant period of time to prepare for this, for returning this money to ratepayers, correct?

A. Yes.

Q. Okay.

MS. HARROD: I have no further questions. Thank you.

THE WITNESS: Yes, ma'am.

COMMISSIONER BROWN-BLAND: All right. Any other cross-examination?

(No response.)

CHAIRPERSON BROWN-BLAND: Any redirect?

MR. JEFFRIES: Couple of questions, Madam Chair.

REDIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. Barkley, when the -- when the Tax Act was enacted, the Commission took some fairly quick action, didn't they, and directed utilities about how to react to that legislation; is that right?

A. They did. They issued an order on January 3rd of 2018, and set up a framework. And one of the most important things in that order was to set up a deferral for the difference between rates at 35 percent and rates at 21 percent. There were some other direction given to all companies, that was in M-100, Sub 148, where they gave guidance to all companies immediately, or virtually immediately, upon the enactment of the Tax Act.

Q. And that deferral you mentioned, that protected -- that preserved the economic impact of the tax reduction for the benefit of your -- for Piedmont's customers, right?

A. It did.

Q. Subject to a later determination about how and when -- the mechanics of how those dollars would be returned?

A. Yes. And even though it was a generic order, the Commission actually ordered rate changes associated with Federal Tax Act at varying times for varying companies. It was not across the board for Piedmont. That occurred on May 1, 2019, again, pursuant to Commission order, I believe, in G-9, Sub 731. Other companies had different times when they adjusted rates.

Q. So you have eliminated about six of my questions with that answer.

But the bottom line is, the Commission did not adopt a generic, across-the-board, as you say, answer for how to return excess deferred income taxes to customers, right?

A. That's right. And one of the things that they did in another case in North Carolina, I believe it was DEC, was four years for state taxes. And so it has -- the return of these various items has varied and it has been situational in many respects.

Q. And it's been addressed individually, right, by individual companies?

A. Yes. Guidance for everybody in the M-100, and then specific rulings in the company dockets.

Q. So we're in a rate case here. Explain to me the relationship between excess deferred income taxes being held as a regulatory liability and its effect on rate base.

A. So if they're held as a liability, then that would increase deferred income taxes, and that lowers rate base. As you return them to customers, then that inevitably raises the rate base upon which the company earns.

Q. So were the rates in the settlement, were they calculated with the amortization periods that were agreed to for unprotected EDIT in mind?

A. They were. And, you know, in the settlement, Mr. Jeffries, we did use a different methodology than I had recommended in my prefiled. I had recommended a rider. But for the purpose of settlement, we adopted an approach which was as recommended by Public Staff Witness Perry where she set up some annuitizations of these amounts. But the years upon which you do the arithmetic in Ms. Perry's schedule, it is very important. And so we did follow the years to set rates -- to answer your question, we follow the years to set rates as agreed to in the stipulation following the math as recommended by Witness Perry.

Q. All right.

MR. JEFFRIES: Thank you. I have no further questions.

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

Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Barkley, I want to ask you just a couple of questions about a different subject. I have -- about disconnections.

A. Yes, sir.

Q. Okay. I've got -- and you don't need to have this. Trust me, I'm not going to quiz you on specific numbers. I'm going to talk to you about it at a fairly high level, but I've got in front of me the results of the monthly reports the Company files in Docket M-100, Sub 61-A on residential disconnections.

When I look at those reports over a 10-year span going back to 2009, 2009 really was a peak year.

In the 10-year period, there were over 53,000 disconnections. And in the last, year 2018, there were just under 35,000. If I didn't have anything else in front of me, my own inference from that trend would be that it's basically due to improvements in the economy, recovery from the recession of '08, '09.

So my question really to you is, is there anything else that might account for that decline -- consistent decline over the 10-year period, such as changes in the way that Piedmont handles disconnections? Have you made any other policy changes or procedural changes that might be a factor in explaining that decline from over 53,000 to 32 to 35,000 a year?

A. Commissioner Clodfelter, I think a couple of responses for you there. The procedures are very similar. Many of the procedures upon which we disconnect are clearly articulated in Commission Rule R12, so we followed those in 2009, and we follow them today. There may be some small administrative differences, but I don't think that there has been a procedural difference. I think you cited the economy, which there was some testimony both given by myself and our Witness Hevert about improvements in the economy over the last 10 years.

I would also point also, I believe that the Commission had a question yesterday from Mr. Yoho around horizontal drilling and fracturing of -- as it relates to the supply of natural gas. And so our rates are considerably lower today than they were in 2009. It looks like our -- for the -- most of 2009, our benchmark commodity cost was around $6.50, and today it's less than $3. So I think the -- those advances and the incredible impact on price that the fracturing has brought about has been really good for customers and contributes to the statistics that you cited.

Q. That's helpful. Thank you for that. General improvement in the economy and declining price of gas, it's -- I just wanted to identify whether there were any policy or process changes inside the Company that might explain that, and I thank you for your answer.

A. Yes, sir.

Q. Second thing I observe about the statistics on that is that, year by year, from year to year, it appears that the disconnections, on a monthly basis, are lowest over the course of the year during the heating months: November, December, January, and February; and then they rise and reach a peak in May, June, and July.

Again, without any other information in front of me, other than that, I would assume from that that that's just the normal lag in the accumulation of the delinquency of the attempt to work with the customer on payment terms, but you're really not disconnecting as many people during the heating season as you are during the off seasons, the shoulder periods and the summer periods.

And again, my question to you is, is that an intentional sort of policy or internal practice, or is that just the normal process of accumulating delinquencies and working with customers trying to get them paid off? Is there anything else going on than that?

A. I think that's -- I think you have addressed it. I think it's the fact that -- the nature of our service is it's very seasonal, in terms of when the majority of the billings are done. And so I think maybe as you come into the heating season, a lot of the accounts are in better shape than they are as you move through January and February. And so then they're kind of accumulating as we work with them on deferred payment arrangements, they're accumulating balances that then need to be addressed.

And, obviously, disconnection is one of our last alternatives. We do not want to disconnect customers, and we work with them to channel them to Health and Human Services, to charities, to federal funds that are out there, everything that we can do for those that are willing to participate.

Q. Thank you for that too. Again, it's useful to observe that your fewest disconnections are during the heating season when people need the fuel the most, so that's actually a good observation from the data. That's all I have.

A. Yes, sir. Thank you.

COMMISSIONER BROWN-BLAND:

Chair Mitchell?

EXAMINATION BY CHAIR MITCHELL:

Q. Good morning, Mr. Barkley.

A. Good morning.

Q. Just a few questions for you. The Company's application proposed additional spending on conservation programs, and there is a term in the stipulation that settles on an amount that the Company will spend going forward. And my understanding is that the Company is not going to increase spending at this point in time on those programs. But here are my questions for you:

Can you talk to us about the programs that the Company currently has in place and just sort of give us a sense of what those programs are; and then, to the extent that you're in a position to do this, let us know what ideas or what plans the Company has for new programs or innovative programs that you-all might implement at some point in the future?

And let me just give you the reason for my question. My assumption is that, in proposing additional spending, you-all had some plans in mind, but help us, to the extent you can, understand what those are.

A. We did, and I think in my testimony I mentioned that they weren't fully developed. And I would also respond that I don't believe what's in the stipulation, and probably could pull it out and read it and the lawyers could help me interpret it. I don't think it means we can't spend more. It means that the stipulation didn't give us funds specifically for that. If we were to say we believe in this strongly enough to go ahead and spend the money, then it wouldn't be, per se, covered in rates. But the day after a rate case is approved by the Commission, many things change. So exactly, it's hard to color the dollars afterwards.

So we're not prohibited from doing more spending; we could do that. It's just that, for the purpose of settlement, it was agreed we wouldn't increase our billing rates above what was basically in the test period in the range of $1.2 million.

Hopefully that makes sense that, if we feel like an initiative needs to be pursued, we have the ability to do so, it's just not directly covered in rates at this point in time. So probably our primary program right now is rebates for high-efficiency equipment. Again, an incentive for something like a water heater, to purchase a high-efficiency model, and you would, upon providing the appropriate paperwork to the Company demonstrating what you had done, you would get a refund check to promote that behavior and get the customer to choose a high-efficiency option.

I think one of the things, in responding to sort of the latter part of your question, is what maybe would we be looking at. I think we've looked at maybe some conversations with builders to look at maybe promotion of efficiency at that level. Ours now are more with homeowners that are going for a second water heater or so forth, maybe not so much with the initial construction, communication with builders. That's something we need to look at. But just to briefly amplify, it has -- the low cost of natural gas, it comes back yet again, in response yesterday and then to Commissioner Clodfelter's question, it does make the passing of the test that needs to occur in order to show that this money is being beneficial to customers. Because, in the long run, whether it's immediate or over the long term, it will -- with your approval, it will be built in the rates. It can only be done so if it's an appropriate investment, if it has these various tests that are run, that it proves cost beneficial. So that's somewhat difficult with the low price of natural gas.

It may be a long way around of saying that the primary program now is around efficient equipment, and some of the thought process when we filed in April was around maybe getting a little closer and working with our builder contacts.

Q. Thank you, Mr. Barkley.

COMMISSIONER BROWN-BLAND: All right.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Barkley, to round out and flesh out the questions that the Commission had issued last week, and in some part because we trust your math better than -- at least better than mine, are you roughly aware of the percentage of Piedmont's residential customers that were disconnected for nonpayment between 2008 and 2018?

A. I do. Based on the fact that y'all issued that Document the other day, we did obtain that information. And so, in 2008, 46,341 disconnections were made. Some of those could have been to the same customer, but generally, I think the amount of disconnections and the amount of customers disconnected is roughly one-to-one. 46,341, that was of the total North Carolina residential customers, 0.65 percent.

In 2018, it was 35,163 out of slightly more than 8 million customers, yielding a percentage of 0.4 -- 0.44 percent. So the number is down approximately 10,000, and the percentage is down from basically 65 percent to 44 percent.

Q. All right. Thank you.

A. 0.44 percent, I'm sorry, I'm going to misspeak. Very small amount, but basically a third deduction.

Q. All right. Thank you for that. And -- let me see. Now, you provided some testimony regarding the

Company's margin decoupling tracker. And what we're looking at is, prior to the Commission authorizing the use of that margin decoupling tracker, did Piedmont have another mechanism in place to adjust bills for abnormal weather?

A. Yes.

Q. And what was that?

A. It was known as WNA, weather normalization adjustment.

Q. Can you tell us how it worked, and was there a deferred account mechanism involved in that?

A. That certainly was before my time with Piedmont, so I don't know all the specifics as to whether -- there are a couple of ways to do it, with the deferred account, as you mentioned, and also you can sort of make adjustments as you go. I'm not sure I have that particular detail. I'm sure -- I would imagine Ms. Powers would have that one, that particular detail as to how it worked, because she was with the Company, I believe, during the days of WNA.

But, regardless of whether we have that, I think there's a couple of ways you can administer a weather normalization adjustment, but the concept is the same. And as you might imagine, it would be, as you send out a billing cycle in the months -- let's say we're talking about January -- normally these things span from October through the end of March, so during when you have colder weather, different states have different periods, but you would look at the difference as you send a bill to a customer between the actual weather that occurred during that billing period, the 30-day cycle, and what would have been deemed normal in the last general rate case. If it was much colder than normal, then you would either immediately or later issue a refund to that customer, but -- because of the impact of weather. Were it much warmer than normal, then you would add a surcharge and either charge more or set up a receivable from customers, again, to track the difference between normal and actual weather temperature.

Q. All right. Thank you for that. Now, going back to the disconnects, does Piedmont get involved with -- or are you aware of the resources that the customers can use if, I think, to avoid disconnection or to get reconnected and ways that they might heat their homes when they are disconnected?

A. So let me address the first part of that first. So the things that -- I'm not frontline on this, Commissioner Brown-Bland, but I know a couple of things that are -- I believe that our call agents do as they're working with customers who are struggling. I think first is deferred payment arrangements. You'll pay a little bit at a time.

If that eventually doesn't pan out, I know there is a federally funded, low-income home energy assistance program, acronym of LIHEAP, that's available under certain circumstances. They send customers to the state Health and Human Services. In Charlotte, I'm aware of one charity, Crisis Assistance Ministry. I know that they work with our customers that are struggling to make payments. I'm sure there's a variety of charities across our state that perform a similar role. So those are some of the places that our team would reference customers that were struggling.

So then I think the second part of your question was, if someone is disconnected, how do they heat their home? That one, I think -- you know, I'm a little less familiar, but I think probably space heaters would be one of the things that they could use. I mean, we've had all kinds of things. Kerosene heaters, charcoal. You see this a lot when the power is out, people make bad choices on how to heat their home, and sometimes even with unfortunate results.

So, therefore, we try to keep this 0.44 percent number as low as possible. We certainly don't want to disconnect a customer, but we do follow the Commission's procedure and have to do so at times.

Q. Your reference to "unfortunate results" is a sort of a reference, is it not, to space heaters being a fire hazard or other forms, being carbon monoxide?

A. Exactly. Both of those can have -- you could have a carbon monoxide issue from improper heating decisions. You also could have a curtain or other -- something in the home to become on fire based on the use of space heaters.

Q. All right.

COMMISSIONER BROWN-BLAND: Are there questions on Commission's questions?

MR. JEFFRIES: Just one.

COMMISSIONER BROWN-BLAND: Go ahead, Mr. Jeffries.

FURTHER REDIRECT EXAMINATION BY MR. JEFFRIES:

Q. When you were discussing disconnects with Commissioner Brown-Bland, you made -- and you were comparing the percentages of disconnects in 2008 and 2018, I believe you misspoke and said that Piedmont had

800 million customers in North Carolina?

A. That was probably one of Mr. Yoho's marketing programs at one point. So if I said 800 million, it's 8 million. Approximately 8 million customers in North Carolina was the total count to use to get that percentage.

Q. 8 million.

A. Okay. That was -- all right. All right. Let me just calm down and do the math for you on this. That was the total for the 12-month period, and that's how the math was done to answer the Commission's question.

Q. Okay.

A. The number of disconnects based on the number of customers at the end of each month. I was going really fast there. So if you wanted the customer count, it would basically be 1/12 of that 8 million, which was -- and I'm sure you're interested, 674,274 customers at the end of the period.

Q. It's entirely possible that I'm the only one in the room that misunderstood what you were saying, but thank you for that clarification.

A. That's a lot of customers, I got to admit. We would love to have that many customers, but I apologize for misspeaking.

COMMISSIONER BROWN-BLAND: All right. Nothing further?

MR. JEFFRIES: That's all.

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

MS. HARROD: Commissioner Brown-Bland, could we move to have the Attorney General's Cross Exhibits Barkley 1 through 3 admitted into evidence?

COMMISSIONER BROWN-BLAND: All right. There being no objection, that motion is allowed and the exhibits will be received into evidence.

(Attorney General's Office Barkley Cross Examination Exhibits 1 through 3 were received into evidence.)

MR. JEFFRIES: Piedmont would also move that Mr. Barkley's prefiled exhibits marked and identified as Exhibits BPB-1 through BPB-3 be admitted into evidence.

COMMISSIONER BROWN-BLAND: That's perfectly balanced, three on each side. They will be received into evidence.

MR. JEFFRIES: Thank you.

(Exhibits BPB-1 through BPB-3 were received into evidence.)

COMMISSIONER BROWN-BLAND: Ms. Force?

MS. FORCE: We are getting ready to move to the next witness, but I have a request from Dr. Woolridge. Dr. Woolridge has a flight that he will miss that's coming up, and I wondered, if it's acceptable to the Company and the Commission, if he were to go next. That would be out of order, I realize, so.

MR. JEFFRIES: Piedmont doesn't have any problem with that.

COMMISSIONER BROWN-BLAND: And I believe CUCA is --

MR. PAGE: We have no objection to that.

COMMISSIONER BROWN-BLAND: All right. Mr. Barkley, you are excused, and you may step down. Thank you for your testimony.

MS. FORCE: Thank you very much.

COMMISSIONER BROWN-BLAND: And yes, Ms. Force, we can move to Dr. Woolridge.

J. RANDALL WOOLRIDGE,

having first been duly sworn, was examined

and testified as follows:

THE WITNESS: I very much appreciate allowing me to go ahead. Thank you.

DIRECT EXAMINATION BY MS. FORCE:

Q. Good morning, Dr. Woolridge. Would you please state your name and position for the record.

A. Yeah. My name is, initial J, Randall Woolridge, spelled W-O-O-L-R-I-D-G-E. I'm a professor of finance at the Pennsylvania State University.

Q. And on July 22, 2019, did you submit 106 pages of prefiled testimony, appendix A, and Exhibits JRW-1 through JRW-13?

A. I did.

Q. And was that testimony prepared by you or under your supervision?

A. Yes, it was.

Q. If you were to give that same testimony from the stand today, would your answers be the same?

A. Yes.

Q. And would you have any corrections to make?

A. There's a couple of corrections that Mr. Hevert pointed out that I'll just talk about my summary. It's in terms of when I took one of their exhibits and tried to do something with it, I did it wrong, so the numbers I had were incorrect, and Mr. Hevert corrected those.

Q. Okay. Thank you.

MS. FORCE: With that, we would ask that the 106 pages of testimony plus appendix A, plus Exhibit J or -- well, I guess we hold off on the exhibits -- be copied into the record.

COMMISSIONER BROWN-BLAND: That motion will be allowed. The testimony will be received into the record and treated as if given orally from the witness stand.

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

TESTIMONY OF J. RANDALL WOOLRIDGE, PH.D.

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

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

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

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

A: I have been asked by the North Carolina Attorney General's Office (AGO") to provide an overall fair rate of return or cost of capital recommendation for Piedmont Natural Gas Company, Inc. ("Piedmont" or "Company").[1]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND THE MAIN ISSUES THAT YOU WILL ADDRESS IN YOUR TESTIMONY.

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[1] In my testimony, I use the terms 'rate of return' and 'cost of capital' interchangeably. This is because the required rate of return of investors on a company's capital is the cost of capital.

1. My capital structure recommendation: Piedmont witness Sullivan has proposed a capital structure consisting of 0.82% short-term debt, 47.18% long-term debt, and 52.00% common equity. That is a higher common equity ratio than other gas distribution companies in the proxy group. I recommend adjusting Piedmont's proposed capital structure to use a common equity ratio of 50 percent, as that is more in line with the capital structures of the utilities in the proxy group as well as Piedmont's parent, Duke Energy. See Part V.

2. My ROE recommendation: I recommend authorizing a 9.0% rate of return on common equity (ROE). My analyses indicate that an ROE of between 7.60% and 8.70% is appropriate. My recommendation is 30 basis points higher than the range to reflect a small increase in risk associated with my adjustment of the proposed equity capital structure. See Part II.B.

3. My recommendation for the overall rate of return: These recommendations produce an overall rate of return for debt and equity capital of 6.76%. See Part II.B.

4. My alternative recommendation: I also provide an alternative recommendation which would apply if Piedmont's proposed 52% common equity capital structure is allowed. In that case, I recommend that the rate of return on equity be fixed at 8.70%, resulting in an overall rate of return of 6.69%. See Part II.B.

5. My cost of equity studies: I performed two studies using the same proxy group of natural gas utilities as was used by Piedmont's witness Hevert. I used a traditional constant-growth discounted cash flow (DCF) model, which estimates the cost of equity by summing the stock's dividend yield and the investors' expected long-

run growth rate for dividends per share. For the growth rate, I gave the most weight to analysts' projected earnings-per-share growth rates, but also considered multiple other growth rate measures. I also used the Capital Asset Pricing Model (CAPM). That approach requires an estimate of the risk-free interest rate, the "beta" (reflecting the risk particular to the particular companies used as comparable investments), and the market or equity risk premium (market risk premium). My estimate of the market risk premium is 5.50%, which factors in multiple approaches to estimating the market premium and uses results of many academic studies that are used by leading investment banks and consulting firms, and are consistent with estimates of surveys, forecasters, analysts, and corporate CFOs. See Part VI.

6. Factors that support the reasonableness of my recommendation:

a. Interest rates and capital costs remain at historically low levels despite forecasts for many years of higher interest rates.

b. The natural gas utility industry is a low-risk industry as measured by *Value Line* betas.

c. The S&P and Moody's ratings of A- and A3 show that Piedmont's investment risk is in line with the risk profile of the proxy group.

d. The authorized rates of return on common equity for natural gas utilities have declined over the years reflecting the lower interest rates and capital costs. See Part VI.C.

7. Piedmont's rate of return analyses: Piedmont's witness Mr. Hevert recommends a much higher rate of return on common equity of 10.75% due to multiple errors

that skew his analyses in an upward direction. The high ROE combined with Piedmont's proposed 52.0% common equity capital structure produce a 7.68% overall rate of return proposal.

8. The most significant errors that contribute to the unreasonableness of Mr. Hevert's analyses and recommendations:

a. Mr. Hevert assumes, without support, that interest rates and the cost of capital will increase. Yet, long-term interest rates and capital costs have not increased in any meaningful way even with the Federal Reserve's actions and the increase in short-term rates. As was explained in a 2015 Moody's article, the persistently low interest rates and the comprehensive suite of cost recovery mechanisms that are allowed for regulated gas and electric utilities ensure a low business risk profile and, as such, reductions in the rates of return authorized by regulators have not impaired their credit profiles or deterred them from raising record amounts of capital. [2] See Part VI C.

b. Mr. Hevert's Discounted Cash Flow analyses rely exclusively on overly optimistic and upwardly biased earnings per share (EPS) growth rate forecasts, without consideration of other measures of growth. For example, his growth factor relies on estimates for growth in future earnings per share for nine comparable natural gas utilities, including an estimate that the long-term rate of growth for one company is 25.5%, based on a *Value Line*

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[2] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

prediction for that growth rate during the next five years.[3] The 25.5% growth prediction follows periods when the company experienced annual rates of growth in earnings of *negative* 11.5% in the past ten years, and *negative* 22.0% in the past five years (i.e., it predicts a turn-around).[4] Obviously, 25.5% is not a realistic estimate of long term growth, and its impact distorts Mr. Hevert's estimate of the growth factor. Yet, that is not the only high growth estimate skewing Mr. Hevert's analyses. See Part VII.A.

c. Mr. Hevert's Capital Asset Pricing Model erroneously uses a too-high risk-free interest rate combined with an exaggerated range of equity market risk premiums. His range of market risk premiums of 10.65% to 13.77% reflect unrealistic assumptions about future long-term economic earnings growth and stock returns, assumptions that are out of line with the lower expected growth expected for our gross domestic product ("GDP"). To illustrate, consider how the expected earnings growth compares over time to the expected growth in GDP. If we use a 13.1% growth rate in earnings to predict what aggregate net income will be for S&P 500 companies in the year 2050, and compare that value to the value of nominal GDP in the United States. which is predicted to grow at a rate of 4.23%, then by 2050 the aggregate net income for the S&P 500 companies would make up 92% of our gross domestic product. Today, by comparison, net income makes up under 7% of our gross domestic product. Warren Buffet has observed that "you have to be wildly optimistic to believe

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[3] See Table 8, shown on page 72.

[4] See Table 9 shown on page73.

that corporate profits as a percent of GDP can, for any sustained period, hold much above 6%."[5] More details about errors in Mr. Hevert's CAPM results are discussed in Part VII.B.

d. Mr. Hevert's Alternative Risk Premium Model relies on inflated risk-free interest rates for his base yield and adds a risk premium that is factored using *authorized* rates of return (i.e., returns estimated by regulators in place of market-based data). As such, the risk premium is a gauge of regulatory commission behavior, not current investor requirements. See Part VII.C.

e. Mr. Hevert's Expected Earnings Approach compares earnings using the book value of equity rather than current stock values. This ignores capital market data about changes in investor rate of return requirements. As a result, the approach is circular, measuring estimates of the rate of return on equity based largely on regulatory determinations, rather than basing the estimates on current market data. See Part VII.D.

f. Mr. Hevert also suggests two other reasons for his high ROE recommendation, namely the riskiness of Piedmont relative to the proxy group, and the need to make an adjustment for "flotation costs," but those reasons lack merit as is discussed in Part VII.E.

g. With respect to economic conditions in North Carolina and in Piedmont's service territory, I conclude that the higher level of natural gas residential rates in North Carolina, coupled with a lower level of household income in

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[5] Carol Loomis, "Mr. Buffet on the Stock Market," *Fortune*, November 22, 1999. https://money.cnn.com/magazines/fortune/fortune_archive/1999/11/22/269071/.

the state and a higher level of unemployment in Piedmont's service territory suggest that affordability can be an issue for an essential utility service such as natural gas. See Part VIII.

h. Finally, Piedmont's overall rate of return request has a significant impact on its overall requested increase in revenues. Piedmont proposes to increase its overall annual operating revenues by $253,435,633, due in part to its proposal to increase its common equity ratio to 52.0% and increase its ROE to 10.60%. See Exhibit JRW-13, page 1 (which reflects Piedmont's Exhibit _(PKP-7 page 2)). On page 2 of Exhibit JRW-13, Piedmont's revenues increase proposal is shown again modified only to show the impact of my recommendation to reduce the common equity ratio to 50.0% and authorize an ROE of 9.0%. Without any other changes to Piedmont's proposal, the overall revenue increase would be reduced by $58 million per year to $195,468,893. The rate of return in Piedmont's proposal is not necessary to attract investors and is not just and reasonable. See Part VIII.

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. First, I provide a brief overview of what comprises a utility's rate of return and provide tables that present my recommendations. Second, I discuss the current capital market environment. Third, I select a proxy group of gas distribution companies for estimating the market cost of equity for Piedmont. Fourth, I present my recommendations for the Company's capital structure and debt cost rates. Fifth, I provide an overview of the concept of the cost of equity capital and then estimate the equity cost rate for Piedmont. Sixth, I critique the Company's rate of return analysis and testimony. Finally, I assess North Carolina's economic conditions and examine the impact of the Company's rate of return proposal on its overall revenue increase request. I have attached one appendix.

II. INTRODUCTION

A. Overview

Q. WHAT COMPRISES A UTILITY'S "RATE OF RETURN?"

A. A company's overall rate of return consists of three main categories: (1) capital structure (i.e., ratios of short-term debt, long-term debt, preferred stock and common equity); (2) cost rates for short-term debt, long-term debt, and preferred stock; and (3) common equity cost, otherwise known as ROE.

Q. WHAT IS A UTILITY'S ROE INTENDED TO REFLECT?

A. An ROE is most simply described as the allowed rate of profit for a regulated company. In a competitive market, a company's profit level is determined by a variety of factors, including the state of the economy, the degree of competition a company faces, the ease of entry into its markets, the existence of substitute or complementary products/services, the company's cost structure, the impact of technological changes, and the supply and demand for its services and/or products. For a regulated monopoly, the regulator determines the level of profit available to the utility. The United States Supreme Court established the guiding principles for establishing an appropriate level of profitability for regulated public utilities in two cases: (1) *Bluefield*[6] and (2) *Hope*.[7] In those cases, the Court recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on investments with similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain the company's credit and to attract capital.

Thus, the appropriate ROE for a regulated utility requires determining the market-based cost of capital. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. The purpose of the economic models and formulas in cost of capital testimony (including those presented later in my testimony) is to estimate, using the market data of similar-risk firms, the rate of return equity investors require for that risk-class of firms in order to set an appropriate ROE for a regulated firm.

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[6] *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923) ("Bluefield").

[7] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944) ("Hope").

B. Table of Recommendations

Q. PLEASE PROVIDE YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE MARKET-BASED RATE OF RETURN FOR PIEDMONT.

A. My rate of return recommendation is provided in Exhibit JRW-1. Panel A in Exhibit JRW-1 shows my primary recommendation, which adjusts Piedmont's proposed equity capital structure to 50% and establishes a 9.00% rate of return on equity:

Table 1
Primary Rate of Return Recommendation

Capital Source	Capitalization Ratios*	Cost Rate	Weighted Cost Rate
Short-Term Debt	0.85%	2.82%	0.02%
Long-Term Debt	49.15%	4.55%	2.24%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	100.00%		6.76%

Q. PLEASE PROVIDE YOUR ALTERNATIVE RATE OF RETURN RECOMMENDATION FOR PIEDMONT.

A. My alternative rate of return recommendation is summarized in Table 2 and Panel B of Exhibit JRW-1.

Table 2
AG's Alternative Rate of Return Recommendation

Capital Source	Capitalization Ratios*	Cost Rate	Weighted Cost Rate
Short-Term Debt	0.82%	2.82%	0.02%
Long-Term Debt	47.18%	4.55%	2.15%
Common Equity	52.00%	8.70%	4.52%
Total Capitalization	100.00%		6.69%

III. CURRENT CAPITAL MARKET CONDITIONS AND AUTHORIZED ROES

Q. IS IT APPROPRIATE TO SET THE AUTHORIZED RATE OF RETURN BASED ON CURRENT INDICATORS OF MARKET-COST RATES, OR SHOULD THE COMMISSION ADJUST THE RATE BASED ON MR. HEVERT'S FORECASTS OF HIGHER INTEREST RATES AND CAPITAL COSTS?

A. I suggest that the Commission set an equity cost rate based on current indicators of market-cost rates and not speculate on the future direction of interest rates.

Economists have been predicting that interest rates would be going up for a decade, and they consistently have been wrong. For example, after the announcement of the end of the Quantitative Easing III ("QE III") program in 2014, all the economists in Bloomberg's interest rate survey forecasted interest rates would increase in 2014, and 100% of the economists were wrong. According to the *Market Watch* article:[8]

> The survey of economists' yield projections is generally skewed toward rising rates — only a few times since early 2009 have a majority of respondents to the Bloomberg survey thought rates would fall. But the unanimity of the rising rate forecasts in the spring was a stark reminder of how one-sided market views can become. It also teaches us that economists

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[8] Ben Eisen, "Yes, 100% of economists were dead wrong about yields, *Market Watch*," October 22, 2014. Perhaps reflecting this fact, *Bloomberg* reported that the Federal Reserve Bank of New York has stopped using the interest rate estimates of professional forecasters in the Bank's interest rate model due to the unreliability of those interest rate forecasts. See Susanne Walker and Liz Capo McCormick, "Unstoppable $100 Trillion Bond Market Renders Models Useless," *Bloomberg.com* (June 2, 2014). http://www.bloomberg.com/news/2014-06-01/the-unstoppable-100-trillion-bond-market-renders-models-useless.html.

can be universally wrong.

Two other financial publications produced studies on how economists consistently predict higher interest rates, and yet they too, have been wrong. The first publication, entitled "How Interest Rates Keep Making People on Wall Street Look Like Fools," evaluated economists' forecasts for the yield on 10-year Treasury bonds at the beginning of the year for the last ten years.[9] The results demonstrated that economists consistently predict that interest rates will go higher, and interest rates have not fulfilled those predictions.

The second study tracked economists' forecasts for the yield on 10-year Treasury bonds on an ongoing basis from 2010 until 2015.[10] The study, entitled "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," indicates that economists are continually forecasting that interest rates are going up, yet they do not. Indeed, as Bloomberg has reported, economists' continued failure in forecasting increasing interest rates has caused the Federal Reserve Bank of New York to stop using the interest-rate estimates of professional forecasters in the Bank's interest-rate model due to the unreliability of those interest-rate forecasts.[11]

Obviously, investors are aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. If investors were

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[9] Joe Weisenthal, "How Interest Rates Keep Making People on Wall Street Look Like Fools," Bloomberg.com, March 16, 2015. http://www.bloomberg.com/news/articles/2015-03-16/how-interest-rates-keep-making-people-on-wall-street-look-like-fools.

[10] Akin Oyedele, "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," *Business Insider*, July 18, 2015. http://www.businessinsider.com/interest-rate-forecasts-are-wrong-most-of-the-time-2015-7.

[11] "*Market Watch*," October 22, 2014.

expecting interest rates to suddenly increase, thereby producing higher yields and negative returns, they would not be buying long-term Treasury bonds or utility stocks at their current yields. For example, consider a utility that pays a dividend of $2.00 with a stock price of $50.00. That produces a current dividend yield of 4.0%. If the stock price goes up to $80, that would produce a dividend yield of 2.5%, a reduction in the yield. If, on the other hand, investors were to require an increase in the dividend yield due to forecasts of higher interest rates as Mr. Hevert suggests, then the price of the utility stock would decline. In the example above where the dividend amount is $2.00, and higher return requirements led the dividend yield to increase from 4.0% to 5.0% in the next year, the stock price would have to decline from $50 to $40, which would be a -20% return on the stock. Obviously, investors would not buy the utility stock with an expected return of -20% due to higher dividend yield requirements.

In sum, the Commission should set the equity cost rate based on current indicators of market-cost rates without speculating about the future direction of interest rates. I am not aware of any study of changes in interest rates that suggests one forecasting service is consistently better than others or that interest-rate forecasts are consistently better than just assuming the current interest rate will be the rate in the future. As discussed above, investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher dividend yields and negative stock returns.

Q. HAVE THE FEDERAL RESERVE'S DECISIONS TO RAISE THE FEDERAL FUNDS RATE IN RECENT YEARS RESULTED IN

INCREASES IN LONG TERM INTEREST RATES AND CAPITAL COSTS?

A. No. Long term interest rates have not increased even as the Federal Reserve has increased its target rate for federal funds.

On December 16, 2015, the Federal Reserve increased its target rate for federal funds from 0.25 to 0.50 percent.[12] This increase came after the rate was kept in the 0.00 to 0.25 percent range for over five years in order to spur economic growth in the wake of the financial crisis associated with the Great Recession. As the economy has improved, with lower unemployment, and steady but slow GDP growth, the Federal Reserve has increased the target federal funds rate on eight additional occasions: December 2016; March, June, December of 2017; and March, June, September, and December of 2018.

Figure 1, below, shows the yield on 30-year Treasury bonds over the period of 2015-2019. I have highlighted the dates in which the Federal Reserve increased the federal funds rate. The 30-year Treasury yield hit its lowest point in the 2015 – 2016 timeframe in the summer of 2016 and subsequently increased with improvements in the economy. Then came November 8, 2016, and financial markets moved significantly in the wake of the results in the U.S. presidential election. The stock market gained more than 10% and the 30-year Treasury yield increased about 50 basis points to 3.2% by year-end 2016. However, over the past three years, even as the Federal Reserve has increased the federal funds rate, the

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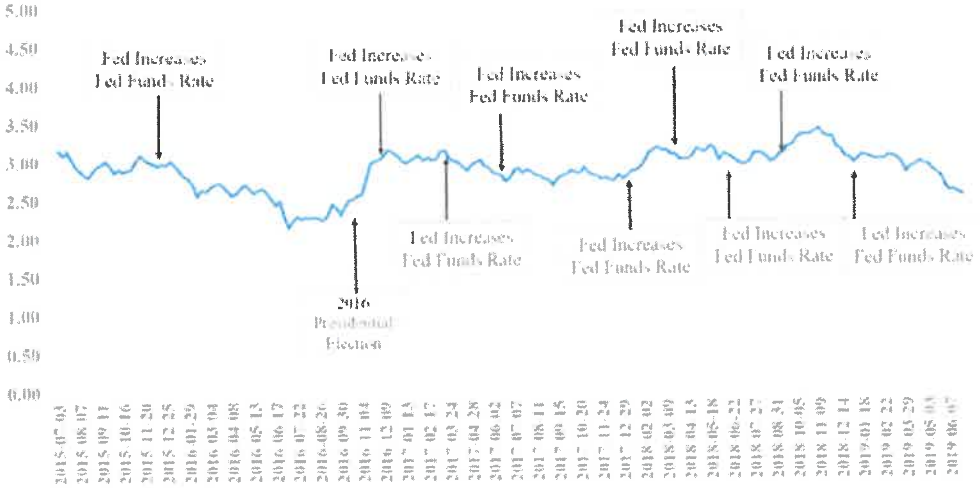
[12] The federal funds rate is set by the Federal Reserve and is the borrowing rate applicable to the most creditworthy financial institutions when they borrow and lend funds overnight to each other.

yield on thirty-year bonds has remained in the 2.5% to 3.3% range.

Figure 1
Thirty-Year Treasury Yield and Federal Reserve Fed Funds Rate Increases
2015-2019



Q. WHY HAVE LONG-TERM TREASURY YIELDS REMAINED IN THE 3.0% RANGE DESPITE THE FEDERAL RESERVE INCREASING SHORT-TERM RATES?

A. Whereas the Federal Reserve can directly affect short-term rates by adjustments to the federal funds rate, long-term rates are primarily driven by expected economic growth and inflation.[13] The relationship between short- and long-term rates is normally evaluated using the yield curve. The yield curve depicts the relationship between the yield-to-maturity and the time-to-maturity for U.S. Treasury bills, notes, and bonds. Figure 2, below, shows the yield curve on a semi-

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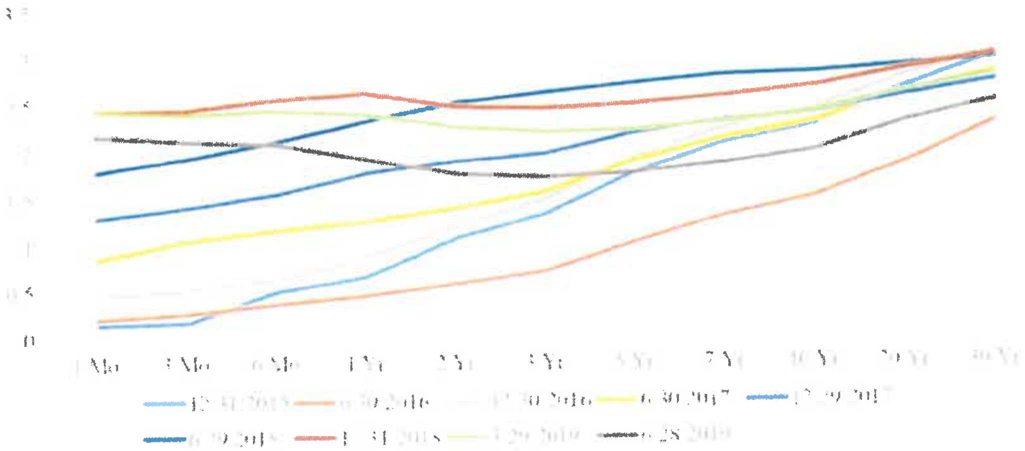
[13] Whereas economic growth picked up in 2018, partly in response to the personal and corporate tax cuts, projected real GDP growth for 2019 and beyond remains in the 2.0% to 2.5% range. In addition, inflation remains low and is also in the 2.0% to 2.5% range.

annual basis since the Federal Reserve started increasing the federal funds rate at the end of 2015. It shows that, except for mid-year 2016, when interest rates dipped to very low levels, the 30-year Treasury yield has remained in the 2.8%-3.3% range despite the fact that short-term rates have increased from near 0.0% to about 2.50%. As such, long-term interest rates and capital costs have not increased in any meaningful way even with the Federal Reserve's actions and the increase in short-term rates.

Figure 2
Semi-Annual Yield Curves
2015-2019

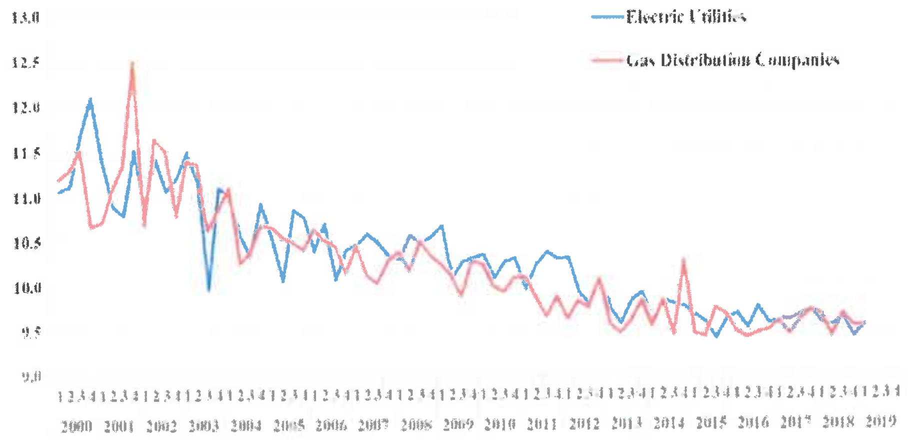


Date Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2019.

Q. PLEASE DISCUSS THE TREND IN AUTHORIZED RETURN ON EQUITY FOR ELECTRIC AND GAS COMPANIES.

A. Over the past five years, with the historically low interest rates and capital costs, authorized ROEs for electric utility and gas distribution companies have slowly declined to reflect the low capital cost environment. In Figure 3, below, I have graphed the quarterly authorized ROEs for electric and gas companies from 2000 to 2018. There is a clear downward trend in the data. On an annual basis, these authorized ROEs for gas distribution companies have largely declined from 9.94% in 2012, to 9.68% in 2013, 9.78% in 2014, 9.60% in 2015, 9.50% in 2016, 9.72% in 2017, 9.59% in 2018, and 9.55% in the first quarter of 2019. The authorized ROEs for electric utilities have declined from an average of 10.01% in 2012, 9.8% in 2013, 9.76% in 2014, 9.58% in 2015, 9.60%, and 9.68% in 2017, 9.56% in 2018, and 9.57% in the first quarter of 2019, according to Regulatory Research Associates.[14]

Figure 3
Authorized ROEs for Electric Utility and Gas Distribution Companies
2000-2019



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[14] *Regulatory Focus*, Regulatory Research Associates, 2019.

IV. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR PIEDMONT.

A. To develop a fair rate of return recommendation for the Company (market cost of equity), I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held gas distribution companies.

Q. PLEASE DESCRIBE YOUR PROXY GROUP OF GAS DISTRIBUTION COMPANIES.

A. This Gas Proxy Group consists of eight natural gas distribution companies. The companies include Atmos Energy, Chesapeake Utilities, Inc. New Jersey Resources, Northwest Natural Gas Company, One Gas, Inc., South Jersey Industries, Southwest Gas, and Spire, Inc. This is the same group used by Mr. Hevert.

Summary financial statistics for the Gas Proxy Group are listed on page 1 of Exhibit JRW-2. The median operating revenues and net plant among members of the Gas Proxy Group are $1,640.2 million and $3,182.7 million, respectively. On average, the group receives 69% of revenues from regulated gas operations, has an "A-" average issuer credit rating from S&P, a median common equity ratio of 47.1%, and a median earned return on common equity of 9.7%.

Q. HOW DOES THE INVESTMENT RISK OF THE COMPANY COMPARE TO THAT OF THE GAS PROXY GROUP?

A. I believe that bond ratings provide a good assessment of the investment risk of a company. The S&P and Moody's issuer credit ratings for Piedmont are A- and A3, respectively. These are in line with those of the companies in the gas proxy group. As such, I believe that the investment risk of Piedmont is similar to the average of the proxy group.

Q. PLEASE DISCUSS THE INVESTMENT RISK OF THE GAS PROXY GROUP AS MEASURED BY THE RISK METRICS PUBLISHED BY *VALUE LINE*?

A. On page 2 of Exhibit JRW-2, I show the riskiness of the Gas Proxy Group using five different risk measures from *Value Line*. These measures include Beta, Financial Strength, Safety, Earnings Predictability, and Stock Price Stability.[15] The comparisons of the risk measures include Beta (0.68), Financial Strength (A), Safety (1.8), Earnings Predictability (71), and Stock Price Stability (88). In my opinion, these risk measures indicate that the group's investment risk is relatively low.

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[15] These metrics are defined on page 3 of Exhibit JRW-2.

V. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. PLEASE DESCRIBE PIEDMONT'S PROPOSED CAPITAL STRUCTURE AND SENIOR CAPITAL COST RATES.

A. Piedmont has proposed a capital structure consisting of 0.82% short-term debt, 47.18% long-term debt, and 52.00% common equity. Piedmont has proposed short-term and long-term debt cost rates of 2.82% and 4.55%.

Q. HOW DO PIEDMONT'S PROPOSED CAPITAL STRUCTURE RATIOS COMPARE TO THE AVERAGE CAPITALIZATION RATIOS FOR COMPANIES IN THE GAS PROXY GROUP?

A. Piedmont's proposed capital structure ratios include a common equity ratio of 52.00%. As shown in Panel B of Exhibit JRW-3, the average quarterly common equity ratio for the Gas Proxy Group in fiscal year 2018 was 46.75%. As such, Piedmont is proposing a capital structure that includes much more common equity in financing its gas operations than the average of the proxy group.

Q. HOW DO PIEDMONT'S PROPOSED CAPITAL STRUCTURE RATIOS COMPARE TO ITS RECENT CAPITALIZATION RATIOS AS WELL AS TO THOSE OF ITS PARENT, DUKE ENERGY CORPORATION?

A. Panel C of Exhibit JRW-3 provides Piedmont's average quarterly capitalization ratio over the 2018-19 time period. The quarterly data are provided on page 2 of Exhibit JRW-3. The company's average capitalization ratios over the 2018-19 time period have been 9.6% short-term debt, 43.3% long-term debt, and 48.10% common equity. Panel C of Exhibit JRW-3 also provides Duke Energy Corporation's average quarterly capitalization ratio over the 2018-19 time period. Duke's average capitalization ratios over the 2018-19 time period have been 6.3% short-term debt, 50.6% long-term debt, and 42.9% common equity.

As a result, the Company's proposed capital structure includes a higher common equity ratio (52.00%) than it has had in recent years and is much higher than common equity ratio of its parent, Duke Energy Corporation.

Q. PLEASE DISCUSS THE ISSUE OF PUBLIC UTILITY HOLDING COMPANIES SUCH AS DUKE ENERGY USING DEBT TO FINANCE THE EQUITY IN SUBSIDIARIES SUCH AS THE COMPANY.

A. Moody's published an article on the use of low-cost debt financing by public utility holding companies to increase their ROEs. The summary observations included the following: [16]

> US utilities use leverage at the holding-company level to invest in other businesses, make acquisitions and earn higher returns on equity. In some cases, an increase in leverage at the parent can hurt the credit profiles of its regulated subsidiaries.

This financial strategy has traditionally been known as double leverage. Moody's defined double leverage in the following way: [17]

> Double leverage is a financial strategy whereby the parent raises debt but downstreams the proceeds to its operating subsidiary, likely in the form of

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[16] Moody's Investors' Service, "High Leverage at the Parent Often Hurts the Whole Family," May 11, 2015, p.1.

[17] *Ibid.* p. 5.

> an equity investment. Therefore, the subsidiary's operations are financed by debt raised at the subsidiary level and by debt financed at the holding-company level. In this way, the subsidiary's equity is leveraged twice, once with the subsidiary debt and once with the holding-company debt. In a simple operating-company / holding-company structure, this practice results in a consolidated debt-to-capitalization ratio that is higher at the parent than at the subsidiary because of the additional debt at the parent.

Moody's goes on to discuss the potential risk to utilities of the strategy, and specifically notes that regulators could take it into consideration in setting authorized ROEs.[18]

> **"Double leverage" drives returns for some utilities but could pose risks down the road.** The use of double leverage, a long-standing practice whereby a holding company takes on debt and downstreams the proceeds to an operating subsidiary as equity, could pose risks down the road if regulators were to ascribe the debt at the parent level to the subsidiaries or adjust the authorized return on capital.

Q. PLEASE DISCUSS THE SIGNIFICANCE OF THE AMOUNT OF EQUITY THAT IS INCLUDED IN A UTILITY'S CAPITAL STRUCTURE.

A. A utility's decision as to the amount of equity capital it will incorporate into its capital structure involves fundamental trade-offs relating to the amount of financial risk the firm carries, the overall revenue requirements its customers are required to bear through the rates they pay, and the return on equity that investors will require.

Q. PLEASE DISCUSS A UTILITY'S DECISION TO USE DEBT VERSUS EQUITY TO MEET ITS CAPITAL NEEDS.

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[18] *Ibid.* p. 1.

A. Utilities satisfy their capital needs through a mix of equity and debt. Because equity capital is more expensive than debt, the issuance of debt enables a utility to raise more capital for a given commitment of dollars than it could raise with just equity. Debt is, therefore, a means of "leveraging" capital dollars. However, as the amount of debt in the capital structure increases, financial risk increases and the risk of the utility, as perceived by equity investors also increases. Significantly for this case, the converse is also true. As the amount of debt in the capital structure decreases, the financial risk decreases. The required return on equity capital is a function of the amount of overall risk that investors perceive, including financial risk in the form of debt.

Q. WHY IS THIS RELATIONSHIP IMPORTANT TO THE UTILITY'S CUSTOMERS?

A. Just as there is a direct correlation between the utility's authorized return on equity and the utility's revenue requirements (the higher the return, the greater the revenue requirement), there is a direct correlation between the amount of equity in the capital structure and the revenue requirements that customers are called on to bear. Again, equity capital is more expensive than debt. Not only does equity command a higher cost rate, it also adds more to the income tax burden that ratepayers are required to pay through rates. As the equity ratio increases, the utility's revenue requirements increase and the rates paid by customers increase. If the proportion of equity is too high, rates will be higher than they need to be. For this reason, the utility's management should pursue a capital acquisition strategy that results in the proper balance in the capital structure.

Q. HOW HAVE UTILITIES TYPICALLY STRUCK THIS BALANCE?

A. Due to regulation and the essential nature of its output, a regulated utility is exposed to less business risk than other companies that are not regulated. This means that a utility can reasonably carry relatively more debt in its capital structure than can most unregulated companies. Thus, a utility should take appropriate advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements.

Q. GIVEN THAT PIEDMONT HAS PROPOSED AN EQUITY RATIO THAT IS HIGHER THAN (1) THE AVERAGE COMMON EQUITY RATIO OF MR. HEVERT'S PROXY GROUP, (2) THE AVERAGE AUTHORIZED COMMON EQUITY RATIO FOR US GAS COMPANIES, AND (3) ITS OWN COMMON EQUITY RATIO AS WELL AS THE COMMON EQUITY RATIO OF ITS PARENT COMPANY, WHAT SHOULD THE COMMISSION DO IN THIS RATEMAKING PROCEEDING?

A. When a regulated utility's actual capital structure contains a high equity ratio, the options are: (1) to impute a more reasonable capital structure that is comparable to the average of the proxy group used to determine the cost of equity and to reflect the imputed capital structure in revenue requirements; or (2) to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a common equity cost rate lower than that of the proxy group.

Q. PLEASE ELABORATE ON THIS "DOWNWARD IMPACT."

A. As I stated earlier, there is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. A relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. Stated differently, a utility cannot expect to "have it both ways." Specifically, a utility cannot maintain an unusually high equity ratio and not expect to have the resulting lower risk reflected in its authorized return on equity. The fundamental relationship between lower risk and the appropriate authorized return should not be ignored.

Q. GIVEN THIS DISCUSSION, PLEASE DISCUSS YOUR PRIMARY CAPITAL STRUCTURE RECOMMENDATION FOR PIEDMONT?

A. My primary capital structure recommendation is presented in Panel C of Exhibit JRW-3. As previously noted, Piedmont's proposed capital structure consists of more common equity and less financial risk than any of the other proxy gas companies. Therefore, in my primary rate of return recommendation, I am proposing a capital structure that includes a common equity ratio of 50.0%. This capital structure includes a common equity ratio that is about half way between Piedmont's proposed capital structure of 52.0% and the average common equity ratio of the proxy group of 46.75%. As shown in Table 3 and Panel C of Exhibit JRW-3, in this capital structure, I have grossed up the percentage amounts of short-term and long-term debt and preferred stock so that they collectively total 50.0% and reduced the amount of common equity from 52.0% to 50.0%.

Table 3
Primary Capital Structure Recommendation

	Piedmont Proposed	Adjustment	AG Proposed	Cost
Short-Term Debt	**0.82%**	**1.041667**	**0.85%**	**2.82%**
Long-Term Debt	**47.18%**	**1.041667**	**49.15%**	**4.55%**
Common Equity	**52.00%**	**0.961538**	**50.00%**	
Total Capital	**100.00%**		**100.00%**	

Q. WHAT IS THE CAPITAL STRUCTURE IN YOUR ALTERNATIVE RATE OF RETURN RECOMMENDATION?

A. In my alternative rate of return recommendation, I am using Piedmont' proposed capital structure which consists of 0.82% short-term debt, 47.18% long-term debt, and 52.00% common equity. I am also using Piedmont's proposed short-term and long-term debt cost rates of 2.82% and 4.55%.

Table 4
Alternative Capital Structure Recommendation

	Percent of Total	Cost
Short-Term Debt	**0.82%**	**2.82%**
Long-Term Debt	47.18%	4.55%
Common Equity	**52.00%**	
Total Capital	**100.00%**	

Q. DO YOU BELIEVE THAT YOUR PROPOSED 50% EQUITY CAPITAL STRUCTURE IS FAIR TO PIEDMONT?

A. Yes, for two reasons: (1) It includes a common equity ratio that is higher than the average common equity ratio for the Gas Proxy Group in 2018 and therefore affords Piedmont with more common equity and less financial risk than other gas distribution companies: and (2) according to Regulatory Research Associates, the average authorized common equity ratio for gas-distribution companies in calendar year 2018 was 50.09%.[19]

VI. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and the economic benefit to society from avoiding duplication of these services and the construction of utility infrastructure facilities, many public utilities are monopolies. Because of the lack of competition and the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, sufficient

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[19] *Regulatory Focus*, Regulatory Research Associates, (2019).

to meet the operating and capital costs of the utility, *i.e.*, provide an adequate return on capital to attract investors.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of a company or firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.

In a competitive market, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of those required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value. [20]

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[20] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1986), p.3.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN ROE AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity– should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book< 1*[21]

To assess the relationship by industry, as suggested above, I performed a regression study between estimated ROE and market-to-book ratios using natural gas distribution and electric utility companies. I used all companies in these two industries that are covered by *Value Line* and have estimated ROE and market-to-

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[21] Benjamin Esty, "Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

book ratio data. The results are presented in Exhibit JRW-4. The average R-square is 0.50.[22] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities. Given that the market-to-book ratios have been above 1.0 for a number of years, this also demonstrates that utilities have been earnings ROEs above the cost of equity capital for many years.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-5 provides indicators of public utility equity cost rates over the past decade.

Page 1 shows the yields on long-term A-rated public utility bonds. These yields decreased from 2000 until 2003, and then hovered in the 5.50%-6.50% range from mid-2003 until mid-2008. These yields peaked in November 2008 at 7.75% during the Great Recession. These yields have generally declined since then, dropping below 4.0% on four occasions - in mid-2013, in the first quarter of 2015, in the summer of 2016, and in late 2017. These yields increased in 2018 but have fallen back to 4.0% in 2019.

Page 2 of Exhibit JRW-5 provides the dividend yields for the companies in the Gas Proxy Group over the past seventeen years. The dividend yields for the gas group declined from 5.8% to 3.1% between the years 2000 to 2007 due to

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[22] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

higher gas company stock prices, increased to about 4.0% in 2009 during the financial crisis, and have declined steadily since that time due to higher utility stock valuations. The average dividend yield was 2.70% in 2017 and 2018.

Average earned returns on common equity and market-to-book ratios for gas utilities are on page 3 of Exhibit JRW-5. For the gas group, earned returns on common equity have been in the range of 9.0% to 12.0% over these years. Over the past decade, the earned ROEs have declined from the 12.0% range to about 9.0%. The average market-to-book ratios for this group, which were about 1.25X in 2000 have increased to over 2.00X in 2017 and 2018. This means that, for at least the last decade, returns on common equity have been greater than the cost of capital, or more than necessary to meet investors' required returns. This also means that customers have been paying more than necessary to support an appropriate profit level for regulated utilities.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business risk and financial risk.

Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF UTILITIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Exhibit JRW-6 provides an assessment of investment risk for 97 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. Beta is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. According to the *Value Line Investment Survey*, the average betas for electric, gas, and water utility companies are 0.60, 0.67, and 0.70, respectively.[23] As such, the cost of equity for utilities is the lowest of all industries in the U.S. based on modern capital market theory.

Q. WHAT IS THE COST OF COMMON EQUITY CAPITAL?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return requirement of the stockholder should be commensurate with the return requirement on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

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[23] The beta for the *Value Line* Electric Utilities is the simple average of *Value Line*'s Electric East (0.55), Central (0.63), and West (0.62) group betas.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR PIEDMONT?

A. I rely primarily on the discounted cash flow ("DCF") model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a capital asset pricing model ("CAPM") study; however. I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. Discounted Cash Flow Analysis

Q. PLEASE DESCRIBE IN SIMPLE TERMS HOW A DISCOUNTED CASH FLOW ANALYSIS IS CALCULATED.

A. Simply put, a constant growth DCF measures the cost of common equity based on the sum of the dividend yield plus the expected rate of growth of dividends for comparable companies.

Q. PLEASE DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are presented in Exhibit JRW-7, Page 1 of 2. This model presumes that a company's dividend payout initially progresses through a growth stage, then proceeds through a transition stage, and finally assumes a maturity (or steady-state) stage. The dividend-payment stage of a firm depends on the profitability of its internal investments which, in turn, is largely a function of the life cycle of the product or service.

1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and an abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by unusually high earnings, leading to a decline in the growth rate.

2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment

opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually, the company reaches a position where its new investment opportunities offer, on average, only slightly attractive ROEs. At that time, its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

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

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for "k" in the above expression to obtain the following:

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

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH VERSION OF THE DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the maturity or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The appropriate DCF valuation procedure for companies in the maturity stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). The dividend yield can be precisely measured at any point in time; however, it tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. WHAT DIVIDEND YIELDS HAVE YOU REVIEWED?

A. I have calculated the dividend yields for the companies in the proxy group using the current annual dividend and 30-day, 90-day, and 180-day average stock prices. These dividend yields are provided in page 2 of Exhibit JRW-8. For the Gas Proxy Group, the median dividend yields using the 30-day, 90-day, and 180-day average stock prices range from 2.4% to 2.6%. I am using the 2.60% as the dividend yield for the Gas Proxy Group.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[24]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield that is computed based upon presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR DO YOU USE FOR YOUR DIVIDEND YIELD?

A. I adjust the dividend yield by one-half (1/2) of the expected growth so as to reflect growth over the coming year. The DCF equity cost rate ("K") is computed as:

$$K = [(D/P) * (1 + 0.5g)] + g$$

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL

A. There is debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors'

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[24] Federal Communications Commission, Docket No. 79-05, *Petition for Modification of Prescribed Rate of Return*, Direct Testimony of Myron J. Gordon and Lawrence I. Gould, p. 62 (Apr. 1980).

expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book-value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUP?

A. I have analyzed a number of measures of growth for companies in the proxy Group. I reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters, and Zacks. These services solicit three-to-five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates per share for earnings, dividends, and book values (EPS, DPS, and BVPS) are readily available to investors and are presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations, due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-term earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE DISCUSS THE SERVICES THAT PROVIDE ANALYSTS' EPS FORECASTS.

A. Analysts' forecasts for earnings per share for companies are collected and published by a number of different investment information services, including Institutional Brokers Estimate System ("I/B/E/S"), Bloomberg, FactSet, Zacks, First Call, and

Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. Bloomberg, FactSet, and Zacks publish their own set of analysts' EPS forecasts for companies. These services do not reveal: (1) the analysts who are solicited for forecasts; or (2) the identity of the analysts who actually provide the EPS forecasts that are used in the compilations published by the services. I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. Thompson Reuters and Zacks do provide limited EPS forecast data free-of-charge on the Internet. Yahoo Finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. The Reuters website (www.reuters.com) also publishes EPS forecasts from Thompson Reuters, but with more detail. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zacks estimates are also available on other websites, such as msn.money (http://money.msn.com).

Q. PLEASE PROVIDE AN EXAMPLE OF THESE EPS FORECASTS.

A. The following example provides the earnings per share forecasts compiled by Reuters for Atmos Energy Corp. (stock symbol "ATO"). The figures are provided on page 2 of Exhibit JRW-7. Line one shows one analysts' EPS estimate for the quarter ending June 30, 2019. The mean, high, and low estimates are $0.72, $0.87, and $0.66, respectively. The second line shows seven analysts' quarterly EPS estimates for the quarter ending September 30, 2019 with mean, high, and low estimates of 0.50, $0.65, and $0.45. Line 3 shows the results for fiscal year ending

September 30, 2019: $4.33 (mean), $4.39 (high), and $4.27 (low). The fourth line shows seven analysts' quarterly EPS estimates for the fiscal year ending September 30, 2020: $4.59 (mean), $4.66 (high), and $4.45 (low). The quarterly and annual EPS forecasts in lines one through four are expressed in dollars and cents. As in the Atmos case shown in Exhibit JRW-7, it is common for more analysts to provide estimates of annual EPS as opposed to quarterly EPS. The bottom line shows the projected long-term EPS growth rate, which is expressed as a percentage. For Atmos, two analysts have provided a long-term EPS growth rate forecast, with mean, high, and low growth rates of 6.45%, 6.90%, and 6.00%, respectively.

Q. WHICH OF THESE EPS FORECASTS IS USED IN DEVELOPING A DCF GROWTH RATE?

A. The Discounted Cash Flow growth rate is the long-term projected growth rate per share in earnings, dividends, and book values. Therefore, in developing an equity cost rate using the DCF model, the projected long-term growth rate is the projection used in the DCF model.

Q. WHY DO YOU NOT RELY EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. There are several issues with using the earnings per share growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the

DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long term, dividends and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, a 2011 study by Lacina, Lee, and Xu has shown that analysts' long-term earnings growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[25] Employing data over a 20-year period, these authors demonstrate that using the most recent year's EPS figure to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' long-term earnings growth rate forecasts. In the authors' opinion, these study results indicate that analysts' long-term earnings growth rate forecasts should be used with caution as inputs for valuation and cost of capital purposes. Finally, and most significantly, it is well known that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years.[26] Hence, using these

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[25] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting* Vol. 8, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[26] The studies that demonstrate analysts' long-term EPS forecasts are overly-optimistic and upwardly biased include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* pp. 643–684, (2003); M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8)*, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101; and Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Easton and Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[27]

Q. IS IT YOUR OPINION THAT STOCK PRICES REFLECT THE UPWARD BIAS IN THE EPS GROWTH RATE FORECASTS?

A. Yes, I do believe that investors are well aware of the bias in analysts' EPS growth rate forecasts and stock prices therefore reflect the upward bias. In other words, given the research on analysts' EPS growth rate forecasts, I believe that investors know that analysts' EPS growth rate forecasts are biased and take this into account when pricing stocks

Q. HOW DOES THAT AFFECT THE USE OF THESE FORECASTS IN A DCF EQUITY COST RATE STUDY?

A. According to the DCF model, the equity cost rate is a function of the dividend yield and expected growth rate. The dividend yield takes into account the impact of investor expectations based on changes in stock prices, but the expected growth rate used in the DCF should also be adjusted downward from the projected EPS growth rate to remove the upward bias by reviewing other measures of growth.

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[27] Peter D. Easton & Gregory A. Sommers, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts," 45 ACCT. RES. 983–1015 (2007).

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE PROXY GROUP, AS PROVIDED BY *VALUE LINE.*

A. Page 3 of Exhibit JRW-8 provides the 5- and 10-year historical growth rates per share for earnings, dividends, and book values for the companies in the proxy group, as published in the *Value Line Investment Survey*. The median historical growth measures per share for earnings, dividends and book values for the Gas Proxy Group, as provided in Panel A, range from 5.0% to 7.5%, with an average of the medians of 6.2%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUP.

A. *Value Line's* projections of per share growth in earnings, dividends, and book values for the companies in the proxy Group are shown on page 4 of Exhibit JRW-8. As stated above, due to the presence of outliers, the medians are used in the analysis. For the Gas Proxy Group, as shown in Panel A of page 4 of Exhibit JRW-8, the medians range from 4.5% to 8.5%, with an average of the medians of 6.3%.

Also provided on page 4 of Exhibit JRW-8 are the prospective sustainable growth rates for the companies in the proxy group as measured by *Value Line*'s average projected return on shareholders' equity and retention rates. As noted above, sustainable growth is a significant and a primary driver of long-run earnings growth. For the Gas Proxy Group, the median prospective sustainable growth rate is 5.0%.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUP AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Yahoo, Zacks, and Reuters collect, summarize, and publish Wall Street analysts' three-to-five year earnings per share growth rate forecasts for the companies in the proxy group. These forecasts are provided for the companies in the proxy group on page 5 of Exhibit JRW-8. I have reported both the mean and median growth rates for the group. Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected three-to-five year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate for each company. The mean/median of analysts' projected EPS growth rates for the gas group 5.6% and 6.2%, respectively.[28]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUP.

A. Page 6 of Exhibit JRW-8 shows the summary DCF growth rate indicators for the proxy group.

The historical growth rate indicators for my Gas Proxy Group imply a baseline growth rate of 6.2%. The average of the projected per share growth rates in earnings, dividends, and book values from *Value Line* is 6.3%, and *Value Line*'s projected sustainable growth rate is 5.0%. The projected earnings per share

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[28] Given the variation in the measures of central tendency of analysts' projected EPS growth rates for the proxy group, I have considered both the means and medians figures in the growth rate analysis.

growth rates of Wall Street analysts for the Gas Proxy Group are 5.6% and 6.2% as measured by the mean and median growth rates. The overall range for the projected growth rate indicators (ignoring historical growth) is 5.0% to 6.3%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate growth rate for the Gas Proxy Group is 6.00%. This is at the high end of the range of projected growth rates.

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE PROXY GROUP?

A. My DCF-derived equity cost rates for the gas group is summarized on page 1 of Exhibit JRW-8 and in Table 5 below.

Table 5
DCF-derived Equity Cost Rate/ROE

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Gas Proxy Group	**2.60%**	**1.0300**	**6.00%**	**8.700%**

The calculation for the Gas Proxy Group is the 2.60% dividend yield, times the one and one-half growth adjustment of 1.030, and a DCF growth rate of 6.00%, which results in an equity cost rate of 8.70%.

B. Capital Asset Pricing Model

Q. PLEASE DESCRIBE IN SIMPLE TERMS HOW A CAPITAL ASSET PRICING MODEL ESTIMATES THE COST OF EQUITY CAPITAL

A. Simply put, a Capital Asset Pricing Model estimates the cost of common equity based on the sum of the risk-free bond rate plus the risk premium associated with comparable investments. And the risk premium is measured using an estimate of the risk premium for the overall market (such as the S&P 500), adjusted to reflect the relative risk of comparable investments.

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL ("CAPM").

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term U.S. Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the S&P 500 is used as a proxy for the "market";
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premiumthe excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term U.S. Treasury bonds. ß, the measure of systematic risk, is more difficult to measure, as there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium $(E(R_m) - (R_f))$. I will discuss each of these inputs below.

Q. PLEASE DISCUSS EXHIBIT JRW-9.

A. Exhibit JRW-9 provides the summary results for my CAPM study. Page 1 shows the results and the following pages contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. As shown on page 2 of Exhibit JRW-9, the yield on 30-year U.S. Treasury bonds has been in the 2.5% to 4.0% range over the 2013–2019 time period. The current 30-year Treasury yield is in the lower end of this range. Given the recent range of yields, I use the higher end 4.0% as the risk-free rate, or R_f, in my CAPM.

Q. DOES YOUR 4.0% RISK-FREE INTEREST RATE TAKE INTO CONSIDERATION FORECASTS OF HIGHER INTEREST RATES?

A. No, it does not. As I stated before, forecasts of higher interest rates have been notoriously wrong for a decade. My 4.0% risk-free interest rate takes into account the range of interest rates in the past and effectively synchronizes the risk-free rate with the market risk premium. The risk-free rate and the Market Risk Premium are interrelated in that the market risk premium is developed in relation to the risk-free rate. As discussed below, my market risk premium is based on the results of many studies and surveys that have been published over time. My risk-free interest rate of 4.0% reflects the 30-year Treasury yield over a period of time since the market risk premiums found in the studies and surveys have been measured and published over the years. Therefore, my risk-free interest rate of 4.0% is effectively a normalized risk-free rate of interest.

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The overall market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-9, the slope of the regression line is the stock's beta. A steeper line indicates that the stock is more sensitive to the return on the overall market. This means that the stock has a higher beta and greater-than-average market risk. A less steep line indicates a lower beta and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to the time period over which beta is measured, and any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy group, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-9, the median beta for the companies in the Gas Proxy Group is 0.65.

Q. PLEASE DISCUSS THE MARKET RISK PREMIUM.

A. The market risk premium is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, $E(R_m)$ minus the risk-free rate of interest (R_f)). It reflects the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the market risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market - $E(R_m)$. As is discussed below, there are different ways to measure expected market returns, and studies have come up with significantly different magnitudes for expected market returns. As Merton Miller, the 1990 Nobel Prize winner in economics indicated, the expected market return is very difficult to measure and is one of the great mysteries in finance.[29]

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE MARKET RISK PREMIUM.

A. Page 4 of Exhibit JRW-9 highlights the primary approaches to, and issues in, estimating the expected market risk premium. The traditional way to measure the market risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called *ex post* returns, were used as the measures of the market's expected return (known as

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[29] Merton Miller, "The History of Finance: An Eyewitness Account," *Journal of Applied Corporate Finance*, 2000, P. 3.

the *ex ante* or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson, who popularized this method of using historical financial market returns as measures of expected returns. However, this historical evaluation of returns can be a problem because: (1) *ex post* returns are not the same as *ex ante* expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market conditions can change such that *ex post* historical returns are poor estimates of *ex ante* expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies as discussed later in my testimony. The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "*Ex Ante* Models and Market Data," compute *ex ante* expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[30]

In addition, there are a number of surveys of financial professionals regarding the market risk premium. There have also been several published surveys of academics on the equity risk premium. *CFO Magazine* conducts a

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[30] Rajnish Mehra & Edward C. Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics*, 145 (1985).

quarterly survey of Chief Financial Officers, which includes questions regarding their views on the current expected returns on stocks and bonds. Usually, over 200 CFOs participate in the survey.[31] Another survey is found in questions regarding expected stock and bond returns that are included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters, which is published as the *Survey of Professional Forecasters*.[32] This survey of professional economists has been published for almost fifty years. In addition, Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.[33]

Q. PLEASE PROVIDE A SUMMARY OF THE MARKET RISK PREMIUM STUDIES.

A. Derrig and Orr (2003), Fernandez (2007), and Song (2007) completed the most comprehensive review of the research on the market risk premium.[34] Derrig and Orr's study evaluated the various approaches to estimating market risk premiums, as well as the issues with the alternative approaches and summarized the findings

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[31] *See* DUKE/CFO Magazine Global Business Outlook Survey, www.cfosurvey.org.

[32] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters* (March 2019). The Survey of Professional Forecasters was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

[33] Pablo Fernandez, Vitaly Pershin and Isabel Fernandez Acín, "Market Risk Premium and Risk-Free Rate used for 59 countries in 2019: a survey." *IESE Business School*, April 2019.

[34] *See* Richard Derrig & Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

of the published research on the market risk premium. Fernandez examined four alternative measures of the market risk premium – historical, expected, required, and implied. He also reviewed the major studies of the market risk premium and presented the summary market risk premium results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the market risk premium.

Q. PLEASE DISCUSS PAGE 5 OF EXHIBIT JRW-8.

A. Page 5 of Exhibit JRW-9 provides a summary of the results of the market risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium, (2) *ex ante* market risk premium studies, (3) market risk premium surveys of CFOs, financial forecasters, analysts, companies and academics, and (4) the Building Blocks approach to the market risk premium. There are results reported for over thirty studies, and the median market risk premium is 4.83%.

Q. PLEASE HIGHLIGHT THE RESULTS OF THE MORE RECENT RISK PREMIUM STUDIES AND SURVEYS.

A. The studies cited on page 5 of Exhibit JRW-9 include every study and survey I could identify that was published over the past fifteen years that provided a market risk premium estimate. Many of these studies were published prior to the financial crisis that began in 2008. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as fifty years of data) and so were not estimating an market risk premium as of a specific point in time (e.g., the year 2001). To assess the effect of the earlier studies on the market risk premium, I have reconstructed page 5 of Exhibit JRW-9 on page 6 of Exhibit JRW-9; however, I have eliminated all studies dated before January 2, '2010. The median for this subset of studies is 4.87%.

Q. PLEASE SUMMARIZE THE MARKET RISK PREMIUM STUDIES AND SURVEYS.

A. As noted above, there are three approaches to estimating the market risk premium – historic stock and bond returns, ex ante or expected returns models, and surveys. The studies on pages 5 and 6 of Exhibit JRW-8 can be summarized in the following manners:

Historic Stock and Bond Returns - Historic stock and bond returns suggest a market risk premium in the 4.40% to 6.26% range, depending on whether one uses arithmetic or geometric mean returns.

Ex Ante Models – Market risk premium studies that use expected or ex ante return models, indicates market risk premiums in the range of 4.49% to 6.00%.

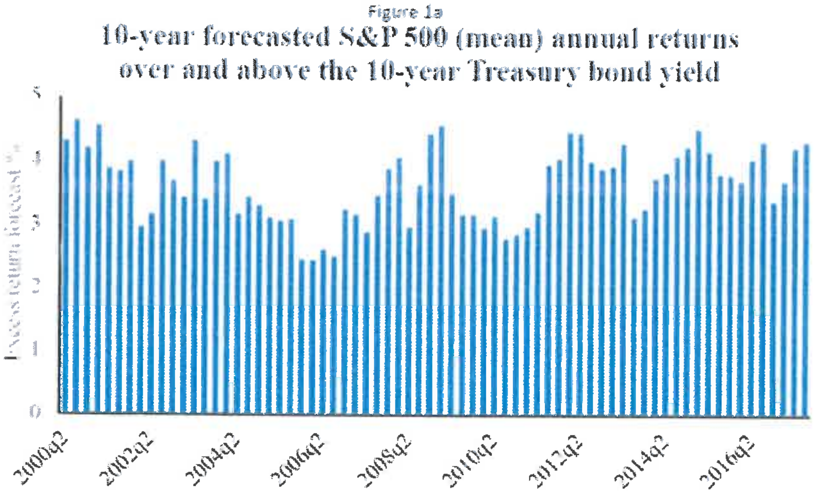
Surveys – Market risk premiums developed from surveys of analysts, companies, financial professionals, and academics find lower market risk premiums, with a range from 1.85% to 5.7%.

Q. PLEASE HIGHLIGHT THE *EX ANTE* MARKET RISK PREMIUM STUDIES AND SURVEYS THAT YOU BELIEVE ARE MOST TIMELY AND RELEVANT.

A. I will highlight several studies/surveys.

CFO Magazine conducts a quarterly survey of Chief Financial Officers, which includes questions regarding their views on the current expected returns on stocks and bonds. Usually, over 200 CFOs participate in the survey.[35] In the December 2018 CFO survey conducted by *CFO Magazine* and Duke University, which included approximately 200 responses, the expected 10-year market risk premium was 3.15%.[36] Figure 4, below, shows the market risk premium associated with the CFO Survey, which has been in the 4.0% range in recent years.

Figure 4
Market Risk Premium
CFO Survey



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[35] *See* DUKE/CFO Magazine Global Business Outlook Survey, https://www.cfosurvey.org/past-results-2018.html, (December 2018). https://www.cfosurvey.org/wp-content/uploads/2018/12/Q4-18-US-Toplines.pdf.

[36] https://www.cfosurvey.org/wp-content/uploads/2018/12/Q4-18-US-Toplines.pdf, P. 45.

Source: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162&download=yes

Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.[37] His survey results are included on pages 5 and 6 of Exhibit JRW-9. The results of his 2019 survey of academics, financial analysts, and companies, which included 4,000 responses, indicated a median market risk premium employed by U.S. analysts and companies of 5.6%.[38] His estimated market risk premium for the U.S. has been in the 5.00%-5.50% range in recent years.

Professor Aswath Damodaran of NYU, a leading expert on valuation and the market risk premium provides a monthly updated market risk premium which is based on projected S&P 500 earnings per share and stock price level, and long-term interest rates. His estimated market risk premium is shown graphically in Figure 5, below, for the past twenty years, has primarily been in the range of 5.0% to 6.0% since 2010.

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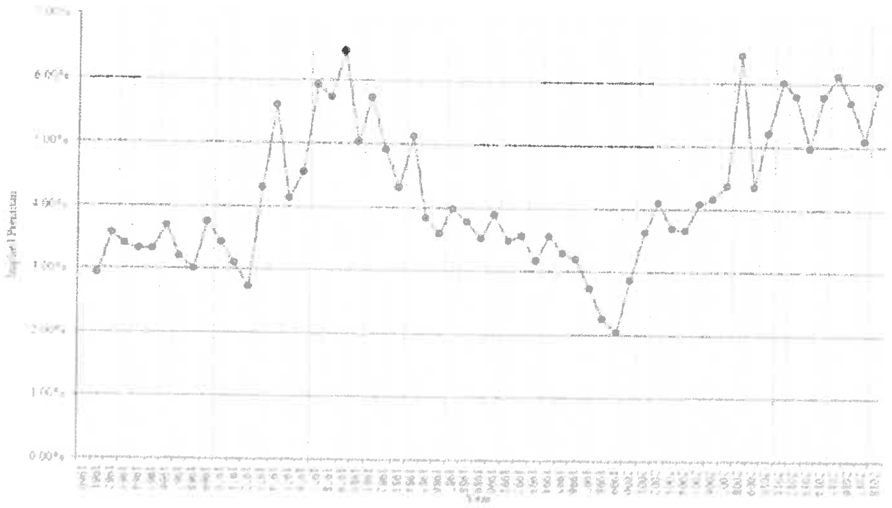
[37] Pablo Fernandez, Vitaly Pershin and Isabel Fernandez Acín, "Market Risk Premium and Risk-Free Rate used for 59 countries in 2019: a survey," *IESE Business School,* (Apr. 2019), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3358901.

[38] *Ibid.* p. 3.

Figure 5
Damodaran Market Risk Premium



Source: http://pages.stern.nyu.edu/~adamodar/

Duff & Phelps, an investment advisory firm, provides recommendations for the risk-free interest rate and market risk premiums to be used in calculating the cost of capital data. Their recommendations over the 2008-2019 time periods are shown on page 7 of Exhibit JRW-9. Duff & Phelps' recommended market risk premium has been in the 5.0% to 6.0% over the past decade. Most recently, on December 31 of 2018, Duff & Phelps increased its recommended market risk premium on January 31, 2016 from 5.00% to 5.50%.[39]

KPMG is one of the largest public accounting firms in the world. Their recommended market risk premium over the 2013-2019 time period is shown in Panel A of page 8 of Exhibit JRW-9. KPMG's recommended market risk premium

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[39] https://www.duffandphelps.com/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates.

has been in the 5.50% to 6.50% range over this time period. Since the third quarter of 2018, KPMG has recommended a market risk premium of 5.50%.[40]

Finally, the website *market-risk-premia.com* provides risk-free interest rates, implied market risk premiums, and overall cost of capital for thirty-six countries around the world. These parameters for the U.S. over the 2002-2019 time period are shown in Panel B of page 8 of Exhibit JRW-9. As of May 31, 2019, market-risk-premia.com estimated an implied cost of capital for the U.S. of 6.40% consisting of a risk-free rate of 2.14% and an implied market risk premium of 4.26%.[41]

Q. GIVEN THESE RESULTS, WHAT MARKET RISK PREMIUM ARE YOU USING IN YOUR CAPM?

A. The studies on page 6 of Exhibit JRW-9, and more importantly the more timely and relevant studies just cited, suggest that the appropriate market risk premium in the U.S. is in the 4.0% to 6.0% range. I will use an expected market risk premium of 5.50%, which is in the upper end of the range, as the market risk premium. I gave most weight to the market risk premium estimates of the CFO Survey, Duff & Phelps, the 2019 Dimson, Marsh, Staunton - Credit Suisse Report, the Fernandez survey, and Damodaran. This is a conservatively high estimate of the market risk premium considering the many studies and surveys of the market risk premium.

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[40] https://assets.kpmg/content/dam/kpmg/nl/pdf/2019/advisory/equity-market-research-summary.pdf

[41] Source: http://www.market-risk-premia.com/us.html.

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy group are summarized on page 1 of Exhibit JRW-9 and in Table 6 below.

Table 6
CAPM-derived Equity Cost Rate/ROE
$K = (R_f) + \beta * [E(R_m) - (R_f)]$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Gas Proxy Group	4.0%	0.65	5.5%	7.6%

For the Gas Proxy Group, the risk-free rate of 4.0% plus the product of the beta of 0.65 times the equity risk premium of 5.5% results in a 7.6% equity cost rate.

C. Equity Cost Rate Summary

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY COST RATE STUDIES.

A. My DCF and CAPM analyses for the Gas Proxy Group indicate equity cost rates of 8.70% and 7.60%, respectively.

Table 7
ROEs Derived from DCF and CAPM Models

	DCF	CAPM
Gas Proxy Group	8.70%	7.60%

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUP?

A. I conclude that the appropriate equity cost rate for companies in the Gas Proxy Group is in the 7.60% to 8.70% range. However, since I rely primarily on the DCF model, I am using the upper end of the range as the equity cost rate for the group.

Q. ARE YOU RECOMMENDING AN EQUITY COST RATE IN THIS RANGE FOR PIEDMONT?

A. No, not as a primary ROE recommendation. While I believe that this range accurately reflects current capital market data, I recognize that the adjustment to the equity ratio that I have recommended in the capital structure, if adopted by the Commission, increases the risk for stockholders somewhat. Therefore, I am recommending 9.0% as a primary ROE for Piedmont.

Q. ARE YOU ALSO PROVIDING AN ALTERNATIVE ROE RECOMMENDATION FOR PIEDMONT?

A. Yes. My alternative recommendation would apply if Piedmont's proposed 52.0% common equity capital structure is allowed. As indicated above, I believe that my equity cost rate range, 7.60% to 8.70%, accurately reflects current capital market data. Capital costs in the U.S. remain low, with low inflation and interest rates and very modest economic growth. To reflect these low capital costs, my alternative ROE recommendation is 8.70%, which is at the high end of my equity cost rate range.

Q. PLEASE INDICATE WHY YOUR EQUITY COST RATE RECOMMENDATIONS ARE APPROPRIATE FOR THE GAS DISTRIBUTION OPERATIONS OF THE COMPANY.

A. There are a number of reasons why equity cost rates of 9.0%/8.70% are appropriate and fair for the Company in this case:

1. The S&P and Moody's issuer credit ratings for Piedmont are A- and A3, respectively. These are in line with those of the companies in the gas proxy group. As such, the investment risk of Piedmont is similar to the average of the proxy group.
2. As shown in Exhibits JRW-5, capital costs for utilities, as indicated by long-term utility bond yields, are still at historically low levels. In addition, given low inflationary expectations and slow global economic growth, interest rates are likely to remain at low levels for some time;
3. As shown in Exhibit JRW-6, the gas distribution industry is among the lowest risk industries in the U.S. as measured by beta. Most notably, the betas for gas companies have been declining in recent years, which indicates the risk of the industry has declined. Overall, the cost of equity capital for this industry is the lowest in the U.S., according to the CAPM;

4. I have recommended an equity cost rate of the high end of the range of my ROE outcomes; and

5. The authorized ROEs for gas distribution companies have largely declined from 9.94% in 2012, to 9.68% in 2013, 9.78% in 2014, 9.60% in 2015, 9.50% in 2016, 9.72% in 2017, 9.59% in 2018, and 9.55% in the first quarter of 2019.[42] In my opinion, authorized ROEs have lagged behind capital market cost rates, or in other words, authorized ROEs have been slow to reflect low capital market cost rates. However, the trend has been towards lower ROEs and the norm now is below 10%. Hence, I believe that my recommended ROE reflects our present historically low capital cost rates, and these low capital cost rates are finally being recognized as the norm by state utility regulatory commissions.

Q. DO YOU BELIEVE THAT YOUR 9.0%/8.70% ROE RECOMMENDATIONS MEET *HOPE* AND *BLUEFIELD* STANDARDS?

A. Yes, I do. As previously noted, according to the *Hope* and *Bluefield* decisions, returns on capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital. As shown in Exhibit JRW-6, gas distribution companies have been earning in the 8.0% to 9.0% range in recent

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[42] *Regulatory Focus*, Regulatory Research Associates, 2019.

years. While my recommendation is below the average authorized ROEs for gas distribution companies, it reflects the downward trend in authorized and earned ROEs of gas distribution companies.

Q. PLEASE ALSO DISCUSS YOUR RECOMMENDATION IN LIGHT OF A MOODY'S PUBLICATION ON ROEs AND CREDIT QUALITY.

A. Moody's published an article on utility ROEs and credit quality in 2015. In the article, Moody's recognizes that authorized ROEs for electric and gas companies are declining due to lower interest rates. The article explains:

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinize their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures.[43]

Moody's indicates that with the lower authorized ROEs, electric and gas companies are earning ROEs of 9.0% to 10.0%, yet this is not impairing their credit profiles and is not deterring them from raising record amounts of capital. With respect to authorized ROEs, Moody's recognizes that utilities and regulatory commissions are having trouble justifying higher ROEs in the face of lower

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[43] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

interest rates and cost recovery mechanisms.

> Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.[44]

Overall, this article further supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital.

Q. ARE UTILITIES ABLE TO ATTRACT CAPITAL WITH THE LOWER ROEs?

A. Moody's also highlights in the article that utilities are raising about $50 billion a year in debt capital, despite the lower ROEs. Furthermore, as indicated in Exhibit JRW-5, page 3, the companies in the Gas Proxy Group have been earning ROEs of about 9.0% in recent years. As shown on page 1 of Exhibit JRW-2, the market to book ratio of utilities in the Gas Proxy Group is still well above 2.0 indicating that their stock is still in great demand.

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[44] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

VI. CRITIQUE OF PIEDMONT'S RATE OF RETURN TESTIMONY

Q. PLEASE REVIEW THE COMPANY'S PROPOSED RATE OF RETURN.

A. Piedmont has proposed a capital structure consisting of 0.82% short-term debt, 47.18% long-term debt, and 52.00% common equity. Piedmont has proposed short-term and long-term debt cost rates of 2.82% and 4.55%. Mr. Robert Hevert has recommended a common equity cost rate, or ROE, of 10.60% for Piedmont. The Company's overall rate of return recommendation is 7.68%. This is summarized in Exhibit JRW-10.

Q. PLEASE REVIEW MR. HEVERT'S EQUITY COST RATE APPROACHES AND RESULTS.

A. Mr. Hevert has developed a proxy group of gas distribution companies and employed Discounted Cash Flow, Capital Asset Price Model, Bond Yield Risk Premium, and Expected Earnings equity cost rate approaches. Mr. Hevert's equity cost rate estimates for Piedmont are summarized on page 1 Exhibit JRW-11. Based on these figures, he concludes that the appropriate equity cost rate is 10.60% for Piedmont.

A. DCF Approach

Q. PLEASE SUMMARIZE MR. HEVERT'S DCF ESTIMATES.

A. On pages 59-66 of his testimony and in Exhibit Nos. RBH-1 – RBH-2, Mr. Hevert develops an equity cost rate by applying the DCF model to the companies in his proxy group. Mr. Hevert's DCF results are summarized in Panel A of Exhibit JRW-11. He uses a constant-growth DCF model. Mr. Hevert uses three dividend yield measures (30, 90, and 180) and has relied on the forecasted EPS growth rates of Zacks, First Call, and *Value Line* as well as retention growth. He reports median and median high results. His DCF results are summarized in Panel A of page 1 of Exhibit JRW-11 and his median results range from 9.60% to 9.65%.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S DCF ANALYSES?

A. The primary issues in Mr. Hevert's DCF analyses are: (1) he relies on the overly optimistic and upwardly biased three-to-five year earnings per share growth rate forecasts of Wall Street analysts and *Value Line*, and (2) he has combined abnormally high *Value Line* projected earnings per share, computed from a three-year base period, with three-to-five-year projected growth rates of First Call and Zack's.

1. Analysts' EPS Growth Rates

Q. PLEASE REVIEW MR. HEVERT'S DCF GROWTH RATE.

A. In his constant-growth DCF model, Mr. Hevert's DCF growth rate is the average of the earnings per share growth rate forecasts of: (1) Wall Street analysts as compiled by First Call, Zacks; and (2) *Value Line*.

Q. PLEASE DISCUSS MR. HEVERT'S EXCLUSIVE RELIANCE ON THE PROJECTED GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE.*

A. It is highly unlikely that investors today would rely exclusively on the earnings per share growth rate forecasts of Wall Street analysts and ignore other growth rate measures in arriving at their expected growth rates for equity investments. The appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. [45] Hence, consideration must be given to other indicators of growth, including historical prospective dividend growth, internal growth, as well as projected earnings growth. Also, analysts' long-term earnings growth rate forecasts have been found to be no more accurate at forecasting future earnings than naïve random walk forecasts of future earnings, according to a study by Lacina, Lee, and Xu (2011).[46] And finally, and most significantly, it is well-known that the long-term earnings per share growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.[47] Hence, using these growth rates as a DCF constant growth rate produces an overstated equity cost rate. A study by Easton and Sommers (2007) found that optimism in analysts'

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[45] See my discussion of the point that the DCF model considers growth in dividends, not earnings in Part VI.B.

[46] M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[47] See footnote 26 and 27 of this testimony.

earnings growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[48]

2. *Value Line* Projected EPS Growth Rates

Q. PLEASE DISCUSS MR. HEVERT'S DCF GROWTH RATE.

A. Table 8 and page 2 of Exhibit JRW-11 shows Mr. Hevert's DCF growth rates from Zacks, First Call, and *Value Line*. The Zacks and First Call growth rates are the average of analysts' three-to-five year projected growth rates compiled by First Call and Zack's. *Value Line* uses a different approach in estimating projected growth. *Value Line* projects growth from a three-year base period – 2015-2017 – to a projected three-year period for the period - 2022-2024. Using this approach, the three-year based period can have a significant impact on the *Value L*ine growth rate if this base period includes years with abnormally high or low earnings. With the exception of one proxy company, the *Value* Line projected growth rates are larger than the First Call and Zack's growth rates, and especially so for Northwest Natural Gas ("NWN") and ONE Gas, Inc. ("OGS").

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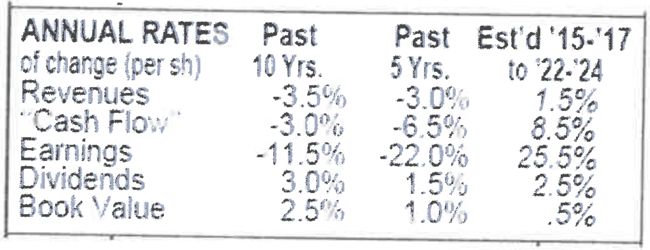
[48] Easton, P., & Sommers, G. (2007). Effect of analysts' optimism on estimates of the expected rate of return implied by earnings forecasts. *Journal of Accounting Research*, 45(5), 983–1015.

Table 8
Mr. Hevert's DCF Growth Rates

Gas Proxy Group	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth
Atmos Energy Corporation	6.50%	6.40%	7.50%
Chesapeake Utilities Corporation	6.00%	6.00%	9.00%
New Jersey Resources Corporation	7.00%	6.00%	2.50%
Northwest Natural Gas Company	4.30%	4.00%	25.50%
ONE Gas, Inc.	5.90%	5.00%	9.00%
South Jersey Industries, Inc.	9.50%	9.50%	9.50%
Southwest Gas Corporation	5.00%	6.20%	8.50%
Spire Inc.	3.90%	2.42%	5.50%
Proxy Group Mean	6.01%	5.69%	9.63%

To see why these growth rates are inflated, I show additional information about the *Value Line* projected earnings per share growth rate of 25.5% for Northwest Natural Gas Company (NWN) in Table 9. Panel A shows that *Value Line* had a 25.5% growth rate from the three-year base period – 2015-2017 – to a projected three-year period 2022-2024. Panel B of Table 9 shows that NWN's base period includes 2015, 2016, and 2017 earnings per share figures of $1.96, $2.12, and -$1.94. NWN's abnormally low 2017 earnings per share figure results in a *Value Line* earnings per share base three-year period average figure of $0.71. From these data, *Value* Line projected earnings per share growth rate of 25.5%. (*Value Line* averages growth rates to the nearest one-half percent.) This 25.5% EPS growth rate projection comes after NWN's EPS declined -22.0% and -11.5% over the previous five and ten years.

Table 9
NWN's *Value Line* Projected EPS Growth Rate
Panel A



ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '22-'24
Revenues	-3.5%	-3.0%	1.5%
"Cash Flow"	-3.0%	-6.5%	8.5%
Earnings	-11.5%	-22.0%	25.5%
Dividends	3.0%	1.5%	2.5%
Book Value	2.5%	1.0%	.5%

Panel B

Northwest Natural Gas Company	**2015**	**2016**	**2017**	**2018**	**2019**	**2022-24**
Earnings Per Share	$ 1.96	$ 2.12	$ (1.94)	$ 2.20	$ 2.45	$ 3.50
3-Year Base & Projected Periods		**2015-17**				**2022-24**
Base and Projected EPS Figures		$ 0.71				$ 3.50
Base Period to Projected Period Growth Rate				25.5%		

* Source: Exhibit JRW-11, page 2.

Q. PLEASE SUMMARIZE THE IMPACT OF COMBINING THE DIFFERENT PROJECTED EPS GROWTH RATES ON MR. HEVERT'S DCF RESULTS.

A. The impact of combining the earnings per share growth rates from Zacks, First Call, and *Value Line* is highly significant for three reasons: (1) This approach greatly inflates Mr. Hevert's DCF results. (2) In the case of Northwest Natural Gas, the *Value Line* growth rate of 25.5% is grossly in excess of the First Call and Zack's projected growth rates of 4.30% and 4.00%. (3) It must be remembered that DCF growth rate is a long-term (infinite) growth rate. In summary, the idea of a regulated gas utility growing its EPS at a 25.5% rate forever is totally unrealistic.[49]

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[49] I have used *Value Line*'s projected growth rates for EPS, DPS, and BVPS. However, due to the

B. CAPM Approach

Q. PLEASE DISCUSS MR. HEVERT'S CAPM.

A. On pages 66-71 of his testimony and in Exhibit Nos. RBH-3 – RBH-5, Mr. Hevert develops an equity cost rate by applying the Capital Asset Pricing Model to the companies in his proxy group. The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Mr. Hevert uses three different measures of the 30-Year Treasury bond yield - a current yield of 3.04%, a near-term projected yield of 3.25%, and a long-term projected yield of 4.05%; (b) two different Betas (an average Bloomberg Beta of 0.584 and an average *Value Line* Beta of 0.688), and (c) two market risk premium measures - a Bloomberg, DCF-derived market risk premium of 10.65% and *Value Line* derived market risk premium of 13.77%. Based on these figures, he finds a CAPM equity cost rate range from 9.26% to 13.52%. Mr. Hevert's CAPM results are summarized in Panel B of page 1 of Exhibit JRW-11.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S CAPM ANALYSES?

A. There are two issues with Mr. Hevert' CAPM analyses: (1) he has used current, near-term projected, and long-term projected Treasury yields yield that are abnormally high relative to current yields; and (2) Mr. Hevert's market risk

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different periods of growth that are measured by *Value Line* compared to First Call and Zack's I have analyzed the *Value Line* data separately from the other growth rate data, and I have used the medians of the growth rates for the proxy group to minimize the impact of outliers such as those discussed above.

premiums of 10.65% and 13.77% include highly unrealistic assumptions regarding future economic and earnings growth and stock returns.

1. Current and Projected Risk-Free Interest Rates

Q. PLEASE DISCUSS THE RISK-FREE RATE OF INTEREST IN MR. HEVERT'S CAPM.

A. Mr. Hevert has used three different measures of the 30-Year Treasury bond yield - a current yield of 3.04%, a near-term projected yield of 3.25%, and a long-term projected yield of 4.05%. The current 30-Year Treasury rate is about 2.55%. Mr. Hevert's figures are between 50 and 150 basis points above this current yield. These yields are excessive for two reasons. First, as discussed previously, economists are always predicting that interest rates are going up, and yet they are almost always wrong. Obviously, investors are well aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. Second, investors would not be buying long-term Treasury bonds at their current yields if they expected interest rates to suddenly increase. If long-term interest rates do increase and the yields on long-term Treasury bonds go up, the prices of these bonds investors bought at today's yields go down, producing a negative return.

2. Market Risk Premiums

Q. PLEASE ASSESS MR. HEVERT'S MARKET RISK PREMIUMS DERIVED FROM APPLYING THE DCF MODEL TO THE S&P 500 AND *VALUE LINE INVESTMENT SURVEY.*

A. Mr. Hevert computes market risk premiums of 10.65% and 13.77% by: (1) calculating an expected market return by applying the DCF model to the S&P 500; and then (2) subtracting the current 30-year Treasury bond yield of 3.04% from his estimate of the expected market return. Mr. Hevert also uses (1) a dividend yield of 2.21% and an expected DCF growth rate of 11.47% for Bloomberg and (2) a dividend yield of 2.08% and an expected DCF growth rate of 14.73% for *Value Line*. The resulting expected annual S&P 500 stock market returns using this approach are 13.68% (using Bloomberg three-to-five-year EPS growth rate estimates) and 16.81% (using *Value Line* three- to five-year EPS growth rate estimates). These results are not realistic in today's market.

Q. ARE MR. HEVERT'S MARKET RISK PREMIUMS OF 10.65% AND 13.77% REFLECTIVE OF THE MARKET RISK PREMIUMS FOUND IN STUDIES AND SURVEYS OF THE MARKET RISK PREMIUM?

A. No. Although there are many studies and surveys that estimate the market risk premium, Mr. Hevert fashions his own estimate. He has labeled his market risk premiums by reference to "Bloomberg" and "*Value Line,*" but his approach does not rely on market risk premium studies performed by Bloomberg or *Value Line*.

Instead, Mr. Hevert created the studies and labels one Bloomberg because it uses a beta and an EPS growth rate calculated by Bloomberg, and likewise the one labeled *Value Line* uses a beta and an EPS growth rate calculated by *Value Line*.

In fact, Mr. Hevert's market risk premiums are well in excess of the market risk premiums: (1) that are discovered in studies of the market risk premium by leading academic scholars; (2) those produced by analyses of historic stock and bond returns; and (3) those found in surveys of financial professionals. Page 5 of Exhibit JRW-9 provides the results of over thirty market risk premium studies from the past fifteen years. Historic stock and bond returns suggest an market risk premium in the 4.5% to 7.0% range, depending on whether one uses arithmetic or geometric mean returns. There have been many studies using expected return (also called *ex ante*) models, and their market risk premium results vary from as low as 2.0% to as high as 7.31%. Finally, the market risk premiums developed from surveys of analysts, companies, financial professionals, and academics suggest lower market risk premiums, in a range of from 1.91% to 5.70%. The bottom line is that there is no support in historic return data, surveys, academic studies, or in reports for investment firms for using a market risk premium as high as those used by Mr. Hevert.

Q. PLEASE ONCE AGAIN ADDRESS THE ISSUES WITH ANALYSTS' EPS GROWTH RATE FORECASTS.

A. The key point is that Mr. Hevert's CAPM market risk premium methodology is based entirely on the concept that analyst projections of companies' three-to-five

EPS growth rates reflect investors' expected *long-term* EPS growth for those companies. However, this seems highly unrealistic given the research on these projections. The short answer is that analysts' three-to-five-year EPS growth rate forecasts are inaccurate, overly optimistic and upwardly biased, and they inflate the indicated market risk premium and cost of equity. As previously noted, numerous studies have shown that the long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased.[50] Moreover, a 2011 study showed that analysts' forecasts of EPS growth over the next three-to-five years earnings are no more accurate than their forecasts of the next single year's EPS growth.[51] The overly-optimistic inaccuracy of analysts' growth rate forecasts leads to an upward bias in equity cost estimates that has been estimated at about 300 basis points.[52]

Q. **HAVE CHANGES IN REGULATIONS IMPACTING WALL STREET ANALYSTS AND THEIR RESEARCH IMPACTED THE UPWARD BIAS**

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[50] Such studies include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research* (2000); K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* pp. 643–684, (2003); M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[51] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting* Vol. 8, Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

[52] Peter D. Easton & Gregory A. Sommers, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts," 45, *Journal of Accounting Research*, pp. 983–1015 (2007).

IN THEIR THREE-TO-FIVE YEAR EPS GROWTH RATE FORECASTS?

A. No. A number of the studies I have cited here demonstrate that the upward bias has continued despite changes in regulations and reporting requirements over the past two decades. This observation is highlighted by a 2010 McKinsey study entitled "Equity Analysts: Still Too Bullish," which involved a study of the accuracy on analysts long-term EPS growth rate forecasts. The authors conclude that after a decade of stricter regulation, analysts' long-term earnings forecasts continue to be excessively optimistic. They made the following observation:[53]

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.

This is the same observation made in a *Bloomberg Businessweek* article.[54]

The author concluded:

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[53] Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010) (emphasis added).

[54] Roben Farzad, "For Analysts, Things Are Always Looking Up," *Bloomberg Businessweek* (June 10, 2010).

> ***The bottom line:*** *Despite reforms intended to improve Wall Street research, stock analysts seem to be promoting an overly rosy view of profit prospects.*

Q. IS THERE OTHER EVIDENCE THAT INDICATES THAT MR. HEVERT'S MARKET RISK PREMIUMS COMPUTED USING S&P 500 EARNINGS PER SHARE GROWTH RATES ARE EXCESSIVE?

A. Beyond my previous discussion of the upwardly biased nature of analysts' projected earnings per share growth rates, the fact is that long-term growth rates of 13.77% and 14.73% based on earnings projections are inconsistent with both historic and projected economic and earnings growth in the U.S for several reasons: (1) Long-term earnings per share and economic growth is about one-half of Mr. Hevert's projected earnings per share growth rates of 13.77% and 14.73%. (2) As discussed below, long-term earnings per share and gross domestic product ("GDP") growth are directly linked; and (3) more recent trends in GDP growth, as well as projections of GDP growth, suggest slower economic and earnings growth in the future.

Long-Term Historic EPS and GDP Growth has been in the 6%-7% Range

I performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 per share growth in earnings and dividends since 1960. The results are provided on page 1 of Exhibit JRW-12, and a summary is shown in the Table 10, below.

Table 10
GDP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	**6.46**
S&P 500 Stock Price	**6.71**
S&P 500 EPS	**6.89**
S&P 500 DPS	**5.85**
Average	**6.48**

The results show that the historical long-run growth rates for Gross Domestic Product, S&P earnings per share, and S&P dividends per share are in the 6% to 7% range. By comparison, Mr. Hevert's long-run growth rate projections of 13.77% and 14.73% are at best overstated. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rate of earnings per shares by 100% in the future and (2) maintain that growth indefinitely in an economy that is expected to grow at about one-third of his projected growth rates.

There is a Direct Link Between Long-Term Earnings Per Share and GDP Growth

The results in Exhibit JRW-12 and Table 10 show that historically there has been a close link between long-term EPS and GDP growth rates. Brad Cornell of the California Institute of Technology published a study on GDP growth, earnings growth, and equity returns. He finds that long-term EPS growth in the U.S. is directly related to GDP growth, with GDP growth providing an upward limit on

EPS growth. In addition, he finds that long-term stock returns are determined by long-term earnings growth. He concludes with the following observations:[55]

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms.

The Trend and Projections Indicate Slower GDP Growth in the Future

The components of nominal GDP growth are real GDP growth and inflation. Page 3 of Exhibit JRW-12 shows annual real GDP growth rate over the 1961 to 2018 time period. Real GDP growth has gradually declined from the 5.0% to 6.0% range in the 1960s to the 2.0% to 3.0% range during the most recent five-year period. The second component of nominal GDP growth is inflation. Page 4 of Exhibit JRW-12 shows inflation as measured by the annual growth rate in the Consumer Price Index (CPI) over the 1961 to 2018 time period. The large increase in prices from the late 1960s to the early 1980s is readily evident. Equally evident is the rapid decline in inflation during the 1980s as inflation declined from above 10% to about 4%. Since that time inflation has gradually declined and has been in the 2.0% range or below over the past five years.

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[55] Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January-February 2010), p. 63.

The graphs on pages 2, 3, and 4 of Exhibit JRW-12 provide clear evidence of the decline, in recent decades, in nominal GDP as well as its components, real GDP, and inflation. To gauge the magnitude of the decline in nominal GDP growth, Table 11, below, provides the compounded GDP growth rates for 10-, 20-, 30-, 40- and 50-years. Whereas the 50-year compounded GDP growth rate is 6.36%, there has been a monotonic and significant decline in nominal GDP growth over subsequent 10-year intervals. These figures strongly suggest that nominal GDP growth in recent decades has slowed and that a figure in the range of 3.0% to 5.0% is more appropriate today for the U.S. economy.

Table 11
Historical Nominal GDP Growth Rates

10-Year Average		**3.37%**
20-Year Average		**4.17%**
30-Year Average		**4.65%**
40-Year Average		**5.56%**
50-Year Average		**6.36%**

Long-Term GDP Projections also Indicate Slower GDP Growth in the Future

A lower range is also consistent with long-term GDP forecasts. There are several forecasts of annual GDP growth that are available from economists and government agencies. These are listed in Panel B of on page 5 of Exhibit JRW-12. The mean 10-year nominal GDP growth forecast (as of March 2019) by economists in the recent *Survey of Financial Forecasters* is 4.27%.[56] The Energy

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[56] https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/

Information Administration ("EIA"), in its projections used in preparing *Annual Energy Outlook,* forecasts long-term GDP growth of 4.3% for the period 2017-2050.[57] The Congressional Budget Office, in its forecasts for the period 2018 to 2048, projects a nominal GDP growth rate of 4.0%.[58] Finally, the Social Security Administration, in its Annual OASDI Report, provides a projection of nominal GDP from 2018-2095.[59] The Social Security Administration's projected growth GDP growth rate over this period is 4.4%. Overall, these forecasts suggest long-term GDP growth rate in the 4.0% to 4.4% range. The trends and projections indicating slower GDP growth make Mr. Hevert's market risk premiums computed using analysts projected EPS growth rates look even more unrealistic. Simply stated, Mr. Hevert's projected EPS growth rates of 13.77% and 14.73% are almost three times projected GDP growth.

Q. WHAT ARE THE FUNDAMENTAL FACTORS THAT HAVE LED TO THE DECLINE IN PROSPECTIVE GDP GROWTH

A. As addressed in a study by the consulting firm McKinsey & Co., two factors drive real GDP growth over time: (a) the number of workers in the economy (employment); and (2) the productivity of those workers (usually defined as output

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[57] U.S. Energy Information Administration, *Annual Energy Outlook 2018*, Table: Macroeconomic Indicators, *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2018&sourcekey=0.*

[58] Congressional Budget Office, The *2018 Long-Term Budget Outlook*, June 1, 2018. https://www.cbo.gov/system/files?file=2018-06/53919-2018ltbo.pdf

[59] Social Security Administration, *2018 Annual Report of the Board of Trustees of the Old-Age, Survivors, and Disability Insurance (OASDI) Program*, Table VI.G4, p. 211(June 15, 2018), https://www.ssa.gov/oact/tr/2018/lr6g4.html. The 4.4% represents the compounded growth rate in projected GDP from $20,307 trillion in 2018 to $548,108 trillion in 2095.

per hour).[60] According to McKinsey, real GDP growth over the past 50 years was driven by population and productivity growth which grew at compound annual rates of 1.7% and 1.8%.

However, global economic growth is projected to slow significantly in the years to come. The primary factor leading to the decline is slow growth in employment (working-age population), which results from slower population growth and longer life expectancy. McKinsey estimates that employment growth will slow to 0.3% over the next fifty years. They conclude that even if productivity remains at the rapid rate of the past fifty years of 1.8%, real GDP growth will fall by 40 percent to 2.1%.

Q. PLEASE PROVIDE MORE INSIGHTS INTO THE RELATIONSHIP BETWEEN S&P 500 EPS AND GDP GROWTH.

A. Figure 6 shows the average annual growth rates for GDP and the S&P 500 EPS since 1960. The one very apparent difference between the two is that the S&P 500 EPS growth rates are much more volatile than the GDP growth rates, when compared using the relatively short, and somewhat arbitrary, annual conventions used in these data.[61] Volatility aside, however, it is clear that over the medium to long run, S&P 500 EPS growth does not outpace GDP growth.

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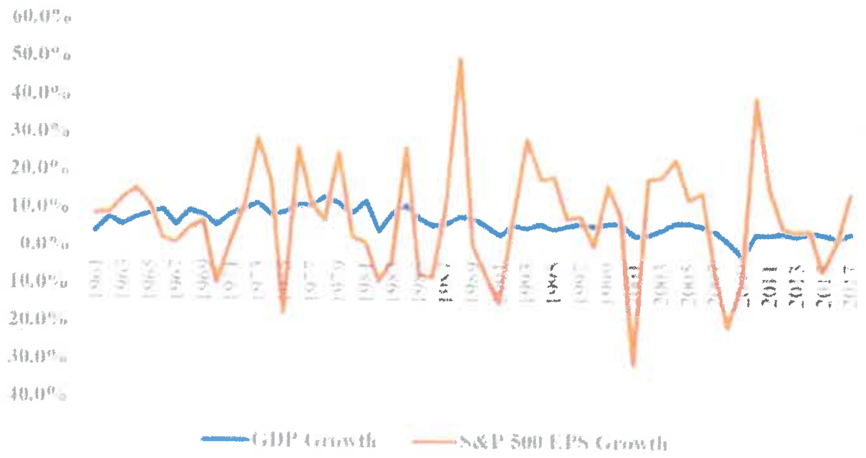
[60] McKinsey & Co., "Can Long-Term Growth be Saved?" McKinsey Global Institute, January 2015.

[61] Timing conventions such as years and quarters are needed for measurement and benchmarking but are somewhat arbitrary. In reality, economic growth and profit accrual occur on continuous bases. A 2014 study evaluated the timing relationship between corporate profits and nominal GDP growth. The authors found that aggregate accounting earnings growth is a leading indicator of the GDP growth with a quarter-ahead forecast horizon. See Yaniv Konchitchki and Panos N. Patatoukas, "Accounting Earnings and Gross Domestic Product," *Journal of Accounting and Economics* 57 (2014), pp. 76–88.

Figure 6
Average Annual Growth Rates
GDP and S&P 500 EPS
1960-2018



Data Sources: Data Sources: GDPA
- http://research.stlouisfed.org/fred2/series/GDPA/downloaddata.
S&P EPS - http://pages.stern.nyu.edu/~adamodar/

A fuller understanding of the relationship between GDP and S&P 500 EPS growth requires consideration of several other factors.

Corporate Profits are Constrained by GDP – Milton Friedman, the noted economist, warned investors and others not to expect corporate profit growth to sustainably exceed GDP growth, stating, "Beware of predictions that earnings can grow faster than the economy for long periods. When earnings are exceptionally high, they don't just keep booming."[62] Friedman also noted that profits must move back down to their traditional share of GDP. In Table 12, below, I show that

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[62] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," Fortune, December 7, 2017. http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

currently the aggregate net income levels for the S&P 500 companies, using 2018 figures, represents 6.73% of nominal GDP.

Table 12
S&P 500 Aggregate Net Income as a Percent of GDP

Aggregate Net Income for S&P 500 Companies ($B)	**$1,406,400.00**
2018 Nominal U.S. GDP ($B)	**$20,891,000.00**
Net Income/GDP (%)	**6.73%**

Data Sources: 2018 Net Income for S&P 500 companies – *Value Line* (March 12, 2019).
2018 Nominal GDP – Moody's - https://www.economy.com/united-states/nominal-gross-domestic-product.

Short-Term Factors Impact S&P 500 EPS – The growth rates in the S&P 500 EPS and GDP can diverge on a year-to-year basis due to short-term factors that impact S&P 500 EPS in a much greater way than GDP. As shown above, S&P EPS growth rates are much more volatile than GDP growth rates. The EPS growth rates for the S&P 500 companies have been influenced by low labor costs and interest rates, commodity prices, the recovery of different sectors such as the energy and financial sectors, the cut in corporate tax rates, etc. These short-term factors can make it appear that there is a disconnect between the economy and corporate profits.

The Differences Between the S&P 500 EPS and GDP – In the last two years, as the EPS for the S&P 500 has grown at a faster rate than U.S. nominal GDP, some have pointed to the differences between the S&P 500 and GDP.[63] These

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[63] See the following studies: Burt White and Jeff Buchbinder, "The S&P and GDP are not the Same Thing," LPL Financial, 2014, https://www.businessinsider.com/sp-is-not-gdp-2014-11; Matt Comer, "How Do We Have 18.4% Earnings Growth In A 2.58% GDP Economy?"; Seeking Alpha, April 2018, https://seekingalpha.com/article/4164052-18_4-percent-earnings-growth-2_58-percent-gdp-economy; Shaun Tully, "How on Earth Can Profits Grow at 10% in a 2% Economy?" *Fortune*, July 27, 2017. http://fortune.com/2017/07/27/profits-economic-growth/ .

differences include: (a) corporate profits are about 2/3 manufacturing driven, while GDP is 2/3 services driven; (b) consumer discretionary spending accounts for a smaller share of S&P 500 profits (15%) than of GDP (23%); (c) corporate profits are more international-trade driven, while exports minus imports tend to drag on GDP; and (d) S&P 500 EPS is impacted not just by corporate profits but also by share buybacks on the positive side (fewer shares boost EPS) and by share dilution on the negative side (new shares dilute EPS). While these differences may seem significant, it must be remembered that the Income Approach to measure GDP includes corporate profits (in addition to employee compensation and taxes on production and imports) and therefore effectively accounts for the first three factors.

The bottom line is that despite the intertemporal short-term differences between S&P 500 EPS and nominal GDP growth, the long-term link between corporate profits and GDP is inevitable.

Q. PLEASE PROVIDE ADDITIONAL EVIDENCE ON HOW UNREALISTIC THE S&P 500 EPS GROWTH RATES ARE THAT MR. HEVERT USES TO COMPUTE HIS MARKET RISK PREMIUMS.

A. Beyond my previous discussion, I have performed the following analysis of S&P 500 EPS and GDP growth in Table 13, below, to show how improbable it is that Mr. Hevert's growth rate estimates reflect long term growth rates. Specifically, I started with the 2018 aggregate net income for the S&P 500 companies and 2018 nominal GDP for the U.S. As shown in Table 12, the aggregate profit for the S&P

500 companies represented 6.73% of nominal GDP in 2018. In Table 13, I then projected the aggregate net income level for the S&P 500 companies and GDP as of the year 2050. For the growth rate for the S&P 500 companies, I used the average of Mr. Hevert's Bloomberg and *Value Line* growth rates, 11.47% and 14.73%, which is 13.10%. As a growth rate for nominal GDP, I used the average of the long-term projected GDP growth rates from Congressional Budget Office, Social Security Administration, and Energy Information Administration (4.0%, 4.4%, and 4.3%), which is 4.23%. The projected 2050 level for the aggregate net income level for the S&P 500 companies is $72.4 trillion. However, over the same period GDP only grows to $78.7 trillion. As such, if the aggregate net income for the S&P 500 grows in accordance with the growth rates used by Mr. Hevert, and if nominal GDP grows at rates projected by major government agencies, the net income of the S&P 500 companies will grow from 6.73% of GDP in 2018 to 91.9% of GDP in 2050. Obviously, it is implausible for the net income of the S&P 500 to become such a large component of GDP.

Table 13
Projected S&P 500 Earnings and Nominal GDP
2018-2050
S&P 500 Aggregate Net Income as a Percent of GDP

Using Mr. Hevert's Growth Rate Estimate

	2018 Value	Growth Rate	No. of Years	2050 Value
Aggregate Net Income for S&P 500 Companies	1,406,400.0	13.10%	32	72,364,670.4
2018 Nominal U.S. GDP	20,891,000.0	4.23%	32	78,735,624.7
Net Income/GDP (%)	6.73%			91.9%

Data Sources: 2018 Aggregate Net Income for S&P 500 companies – *Value Line* (March 12, 2019).
2018 Nominal GDP – Moody's - https://www.economy.com/united-states/nominal-gross-domestic-product.
S&P 500 EPS Growth Rate - Average of Hevert's Bloomberg and *Value Line* growth rates - 11.47% and 14.73%;
Nominal GDP Growth Rate – The average of the long-term projected GDP growth rates from CBO, SSA, and EIA (4.0%, 4.4%, and 4.3%).

Q. PLEASE PROVIDE A SUMMARY ANALYSIS ON GDP AND S&P 500 EPS GROWTH RATES.

A. As noted above, the long-term link between corporate profits and GDP is inevitable. The short-term differences in growth between the two have been highlighted by some notable market observers, including Warren Buffet, who indicated that corporate profits as a share of GDP tend to go far higher after periods where they are depressed, and then drop sharply after they have been hovering at historically high levels. In a famous 1999 *Fortune* article, he made the following observation: [64]

> You know, someone once told me that New York has more lawyers than people. I think that's the same fellow who thinks profits will become larger

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[64] Carol Loomis, "Mr. Buffet on the Stock Market," *Fortune*, November 22, 1999. https://money.cnn.com/magazines/fortune/fortune_archive/1999/11/22/269071/.

> than GDP. When you begin to expect the growth of a component factor to forever outpace that of the aggregate, you get into certain mathematical problems. In my opinion, you have to be wildly optimistic to believe that corporate profits as a percent of GDP can, for any sustained period, hold much above 6%. One thing keeping the percentage down will be competition, which is alive and well. In addition, there's a public-policy point: If corporate investors, in aggregate, are going to eat an ever-growing portion of the American economic pie, some other group will have to settle for a smaller portion. That would justifiably raise political problems--and in my view a major reslicing of the pie just isn't going to happen.

In sum, Mr. Hevert's long-term S&P 500 EPS growth rates of 11.47% and 14.73% are grossly overstated and are not credible. In the end, the big question remains as to whether corporate profits can grow faster than GDP. Jeremy Siegel, the renowned finance professor at the Wharton School of the University of Pennsylvania, believes that, going forward, earnings per share can grow about half a point faster than nominal GDP, or about 5.0%, due to the big gains in the technology sector. But he also believes that sustained EPS growth matching analysts' near-term projections is absurd: "The idea of 8% or 10% or 12% growth is ridiculous. It will not happen."[65]

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE CAPM RESULTS FROM USING *VALUE LINE* DATA.

A. There are several additional issues with the CAPM-*Value Line* results. Simply put, Mr. Hevert's 16.81% expected stock market return shown in Exhibit RBH-3,

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[65] Shaun Tully, "Corporate Profits Are Soaring. Here's Why It Can't Last," *Fortune*, December 7, 2017. http://fortune.com/2017/12/07/corporate-earnings-profit-boom-end/.

p. 14 is outrageous.[66] The compounded annual return in the U.S. stock market is about 10% (9.49% according to Damodaran between 1928-2018).[67] Mr. Hevert's *Value Line* CAPM results assume that return on the U.S. stock market will be more than 50% higher in the future than it has been in the past. The extremely high expected stock market return, and the resulting market risk premium and equity cost rate results, are directly related to the 14.73% expected earnings per share growth rate. There are a number of fallacies with this growth rate. First, the expected growth rate is not from today going forward, but instead it is computed from a three-year base period in the past (2015-2017) to a projected three-year period in the future (2022-2024). The problem here is that it incorporates historic growth in the base period, which can inflate projected growth for the future if the base period includes poor earnings. This issue was previously discussed as it related to the use of *Value Line* EPS growth rates in the DCF model. Second, and most significantly, a projected growth rate of 14.73% does not reflect economic reality. As noted above, it assumes that S&P 500 companies can grow their earnings in the future at a rate that is triple the expected GDP growth rate.

C. Bond Yield Risk Premium ("BYRP") Approach

Q. PLEASE DISCUSS MR. HEVERT'S BYRP APPROACH.

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[66] The 16.81% stock return is the presumed annual S&P 500 stock market return (forever!) computed using *Value Line* data. It is the sum of a dividend yield of 2.08% and a long-term EPS growth rate of 14.73% for *Value Line*.

[67] http://pages.stern.nyu.edu/~adamodar/

A. On pages 72-75 of his testimony and in Exhibit No. RBH-6, Mr. Hevert develops an equity cost rate using his Bond Yield Risk Premium approach. Mr. Hevert develops an equity cost rate by: (1) regressing the authorized returns on equity for gas distribution companies from the January 1, 1980to January 18, 2019, time period on the thirty-year Treasury Yield; and (2) adding the risk premium established in step (1) to three different thirty-year Treasury yields: (a) current yield of 3.04%, a near-term projected yield of 3.25%, and a long-term projected yield of 4.05% Mr. Hevert's risk premium results are provided in Exhibit JRW-11. He reports Bond Yield Risk Premium equity cost rates ranging from 9.89% to 10.11%.

Q. WHAT ARE THE ERRORS IN MR. HEVERT'S ANALYSIS?

A. There are errors in both the risk-free rate and the risk premium components.

1. Current and Projected Risk-Free Interest Rates

Q. PLEASE DISCUSS THE RISK-FREE RATE OF INTEREST IN MR. HEVERT's BYRP APPROACH.

A. As with his CAPM approach, Mr. Hevert has used three different measures of the 30-Year Treasury bond yield - a current yield of 3.04%, a near-term projected yield of 3.25%, and a long-term projected yield of 4.05%. As previously discussed, the current 30-Year Treasury rate is 2.55% and so Mr. Hevert's current, near-term projected, and long-term projected yield are unrealistic.

2. Risk Premium

Q. WHAT ARE THE ISSUES WITH MR. HEVERT'S RISK PREMIUM?

A. There are several problems with this approach. First, his Bond Yield Risk Premium methodology produces an inflated measure of the risk premium because the approach uses historic authorized ROEs and Treasury yields, and the resulting risk premium is applied to projected Treasury Yields. Since Treasury yields are always forecasted to increase, the resulting risk premium would be smaller if done correctly, which would be to use projected Treasury yields in the analysis rather than historic Treasury yields.

In addition, Mr. Hevert's Risk Premium approach is a gauge of *commission* behavior and not *investor* behavior. Capital costs are determined in the market place through the financial decisions of investors and are reflected in such fundamental factors as dividend yields, expected growth rates, interest rates, and investors' assessment of the risk and expected return of different investments. Regulatory commissions evaluate capital market data in setting authorized ROEs, but also take into account other utility- and rate case-specific information in setting ROEs. As such, Mr. Hevert's approach and results reflect other factors such as capital structure, credit ratings and other risk measures, service territory, capital expenditures, energy supply issues, rate design, investment and expense trackers, and other factors used by utility commissions in determining an appropriate ROE in addition to capital costs. This may especially be true when the authorized ROE data includes the results of rate cases that are settled and not fully litigated.

Finally, Mr. Hevert's methodology produces an inflated required rate of return since utilities have been selling at market-to-book ratios in excess of 1.0 for many years. As was explained earlier in Part VI.A, a market-to-book ratio above 1.0 indicates a company's ROE is above its equity cost rate. Therefore, a risk premium based on authorized returns can be expected to produce an inflated equity cost rate.

D. Expected Earnings Approach

Q. PLEASE REVIEW MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. On pages 75-76 of his testimony and in Exhibit RBH-7, Mr. Hevert develops an equity cost rate using his Expected Earnings approach. Mr. Hevert's approach involves using *Value Line*'s projected ROE for the years 2021-23/2022-24 for his proxy group and then adjusting this ROE to account for the fact the *Value Line* uses year-end equity in computing ROE. Mr. Hevert's Expected Earnings results are summarized in Panel D of page 1 of Exhibit JRW-11. He reports an Expected Earnings result of 10.73%.

Q. PLEASE ADDRESS THE ISSUES WITH MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. There are a number of issues with this so-called Expected Earnings approach. As such, I strongly suggest that the Commission ignore this approach in setting an ROE for Piedmont. These issues include:

The Expected Earnings Approach Does Not Measure the Market Cost of Equity Capital – First and foremost, this is an accounting-based methodology that does not measure investor return requirements. As indicated by Professor Roger Morin, a long-time rate of return witness for utility companies, "More simply, the Comparable (Expected) Earnings standard ignores capital markets. If interest rates go up 2% for example, investor requirements and the cost of equity should increase commensurably, but if regulation is based on accounting returns, no immediate change in equity cost results."[68] As such, this method does not measure the market cost of equity capital.

Changes in ROE Ratios do not Track Capital Market Conditions - As also indicated by Morin, "The denominator of accounting return, book equity, is a historical cost-based concept, which is insensitive to changes in investor return requirements. Only stock market price is sensitive to a change in investor

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[68] Roger Morin, *New Regulatory Finance* (2006), p. 293.

requirements. Investors can only purchase new shares of common stock at current market prices and not at book value."[69]

The Expected Earnings Approach is Circular - The ROEs ratios for the proxy companies are not determined by competitive market forces, but instead are largely the result of federal and state rate regulation, including the present proceedings.

The Proxies' ROEs Reflect Earnings on Business Activities that are not Representative of Piedmont's Rate-Regulated Utility Activities - The numerators of the proxy companies' ROEs include earnings from business activities that are riskier and produce more projected earnings per dollar of book investment than does regulated transmission with formula rates. These include earnings from unregulated businesses such as gas marketing operations, wholesale gas sales, gas storage, construction services, and other energy services.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF MR. HEVERT'S EXPECTED EARNINGS APPROACH.

A. In short, Mr. Hevert's Expected Earnings approach does not measure the market cost of equity capital, is independent of most cost of capital indicators and, as

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[69] *Id.*

shown above, has a number of other empirical issues. Therefore, the Commission should ignore this approach in determining the appropriate ROE for Piedmont.

E. Other Issues

1. Piedmont's Capital Expenditures

Q. PLEASE ADDRESS MR. HEVERT'S CONSIDERATION OF THE COMPANY'S CAPITAL EXPENDITURES.

A. Mr. Hevert also considers the magnitude of Piedmont's capital expenditures in arriving at his 10.60% ROE recommendation. Capital expenditures are a risk factor considered as part of the credit-rating process used by major rating agencies. In addition, as I noted above, Piedmont's S&P and Moody's credit ratings of A- and A3 suggest that the Company's investment risk is in line with other gas companies.

2. Flotation Costs

Q. PLEASE DISCUSS MR. HEVERT'S ADJUSTMENT FOR FLOTATION COSTS.

A. Mr. Hevert argues that a flotation cost adjustment is appropriate for Piedmont and he has considered flotation costs in arriving at his 10.60% ROE recommendation.

First and foremost, Mr. Hevert has not identified any flotation cost for Piedmont. Therefore, he is asking for higher revenues in the form of a higher ROE for expenses that he has not identified.

Second, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the existing shareholders. This is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for gas distribution companies are over 1.95X actually suggests that there should be a flotation cost reduction (and not an increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of gas distribution companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above, gas distribution companies are selling at market prices

well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per-share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Therefore, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, and who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transaction costs, it has not accounted for other market transaction costs in determining its cost of equity. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by

investors to buy shares. If the Company had included these brokerage fees or transaction costs in its DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to their DCF equity cost rate.

VIII. NORTH CAROLINA ECONOMIC CONDITIONS AND PIEDMONT'S RATE OF RETURN AND REVENUE RECOMMENDATIONS

Q. PLEASE DISCUSS MR. HEVERT'S CONSIDERATION OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. Mr. Hevert has acknowledged that the North Carolina Commission must balance the interests of investors and customers in setting the ROE. In addition, Mr. Hevert notes that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions.[70] On this issue, the ROE should be the minimum amount needed to meet the *Hope* and *Bluefield* standards. Finally, Mr. Hevert also highlights that the North Carolina Supreme Court also has indicated that in retail utility service rate cases the Commission must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility.[71]

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[70] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Sept. 24, 2013 at 24; see also DEC Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").

[71] *State of North Carolina ex rel. Utilities Commission v. Cooper*, 758 S.E.2d 635, 642 (2014) ("Cooper II").

With respect to this latter mandate, Mr. Hevert evaluates a number of factors such as employment and income levels and, based on his review of the data, comes to the following conclusion: Piedmont's proposed ROE of 10.60 percent is fair and reasonable to Piedmont, its shareholders, and its customers in light of the effect of those changing economic conditions.[72]

Q. DO YOU AGREE WITH MR. HEVERT'S ASSESSMENT OF ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. As highlighted by the correlations between U.S. and North Carolina economic data, I agree with Mr. Hevert that economic conditions have improved with the overall economy over the past decade.

Q. DO YOU AGREE WITH MR. HEVERT'S CONCLUSION THAT THE IMPROVEMENT IN ECONOMIC CONDITIONS IN NORTH CAROLINA AND THE COMPANY'S SERVICE TERRITORY JUSTIFY THE COMPANY'S PROPOSED RATE OF RETURN INCLUDING A 10.60% ROE?

A. No. Whereas economic conditions have improved in North Carolina, it does not necessarily justify such a high rate of return and ROE. I have three observations on Mr. Hevert' assessment of the economic conditions in North Carolina and Piedmont's service territory.

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[72] Hevert Testimony, pp. 43-4.

1. Whereas North Carolina's unemployment rate has fallen by one-third since its peak in the 2009-2010 period and is equal to the national average of 3.70%, the unemployment rate in Piedmont's service territory is seventy basis point higher at 4.40%;

2. As Mr. Hevert notes, North Carolina's median household income has grown at a somewhat slower pace than the national average, and is more than 10% below the U.S. norm; and

3. North Carolina's natural gas residential rates are more than 15% higher than national average gas rates.

Q. WHAT IS YOUR CONCLUSION REGARDING THE ECONOMIC CONDITIONS IN NORTH CAROLINA AND THE COMPANY'S SERVICE TERRITORY?

A. The higher level of natural gas residential rates in North Carolina, coupled with lower level of household income in the state and the higher level of unemployment in Piedmont's service territory suggest that affordability can be an issue for an essential utility service such as natural gas. And Piedmont's overall rate of return request has a significant impact on its overall requested increase in revenues.

Q. HOW MUCH OF AN IMPACT DOES THE COMPANY'S RATE OF RETURN REQUEST HAVE ON THE COMPANY'S OVERALL INCREASE IN REVENUES.

A. Page 1 of Exhibit JRW-13 provides a summary of Piedmont's overall rate of return and revenue. This comes from Piedmont's revenue requirement exhibits (Exhibits_ (PKP)-1 through (PKP)-8. Page 2 of Exhibit_ (PKP)-7 provide the revenue requirements and capital costs. Page 1 of Exhibit JRW-13 is the Company's position and shows the Company's overall annual operating revenue increase of $253,435,633 with Piedmont's proposed 52.0% common equity ratio and 10.60% ROE. Page 2 of Exhibit JRW-13 provides Piedmont's revenues increase but substitutes the 50%/50% debt-equity capital structure and 9.00% ROE that I have recommended. Without any other changes to Piedmont's proposal, my rate of return recommendations reduce the overall revenue increase by $58 million per year to $195,468,893. As I discussed earlier in my testimony, a 50%50% debt-equity capital structure and a 9.00% ROE is more than adequate to meet *Hope* and *Bluefield* standards with respect to comparable returns, financial integrity and ability to attract capital.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. He has taught Finance courses including corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on empirical issues in corporation finance and financial markets. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance*, the *Journal of Financial Economics*, and the *Harvard Business Review*. His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes*, *Fortune*, *The Economist*, *Barron's*, *Wall Street Journal*, *Business Week*, *Investors' Business Daily*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg's *Morning Call*.

Professor Woolridge's stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a textbook entitled *Basic Principles of Finance* (Kendall Hunt, 2011).

Professor Woolridge has also consulted with corporations, financial institutions, and government agencies. In addition, he has directed and participated in university- and company-sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Over the past twenty-five years Dr. Woolridge has prepared testimony and/or provided consultation services in regulatory rate cases in the rate of return area in following states: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Indiana, Kansas, Kentucky, Maryland, Massachusetts, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, and Washington, D.C. He has also testified before the Federal Energy Regulatory Commission.

J. Randall Woolridge

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814-865-1160

Home Address
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State College, PA 16801
814-238-9428

Academic Experience

Professor of Finance, the Smeal College of Business Administration, the Pennsylvania State University (July 1, 1990 to the present).

- **President, Nittany Lion Fund LLC,** (January 1, 2005 to the present)
- **Director, the Smeal College Trading Room** (January 1, 2001 to the present)
- **Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration** (July 1, 1987 to the present).

Associate Professor of Finance, College of Business Administration, the Pennsylvania State University (July 1, 1984 to June 30, 1990).

Assistant Professor of Finance, College of Business Administration, the Pennsylvania State University (September, 1979 to June 30, 1984).

Education

Doctor of Philosophy in Business Administration, the University of Iowa. Major field: Finance.
Master of Business Administration, the Pennsylvania State University.
Bachelor of Arts, the University of North Carolina. Major field: Economics.

Books

James A. Miles and J. Randall Woolridge, *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation), 1999
Patrick Cusatis, Gary Gray, and J. Randall Woolridge, *The StreetSmart Guide to Valuing a Stock* (2nd Edition, McGraw-Hill), 2003.
J. Randall Woolridge and Gary Gray, *The New Corporate Finance, Capital Markets, and Valuation: An Introductory Text* (Kendall Hunt, 2003).

Research

Dr. Woolridge has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.*

COMMISSIONER BROWN-BLAND: The exhibits need to be identified.

MS. FORCE: And would you please identify those as Exhibits JRW-1 through JRW-13?

COMMISSIONER BROWN-BLAND: Yes, they will be so identified.

MS. FORCE: Thank you.

(Exhibits JRW-1 through JRW-13 were
marked for identification.)

Q. Do you have a copy?

A. I do.

Q. Okay. I'm going to pass out the summary, and would you go ahead and start reading that?

A. Okay. Good morning, Commissioners. Thank you for having me and allowing me to go a little early today. My testimony focuses on the cost of capital for Piedmont. I have used -- on the return of equity, I have used the discounted cash flow and capital asset pricing model approaches and established a rate of return on equity in the range of 7.6 to 8.7 percent. As a primary return on equity recommendation for Piedmont, I have chosen 9 percent with a 50 percent debt and a 50 percent equity capital structure. As an alternative return on equity recommendation, I am recommending 8.7 percent with the Company's proposed 52 percent equity, 48 percent debt capital structure.

As summarize in my testimony, there is a number of issues with respect to the cost of capital for Piedmont. The first is your capital market conditions. The Company's return on equity recommendation is based on the assumption of higher interest rates and capital costs. As I document in my testimony, economists have been saying that interest rates are going up for a decade, and they have been wrong. In fact, the New York fed stopped using these forecasts in 2015 because they have been so bad.

In addition, I also show that as the fed has increased the federal funds rate seven times over the 2015-'18 time period, the 30-year treasury yield has remained about 3 percent range. Now, due to slow growth, low inflation, and with the trade issue with China looming, rates have declined in 2019. And in July, the Federal Reserve cut the federal funds rate. And last week, as Mr. Hevert stated yesterday, the 30-year treasury hit an all-time low yield at about 2 percent.

With respect to the discounted cash flow approach, as I indicate in my testimony, I have reviewed 13 alternative growth rates for my proxy groups, and give primary weight to analysts' earnings per share growth rate forecasts. Mr. Hevert relies exclusively on what I call the overly optimistic and upwardly biased earnings per share growth rates of Wall Street analysts.

As I demonstrate in my testimony, there are issues with the value line growth rates for the gas companies. They are computed from a three-year base period and not from the present. As I indicate, the value line growth rates are high for eight of the nine proxy companies including outlier growth rates such as 25.5 percent for Northwest Natural Gas.

The capital asset pricing model requires an estimate of the risk-free rate, beta, and the market risk premium. Mr. Heaver uses projected interest rates that are well above current yields. But the biggest issue is the market risk premium. I use a market risk premium of 5.5 percent, which is based over 30 studies and surveys, historical returns and ex ante expectations, including the Duke/CFO Magazine Global Business Outlook Survey.

Mr. Hevert ignores all the results of the published market risk premium studies and conducts his own study. In his approach, he applies the discounted cash flow model to the S&P 500 and uses earnings per share growth rates as the discounted cash flow growth rate. As I note above, it is well above the projected earning per share growth rates of Wall Street analysts. It's well known and documented that they are overly optimistic and upwardly biased.

Mr. Hevert's study uses growth rates in excess of 10 percent per year for the S&P 500. I demonstrate that earnings growth rates are constrained by the growth of the economy or gross domestic product. Currently, I show that the earnings of the S&P 500 represent about 6 percent of GDP. If they grow as Mr. Hevert's overstated growth rates, while gross domestic product grows at its projected rate of 4.5 percent, the profits of the S&P 500 companies will be almost 100 percent GDP by the year 2050. Obviously, this is impossible. On this issue, I quote Warren Buffet who has observed that, quote, you have to be wildly optimistic to believe that corporate profits as a percent of gross domestic product can, for any sustained period, hold much above 6 percent.

Mr. Hevert's premium risk study is based on a regression of authorized return on equity, ROEs, for gas companies and U.S. treasury bond yields since 1980. His risk premium results overstate the required returns in several ways. First, he uses the treasury yields of 3.04 percent, 3.25 percent, and 4.05 percent, which are anywhere between a 100 and 200 basis points above current treasury yields. Second, the market-to-book ratios for gas companies are in excess of 2.0, which indicates the current rates on equity are well above the returns of investors require. And third, Mr. Hevert uses the authorized returns approved by regulatory commissions in his analysis, rather than the stock market data, so his risk analysis is more effective as a measure of the behavior of regulatory commissions than it is of investors' behavior.

There are two other issues. First, Mr. Hevert notes that Piedmont's capital expenditure program makes the Company risker than other gas companies. However, I note that Piedmont's S&P and Moody's ratings of A- and A3 are in line with other gas companies. In addition, Mr. Hevert cites floatation costs. However, he's not identified any floatation costs for Piedmont. Therefore, there is no reason to give Piedmont higher revenues in the form of higher ROE for floatation costs that it does not incur.

With respect to economic conditions in North Carolina and in Piedmont's service territory, I concluded that the higher level of natural gas residential rates in North Carolina, coupled with a lower-level household income in the state, and higher level of unemployment in Piedmont's service territory suggest that affordability can't be an issue for an essential utility service such as natural gas.

Finally, in my testimony, I attempted to provide an estimate of the revenue impact of the capital structure and return on equity in this case. As noted by Mr. Hevert, my attempted analysis using the Company's document had some errors. Therefore, we asked the Company to provide a summary of the revenue impact of the settlement capital structure and return on equity relative to the Attorney General's position. The Company did not respond to the request, but it did provide a working spreadsheet. According to that spreadsheet, under the settlement, with a 52 percent common equity ratio and a 9.7 percent return on equity, the additional gross revenue requirement is $108,796,785. The AG's position, with a 52 percent common equity ratio and an 8.7 percent return on equity, the additional gross revenue requirement is

$85,341,751 for an annual difference of $23,445,034.

To be clear, at the end, 9.7 percent is considerably higher than what I view as being the market cost of equity, and the use of a high ROE has a significant revenue impact on the customers in North Carolina.

Here are my two final thoughts: First, there is no way Mr. Hevert's 30-year treasury yield had hit an all-time low yesterday, now hovers about slightly above 2 percent. The yield is almost 100 basis points below the 3.04 percent treasury yield in March when Mr. Hevert made his 10.6 percent ROE recommendation for Piedmont. Second, utility stocks, as measured by the Dow Jones Utility Index, has hit an all-time high this week. The bottom line, with historically low bond yields and high utility stock prices, capital costs are at record lows for public utilities.

Q. Does that conclude your summary?

A. It does.

MS. FORCE: The witness is available for cross-examination.

COMMISSIONER BROWN-BLAND: All right. Is there any intervenor cross-examination?

(No response.)

COMMISSIONER BROWN-BLAND: Mr. Jeffries?

MR. JEFFRIES: Thank you, Madam Chairman.

CROSS EXAMINATION BY MR. JEFFRIES:

Q. Do you prefer doctor or professor?

A. It doesn't matter.

Q. Okay. And what time is your flight?

A. It's at 1:00.

Q. Okay. I'll do my best not to keep you from getting that.

A. Thank you.

Q. I think I'm probably the principle obstacle, so let's get started.

COMMISSIONER BROWN-BLAND: Let me ask both of you, as you have this discussion, make sure you speak into the mic.

MR. JEFFRIES: Thank you.

Q. You're a professor at Penn State, correct?

A. Yes, I am.

Q. And it looks to me, from your résumé, that you've had two primary pursuits in your career. One is being a professor at Penn State, and the other is working as a consultant providing analysis and testimony before various state and federal regulatory commissions; is that correct?

A. I've done that. I've done a number of other consulting jobs for financial institutions, investment banks, that sort of thing.

Q. Okay. Your résumé doesn't indicate that you've ever worked for regulated utilities.

A. No, I haven't.

Q. Okay. And no experience as a state or federal regulatory commissioner?

A. No.

Q. Okay. And you frequently testify in cost of equity capital for regulated utilities, though; is that correct?

A. Yes. I run into Mr. Hevert a lot.

Q. Is it fair to say that your analysis on cost of capital is typically focused on applying one or more of the various econometric models used for that purpose, discounted cash flow, CAPM comparable earnings type?

A. Yes.

Q. Okay. And it's not unusual for there to be other cost of capital witnesses in the cases you appear in, right?

A. That's correct.

Q. Okay. And, typically, the utility would have a witness, and one or more consumer advocates would have a witness?

A. Some industrial intervenors, others, yeah. Sometimes the staff has witnesses as well.

Q. Right. In fact, that's what's happened in this case, right?

A. Yes.

Q. Okay. And it's not unusual for the company witness and the consumer advocate witness to disagree on recommended ROEs, is it?

A. No. Mr. Hevert and I disagree on some issues, and -- you know, there's disagreement in every rate case in every area, and including return on equity and cost of capital.

Q. Right. And it's also not unusual for the folks that are serving as cost of capital witnesses to use variations -- different variations of the econometric models we discussed; is that right?

A. Yeah. I mean, there's judgment in everything we do. Which models we use, what inputs we use, what are reasonable inputs. So yeah, I mean, there's judgment in all the applications and in the selection of the models.

Q. And not to belabor the obvious, but it's pretty typical that the company's cost of capital witness recommends a higher ORE and the consumer advocate witnesses recommended a lower ROE, correct?

A. Yes.

Q. So you would recognize, would you not, Dr. Woolridge, that, after the expert testimony is filed and considered by the Commission, at the end of the day, the determination of an appropriate return on equity is usually decided by the Commission, correct?

A. Yes.

Q. Okay. And, in this case, that decision will be made by the commissioners we're appearing in front of, correct?

A. Yes.

Q. Okay. And they're able to look at factors beyond just the economic -- econometric models prepared by you and other cost of capital witnesses, right?

A. Yes.

Q. All right. Is it your understanding that, in undertaking its valuation, the Commission is entitled to treat, as material evidence, an agreement by some or all of the parties to this case as to the appropriate cost of capital?

A. Yes.

Q. Okay. And you recognize, of course, that the majority of active parties in this case have reached agreement on the appropriate cost of capital for Piedmont, right?

A. Yes.

Q. And that agreement is reflected in the stipulation that was filed by Piedmont, the Public Staff, CUCA and CIGFUR IV on August 12, 2019?

A. Yes.

Q. And among other things, that agreement reflects a 52 percent equity ratio and a 9.7 return on common equity?

A. It does.

Q. Now, in your testimony, you propose two alternative equity ratios, I believe?

A. I did, yes.

Q. And with varying ROEs that correspond to those equity ratios?

A. Yes.

Q. Okay. And one was a proposal for a 50 percent equity ratio and a 9.0 percent ROE, correct?

A. Yes.

Q. And the other is, if the equity ratio is

52 percent, then you would recommend an 8.7 percent ROE?

A. That's correct.

Q. Okay. And we just established that the settlement stipulation contains a 52 percent equity ratio, correct?

A. Yes, which the Company proposed.

Q. All right. And so unless the Commission were to throw out that stipulated equity ratio, your recommendation to the Commission today, in the context of the stipulation, is that an 8.7 return on equity is the appropriate?

A. Yes.

Q. Okay. Thank you. So we've already discussed the fact that cost of capital witnesses have some discretion in the selection of the models they use, and also in the inputs for those models, right?

A. Yes.

Q. Okay. And that happened in this case, both with you and Mr. Hevert, correct?

A. Yes.

Q. Okay. And, in fact, a significant part of your testimony is devoted to a critique of Mr. -- and your summary as well -- devoted to a critique of

Mr. Hevert's analysis and the various inputs he used in conducting that analysis; and a good bit of his rebuttal testimony is similarly addressed to what he contends are flaws in your analysis, right?

A. That is correct.

Q. On page 3 of your testimony, you identify several factors that you contend support the reasonableness of your return recommendations?

A. Yes.

Q. And I'm paraphrasing here, and tell me if I get this wrong, but there are four of them. One of them is historically low interest rates and capital costs; the other is low-risk characterization of the natural gas industry by value line; the third is consistent risk profile of Piedmont with the proxy group; and the fourth are declining rates of return on equity.

A. Yes.

Q. Do you believe that these factors are equally applicable to the gas companies in your proxy group?

A. No. I mean, the proxy group is just to put together a group that you feel are similar in risk and then apply these models. So, you know, it may affect one versus the other a little bit differently, like, one may be a little bit riskier than the other and that sort of thing, but that's why you average them out to get something that you feel is consistently reflective of the business.

Q. Okay. So let's look at these individually. The first factor, historically low interest rates and capital cost.

Is your testimony that what you meant by that was only with respect to Piedmont, or are those industry-wide characteristics?

A. That's industry-wide.

Q. Okay. And number two, the low-risk characterization of the natural gas industry; that's clearly industry-wide, right?

A. That is, but, you know, different companies in the proxy group have different betas and different credit ratings. So within the proxy group, there may be differences, but the average, especially the average credit rating, is similar to Piedmont's.

Q. Right. And number three is the consistent risk profile of Piedmont with the proxy group.

I'm thinking that, if Piedmont has a consistent risk profile with the proxy group, that the proxy group must also have a consistent risk profile with Piedmont?

A. The average of the proxy.

Q. Okay. Okay. And then declining rates or return on equity, you weren't talking just about Piedmont's equity?

A. No. That's nationwide.

Q. All right. Thank you. So if -- well, let me just ask you this:

What is the average return or earned return on equity for your proxy group?

A. Average earned?

Q. Yes.

A. It's around 9 percent, 9.7 percent. That's the earned return.

Q. Right. And that's reflected on page 18, line 21 of your testimony, right?

A. Yes.

Q. The 9.7 figure?

A. Yes.

Q. Okay. And that's the same as the stipulated return in this case, correct?

A. It is.

Q. Okay. Are you familiar with Mr. Sullivan's explanation for why the Company chose an equity ratio of 52 percent?

A. Yes.

Q. And I believe he testified that recent -- in the recent past, future predicted equity ratios are -- were and are expected to be in excess of 53 percent; is that right?

A. Yes. I think he testified -- yesterday he testified about how it bumped down because of the $600 million bond. Yeah, it's going to move around a little bit.

Q. And he provided -- he sort of illustrated that in his Exhibit JLS-1, right, where he sort of gave four snapshots, right?

A. Yes.

Q. Okay. So -- but the end of the test period, which was December 31, 2018, that ratio was 53.43 percent, correct?

A. Yes.

Q. And then, within the two-year planning window, the Company is projecting a 53.31 percent equity ratio, right?

A. Yes.

Q. Okay. You also noted a moment ago that Mr. Sullivan's testimony, that the Company had issued a large debt issuance recently and that drove the equity ratio down, right?

A. Yes.

Q. And all else -- all other things being equal, that's what you'd expect to happen when you issued a large debt?

A. Certainly. For gas companies, it really happens a lot over the year quarter to quarter, day to day because of using short-term debt to fund gas inventories.

Q. Okay. Do you have any basis to challenge Mr. Sullivan's testimony about the past or the anticipated future movements of Piedmont's actual capital structure?

A. No.

Q. Okay. Would you concede that he probably has a better vantage point over the Company's planned capitalization going forward than you do?

A. Oh, he does. But again, I look at outside, what's going on outside. What are the capital structures of the gas companies. I look at the average approved equity ratio, which is about 50 percent as published by Regulatory Research Associates, that sort of thing. So there's other benchmarks to look at.

Q. Right. So you were looking at, sort of, for lack of a better phrase, industry norms as opposed to what Piedmont's actual anticipated capital --

A. That's correct.

Q. Okay. Thank you. So let's talk about your 50 percent equity proposal here for a minute.

MR. JEFFRIES: May I approach the witness, Your Honor?

COMMISSIONER BROWN-BLAND: Yes, you may.

Q. So, Dr. Woolridge, I'm going to hand you what was admitted into evidence yesterday by Mr. Sullivan as Exhibit JLS-4. We made additional copies in case people lost theirs from yesterday, and we've actually added the exhibit designation on here. But I will represent to you that this is the same document that Mr. Sullivan entered into evidence.

Dr. Woolridge, can you locate the 2016 -- well, let me start with this. And just to refresh everybody's recollection, this is a summary of significant gas and electricity rate cases, and from the period 2008 to 2018 issued by the North Carolina Utilities Commission. It -- the chart shows the company involved, the nature of the service, the docket numbers, the date of the order, the allowed overall return, the percentage equity, and allowed return on equity over that time period.

Could you locate the 2016 rate case involving Public Service Company of North Carolina on this chart.

A. Yes.

Q. Okay. And to my knowledge, this is the most recent decision of the North Carolina Utilities Commission in a natural gas rate case.

What is the equity ratio indicated and was adopted in that case?

A. 52 percent.

Q. Okay. And what are the equity ratios reflected for the 2018 DEC and DEP rate case decisions by the Commission?

A. 52 percent. Seems to be a popular number here.

Q. I think you've made my point.

And you're aware, of course, that DEC and DEP are sister utilities to Piedmont, correct?

A. Yes.

Q. And would you agree with me that 8 of the 13 rate case results summarized on this exhibit reflect an equity ratio of 52 percent or higher?

A. Yes.

Q. And one reflects an equity ratio that is just below 52 percent at 51.75, right?

A. Yes. A couple at 51 and 50.66.

Q. Right. Right. Yeah, there are several below the 52 mark, right?

A. Yes.

Q. It's not fair of me to ask you to average all 13 equity ratios reflected on this schedule, but would you accept, subject to check, that the average ratio is 52.07?

A. Yeah. It is a popular number. Yes, I would agree.

Q. And to be fair, would you also accept, subject to check, that the ratio for the gas cases is slightly lower than that at 51.92?

A. Yes.

Q. Okay. Thank you. So based on the Commission's resolution of major electric and natural gas rate cases in the last 10 years as reflected on this exhibit, would you agree with me that a 52 percent equity ratio in this case would not be aberrational?

A. I mean, it would be consistent with the -- with the practice of this Commission. Again, you know, you look at other benchmarks, like, RRA publishes it, for gas companies, about 50 percent. It's been that way for a couple of years. It goes up and down depending on what commissions, what companies were in rate cases, but it's been around there. And that's a similar number for the electric utilities as well.

Q. And do you recall Witness O'Donnell's direct testimony, whether he took issue with Piedmont's proposed equity ratio of 52 percent?

A. I don't believe he did. I'm not sure. He might have. I forget.

Q. Okay. So I'd like to switch over to talk about return on equity for a little bit.

And so, as we discussed, based on a 52 percent equity ratio, your recommendation is 8.7 percent return on equity, right?

A. Yes.

Q. And 8.7 percent was the top of the range you recommended as a result of your econometric analysis, right?

A. Yes.

Q. The entire range was 7.6 percent to 8.7 percent?

A. Yes, it was. And my other approach indicated lower. And I think it was pretty consistent with some of the other witnesses in this case about where -- you know, being around 9 percent or in that vicinity.

Q. Yeah. In fact, there were four separate ROE recommendations in this case, right --

A. Yes.

Q. -- by expert witnesses? Okay. And we're going to go back to Exhibit JLS-4 for a few minutes. We were looking at equity ratios before, and we're going to look at the last column this time, which is the ROEs.

What's the lowest ROE you see reflected on this exhibit?

A. I see 9.7 percent in the 2016 gas case.

Q. Yeah. That's the PSNC case, right?

A. Yes.

Q. But you're recommending that Piedmont be allowed to return on common equity that is at least 100 basis points lower than PSNC was awarded, correct?

A. Yes. My explanation was just in my summary and in my testimony about why it is. It's about the market conditions and the market cost of capital.

Q. And are you aware of what Piedmont's current allowed ROE is?

A. I believe it's 10 percent.

Q. Right. So the differential between its current ROE and what you're proposing would be -- or the high end of what you're proposing is 130 basis points, right?

A. Yes. And I forget -- I forget. I think that was established several years ago, I know that, and interest rates were higher, capital market conditions were different.

Q. Yeah. And that's reflected on the chart there, the 2013 Piedmont decision that reflects the 10.0?

A. Yes.

Q. Okay. When you look at the ROE results reflected on this exhibit, what's the biggest sequential differential in ROEs awarded by the Commission that you see?

A. About 30 basis points.

Q. Okay. I agree with that. And over the entire 10-year period reflected on this exhibit, the entire range of ROE decisions spans only 100 basis points, correct?

A. Yeah, it does. I mean, if you go back, for example, to 2008, in 2008 the Commission was awarding 10.6, 10.7 percent. And you go back and look, the

30-year treasury was 5 percent then. You know, the 30 -- so today, 30-year treasury is about 2 percent. So it's declined 300 basis points. And I look at these ROEs, they declined about 70 or 80. So, you know, there's been a lag to catch up with what the -- with what the market -- capital markets say, you know, capital costs are.

Q. Have you ever observed a state or federal regulatory commission reduce a utility's allowed return on equity by 131 basis points in a single case?

A. I don't recall.

Q. Okay. A reduction of that magnitude would surely have a dramatic impact on Piedmont's ability to compete for capital, wouldn't it?

A. It would -- it would be -- you know, it would be lower than what they've been already. You know, I think the example was given yesterday of the cotter tail ^ getting 8.75. And so no, they would still be able to keep -- in my opinion, they could still compete for capital, because gas companies are very low risk, especially given all the adjustment mechanisms and that sort of thing. And that's where I highlighted, I said in my testimony to Moody's article, which talked about how authorized returns are coming down but the credit profiles have remained strong, and they're raising $50 billion a year in capital.

Q. So is your testimony that an 8.7 ROE allowance by this Commission would allow Piedmont to compete with the other members of your proxy group who are earning 9.7 equity?

A. Again, year to year -- in my -- in my study, if you look at JRW -- JRW-5, page 3, I show the earned returns on equity and the market-to-book ratios for electric utilities, and they've been in the 8 to 9 percent range over the last three years. They bumped some up in 2018. And their market-to-book ratios are over 2, which means it's over more than enough to meet investor return requirements. You know, you get a market above about 1, it tells you your earned return is above the return that investors require. Their earned return now has been in 8 to 9 percent range, now it's over 9 percent, and these are just the companies within the proxy group, and now their market-to-books are 2. I mean, obviously, if their market-to-books were below 1, I would say the returns are clearly inadequate.

Q. So just to be clear, we've established that the average earned return on equity for your proxy group is 9.7 percent; you testified to that in your prefiled testimony?

A. Last year, yes.

Q. Right. And your proposal is 8.7 for Piedmont, and your testimony is that that would not impair their ability to compete with this proxy group?

A. No, that's correct.

Q. Okay. Thank you. Do you think it would result in a ratings adjustment for Piedmont?

A. I don't -- I mean, you'd have to look at the metrics they use, in terms of their cash flow metrics, but, you know, a lot of these utilities are seeing lower returns because of the capital market conditions.

Q. So is the answer it would not result in a ratings downgrade or I don't know?

A. I don't know.

Q. Okay. Thank you.

Would it result in a reevaluation of this Commission's relative degree of supportiveness for its regulated utilities?

A. I mean, it would be something that RRA and others would look at.

Q. Okay. Dr. Woolridge, can you point us to a case where this Commission has ever approved a rate of return for an electric or natural gas utility that's lower than 9 percent?

A. No.

Q. How about 9.2?

A. I do not know.

Q. Okay.

A. But again, capital market conditions are -- you know, interest rates is historic low, utility stock prices is historic high. That says something about the cost of capital.

Q. Okay. So let's broaden our perspective a little bit.

MR. JEFFRIES: Madam Chair, may I approach the witness?

COMMISSIONER BROWN-BLAND: Yes, you may.

MR. JEFFRIES: I am going to apologize profusely for the size of this type, but I could not get it any bigger, so we're going to have to muddle through this together.

MS. FORCE: Can I get a copy of that, please, while you're passing them out first, so I could look at it while -- thank you.

MR. JEFFRIES: Madam Chair, we would request that this exhibit be marked for identification as Piedmont Woolridge Cross Exhibit Number 1.

COMMISSIONER BROWN-BLAND: It will be so identified.

(Piedmont Woolridge Cross Exhibit Number 1 was marked for identification.)

COMMISSIONER CLODFELTER: And we request that you have a larger typeface.

MR. JEFFRIES: If it makes you feel better, there will be more with larger type that reflect the same thing, but we're not going to spend a lot of time on this exhibit. There's just a couple of things I want to cover.

Q. Dr. Woolridge, would you look up in the upper left-hand corner of this document.

This indicates that it's an S&P global market intelligence kind of product; is that right?

A. Yes. I'm very familiar with these.

Q. And so it's -- what it is, it's a rate case's history from -- and if you look on about the fifth line down up on the left-hand corner it shows the years 2019, 2018, and 2017, correct?

A. Yes.

Q. And the services type is listed as natural gas, right?

A. Yes.

Q. Okay. So if you look, there's a couple of columns that are shaded in blue. And the first column shaded in blue indicates, at the top, that these are requested returns on equity and requested common equity percentages, right?

A. Yes.

Q. Okay. And then the second column is the approval date which shows -- appear to be in sequence starting in early 2017 and going through on the second page to as late as May of 2019, correct?

A. Yes.

Q. Okay. And as you look at the company names that are indicated -- and I should say the far left column indicates the state of the decisions, and the second column indicates the companies, right?

A. Yes.

Q. And you're familiar with the natural gas distribution industry, I take it?

A. Yes.

Q. Okay. And did those look like natural gas distribution companies listed in the company column?

A. Oh, yes.

Q. And you don't see any interstate pipelines on there, do you?

A. No.

Q. Okay. So going back to the third shaded column, could you take a quick look and tell us how many rate decisions, in 2017 through 2019, reflect an approved ROE below 9 percent?

A. I don't see any below 9 percent. I see a couple at 9 percent. I don't see any below 9 percent.

Q. Yeah. I think what I would tell you is that I think there actually are two, if I can find them. Maybe they're on the second page.

COMMISSIONER BROWN-BLAND: It's an eye examination.

THE WITNESS: I see an 8.7 percent in New York for National Fuel Gas.

Q. Right. Yeah. There are two. One is the one you just identified, and then there's another one for Central Hudson, which is also in New York.

A. 8.8 percent, yes.

Q. Correct?

A. Sorry I didn't pick those up.

Q. Now, listen, we're going to get out of this exhibit pretty quick before someone shoots me. So I will -- I won't ask you to count. I did.

It appears to me that there are 70 decisions listed on here, and two of those were below 9 percent, right?

A. And several were at 9 percent, yes.

Q. Okay. Would you look on the second page, and this is the last question on this exhibit. But would you look under the allowed ROE column and tell me what the average return on equity reflected on this chart is?

A. It looks like it's 9.84 percent, I believe, or -- and then 9.8 percent is a median which is -- you know, reflects -- again, this is -- reflects capital markets where interest rates were higher and, you know, capital costs were higher.

Q. Okay.

A. It reflects a couple -- I mean, I see a couple 9s, a couple below 9, I don't see any as high as 10.6. There is a 10.55, which is in Alaska. But I remember that Mr. Hevert was involved in that case as well. But, at that time -- in Alaska, there's some unique risk factors, and they were asking for 12.55.

Q. So let's give everybody's eyes a break and go to the next exhibit.

COMMISSIONER BROWN-BLAND: Mr. Jeffries, do you have much more?

MR. JEFFRIES: I'm sorry, I probably have 10 minutes, 15 minutes maybe, at the most.

COMMISSIONER BROWN-BLAND: I think we'll take our morning break now and come back at 11:30.

MR. JEFFRIES: Okay.

(At this time, a recess was taken from 11:16 a.m. to 11:30 a.m.)

COMMISSIONER BROWN-BLAND: Let's come back to order. All right, Mr. Jeffries, you can proceed.

MR. JEFFRIES: Thank you, Madam Chair. May I approach the Commission? I have an additional cross-examination exhibit.

COMMISSIONER BROWN-BLAND: Yes.

MR. JEFFRIES: Madam Chair, we would ask that this exhibit be identified as Piedmont Woolridge Cross Examination Exhibit Number 2.

COMMISSIONER BROWN-BLAND: It will be so identified.

(Piedmont Woolridge Cross Examination Exhibit Number 2 was marked for identification.)

COMMISSIONER BROWN-BLAND: And the record will reflect that this is kinder on the eyes than the previous exhibit.

MR. JEFFRIES: I apologize for that.

Q. Dr. Woolridge, is this form of report familiar to you?

A. It is. It's -- again, I guess, historically, this is called ROE Regulatory Research Associates, now they call it S&P Global Market Intelligence, but it's their utility product that they have compiled this type of information.

Q. Thank you. This indicates that, in addition to the source, it indicates that it's a table of electric and gas utility decisions, correct?

A. That's correct.

Q. And then, if you look along the left-hand margin, just to sort of get familiar with the exhibit, the dates -- their dates indicated, which are all in 2019, the first page are, at least as I understand it, and tell me if your understanding is the same, the first page below the -- or above the first white bar are decisions for electric companies in the first quarter of 2019; and then below that are decisions for electric companies in the second quarter of 2019.

Is that how you understand this?

A. Yes.

Q. And then, on the second page, there are decisions for gas companies, again, by quarter, first and second quarter, correct?

A. Yes.

Q. Okay. And again, no interstate pipelines on the second page, right, all LDCs?

A. That's correct.

Q. Okay. If you could focus your attention on the first quarter average on the second page, which is the white block about a quarter of the way down the page.

Can you tell us what the average ROE awarded to natural gas distribution utilities was in the first quarter of 2019?

A. It was 9.55 percent of -- and one of the things when you look at quarterly numbers, they kind of bounce around a lot. It really depends what state's reporting and, you know, that sort of thing. In this case, one case there, Baltimore Gas and Electric, that's a combination of electric and gas, and they tend have a little higher ROEs than pure gas companies.

Q. Okay. Can you tell us what the average ROE awarded was for the second quarter of 2019 for gas companies?

A. Yeah. There was only three cases where a decision on ROE was made. It was 9.73 percent. The average for the first half was 9.63 percent. That's a pretty low number of rate cases, just because of the ins and outs of rate cases, I guess, but that's a low number compared to what they usually have.

Q. There was actually a record number of rate cases filed last year, right?

A. Yes.

Q. Okay. So that might explain slightly lower numbers for this year?

A. Exactly.

Q. Okay. Are any companies whose cases were decided in the second quarter reflected on here in your proxy group?

A. Atmos Energy is in the proxy group, and of course they have subsidiaries in, I think, 10 different states, something like that. So this was a Texas decision.

Q. And that's their primary state, right?

A. Yes.

Q. Okay. What about the first quarter; are there any decisions in the first quarter?

A. No. I mean, no, none -- no pure gas companies in the proxy group.

Q. Right. Okay. Were any of the ROE decisions in the first quarter or the second quarter below 9.0 percent?

A. No. There was one at 9, yes.

Q. All right.

MR. JEFFRIES: Madam Chair, one final exhibit for Dr. Woolridge.

(Exhibit handed out.)

MR. JEFFRIES: Madam Chair, Piedmont would ask that the exhibit being distributed be marked and identified as Piedmont Woolridge Cross Exhibit 3.

COMMISSIONER BROWN-BLAND: It will be marked as Piedmont Woolridge Cross Examination Exhibit 3.

(Piedmont Woolridge Cross Exhibit 3 was marked for identification.)

Q. Dr. Woolridge, again, do you recognize this document?

A. Yes, I do.

Q. Okay. And it looks like, from the date in the upper right-hand corner, it was issued roughly three weeks ago; is that right?

A. Yes.

Q. Okay. I draw your attention to the graphic in the upper right corner of the first page of this exhibit. And, at least as I understand it, the top part of that graphic represents a comparison of 2018 rate case results for -- to the first half of 2019 for gas and electric companies?

A. Yes.

Q. Is that what you understand as well?

Electricity companies are on the left, gas companies on the right?

A. Yup, yes.

Q. Okay. And the bars indicate average allowed ROEs for various types of rate decisions by state utility commissions, right?

A. Yes.

Q. And, for example, on the gas side, there are four categories, there's an all cases comparison, a general category, a settle category, and a fully litigated, correct?

A. Yes.

Q. And if you're looking on the right side on the gas cases, the dark blue bars for all cases, general cases, and litigated cases are all higher in 2019 than they are for 2018, correct?

A. They are. And again, there's only seven cases in the first half of 2019. I think that, you know, when you don't have many cases, one or two decisions can have a bigger impact on it, but that's -- so I think a better comparison is looking at the annual numbers. But they're a little bit higher I think because of the limited number of cases.

Q. If you look a little bit lower on the page, the graphic indicates that the average litigated ROE in 2019 is 9.73 percent, correct?

A. Yes.

Q. Okay.

A. And again, I think that's more just a numbers issue, just on not a lot of cases.

Q. And that compares to 9.57 in 2018, right?

A. Yes.

Q. And we already discussed that 2018 was somewhat of a record year for rate cases?

A. It was. Yeah. It's probably a better sample, especially given -- if you look what's happened with interest rates, they've gone down so far you would expect ROEs to reflect that to some degree, and it hasn't yet. So as more cases come in this year, I would expect the ROEs to go down.

Q. This certainly doesn't reflect that, though, does it?

A. No.

Q. And there are little arrows -- little green and red arrows off to the right-hand side at the bottom of the graphic.

Does that indicate sort of the direction and the average returns in those categories?

A. Yeah, it does. The green, the red, yeah, it must associate green with good and red with bad, I guess.

Q. That would be the company perspective?

A. Yeah, it definitely is.

Q. So anyway, I'd like you to look at some of the text in this report and read a couple of provisions. The first sentence I would ask you -- or that I would call your attention to is the last sentence of the fifth paragraph on page 5. So that's the paragraph that begins with "the average ROE authorized."

Do you see that?

A. Page 5?

Q. No, no, I'm sorry, first page.

A. Oh, oh, okay.

Q. I'm sorry.

A. "The average ROE authorized gas utilities" --

Q. That paragraph, the last sentence.

A. -- "was 9.63 percent in cases decided during the first half of 2019 just above the 9.59 percent full year 2018. There were only seven gas cases that included an ROE determination in the first six months of 2019 versus 40 in 2018. In the first six months of 2019, the median authorized ROE for all electric utilities was 9.63 percent versus 9.58 percent for full year 2018. For gas utilities, the median authorized ROE in the first six months of 2019 was 9.7 percent versus 9.6 percent in 2018."

Q. There's that number again, right?

A. That is that number, yes.

Q. Okay. If you turn to page 3 under capital structure trends, could you read the last sentence of the first paragraph?

A. Is it the paragraph starting "is it also" -- "it is also" -- oh, capital.

Q. Capital structure.

A. "The average allowed equity ratio for gas utilities nationwide was 54.6 percent the first six months of 2019, 50.09 percent in '18, and 49.88 percent in 2017."

I mean, yeah, I agree. I mean, I noted, you know, the 50 percent. That was part of the reason I had a 50 percent in there. And again, if you go back to the previous exhibit, you look at the cases involved, you had, like Atmos in Texas at 58 and 60 percent, which is really -- I mean, again, you only have seven cases, but those three decisions -- well, they're in Texas, Tennessee, and Kentucky, they've -- you know, Atmos has a very high equity ratio and they've been getting it passed in some states.

Q. Yeah. Well, I'm glad you raised that, so -- because I want to be fair about this. I mean, we've covered a number of different reports that show -- that reflect ROE results for natural gas utilities and equity ratios, and you can find a fairly broad array of numbers in there, including some that comport with your recommendations, right?

A. Yes.

Q. Okay. So I don't want to overstate the position, but would you agree with me that, as a general statement, that the averages we're seeing in these reports that we looked at that start at 2017 and come forward to the most recent quarter in 2019 are more consistent with the stipulation than they are with your recommendations?

A. I would agree that they are. And again, you know, it depends at different times what states, what type -- are they a combination or pure gas utilities. And again, I'll go back to what my statement earlier. You know, we have historic low interest rates and historic high utility stock prices. That means capital is low. The cost of capital is low for utilities. So, I mean -- and that's, you know, obviously, because we've discussed in here in the last two days, you know, this has been a situation that's really come about in 2019.

Q. Thank you.

MR. JEFFRIES: Those are all the substantive questions I have for Dr. Woolridge. At some fear of retribution, I would like to return to Piedmont Woolridge Cross Exhibit Number 1. That's the one with the microscopic type.

Q. And my question of you, Dr. Woolridge, I asked you what the average rate of return was, and I believe you said 9.84. Mr. Heslin has better eyes than I do and pointed out to me that I believe the number is actually 9.64. So I wanted to make sure the record was --

A. I agree, yes. Thank you.

MR. JEFFRIES: That's all the questions I have of Dr. Woolridge.

COMMISSIONER BROWN-BLAND: Redirect?

MS. FORCE: Thank you.

REDIRECT EXAMINATION BY MS. FORCE:

Q. Just have a few, Dr. Woolridge. Mr. Jeffries, earlier in his questioning and throughout his questioning, asks you about authorized returns. And there was some question early on about factors that commissions might consider when they're setting the rate of return on equity.

Does that vary from state to state, exactly the factors that might go into a determination?

A. Yeah. I think different states take different approaches. Some of them -- some commissions like to be pretty specific about how they lay out a return on equity determination. Some commissions just say, here are the numbers, this is what we think it is. And to be honest with you, I think in recent years, commissions have been going more that direction where they say, here are all the numbers, here's what this witness said, here's what that witness said, this is the number we're going to use.

So I think they don't want to get nailed -- they don't want to have some strict rule they use, we're going to average the DCF and the CAPM. I think they want to avoid that in case there are errors or something like that. And sometimes they get challenged -- those decisions get challenged. So I think commissions have moved more to kind of more of a general here's our number and it comports with the data we looked at.

Q. And along those lines but expanding on it, are there sometimes policy considerations that are specific to a particular state that are taken into account?

A. Well, some states, for example, Maryland came up yesterday. They specifically point to gradualism in their decisions. And, you know, that's what -- in situations like this year, you know, despite the decline in interest rates, it may suggest capital costs are lower, they want to gradually adjust returns on equity to the levels that are indicated by the -- by the interest rates, stock prices, and that sort of thing.

Q. So taking a more gradual approach, is that what you -- we heard -- I think, was it yesterday, Virginia case?

A. Virginia also had that, yes.

Q. And so could you say again, gradualism, what that refers to is?

A. They want to gradually adjust returns on equity authorizations to what capital market data suggests.

Q. Okay. Thanks. There was mention early, and I can't give you the exact context, but of beta as a term, and that comes up in some of these studies.

Could you just give a quick explanation for what that refers to?

A. Beta is a method of major risk, and it's really stock risk. And what they do is they look at the -- they use a regression of stock returns relative to the market. The simple explanation, the stock market has a beta of one. Stocks that are riskier than average have a beta of bulk one; stocks that are less risky than the overall market have betas less than one. In my testimony, in fact, what I do, in Exhibit JRW --

JWR-6, I show the average betas for 97 different industries that as -- by value line. And, you know, you look at the lowest risk industries, water utility, natural gas, electric utility east, central, and west.

So the utilities are generally -- I mean, you look at beta as a major of equity risk, they're significantly less risky than -- and remain that way for some time, just because of the regulated status and that sort of thing.

Q. And you said "value line." When you say "they," are you talking about publications or resources?

A. Yes. Yahoo, Bloomberg, all these financial information sources produce betas.

Q. And you answered a question from Mr. Jeffries referring to page 18 of your testimony, and you said that the average return -- earned return from the proxy group was 9.7 percent.

Do you remember that?

A. Yeah. Actually, I misspoke there. The average -- the median -- if you look at page -- JRW-2, page 1, the median is 9.7. The average is only 6.9. And that's because there's two companies who last year in their 10-K reports had negative earnings. One was

SJ -- South Jersey Industries, and the other big one was Northwest Natural Gas. But they had write-offs last year, and so, in their 10-K, when they reported their earnings, they had negative earnings.

Q. And when we're talking about the average or the median earned return of the company, does that reflect the investor behavior or a response to that?

A. No. That's the accounting return.

Q. So --

A. That's not the stock market return, it's not the authorized return, it's what they earned last year.

Q. Okay. And so by comparison, when we look at the discounted cash flow method of analyzing estimated return, that looks at stock prices -- current stock prices?

A. Yes.

Q. Okay. You -- there were some questions about the capital structure of various different entities, and do you recall the capital structure, how much of it is equity for Duke Energy Corporation, the parent company for Piedmont?

A. I think I put that in my testimony.

Q. It's -- if you'd look at JRW-3.

A. Yes. JRW-3, I show -- in panel C, I show the average quarterly capitalization ratios for 2018 for Piedmont where the average equity component over that time frame is 48.1 percent. For Duke Energy, over that time frame, 2018/'19, their average common equity ratio is 42.9 percent.

Q. Okay. Thank you. In the exhibits that we were looking at, some of them easier to read than others that are from S&P Global, there are lists of authorized returns there.

Can you say whether -- especially the first one -- were any of those companies combined gas and electric companies?

A. I did. I mentioned Baltimore Gas and Electric, combination companies.

Q. Okay. And maybe you said that about Exhibit 1, but I think isn't it also so that, in some of the past years, that some of them referred to combined?

A. Yes. Some states, electric and gas. Wisconsin does it, Maryland does it, Kentucky does it, just a couple that I know.

Q. And would that -- I think you said before, that might have an impact on the --

A. Well, I think they're a little bit higher usually.

Q. Okay. Sorry. Bear with me a minute. I'm trying to understand what I scratched down here. Oh, the authorized returns that are shown in that third exhibit that was used in cross examination, you've already answered this question.

The ROE decisions are trending upward; is that consistent with where the market has gone?

A. No. I said the reason is just very few decisions this year compared to last year.

Q. Right. Okay.

A. So one or two high observations or low observations would throw off what you would think the norm would be.

MS. FORCE: Thank you. I don't have any other questions.

COMMISSIONER BROWN-BLAND: All right. Questions by the Commission?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. All right. Dr. Woolridge, just a couple of questions. If you were -- if the parent company, Duke Energy, had opportunities, let's say, in the pipeline industry to make investments there where the returns were higher than your recommended 8.7 percent, would you -- would you think that Duke -- the Duke executive would have a reason to invest in their Piedmont subsidiary?

A. Well, I think the pipeline industry is riskier, so they would expect to have a higher rate of return because they're taking on more risk than a natural gas distribution company.

Q. So is it -- you would say that their risk would somehow counterbalance the opportunity to get a higher rate of return?

A. Yeah. I mean, the two magic words in finance are "risk" and "return." If you have a higher risk, you require a higher rate of return.

Q. Are you aware that Duke Energy is a partner in the Atlantic Coast Pipeline Project, and that that has an embedded rate of 14 percent, recourse rate of 14 percent?

A. Yeah. I mean, a lot goes into it. I haven't looked. I've done some gas pipeline cases, that sort of thing. But interstate pipeline here is being a somewhat significant riskier business than a local -- you know, a local distribution company.

Q. Would differences like that entice the parent company to make investments in -- to pull away from the -- making it -- investing in capital in Piedmont?

A. And FERC has put in a lot of incentives for people to build pipelines and that sort of thing, so they boost the returns. You know, they start at one level, and they put adders in because of the risk, but also they want to incentivize the build-out of electric transmission as well as gas pipelines.

Q. And you're aware that the only pipeline that crosses North Carolina right now, there's been a rate case file or request for increase with the proposed ROE of up to 16 -- more than 16 percent?

A. I'm not familiar with the case.

Q. Do you accept that, subject to check?

A. Yes.

Q. And so, again, that would be a comparison of an opportunity of a 16 percent return on your investment versus 8.7 if your recommendation was the same?

A. Yeah. Again, it's taking on much more risk, I think.

COMMISSIONER BROWN-BLAND: All right. Questions on the Commission's questions?

MS. FORCE: No questions.

MR. JEFFRIES: No questions.

COMMISSIONER BROWN-BLAND: All right. Thank you, Dr. Woolridge, and I'll entertain a motion.

MR. JEFFRIES: Madam Chair, Piedmont would move the admission into evidence of the exhibits previously marked and identified as Piedmont Woolridge Cross Exhibits 1, 2, and 3.

COMMISSIONER BROWN-BLAND: All right. Those cross examination exhibits will be received into evidence.

(Piedmont Woolridge Cross Exhibits 1, 2, and 3 were received into evidence.)

MS. FORCE: And the Attorney General would move the admission of Exhibits JRW-1 through JRW-13.

COMMISSIONER BROWN-BLAND: There being no objection, those exhibits will also be received into evidence.

(Exhibits JRW-1 through JRW-13 were received into evidence.)

COMMISSIONER BROWN-BLAND: Hope you make your plane. You're excused, Doctor.

THE WITNESS: Thank you. I appreciate all parties saving me a 10-hour car drive. I appreciate it.

COMMISSIONER BROWN-BLAND: All right. We will return back. I think you saved the best for last. You have one more witness.

MR. JEFFRIES: Ms. Powers. Piedmont will call Ms. Powers to the stand, please.

PIA POWERS,

having first been duly sworn, was examined

and testified as follows:

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Good morning, Ms. Powers.

A. Good morning.

Q. Just barely. Could you state your name and business address for the record, please?

A. My name is Pia Powers. My business address is 4720 Piedmont Road Drive, Charlotte, North Carolina.

Q. Okay. And you work at Piedmont Natural Gas; is that right?

A. Yes.

Q. Okay. And what are your -- what's your title at Piedmont?

A. Director of gas rates and regulatory affairs.

Q. And what are your responsibilities in that position?

A. My responsibilities will include rate filings, other petitions before this Commission and our two other states.

Q. Okay. Thanks. Ms. Powers, you prefiled three sets of testimony in this proceeding, correct?

A. Yes.

Q. Okay. And the first was on April 1st, you filed direct testimony of 21 pages, and attached to that testimony were exhibits marked PKP-1 through PKP-8, correct?

A. Yes.

Q. Okay. And then on July 29th you filed supplemental testimony which was to support the updates that the Company made to their final case, correct?

A. Yes.

Q. And that testimony consisted of 10 pages and exhibits marked as Exhibits PKP-1 through PKP-8 updated, correct?

A. Yes.

Q. Okay. And then finally, on August 12th, you filed settlement testimony which consisted of 19 pages and one exhibit marked as settlement -- or exhibit -- Settlement Exhibit PKP-1, correct?

A. Correct.

Q. Okay. Ms. Powers, were those testimonies and exhibits prepared by you or under your direction?

A. Yes, they were.

Q. All right. And if I asked you to -- well, I'm sorry.

Do you have any corrections to your prefiled testimony?

A. I do not.

Q. Okay. If I asked you the same questions that are contained in your prefiled testimony while you're on the stand today, would your answers be the same?

A. Yes, they would.

MR. JEFFRIES: Madam Chair, Piedmont would request that Ms. Powers' prefiled direct, prefiled supplemental, and prefiled settlement testimonies be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: Without objection, that motion will be allowed, and the three sets of testimony would be received into evidence.

(Whereupon, the prefiled direct, prefiled supplemental, and prefiled settlement testimony of Pia Powers was

copied into the record as if given orally from the stand.)

Q. Ms. Powers, please state your name and business address.

A. My name is Pia K. Powers. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. By whom and in what capacity are you employed?

A. I am the Director – Gas Rates & Regulatory Affairs for Piedmont Natural Gas Company, Inc., ("Piedmont" or "the Company"). In this capacity, I am responsible for a variety matters including the development and execution of all rate requests and financial report filings by Piedmont.

Q. Please describe your educational and professional background.

A. I graduated from Fairfield University in 1995 a Bachelor of Arts degree in economics and subsequently earned a Master of Science degree in environmental and resource economics from the University College London. From 1999 through 2003, I was employed as an Economist with the Energy Information Administration, the statistical agency of the U.S. Department of Energy, where I focused on international energy forecasting and environmental issues. I was hired by Piedmont as a Regulatory Analyst in 2003, promoted to Supervisor – Federal Regulatory in 2005, and promoted to Manager of Regulatory Affairs in 2006. In 2013, I was promoted to my current position as a Director.

Q. Have you previously testified before this Commission or any other regulatory authority?

A. Yes. I have presented testimony before this Commission, the Public Service Commission of South Carolina, and the Tennessee Public Utility

Commission (and its predecessor agency, the Tennessee Regulatory Authority) on a number of occasions.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony is filed in support of Piedmont's application in this case. Specifically, the purpose of my testimony is to explain and support: (1) Piedmont's rate base at December 31, 2018 and the actual results of Piedmont's operations for the twelve month ending December 31, 2018 (the "Test Period"); (2) the results of Piedmont's Test Period operations under present rates, as adjusted for accounting and pro forma changes to the Company's operating revenue, operating expense, capital structure and rate base; (3) the additional revenue required to appropriately support Piedmont's pro forma cost of service; (4) Piedmont's compliance with NCUC Form G-1 Minimum Filing Requirements for this general rate case application; and (5) the amortization of certain deferred expenses that have been previously granted regulatory asset treatment by the Commission.

Q. Do you have any exhibits supporting your testimony?

A. Yes. The following exhibits are included with my testimony:

Exhibit_(PKP-1) Summary of Rate Base
Exhibit_(PKP-2) Original Cost of Property Used and Useful
Exhibit_(PKP-3) Accumulated Depreciation of Property Used and Useful
Exhibit_(PKP-4) Working Capital
Exhibit_(PKP-5) Accumulated Deferred Income Taxes
Exhibit_(PKP-6) Depreciation Policy and Rates

Exhibit_(PKP-7) Net Operating Income and Rates of Return

Exhibit_(PKP-8) Piedmont Balance Sheet and Income Statement

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

Q. Are you familiar with the accounting procedures and books of account of Piedmont?

A. Yes. The books of account of Piedmont follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission. The Test Period amounts shown on all of my exhibits are those represented on Piedmont's books of account, and all of the pro forma adjustments shown on my exhibits conform to the Company's accounting procedures.

Q. What steps does the Company take to ensure that its books and records are accurate and complete?

A. Piedmont maintains and relies upon an extensive system of internal accounting controls and audits by both internal and external auditors. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management's authorization and are recorded properly. The system of internal accounting controls is reviewed annually, tested and documented by the Company to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that the Company's financial statements are materially accurate.

Piedmont's Rate Base

Q. Please explain the computation of rate base reflected in your exhibits.

A. Exhibit_(PKP-1) is a summary of Piedmont's end of Test Period rate base amount applicable to its utility operations in North Carolina. Piedmont's end of Test Period rate base is approximately $3.1 billion. This amount reflects the December 31, 2018 balances in the Company's accounting records for utility plant in service, less accumulated depreciation and accumulated deferred income taxes, plus an allowance for working capital. The largest component of Piedmont's North Carolina rate base is utility plant in service, which is approximately $5.2 billion computed at the original cost of such used and useful property. Exhibit_(PKP-2) identifies utility plant in service by asset category at the end of the Test Period, with approximately 90% of those assets being transmission and distribution plant (predominantly consisting of pipe in the ground, classified as either mains or service lines). Exhibit_(PKP-3) identifies accumulated depreciation by asset category at the end of the Test Period, which is a deduction to rate base of approximately $1.5 billion. Exhibit_(PKP-5) identifies accumulated deferred income taxes ("ADIT") at the end of the Test Period, which is a deduction to rate base of approximately $.8 billion; this exhibit also separately identifies the portions of ADIT which are classified as excess pursuant to recent reductions in state and federal income tax rates. The Test Period allowance for working capital reflects the combined average per books balance for the 13-months ended December 31, 2018 for the various other book assets and liabilities supporting Piedmont's utility operations in North Carolina, as well as the results of the cash working capital lead/lag study reflected in the testimony of Piedmont witness Paul Normand. The various components of the Test Period allowance for working capital are delineated in Exhibit_(PKP-4) totaling approximately $.2 billion.

Q. How has Piedmont's rate base changed since its last general rate case?

A. Piedmont's last general rate case reflected a Test Period rate base at February 29, 2013, updated for known and measurable changes through September 30, 2013. The amount of Piedmont's rate base coming out of that proceeding was $1.8 billion, compared to $3.1 billion at the end of this current Test Period. Utility plant in service, which is the largest component of rate base, grew by more than $2 billion over this period of time, most significantly in the transmission asset category. See Table 1 as follows for such growth by major plant asset category.

Table 1

Plant Asset Category	As of September 30, 2013	As of December 31, 2018	% Increase
Storage Plant	$95,820,160	$111,416,739	16%
Transmission Plant	$1,238,974,564	$2,558,740,963	107%
Distribution Plant	$1,599,604,518	$2,127,736,635	33%
General Plant & Intangibles	$236,630,335	$432,112,416	83%
Total Utility Plant	$3,171,029,577	$5,230,006,753	65%

Q. What factors have contributed to this increase in rate base since 2013?

A. Piedmont's rate base growth is the result of several factors. First, Piedmont has been aggressively pursuing compliance with federal pipeline safety and integrity obligations created by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and much of that compliance work has involved capital projects. This work is explained in greater detail in the testimony of Piedmont witness Victor Gaglio. Up until the filing of this rate case, a significant portion of this capital investment has been handled under the Integrity Management Rider ("IMR") mechanism and Piedmont's base rates have not included any component designed to compensate Piedmont for that investment. As part of this general rate case, we are "rolling-in" our cumulative integrity management capital investment for inclusion in base rates. That integrity management investment since the last rate case accounts for approximately half of the growth in Piedmont's plant in service shown in Table 1 above.

Another significant driver for the increase in rate base is the capital investments undertaken to support system infrastructure upgrades. These upgrades have been needed to support the continued provision of reliable firm natural gas service in light of increasing system demands largely driven by customer growth and the associated increase in natural gas throughput. Piedmont's service territory covers a significant physical and demographic portion of the state of North Carolina including major, growing metropolitan areas. Accordingly, the demand for firm natural gas service has continued to steadily increase in Piedmont's service territory.

Q. Were capital investments made by Piedmont a result of the integration with Duke Energy Corporation?

A. Yes. While not a significant contributor to the growth in Piedmont's rate base, Piedmont has made capital investments (primarily information technology system assets) associated with integration of Piedmont's operations into the overall corporate structure of Duke Energy. As of the end of the Test Period, these plant additions have amounted to less than $5 million – less than a quarter of a percent of Piedmont's total plant growth since the last rate case. These integration-related plant additions are included in rate base in this proceeding.

Piedmont's Per Books Test Period Cost of Service

Q. What are the actual financial results of Piedmont's North Carolina operations for the Test Period?

A. A summary of the Test Period financial results for Piedmont's North Carolina operations is shown on page 1 column 1 of Exhibit_(PKP-7).[1] Amounts in column 1 were taken from Piedmont's books of account as of December 31, 2018. Column 1 Line 15 shows per books net operating income for return for the Test Period of $156.5 million. Line 21 shows actual end of Test Period rate base of $3.1 billion. Column 1 Line 22 shows that the Test Period per books overall rate of return on rate base before accounting and pro forma adjustments is 5.04%. This rate of return is computed as the quotient of net operating income for return (Column 1 Line 15) and total rate base (Column 1 Line 21).

Q. Are there are any particular aspects of the Test Period financial results that you would like to further explain?

A. Yes. For the purposes of providing clarity for the record, I would like to point out that during the Test Period Piedmont did incur some operating expenses related to post-merger integration activities. These expenses have been wholly excluded from the Test Period cost of service represented herein, consistent with the requirements set forth by Commission Order in the merger proceeding (Docket No. G-9, Sub 682).

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[1] Included in Item 4a of Piedmont's G-1 Minimum Filing Requirements submission in this proceeding are schedules reconciling the actual per books Test Period financial results for Piedmont's North Carolina operations as shown in Column 1 of Exhibit_(PKP-7) to the actual per books Test Period financial results for the total Company (Total Piedmont) as shown in G-1 Item 1.

Also, pursuant to the Commission's January 3, 2018 Order in the federal tax reform proceeding (Docket No. M-100, Sub 148), Piedmont recorded to a deferred account each month during the Test Period the difference between revenues billed under rates in effect (which reflected Piedmont's approved cost of service under a 35% federal corporate income tax rate) and revenues that would have been billed had its approved cost of service been computed under the now current 21% federal corporate income tax rate. Accordingly, the Test Period per books operating revenues shown in Column 1 on Exhibit_(PKP-7) do not include the operating revenues recorded to such deferred account in 2018.

Piedmont's Pro Forma Cost of Service

Q. Please describe the results of Piedmont's Test Period operations under present rates, as adjusted for pro forma changes to the Company's operating revenue, operating expense, capital structure and rate base?

A. Column 3 of Exhibit_(PKP-7) summarizes the results of Piedmont's Test Period operations under present rates, as adjusted for accounting and pro forma changes to the Company's operating revenue, operating expense, capital structure and rate base. Each of the accounting and pro forma adjustments shown in Column 2 of Exhibit_(PKP-7), which comprise the difference between the amounts shown in Column 1 and Column 3 of Exhibit_(PKP-7), are based on known and measurable information. Overall, the combined effect of the accounting and pro forma adjustments to the Test Period yields a 4.96% overall rate of return on rate base, as shown in Column 3 Line 22 of Exhibit _(PKP-7).

Q. Please explain the accounting and pro forma adjustments to revenues and operating expenses used to compute Piedmont's pro forma cost of service.

A. Each accounting and proforma adjustment is numbered and shown alongside Column 2 on page 1 of Exhibit_(PKP-7). A description of each adjustment is also provided on pages 3, 4 and 5 of Exhibit_(PKP-7). Adjustment 1 is performed for the purpose of normalizing annual revenues for the sale and transportation of gas to present billing rates and current customer throughput levels. Adjustment 2 is performed for the purpose of bringing other operating revenues, which largely consists of revenue from late payment charges, rental of gas property and other miscellaneous revenue, to the going-level annual amount. The specific computation of these pro forma revenue adjustments is discussed in the testimony of Piedmont witness Kally Couzens.

Adjustments 3 through 10 are performed for the purpose of bringing annual operating expenses to the going-level amount. Adjustment 3 specifically aligns the total annual cost of gas to the present billing rates and current customer throughput levels consistent with Adjustment 1 discussed above. Adjustment 4 increases operations and maintenance ("O&M") expense to the going-level amount of $227.9 million. I prepared this adjustment by segregating the Test Period O&M

expense into its major categories and analyzing the Test Period transactions and the specific cost drivers for each of these major categories to appropriately develop the going level expense amount for each major category. Page 3 of Exhibit_(PKP-7) lists each O&M expense category and the adjustment amount. Included in adjustment 4 is a refresh of Piedmont's regulatory amortization expense, which is for the expensing of costs granted regulatory asset treatment by this Commission. I will discuss this unique category of O&M expense in more detail later in my testimony.

Adjustment 5 is for the purpose of annualizing depreciation expense so as to align with the new depreciation rates proposed by witness Dane Watson and to align with the pro forma amount of plant in service per adjustment 10 herein. Adjustment 6 is to annualize general tax expense (which is predominantly comprised of property tax expense, payroll tax expense and NC franchise tax expense) consistent with the other related pro forma adjustments in this proceeding. Adjustments 7 and 8 simply provide an update of annual state and federal income tax expense (at current rates of 2.5% and 21%, respectively) consistent with the other related pro forma adjustments in this proceeding. Lastly, adjustment 9 brings forward the annual amortized expense level for federal investment tax credits.

Q. Please explain the accounting and pro forma adjustments to rate base.

A. Adjustments 10, 11 and 12 were made to update the per books end of Test Period rate base amounts to June 30, 2019. Adjustment 10 to plant in service anticipates that additional plant assets totaling $285,082,725 will be placed in service between December 31, 2018 and June 30, 2019. Adjustment 11 reflects the change in accumulated depreciation, an increase of $6,257,073 that we anticipate occurring between December 31, 2018 and June 30, 2019 based on the estimated change to plant in service over this period of time. Adjustment 12a reflects the change in the accumulated deferred income tax balance, an increase of $48,364,846 that we anticipate occurring between December 31, 2018 and June 30, 2019. Adjustments 10, 11 and 12a will be amended so as to replace the estimates with the actual per books amount of plant in service, accumulated depreciation and accumulated deferred income taxes, respectively, as of June 30, 2019. Adjustment 12 similarly reflects anticipated changes in the 13-month average balance for the asset and liability accounts included in allowance for working capital components as of June 30, 2019. Piedmont will subsequently update these projected 13-month average balances for allowance for working capital with actuals as of June 30, 2019. Adjustment 12 also includes the results of the cash working capital lead/lag study based on the Company's cost of service after adjustments for proposed rates.

Piedmont's Revenue Requirement

Q. Please explain the additional revenue necessary to appropriately support Piedmont's North Carolina utility operations.

A. Adjustment 13 shown in Column 4 on page 1 of Exhibit_(PKP-7) reflects the adjustment to the Company's base margin revenues needed to produce a 10.6% return on equity as recommended by Piedmont witness Robert Hevert in his testimony. To develop adjustment 13, Piedmont's rate base was allocated to its capital source components of long-term debt, short-term debt and common equity. This allocation, as shown in Column 5 on page 2 of Exhibit_(PKP-7), is based on the proposed capitalization ratios of 47.18% long-term debt, 0.82% short-term debt and 52.00% common equity. This is the Company's targeted capital structure and is supported in testimony by Company witness Jack Sullivan. At present rates and in light of the targeted capital structure and the pro forma cost of debt, Piedmont's revenues and expenses will yield a 5.36% return on equity, as shown in Column 6 Line 3 on page 2 of Exhibit_(PKP-7).

Q. Is Piedmont proposing any other changes in this proceeding which impact the revenue requirement adjustment being sought through proposed rates?

A. Yes. At this time, Piedmont is proposing that a further cost of gas adjustment be incorporated into the proposed revenue requirement. Piedmont is also proposing that a rider mechanism be used to return to customers the excess deferred income taxes ("EDIT") on its books as well to return the overcollected revenues accrued since January 2018 associated with recent federal tax reform. The effect of these two matters on the Company's revenue requirement computation in Exhibit_(PKP-7) is shown via adjustments 17 and 20, respectively.

Q. Please explain proposed adjustment 17 for the cost of gas.

A. Adjustment 17 is a revenue requirement adjustment of $1,665,536 to facilitate timely recovery of an increase in the demand cost of gas. This cost largely represents the current annualized cost associated with obtaining upstream natural gas storage and transportation service. A significant portion of the cost increase is the result of a pending FERC rate proposal by Transcontinental Gas Pipe Line which is currently in effect but which we anticipate will be materially reduced in the next 12 months. Detailed support for the adjustment to the demand cost of gas is shown in G-1 Item 4c.

Q. Please explain proposed adjustment 20 for the EDIT Rider.

A. The components and proposed operation of the EDIT Rider are covered in Piedmont witness Barkley's testimony and exhibits. As proposed, the first year operation of the proposed EDIT Rider will facilitate the return to customers of $36,963,249 of revenues currently recorded on the Company's books as a regulatory liability pursuant compliance with the Commission's orders in Docket No. M-100, Sub 148.

Q. How do adjustments 17 and 20 impact the revenue requirement adjustment being sought through proposed rates in this proceeding?

A. Once these two adjustments are incorporated into the revenue requirement computation, the total proposed revenue adjustment in this proceeding amounts to $82,818,884. This proposed revenue increase is reflected as the difference between $1,003,429,366 (representing total proposed revenues after all adjustments, which is shown on Column 9 Line 3 on page 1 of Exhibit _(PKP-7)) and $920,610,481 (representing total pro forma revenues, as shown on Column 4 Line 3 on page 1 of Exhibit _(PKP-7)).

Q. Does your proposed increased in the revenue requirement comport with the proposed rates shown in Appendix I to the petition?

A. Yes, it does. The proposed rates shown in Appendix I will produce a revenue increase of $82,818,884, which is the proposed revenue requirement adjustment shown in my analysis herein. The testimony and exhibits of witness Couzens support the derivation of proposed rates for this proposed revenue requirement adjustment amount.

Q. Does this complete the cost of service portion of your testimony?

A. Yes, it does. As stated in our petition, we plan to offer at the hearing such additional relevant, material and competent evidence as may be permitted under North Carolina statutes and the rules of this Commission. Except as shown in the exhibits, working papers and testimony filed with the petition, information is not currently available that would enable us to provide details of any actual changes in revenues, costs and rate base that may occur from the time of the filing of the petition and my testimony up to the time the hearing is closed. We reserve the right to file such updated information at or before the hearing of this docket to the extent such information is relevant to a determination of the matters at issue in this proceeding.

G-1 Compliance

Q. Has Piedmont complied with Commission Rule R1-17(b)(12)(c) in this proceeding by filing the information required by NCUC Form G-1 in connection with the filing of this general rate case?

A. Yes. Piedmont's G-1 Minimum Filing Requirements were prepared and filed with the Commission concurrent with its Petition and supporting testimony in this proceeding on April 1, 2019.

Amortization of Deferred Expenses

Q. Is Piedmont proposing to amortize and recover any deferred expenses in this proceeding?

A. Yes. Piedmont proposes to amortize expensed that have been previously deferred pursuant to Commission Order.

Q. What are those main categories of deferred expense?

A. Piedmont has previously deferred and now seeks recovery of certain transmission pipeline integrity management costs, certain environmental compliance costs and certain regulatory fee costs. These costs have been deferred in accordance with prior Commission orders.

Q. Can you please describe these costs and how they came to be deferred?

A. Yes. On December 2, 2004, the Commission issued its *Order Approving Deferred Accounting Treatment* in which, pursuant to Piedmont's previous request, it ordered that "effective November 1, 2004, Piedmont is authorized to segregate its incremental and extraordinary O&M expenses for PNG-NC and NCNG incurred in compliance with the new Pipeline Integrity Management Regulations issued by the USDOT pursuant to the Pipeline Safety Improvement Act of 2002 into a special deferred account until recovery of such costs can be sought in a general rate case, subject to a determination that the costs have been prudently incurred and properly accounted for and a determination as to the proper method of recovery."

Q. How has the Commission treated these types of costs since its December 1, 2004 order?

A. Following that order, Piedmont deferred operating and maintenance expenses of the type authorized by the Commission and then sought amortization and recovery of those costs in its 2005, 2008, and 2013 rate case filings (per Docket Nos. G-9, Sub 499, G-9, Sub 550, and G-9, Sub 631, respectively). In those cases, in conformance with settlements of those dockets, the Commission authorized Piedmont to amortize the costs it had deferred and approved a continuation of the mechanism in each case.

Q. Has Piedmont continued to defer pipeline integrity O&M costs since the last rate case?

A. Yes. In Piedmont's last rate case, it was granted 5-year amortized recovery of a balance of $17,348,593, which reflected actual deferred expenses through August 31, 2013 net of regulatory amortizations through December 31, 2013. In this case, Piedmont seeks to amortize the costs incurred and deferred since that date. Piedmont is proposing a 3-year amortization of these costs, bringing the pro forma annual cost of service for this expense to $15,672,545. This amount is included in Piedmont's cost of service in this case, and is reflected in pro forma O&M expense on Exhibit_(PKP-7).

Q. Were these costs prudently incurred and have they been properly accounted for?

A. Yes, they were incurred in compliance with federal laws and regulations and in the ordinary conduct of Piedmont's business.

Q. Is Piedmont proposing continued regulatory asset treatment for these integrity costs going forward?

A. Yes. The same reasons which supported deferral of these costs previously continue to persist and support continued regulatory asset treatment for these costs.

Q. What is the basis for Piedmont's proposed amortization and recovery of deferred environmental compliance costs?

A. On December 16, 1992, Piedmont requested authorization 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. This request was made in Docket No. G-9, Sub 333. On December 23, 1992, the Commission issued its *Order Granting Request* in this Docket in which it ordered that "the request of special accounting for environmental assessment and cleanup costs filed by Piedmont Natural Gas Company is hereby granted, without prejudice to the right of any party to take issue with the special accounting in a regulatory proceeding."

Q. Has Piedmont utilized this deferral authority for environmental compliance expenses incurred in the years since it was granted by the Commission?

A. Yes, it has. Piedmont has routinely deferred its environmental assessment and clean-up costs pursuant to the authority granted by the Commission in Docket No. G-9, Sub 333 and has filed for and been granted amortization of such costs in rate case proceedings since 1992.

Q. Has Piedmont continued to defer environmental compliance expenses since the last rate case?

A. Yes. In the last rate case, Piedmont was granted a 5-year amortized recovery of a balance of $6,346,642, which was the unamortized deferred balance as of August 31, 2013. In this case, Piedmont is proposing a 3-year amortization of an unamortized balance of $(576,988) – a credit balance due to the fact that the recording of regulatory amortizations has outpaced the recording of incremental deferrals of environmental compliance expenses.

Q. Were these costs prudently incurred and have they been properly accounted for?

A. Yes, they were incurred in compliance with federal laws and regulations and in the ordinary conduct of Piedmont's business.

Q. What is the basis for Piedmont's proposed amortization and recovery of deferred regulatory fee expenses?

A. On August 15, 2016, the Commission issued its *Order Amending Commission Rule R15-1* in Docket No. M-100, Sub 142. This order authorized and approved "the establishment of deferral accounts (regulatory asset or regulatory liability accounts) by utilities to allow the companies to comply with Commission Rule R15-1. Such authority is granted nunc pro tunc back to July 1, 2015, the effective date of statutory language changes in HB 1052 that authorize the Commission to allow utilities to either adjust base rates or establish regulatory asset or regulatory liability accounts for regulatory fee increases (that was subsequently changed in HB 356, effective July 1, 2015, for any changes, increases or decreases, in the regulatory fee obligation)."

Q. Has Piedmont deferred its regulatory fees consistent with Commission authorization?

A. Yes. In this case, Piedmont seeks to amortize the cumulative deferred regulatory fee expense of $374,697. Piedmont is proposing a 3-year amortization of these costs, bringing the pro forma annual cost of service for this expense to $124,899. This amount is included in Piedmont's cost of service in this case, and is reflected in pro forma O&M expense on Exhibit_(PKP-7).

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Pia K. Powers. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. By whom and in what capacity are you employed?

A. I am the Director – Gas Rates & Regulatory Affairs for Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company").

Q. What is the purpose of your Supplemental Testimony in this proceeding?

A. N.C. Gen. Stat. § 62-133(c) and Commission Rule R1-17(c) permit Piedmont to update its rate case filing through the date of the hearing of this matter. In our Application in this proceeding filed on April 1, 2019, we specifically and expressly reserved our right to make these updates. In that initial filing, we based our revenue request on a number of pro forma adjustments that were developed on the basis of estimated going-levels of expense and utility rate base as of June 30, 2019. We now have available "actuals" rather than "estimates" to support those pro forma expense adjustments and utility rate base as of June 30, 2019. Furthermore, our commission-approved customer billing rates have materially changed since the time of our Application filing[1], which necessitates an update to the pro forma revenue calculation reflected in our Application. For this reason, we are filing, concurrent with my Supplemental Testimony and the Supplemental Testimony of Kally Couzens,

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[1] Rate changes were approved by the Commission effective May 1, 2019 per order in Docket No. G-9, Sub 731 and G-9, Sub 737. Additional rate changes were approved by the Commission effective June 1, 2019 per order in Docket No. G-9, Sub 748.

updates to the schedules required by Commission Rule R1-17(b) ("Updated Schedules") to reflect our actual cost of service calculation as of June 30, 2019 and the components thereof relative to our original filed Application.

Q. Please explain how, if at all, this update filing impacts the Test Period amounts shown by Piedmont in its original filed Application.

A. Nothing about this update filing nor the Updated Schedules changes the per books Test Period amounts shown in Piedmont's original Application and in my Direct Testimony. The Test Period for this general rate case proceeding continues to be the 12-months ending December 31, 2018. This update filing simply uses the now known actuals at June 30, 2019 to update: 1) the pro forma utility rate base adjustments in the Company's original filed application that were developed based on then-estimated June 30, 2019 figures and amounts; 2) certain pro forma expense adjustments in the Company's original filed application that were developed based on then-estimated June 30, 2019 figures and amounts; and 3) the pro forma adjustment to utility gas sales and transportation revenue in the Company's original filed application that was developed based on the then-present Commission approved customer billing rates which have since been reset by this Commission.

Q. Does this update filing incorporate any of the alternative positions of the parties as expressed in the various intervenor direct testimonies and exhibits filed in this docket on July 19, 2019?

A. No, it does not. Piedmont intends to address the various intervenor positions and recommendations via its forthcoming Rebuttal Testimony.

Q. Does this update filing incorporate any changes to the methodology used by the Company in its computation of the pro forma adjustments compared to those used for the original filed Application?

A. No. The approach used to compute each pro forma adjustment for this update filing and for the Updated Schedules is the same as used to compute each pro forma adjustment in the Company's original filed application.

Q. Were the Updated Schedules for this update filing prepared by you and/or prepared under your direct supervision?

A. Yes.

Q. Do you have any exhibits supporting your Supplemental Testimony?

A. Yes. Since many of the schedules provided by Piedmont in its original filed Application for fulfillment of Commission Rule R1-17(b) were in fact exhibits to my Direct Testimony, I have updated all eight of the exhibits to my Direct Testimony in support of the Updated Schedules, as follows:

- Exhibit_(PKP-1 UPDATED) Summary of Rate Base
- Exhibit_(PKP-2 UPDATED) Original Cost of Used and Useful Property
- Exhibit_(PKP-3 UPDATED) Accumulated Depreciation of Property Used and Useful
- Exhibit_(PKP-4 UPDATED) Working Capital
- Exhibit_(PKP-5 UPDATED) Accumulated Deferred Income Taxes

- Exhibit_(PKP-6 UPDATED) Depreciation Policy and Rates
- Exhibit_(PKP-7 UPDATED) Net Operating Income and Rates of Return
- Exhibit_(PKP-8 UPDATED) Piedmont Balance Sheet and Income Statement

Q. Please explain the updates to pro forma utility rate base reflected in your exhibits and the Updated Schedules.

A. Exhibit_(PKP-1 UPDATED) summarizes the main components of rate base. The first column in this exhibit shows that Piedmont's end of Test Period rate base is approximately $3.1 billion. In our original filed Application, we had anticipated that rate base would grow to $3,299,177,177 by June 30, 2019; this estimated June 30, 2019 rate base amount was used in the revenue request computation shown in my original Exhibit_(PKP-7). Now it is known that Piedmont's rate base as of June 30, 2019 is $3,364,074,164, which reflects a difference of less than 2% from the estimated June 30, 2019 rate base amount (i.e. the pro forma rate base amount shown in the exhibits to my Direct Testimony). I updated my revenue request computation to this actual June 30, 2019 rate base amount accordingly in Exhibit_(PKP-7 UPDATED).

Q. Was each component of pro forma utility rate base updated using actual amounts as of June 30, 2019?

A. Yes. The largest component of rate base is utility plant in service. Exhibit_(PKP-2 UPDATED) identifies utility plant in service by asset category at the end of the Test Period and as of June 30, 2019. Exhibit_(PKP-

3 UPDATED) identifies accumulated depreciation by asset category at the end of the Test Period and as of June 30, 2019. Exhibit_(PKP-5 UPDATED) identifies accumulated deferred income taxes at the end of the Test Period and as of June 30, 2019. Exhibit_(PKP-4 UPDATED) identifies the components of allowance for working capital, which for the Test Period is the 13-months average balance ended December 31, 2018 and on a pro forma basis is the 13-months average balance ended June 30, 2019.

Q. Please explain the updates to pro forma depreciation expense reflected in your exhibits and the Updated Schedules.

A. In our original filed Application, I presented a pro forma adjustment to depreciation expense that was aligned with the pro forma amount of utility plant in service as estimated at June 30, 2019. Now that Piedmont's utility plant in service amount by asset account at June 30, 2019 is known, I have updated the computation of pro forma depreciation expense accordingly. As part of this update, I also incorporated the accrual for reallocation of the reserve account based on the actual June 30, 2019 utility plant balances. My revenue request computation shown in in Exhibit_(PKP-7 UPDATED) incorporates this updated pro forma depreciation expense amount accordingly. Exhibit_(PKP-6 UPDATED) identifies the composite deprecation rates by major asset category.

Q. Please explain the updates to pro forma revenues reflected in your exhibits and the Updated Schedules.

A. My revenue request computation shown in Exhibit_(PKP-7 UPDATED) incorporates an update to the pro forma gas sales and transportation revenue amount. The computation of updated pro forma gas sales and transportation revenue, as explained in the Supplemental Testimony of Piedmont witness Kally Couzens, incorporates the now current Commission-approved customer billing rates.

Q. Please explain the update to pro forma cost of gas expense reflected in your exhibits and the Updated Schedules.

A. An update to the pro forma cost of gas expense was made in alignment with the June 30, 2019 update to the pro forma gas sales and transportation revenue amount. My revenue request computation shown in Exhibit_(PKP-7 UPDATED) incorporates this update to the pro forma cost of gas.

Q. Please explain the updates to pro forma operations and maintenance ("O&M") expense reflected in your exhibits and the Updated Schedules.

A. In the Company's original filed application, and as shown in Exhibit_(PKP-7) to my Direct Testimony, there were twenty discrete pro forma adjustments to the Test Period level of O&M expense.[2] Now, with June 30, 2019 actuals being known and available, an update to seven of those pro forma O&M expense adjustments was warranted. The seven updated pro forma adjustments are for the following matters: uncollectibles expense, regulatory

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[2] See Pro Forma Adjustments 4A through 4T as shown in Exhibit_(PKP-7) Page 3 of 5 in my direct filed testimony.

fee expense, salaries and wages expense, short-term incentive plan expense, regulatory amortization expense for deferred transmission pipeline integrity expenses, regulatory amortization expense for deferred environmental compliance expenses, and regulatory amortization expense for deferred regulatory fee expenses. The update to pro forma uncollectibles expense was necessary for alignment to the updated pro forma gas sales and transportation revenues amount; as a part of this pro forma expense update, I also corrected an error in the Company's original computation of the uncollectibles factor, which is also used in the overall revenue requirement computation. The update to pro forma regulatory fee expense was necessary for alignment to the updated pro forma gas sales and transportation revenues amount and for alignment to the current NCUC Regulatory Fee Rate.[3] The update to pro forma salaries and wages expense was necessary to update to actual employee salary and wage rates as of June 30, 2019 in lieu of the estimated employee salary and wage rates used in the pro forma computation included in the Company's filed application. The estimated employee salary and wage rates was a factor used in the computation of pro forma short-term incentive plan expense in the Company's filed application; accordingly, the pro forma adjustment for short-term incentive plan expense was updated in alignment with actual employee salary and wage rates as of June 30, 2019. The update

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[3] Per the Commission's June 18, 2019 Order in Docket No. M-100, Sub 142, the regulatory fee for noncompetitive jurisdictional revenues was reduced from 0.148% to 0.13% effective July 1, 2019.

to pro forma regulatory amortization expense for deferred transmission pipeline integrity expenses was necessary to update to expense deferrals through June 30, 2019. In a similar vein, I updated the pro forma regulatory amortization expense for deferred environmental compliance expenses and deferred regulatory fee expenses. I updated my revenue request computation for the overall impact of the updated pro forma O&M expenses accordingly in Exhibit_(PKP-7 UPDATED).

Q. Please explain the updates to pro forma general tax expense reflected in your exhibits and the Updated Schedules.

A. Only one update to pro forma general tax expense was warranted, which was to the pro forma payroll tax component of general tax expense. The update to pro forma payroll tax expense was necessary for alignment to the updated pro forma salaries and wages expense adjustment and for alignment to the updated pro forma short-term incentive plan expense adjustment. I updated my revenue request computation for the updated pro forma general tax expense accordingly in Exhibit_(PKP-7 UPDATED).

Q. Are there any updates to the embedded cost of debt reflected in your exhibits and the Updated Schedules?

A. Yes, there are two updates. The embedded cost of long term debt was updated to incorporate the actual cost of the $600 million long term debt issuance that occurred in May 2019 in lieu of the estimated cost of that issuance that was included in the Company's filed application; this update yielded a reduction in the embedded cost of long term debt from 4.55% to 4.40%. The embedded cost of short term debt was updated to incorporate the actual cost rates as of June 30, 2019; this update yielded a reduction in the embedded cost of short term debt from 2.82% to 2.78%. I also updated my revenue request computation shown in Exhibit_(PKP-7 UPDATED) accordingly.

Q. Are there any updates to the EDIT Rider amounts reflected in your exhibits and the Updated Schedules?

A. Yes. The EDIT Rider amount was updated for alignment with the updated uncollectibles factor, the updated NCUC regulatory fee factor, and an updated amount of over-collected deferred tax revenue due customers (as a result of the impacts of the Tax Cuts and Jobs Act as ordered by the Commission in Docket No. G-9, Sub 731). I updated my revenue request computation shown in Exhibit_(PKP-7 UPDATED) accordingly.

Q. Please explain the updates to income tax expense reflected in your exhibits and the Updated Schedules.

A. The updates to federal and state income tax expense were made in alignment with the overall impact of the updates I have previously described in my Supplemental Testimony. My revenue request computation shown in Exhibit_(PKP-7 UPDATED) was updated accordingly.

Q. In total, how do these updates impact Piedmont's revenue requirement and proposed rates in this proceeding?

A. The proposed rates shown in the Updated Schedules (specifically, in Updated Appendix I) are designed to produce annual gas sales and transportation revenues of $1,004,331,372, which is the level needed to support the Company's cost of service shown in my updated analysis in Exhibit_(PKP-7 UPDATED). This difference between this amount and the proposed annual gas sales and transportation revenues shown in the Company's original filed Application and in my original analysis in Exhibit_(PKP-7) is less than 1%.

Q. What are you asking the Commission to do with this information?

A. We request that the Commission accept and consider our Updated Schedules in their consideration of what constitutes a just and reasonable cost of service for Piedmont in this proceeding and in approving new rates for our customers.

Q. Do you have any further testimony regarding Piedmont's Updated Schedules?

A. No, not at this time.

Q. Ms. Powers, please state your name and business address.

A. My name is Pia K. Powers. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. By whom and in what capacity are you employed?

A. I am the Director – Gas Rates & Regulatory Affairs for Piedmont Natural Gas Company, Inc. ("Piedmont" or "the Company"). In this capacity, I am responsible for a variety matters including the development and execution of all rate requests and financial report filings by Piedmont.

Q. Please describe your educational and professional background.

A. I graduated from Fairfield University in 1995 a Bachelor of Arts degree in economics and subsequently earned a Master of Science degree in environmental and resource economics from the University College London. From 1999 through 2003, I was employed as an Economist with the Energy Information Administration, the statistical agency of the U.S. Department of Energy, where I focused on international energy forecasting and environmental issues. I was hired by Piedmont as a Regulatory Analyst in 2003, promoted to Supervisor – Federal Regulatory in 2005, and promoted to Manager of Regulatory Affairs in 2006. In 2013, I was promoted to my current position as a Director.

Q. Have you previously testified in this proceeding?

A. Yes. I prefiled Direct Testimony in this docket on April 1, 2019 in support of Piedmont's Application. I also filed Supplemental Testimony in this docket on July 29, 2019 in support of the Company's updated cost of service calculation as of June 30, 2010 which was performed and filed pursuant to N.C. Gen. Stat. § 62-133(c) and Commission Rule R1-17(c) ("Update Filing").

Q. What is the purpose of your Settlement Testimony in this proceeding?

A. My Settlement Testimony explains the economic adjustments to Piedmont's filed case (as updated through June 30, 2019) reflected in the Stipulation between Piedmont, the Public Staff -- North Carolina Utilities Commission ("Public Staff"), the Carolina Utility Customers Association, Inc. ("CUCA"), and the Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR IV") (together, the "Stipulating Parties") and also addresses certain non-economic stipulations such as the continuation of the Integrity Management Rider ("IMR") mechanism and consolidation of Common Gas Areas, among others.

Q. Do you have any exhibits supporting your testimony?

A. Yes. I have attached, as Settlement Exhibit__(PKP-1), a reconciliation chart identifying the adjustments to Piedmont's filed/updated rate increase request reflected in the Stipulation.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes.

Q. Can you explain how the Public Staff pursued its investigation in this matter?

A. Following the filing of our Application and supporting testimony, the Public Staff engaged in substantial discovery regarding our filing. This included two on-site audits totaling five days at Piedmont's corporate headquarters and more than 600 discrete questions (not including parts and subparts) in 95 sets of discovery requests to the Company. When Piedmont filed its Update Filing, the Public Staff also engaged in an additional due diligence review of that true-up filing.

Q. How did the Public Staff and Piedmont go about pursuing settlement discussions in this case?

A. We met with the Public Staff for several days to explore settlement. Our initial discussions were aimed at making sure we had a common understanding of our respective litigation positions and filed testimony. After we completed these discussions we moved on to substantive settlement negotiations and over the course of two additional days we were able to reach agreement on all issues in this case between Piedmont and the Public Staff.[1] This agreement is reflected in the Stipulation filed concurrently with this testimony.

Q. How did the Public Staff and Piedmont go about pursuing settlement discussions with CUCA and CIGFUR IV in this case ?

A. We held discussions with CUCA and CIGFUR IV in an effort to obtain their consent to join in the settlement, and we able to do so after reaching a

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[1] A representative of the Attorney General was also present at the substantive settlement discussions between Piedmont and the Public Staff.

proposed rate design that is acceptable to all. Also, we indicated to the Attorney General that we are willing to engage in settlement discussions. Furthermore, we did not reach out to NUCOR or The Fayetteville Public Works Commission for settlement purposes since these parties did not file testimony in this proceeding.

Q. Do you believe the settlement with the Stipulating Parties is in the public interest and otherwise just and reasonable?

A. Yes, I do. The settlement results in substantial economic benefits to our customers through the cost reductions agreed to with the Stipulating Parties and it provides for the continued operation of the Company's IMR mechanism. It also avoids the expenditure of resources that would otherwise be necessary to litigate each of the contested issues in this docket and provides greater certainty of outcome to the Stipulating Parties.

Q. Can you provide a brief overview of the revenue impact associated with this settlement?

A. Yes. There are two main elements of the settlement impacting revenues. First, the settlement recommends revised base rates to customers based on a cost of service in years one through three that are significantly less than the amount sought by the Company in its Application and Update Filing. Second, the settlement also provides for a more accelerated refund via rate rider to customers of tax savings associated with the recent federal and state tax reform as compared to that proposed by the Company in its Application and Update Filing. The combined effect of these two elements – the stipulated base rates plus the stipulated tax rider rates -- is that the settlement achieves an overall 3.1% increase to the Company's revenues, which is an approximate $28.1 million increase in revenues in year one compared to the Company's requested overall increase of approximately $108.4 million per the Update Filing. The stipulated revenue increase effectively rises after year one as a result of the termination of the one-year amortization of the federal tax savings accrued since January 1, 2018 (i.e., the overcollected revenues accrued since January 1, 2018). Accordingly, starting in year two, there is an additional stipulated 4.1% increase yielding a total annual revenue increase of approximately $64.8 million ($28.1 million increase starting year one + an additional $36.7 million increase starting year two). On a levelized basis, this will be an increase in rates of less than 1% per year since the effective date of rates in Piedmont's last general rate case in January 2014 -- a figure well below the rate of inflation over the same period of time. The rate impacts relating to the termination of additional riders is explained later in my testimony.

Q. Please explain the adjustments to Piedmont's cost of service as agreed to in this settlement, and the associated impact to the revenue requirement.

A. The individual cost of service adjustments are identified on Settlement Exhibit__(PKP-1) attached hereto and represent a total downward adjustment of approximately ($34.8 million) from Piedmont's proposed annual margin revenues in its Update Filing in this docket. This cumulative impact to margin revenues of each of these cost of service adjustments is shown on line 46 of Settlement Exhibit__(PKP-1). The individual adjustment can be categorized as follows:

1. Capital Structure and Cost of Capital. Pursuant to Paragraph 6 of the Stipulation, the Stipulating Parties agreed that the appropriate capital structure for use in this proceeding consists of 52.00% common equity, 47.15% long-term debt, and 0.85% short-term debt. The agreed cost of long-term debt is 4.41% and the agreed cost of short-term debt is 2.72%. The agreed return on common equity appropriate for use in this proceeding is 9.70%. These modifications resulted in a downward adjustment to Piedmont's updated annual revenue requirement of approximately ($20.5 million), which is represented on Settlement Exhibit_(PKP-1) as the sum of the adjustments on lines 4 thru 7.

2. Customer Volumes and Margins. Under the settlement, the Stipulating Parties agreed to adjust the Company's pro forma customer volumes and associated revenues as of June 30, 2019. These modifications resulted in a downward adjustment to Piedmont's updated annual revenue requirement of approximately ($0.1 million), which is represented on Settlement Exhibit_(PKP-1) as the sum of the adjustments on lines 13 and 14.

3. Employee Compensation Adjustments. Under the settlement, the Stipulating Parties agreed to remove certain employee

compensation costs for ratemaking, including a portion of executive payroll, and certain incentive pay. Adjustments were also agreed upon regarding the going-level cost of the remaining straight time and overtime payroll, pension and other employee benefits. These modifications resulted in a downward adjustment to Piedmont's updated annual revenue requirement of approximately ($4.8 million), which is represented on Settlement Exhibit_(PKP-1) as the sum of the adjustments on lines 17 thru 19, 21, 22 and 28.

4. Amortization of Certain Regulatory Assets/Liabilities and Rate Case Expense. Under the settlement, the Stipulating Parties agreed to amortize all previously authorized regulatory asset and liability end of period balances (comprised of Pipeline Integrity Management - Transmission deferred O&M expenses, EasternNC deferred O&M expenses, Environmental Compliance Assessment and Clean-Up deferred O&M expense, and a newly determined under-collection of regulatory fee expense) over a period of four years in each case. The Company had sought in its Application to amortize the recovery of these amounts over a period of 3 years, while the Public Staff recommended a 5-year amortization period. On these matters, the settlement resulted in a downward adjustment to Piedmont's updated annual revenue requirement of approximately ($6.3 million), which is represented on Settlement Exhibit_(PKP-1) as the sum of the adjustments on lines 29, 30, 32 and 33. Under the settlement, the

Stipulating Parties have agreed to recovery of a lower amount of rate case expense than originally proposed by the Company, and to amortize recovery of that cost over 4 years instead of 3 years. On rate case expense, the settlement resulted in a downward adjustment to Piedmont's updated annual revenue requirement of approximately ($0.3 million), which is represented on Settlement Exhibit_(PKP-1) as the adjustment on line 23.

5. Operations and Maintenance ("O&M") Expenses. Under the settlement, the Stipulating Parties agreed to a variety of adjustments to other O&M expenses for ratemaking that encompass the following categories of expense: Board of Directors expenses, sponsorships and donations, inflation, lobbying, uncollectibles, regulatory fee, rents, line locates expense, aviation, advertising, and miscellaneous general expense. These modifications taken together resulted in a downward adjustment to Piedmont's updated annual revenue requirement of approximately ($4.0 million), which is represented on Settlement Exhibit_(PKP-1) as the sum of the adjustments on lines 20, 24 thru 26, 34 thru 38, 40, 42, 43 and 45.

6. Additional Conservation Program Funding. Under the settlement, the Stipulating Parties agreed that the Company's proposal to increase its recoverable expenditures on Conservation Programs for customers as contained in Piedmont's Application in this docket should not be approved. Accordingly, the settlement resulted in a downward adjustment to Piedmont's updated annual revenue requirement of

approximately ($1.2 million), which is represented on Settlement Exhibit_(PKP-1) on line 15.

7. GTI Funding. Under the settlement, the Stipulating Parties agreed that the proposed annual funding increase for its GTI Operations Technology Development program participation should be included in Piedmont's annual revenue requirement but that the total proposed annual funding for its GTI Utilization Technology Development program participation should not be included in Piedmont's annual revenue requirement. Accordingly, the settlement resulted in a downward adjustment to Piedmont's updated annual revenue requirement of approximately ($0.4 million), which is represented on Settlement Exhibit_(PKP-1) on line 39.

8. Non-Utility Adjustment. Under the settlement, the Stipulating Parties agreed to include a non-utility adjustment for ratemaking that was greater than the Company's proposed non-utility adjustment in its Application. Accordingly, the settlement resulted in a downward adjustment to Piedmont's updated annual revenue requirement of approximately ($1.4 million), which is represented on Settlement Exhibit_(PKP-1) on line 27.

9. Plant, Accumulated Depreciation, Accumulated Deferred Income Taxes, and other Rate Base-Related Adjustments. Under the settlement, the Stipulating Parties agreed to several changes to Piedmont's

rate base in the Stipulation, including an adjustment to increase accumulated depreciation (which is a deduction to rate base) that aligns with the stipulated going-level depreciation expense associated with plant in service as of June 30, 2019, adjustments to working capital that align to the settled amortization of the regulatory assets and liabilities, adjustments to exclude state and federal Excess Deferred Income Taxes ("EDIT") from the accumulated deferred income tax ("ADIT") rate base deduction, and the amortization of protected EDIT. Other rate base-related adjustments include changes to depreciation expense to adopt the revised depreciation rates and reallocations of book reserves reflected in the depreciation study while also reflecting the cost of service impacts of the reallocation of the reserve accounts related to the NC direct and corporate allocated general plant accounts, as well as property tax that align with the settled changes to rate base net of non-utility adjustments. In total, these modifications resulted in an upward adjustment to Piedmont's updated annual revenue requirement of approximately $4.0 million, which is represented on Settlement Exhibit_(PKP-1) as the sum of the adjustments on lines 8 thru 12, 16, 31, 41 and 44.

Q. Please explain the adjustments in this settlement for the flow-through to customers of savings related to recent federal and state tax reform, and the associated impact to the overall revenue requirement for Piedmont.

A. As mentioned earlier in my Settlement Testimony, the settlement also provides for a more accelerated refund to customers of the tax savings associated with the recent federal and state tax reform as compared to that proposed by the Company in its Application and Update Filing. Specifically, the Stipulating Parties agreed to a number of amortizations of regulatory liabilities associated with the Tax Cuts and Jobs Acts ("TCJA") of 2017 as well as previous North Carolina legislation lowering the state corporate income tax rate for Piedmont. These include a one-year amortization for deferred tax savings accrued since January 1, 2018 (i.e., the overcollected revenues accrued since January 1, 2018) associated with the TCJA's reduction in federal corporate income tax rates from 35% to 21%, a three-year amortization of state EDIT resulting from prior reductions in the North Carolina corporate income tax rates, and a five-year amortization of federal Unprotected EDIT resulting from the TCJA. The Stipulating Parties agree that each of these three categories of tax savings be flowed to customers via a rider, and the cumulative impact of these riders substantially mitigates the impact of Piedmont's proposed margin revenue increase. In year one, that cumulative impact of the riders is a downward adjustment to the revenue requirement of ($80.7 million), which is shown on line 51 of Settlement Exhibit_(PKP-1) and represents the aggregate effect of the individual riders shown on lines 48 thru 50 of Settlement Exhibit_(PKP-1). The impact of the settled increase in the margin revenues net of the tax rider adjustments is a total revenue requirement increase in year one of approximately $28.1 million. This amount is shown on line 52 of Settlement Exhibit_(PKP-1). Starting in year two, the impact of the settled increase in the margin revenues net of the tax rider adjustments is a total revenue requirement increase of approximately $64.8 million, which is shown on line 53 of Settlement Exhibit_(PKP-1).

Q. Please explain the impact of the stipulated cap to the revenue increase starting in year four.

A. Lines 54 and 55 of Settlement Exhibit_(PKP-1) show the revenue requirement increase without consideration of the revenue increase cap articulated in Paragraph 6G of the Stipulation. Starting in year four (when two of the three tax riders have been fully amortized), the impact of the settled increase in the margin revenues net of the tax rider adjustments would be a total revenue requirement increase of approximately $85.5 million. And starting in year six (when all three riders have been fully amortized), the impact of the settled increase in the margin revenues net of the tax rider adjustments would be a total revenue requirement increase of approximately $108.8 million. This overall increase of approximately $108.8 million starting in year six, is also shown in column (e) of Exhibit A of the settlement.

Paragraph 6G of the Stipulation articulates that the rates and charges approved in this case yield a revenue increase subsequent to year three of no greater than $82,820,089, which is the exact amount of the revenue increase requested in the Company's April 1, 2019 filed Application and the revenue increase accordingly cited in the public Notice of Hearings in this case. Accordingly, starting in year four (when two of the three tax riders have been fully amortized), the impact of the settled increase in the margin revenues net of the tax rider adjustments will be a total revenue requirement increase of $82.8 million (not $85.5 million) due to the stipulated cap. And starting in year six (when all three riders have been fully amortized), the impact of the settled increase in the margin revenue net of the tax rider adjustments will remain at $82.2 million (not $108.8 million) due to the stipulated cap.

Q. Did Piedmont expressly agree with each of the component adjustments in the settlement?

A. No. In fact, Piedmont strongly disagreed with many of these adjustments on an individual basis. I believe Public Staff, CUCA and CIGFUR IV each likewise opposed many of these adjustments in isolation. In order to reach settlement, however, each of the Stipulating Parties compromised on a large number of individual issues in order to reach a comprehensive agreement in this case. The settlement was arrived at as a whole and, as the Stipulation indicates, each individual adjustment may not have been agreeable to all parties participating in this settlement. However, when considered as a whole, the totality of the adjustments was acceptable to each of the

Stipulating Parties. For this reason, the Stipulating Parties agree that no precedent is intended to be established by the individual adjustments or component provisions of the Stipulation but that each would support the Stipulation as a whole before the Commission as a reasonable resolution of Piedmont's rate case filing.

Q. Do you believe that the overall settlement reached by the Stipulating Parties and presented to the Commission is just and reasonable and otherwise compliant with the requirements of North Carolina law?

A. Yes, I do.

Q. Does Piedmont support the 9.70% rate of return on common equity set forth in the settlement?

A. Yes. However, I would note that this is an example of an individual issue that Piedmont would not have agreed to in isolation but has agreed to as part of the overall settlement.

Q. Do you believe the agreed rate of return on common equity is fair to customers?

A. Yes, I do. Piedmont witness Hevert is filing testimony supporting the reasonableness of the agreed ROE as is Public Staff witness Hinton. In addition to the testimony of these two experts, there are other extrinsic indicators that the agreed return on equity ("ROE") is just and reasonable. For example, the settled ROE is 90 basis points lower than the requested ROE of 10.60%. It is also 30 basis points lower than the ROE of 10.00%

approved in Piedmont's last general rate proceeding in North Carolina, which is Piedmont's current allowed ROE. It is also comparable to the rate of return on common equity currently allowed for Public Service Company of North Carolina, Inc., and is within 5 basis points of the most recently litigated ROE for a North Carolina water utility. It is also well below the current allowed ROE's for Piedmont's two sister electric utilities in North Carolina -- Duke Energy Carolinas and Duke Energy Progress. It is also within 6 basis points of the national average ROE granted to local distribution utilities in 2019. Finally, it is lower than Piedmont's approved rates of return on common equity in South Carolina and Tennessee. These are all indicators that the settled ROE of 9.70% is just and reasonable in this case.

Q. Does the Stipulation address any non-economic issues?

A. Yes. There were several non-economic issues raised by our filing in this docket and the agreements of the Stipulating Parties on these non-economic issues are as described below.

1. <u>Continuation of IMR</u>. The Stipulating Parties agreed that this safety related surcharge mechanism should be continued for the benefit of the citizens of the State of North Carolina. The Stipulating Parties also agree that the special contract credit mechanism currently reflected in Appendix E to Piedmont's North Carolina Service Regulations, which Piedmont had originally proposed to remove from its tariffs, should be

updated and continued and those revisions will be incorporated into the revised IMR tariff set forth in the Exhibit F to the Stipulation.

2. Tariff and Service Regulation Changes. The Stipulating Parties agreed that Piedmont's other proposed tariff changes, including elimination of its Standby Sales Service for transportation customers but not including Piedmont's proposed Appendix G – EDIT Rider to its North Carolina Service Regulations, should be approved. The Stipulating Parties agreed that Piedmont's proposed Appendix G to its North Carolina Service Regulations should not be approved. Those changes are incorporated into the revised rate schedules and service regulations attached to the Stipulation as Exhibits G and H.

3. Depreciation Study. The Stipulating Parties agreed that Piedmont should implement the revised depreciation rates and reallocations of book reserves set forth in the testimony and depreciation study of Piedmont witness Watson and further agreed that Piedmont's filings in this case satisfy the requirements of Commission Rule R6-80.

4. DIMP O&M Deferral. The Stipulating Parties agreed that Piedmont's proposed DIMP O&M deferral request should be approved.

5. Annual TIMP and DIMP O&M Deferral Reports. Piedmont agreed to provide annual reports to the Public Staff with documentation on its incremental expenses subject to the TIMP and DIMP O&M deferral mechanisms to assist the Public Staff in its audit function with regard to those deferred accounts.

6. Consolidation of Common Gas Areas ("CGAs"). The Stipulating Parties agreed to the consolidation of Piedmont's CGAs from eleven to two such areas.

7. Line 434 Revenue Rider. The Stipulating Parties agreed that Piedmont shall establish a new rider, called the Line 434 Revenue Rider, to flow through to tariff customers any specific demand charge revenue from Special Contract Customers that may begin to be recovered by Piedmont subsequent to the effective date of the rates approved in this case related to Piedmont's Line 434 project (which became used and useful in the provision of gas service to the benefit of Piedmont's customers in November 2018, and is accordingly included in rate base in this proceeding), but before the first general rate case proceeding after the beginning of the Company's receipt of such demand charge revenue.

8. Rates for Special Contracts (including Contracts Rates for Electric Generation Customers). Piedmont and the Public Staff have also agreed to work together toward a rate mechanism whereby in future special contracts, including electric generation service contract arrangements, Piedmont will incorporate a volumetric rate component to those customers to support Piedmont's existing system infrastructure to the extent that infrastructure is relied upon to provide service to those customers.

Q. Are the rates proposed by the Stipulation fair, just and reasonable?

A. Yes. The rates agreed to as part of the Stipulation and reflected in Exhibit C thereto were the product of give and take negotiations between the

Stipulating Parties. Each party analyzed the settlement rates and concluded they were reasonable for purposes of settling this proceeding. The settlement rates are also very beneficial to customers compared to Piedmont's proposed rates in this docket.

Q. Please explain the stipulated rate design.

A. The rate design portion of the settlement reflects considerable compromise between the Stipulating Parties. The rate designs recommended by Piedmont witness Yardley, Public Staff witness Patel, CUCA witness O'Donnell and CIGFUR IV witness Phillips expressed varying viewpoints. As stated by witness Patel in her prefiled direct testimony, rate design considers many factors including 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 an allocated cost of service study. Whereas the overall revenue requirement increase in year one is 3.1% (as explained earlier in my testimony), the stipulated rate design does not yield an across-the-board 3.1% increase for all customer classes. The impact by customer class (rate schedule) of the stipulated revenue requirement increase is shown on Exhibit J to the settlement agreement.

Q. Do you believe that the stipulated rate increase, including the stipulated ROE is consistent with the statutory factors identified in G.S. 62-133 and is otherwise fair and reasonable to Piedmont and its customers considering changing economic conditions?

A. Yes, I do, for all of the reasons I mentioned above.

Q. What are you requesting the Commission do in this case?

A. I am requesting that the Commission, on the basis of its own independent evaluation of all the evidence presented in this case, approve the terms of the settlement reached with the Public Staff as just and reasonable and the appropriate resolution of this case.

Q. Does this conclude your Settlement Testimony?

A. Yes.

MR. JEFFRIES: And we would also ask that Ms. Powers' prefiled exhibits be identified as marked.

COMMISSIONER BROWN-BLAND: That motion is allowed as well.

MR. JEFFRIES: Thank you.

(Exhibits PKP 1 through PKP 8, PKP-1 Updated through PKP-8 Updated, and Settlement Exhibit PKP-1 were marked for identification.)

Q. Ms. Powers, have you prepared a summary of your testimony?

A. I have.

Q. Okay. Mr. Heslin is going to distribute that. Once he's done, could you go ahead and provide that?

A. I will.

(Summary handed out.)

A. Okay. My name is Pia Powers, and I am the director of gas rates and regulatory affairs for Piedmont Natural Gas Company. I prefiled direct testimony and exhibits in this docket on April 1, 2019, in support of Piedmont's application for a general rate increase. I also filed supplemental testimony and exhibits on July 29, 2019, in support of the Company's updated cost of service calculation as of June 30, 2019. On August 12, 2019, I filed settlement testimony and a supporting exhibit that explains the economic adjustments to Piedmont's filed rate case, as updated through June 30, 2019, reflected in the stipulation entered amongst Piedmont, the Public Staff, CUCA, and CIGFUR, herein after referred to as the stipulating parties.

My direct testimony -- my prefiled direct testimony explains and supports Piedmont's rate base at December 31, 2018, and the actual results of Piedmont's operations for the test period, which is the 12-month period ending December 31, 2018. Two, the results of Piedmont's test period operations under present rates, as adjusted for accounting and pro forma changes to the Company's operating revenue, operating expense, capital structure, and rate base. Three, the additional revenue required to appropriately support Piedmont's pro forma cost of service. Four, Piedmont's compliance with NCUC Form G-1 minimum filing requirements for this general rate case application. And five, the amortization of certain deferred expenses that previously have been granted regulatory asset treatment by the Commission.

My prefiled direct testimony is accompanied by eight exhibits which provide support for the five topics I previously mentioned.

I also filed supplemental testimony in this docket on July 29, 2019, in support of the Company's updated cost of service calculation as of June 30, 2019, which was performed and filed pursuant to North Carolina General Statute 62-133(c) and Commission Rule R1-17(c).

Most recently, on August 12th, I submitted prefiled settlement testimony that describes how settlement discussions were pursued and explains why the settlement amongst the stipulating parties is in the public interest and otherwise just and reasonable. My settlement testimony explains the economic adjustments to Piedmont's filed case, as updated through June 30, 2019, that are reflected in the stipulation and addresses the agreed-upon non-economic stipulations, such as the extension of the integrity management rider mechanism and consolidation of common gas areas, among others.

In addition, my settlement testimony discusses why Piedmont supports the rate of return on common equity set forth in this settlement.

In summary, I explain that the rates and non-economic turns agreed to as part of the stipulation and reflected in the stipulation exhibits were the product of give-and-take negotiations between the stipulating parties. Each party analyzed the settlement rates and concluded that the terms and rates were reasonable for purposes of settling this proceeding. The settlement is also very beneficial to customers compared to Piedmont's proposed revenue requirement and proposed rates in this docket.

That concludes the summary of my prefiled direct testimony, supplemental testimony, and settlement testimony. Based upon my prefiled testimony, Piedmont respectfully requests approval of the stipulation.

MR. JEFFRIES: Thank you, Ms. Powers. Ms. Powers is available for cross examination and questions by the Commission.

COMMISSIONER BROWN-BLAND: All right. Cross examination?

MS. FORCE: We're going to pass out an exhibit.

MS. HARROD: May I approach?

COMMISSIONER BROWN-BLAND: Yes, you may.

CROSS EXAMINATION BY MS. FORCE:

Q. Ms. Powers, as that's being distributed, if you would turn, please, to your Exhibit J that's part of the stipulation. I'm going to have a couple of questions about that.

COMMISSIONER GRAY: Ms. Force, could you pull it just a touch.

MS. FORCE: I keep banging into it. I'm not very good. Sorry about that.

Q. We've met before, my name is Margaret Force, Peggy Force, with the Attorney General's office. Good afternoon.

A. Good afternoon.

Q. Do you have that?

A. Yes. If you give me one more moment.

Q. That's just fine, it's being distributed still. We expanded the page for printing, and, unfortunately, few were copied before we got that message across in our office, so we passed out the larger form, but some folks are getting the smaller read.

Are you ready?

A. I am.

Q. I think we all have copies now. I asked you to turn to your Exhibit J, and in the settlement documents, that shows the impact of the stipulation -- the stipulated rate increase by customer class; is that right?

A. It does, for year one.

Q. For year one only. And it doesn't show in that schedule what the effect on the year-one adjustment to rates is due to the return of the tax numbers that EDIT and other items that are addressed in that tax rider; is that right?

A. So --

Q. Doesn't break it out?

A. It doesn't break it out, but what it does show is the net effect of -- including the EDIT rider givebacks.

Q. Okay. That's right. So I didn't mean to say it was not included; it's already included without breaking it out, so we don't know exactly how that affected it from --

A. From this exhibit.

Q. From that exhibit, okay.

And would you agree with me that the Attorney General's office asked Piedmont to provide the details about the stipulation that would show the impact of the stipulated rate increase, not only in year one but in subsequent years, and to break out the effect of the tax rider?

A. Yes.

MS. FORCE: And I would ask that the top page of the handout that you have be marked Attorney General or AGO Power Cross -- Powers, excuse me, Cross Examination Exhibit 1.

COMMISSIONER BROWN-BLAND: That's the one that starts "Jim, In summary"?

MS. FORCE: That's right.

COMMISSIONER BROWN-BLAND: All right. It will be so identified as Powers Cross Examination Exhibit 1.

(AGO Powers Cross Examination Exhibit 1 was marked for identification.)

Q. Does this look familiar to you, Ms. Powers?

A. It does.

Q. These are your notes about the schedule that you provided explaining the answer to that discovery request; is that right?

A. It is.

Q. Okay.

MS. FORCE: And then turning to the next four pages, I'd ask that that reflects a spreadsheet that starts at the top, Piedmont Natural Gas comparison of end-of-period revenues to stipulated proposed revenues. And there are four pages. I'd ask that that be marked as AGO Powers Cross Examination Exhibit 2.

COMMISSIONER BROWN-BLAND: It will be so identified.

(AGO Powers Cross Examination Exhibit 2 was marked for identification.)

Q. Now, if we look at the far right column in that schedule, it shows the year-one total revenue impact.

And those numbers, as I see it, line up with the numbers in your Exhibit J; am I right about that?

A. That's correct.

Q. Okay. And -- but it also shows some of the other information broken out. So let's look at the year-one second group of numbers, the one that's labeled year-one base margin revenue. Okay?

And if we look at the number that's the revenue increase or decrease, that's the total at the bottom of that column, it says $108,795,279; is that right?

A. Yes.

Q. And then when you look across, that's what is distributed across the different customer classes and appears in the percentage increase in column -- the fourth column, the total revenue; is that right?

A. The very last column?

Q. In the very last column.

A. Yes.

Q. And it reflects also in year one, tax rider revenue in column 2. If we look at that, the amount that goes back -- that's the amount -- if we look at total, that's the amount that goes back to customers in that year through the rider; is that right?

A. Yes.

Q. And it's my understanding that that reflects three different items. We talked about that earlier today. Just for purposes of speeding it along as we go through the document here, in the first year it reflects all three of those; is that right?

A. Yes.

Q. So it would be returning -- the one-year return of money, and then there's also a three-year return of state income tax dollars, and also the proposed five-year return of federal unprotected EDIT?

A. Yes.

Q. Is that right? Okay.

Just for my own edification -- maybe I shouldn't ask this question, but the protected -- the return of protected EDIT, how is that reflected in the rates?

A. So the return of protected EDIT would be reflected in the columns represented as base margin revenue.

Q. That's not part of this tax rider?

A. It's -- pursuant to settlement is not part of a rider.

Q. I understand. Okay. Thank you.

Let's -- and if you look over to the far right, these are the percentage increases for the various customers?

A. Yes, matching Exhibit J.

Q. In year one. All right. Now, if we turn to the second page, you've shown the -- in the far right column, you're showing the percentage impact on various customer classes. But in column one where you show years two and three base margin revenue, that's the amount of increase over the different customers broken down, not by percentages, but shows the dollar amounts under the settlement?

A. Yes. Base margin revenue years two and three, and those amounts would be identical to what was shown in year one for base margin revenue.

Q. Okay. And then when you look at the next column of the tax adjustment, the tax rider, that one is a little bit less, because we no longer had that one-year amount?

A. Yes. That first -- that amortization was fully amortized at that point, yes.

Q. Good. Okay. And when you look over to the percentages, then, for residential and different customer classes, then the percentages are a little bit different; they speak for themselves?

A. Yes.

Q. Okay. When you go over to the next page, page 3, the base revenue margin in column 1, we talked about 100 -- we talked about 108,796 on the first two pages, but that drops a little bit --

A. Yes.

Q. -- on this one?

And if you flip over to page 4, when you're done -- all done with the taxes, it's even less than that; is that right?

A. Yes.

Q. Am I understanding it correctly that the reason that it's -- it goes down is because the stipulation agreed that a maximum of $82,820,702 would be the amount of the rate increase at the end of the return of share of -- of ratepayer money for the tax rider part of it?

A. I think the stipulation is worded just a little bit differently, but that is --

Q. Probably more articulate.

A. -- essentially, yes, that's correct.

Q. So there is a cap that goes into the calculation in year six, because the notice that went to customers said that the rate adjustment that was being proposed by the Company was $82.8 million?

A. Yes. The cap is active in year six, and it also is active in years four and five. So both the lack of -- page 3 and 4 of what you handed me reflect -- incorporates the impact of the cap.

Q. Okay. And so, in years 4 and 5, if we look at the tax rider column, then the amount is smaller than it was in the prior year because it's only the federal, not the state?

A. At that point, there is only that one EDIT rider left that will be fully amortized at the end of the fifth year.

Q. Right. And the others had already been amortized. Okay. Now, when we look across -- let's look -- you see the percentages in the last column of how customers are affected.

When we take out the tax impact, aside from the fact that there's a cap in the year six, the total revenue increase, am I correct, then, that year six represents the percentage increase that falls on the various customer classes if you're not -- taking out of consideration that tax rider return of money?

A. Yes.

Q. So for residential customers, the percentage increase, without taking into account the tax rider, is 11.1 percent, small general service, the percentage increase is 11.6 percent, the overall is 9.2 percent, and then it varies from one to another of the industrial customers; is that right?

A. Yes.

Q. So these interruptible large general transportation customers, that's rate 114 if you go across, they have a rate increase under this of

1.4 percent?

A. Yes.

Q. And then the other numbers speak for themselves. I won't go through all of them. I actually did in my notes, but I won't here. Okay.

I think it would be good to turn to the third page, then, now, or the third item in your stack, please.

MS. FORCE: And I'd ask that this next item be marked -- well, just to identify it, this is, I would represent, the order scheduling investigation and hearings in this rate case. And I would ask that that be marked as AGO Powers Cross Examination Exhibit 3.

COMMISSIONER BROWN-BLAND: It will be so identified.

(AGO Powers Cross Examination Exhibit 3 was marked for identification.)

Q. Ms. Powers, have you seen this before? Are you familiar with the order that was issued scheduling the hearing?

A. Yes, I've seen it.

Q. And if you were to look at that, the page, there's a -- what do you call it, an appendix A to that; do you see that?

A. Yes.

Q. And if we look at page 2 of that, there's a chart that shows the proposed rate increase and how it falls on different customer classes; would you agree with me?

A. Yes.

Q. And if we look at the number for the proposed change overall total, it's $82,820,089, right?

A. Yes.

Q. That's the number we were talking about that's stipulated in the stipulation; it's the cap --

A. Yes.

Q. -- correct?

And if you look, that percentage change that's reported in the notice is 9.04 percent. Then there's a breakdown for different customer classes, including residential service at 9.82 percent, small general service at 11.09 percent.

I don't know -- you don't break out the number or the large interruptible transportation customers, do you? Is that 14.8 -- excuse me, 14.13; is that the percentage?

A. So, in appendix A, notice to customers, large interruptible is all -- whether it's sales or transportation, is all bundled on that single line labeled large interruptible general service.

Q. Okay. And the other percentages are shown there too. So I take it from this, then, when you issued the notice in the case to customers, that the total proposed change in rates in that column, that $82.8 million, that's net of the money that's being returned through the tax rider; is that right?

A. Yes.

Q. Okay. Let me see. Give me a second to get my notes.

Looking back at the schedule I passed out, I'm going to ask you, would you agree with me that the settlement has quite different results, in terms of the percentage increase, depending on the class of customers than what was shown in the notice that went to customers?

A. It does, for a couple of reasons.

Q. And in the notice that went to customers, that was based on the proposed rate increase from the Company; am I right?

A. Yes. That was based on our April filing.

Q. Okay.

A. April 1st.

Q. And after the April filing, you actually filed supplemental testimony that increased the amount that you were seeking to recover; is that right?

A. It updated a variety of factors, and it did have that result, as you --

Q. And could you tell me, what's the amount that was sought, then, as the revenue requirement when you add the supplemental; do you have that?

A. Settlement Exhibit PKP-1, if you were to look at that, I feel like that's just the cleanest -- easiest place to point to, that the third line, increase in margin revenue requested due to Company update, that would be the amount there, $143.6 million.

Q. Okay. Thank you. All right. Let's turn to -- I do have another question for you that concerns the discovery about the settlement. If you would turn to the next of the handouts.

MS. FORCE: And I'd ask that this be marked as AGO Powers Cross Examination Exhibit 4, please.

COMMISSIONER BROWN-BLAND: It will be so marked.

(AGO Powers Cross Examination Exhibit 4

was marked for identification.)

MS. FORCE: Thank you.

Q. Do you recognize this one? Do you have that?

A. Yes, I do recognize it.

Q. And I'm not asking -- I don't believe you prepared this.

This was prepared by the Public Staff in response to the Attorney General's requested information about the settlement?

A. That's my understanding.

Q. And I'd like to ask -- Mr. Jeffries and I talked about this before I started asking questions.

MS. FORCE: And I think that there's an agreement that you would stipulate that this is authentically a response from the Public Staff?

MR. JEFFRIES: Yeah.

MS. FORCE: So we can ask questions about it? Show that for the record.

Q. If you would take a minute to look at the exhibit, I have a couple of questions about it. And this is basically -- this describes how the EDIT or the -- really, I guess you call it the tax rider refund mechanism flows back amounts to ratepayers in years one, two, three, and four, and five, and indicates that the amounts were apportioned based on the non-gas cost origin of the stipulated rates as contained in Exhibit F, revised integrity management rider that was filed with the stipulation. And then it balances, in each group -- the balances in each group were divided by the annual volumes for each group to calculate the rate of EDIT that would apply to the various customers. It says it better in the handout, and you can look at that.

This is basically describing how the amount, the factor was decided, and that there were four factors used to return the tax amount; am I right about that?

A. Yeah. Well, I have my eyes on the third page, or the last page in that packet, which is the table. I guess I was a little bit thrown when you spoke, because it only speaks to years one, two, and three.

Q. You're right. Okay. Let me start back again. Look on page 1 of the response. And it says that there are -- it identifies residential -- about the middle of the page, residential and gives rate schedules, commercial and gives rate schedules, large general firm, and then large general interruptible.

And as I understand it, then, it explains how the amounts were identified per DT for those four types of -- four classes to identify a per DT amount in that tax column.

Do you follow me?

A. Yes, I see the words.

Q. It provides the explanation. I'm not going to ask you more questions about that. I just wanted to establish that's the methodology that was used?

A. (No verbal response.)

Q. Okay. The next page that you were referring to, I guess it's page 3 that's the revised Patel Exhibit 3, that's what was provided by the Public Staff in response. And you agree that that's a response to our question prepared by the Public Staff that shows margin changes and flowback of EDIT for the various customer classes?

A. Yes. That's the information that Witness Patel provided accompanying the -- this narrative you just pointed me to, yes.

Q. Okay. Thank you.

MS. FORCE: I would like to ask that this -- we had three pages at the end. Just for clarification, I had lumped them together because the third page is marked -- is referenced in the first part as an attachment. But if it's better for the record to identify that separately, we could mark it as AGO Powers Cross Examination Exhibit 5.

COMMISSIONER BROWN-BLAND: What we're marking is a single page that's caption is "Revised Patel Exhibit 3"?

MS. FORCE: That's right.

COMMISSIONER BROWN-BLAND: It will so be identified as Powers Cross Examination Exhibit 5.

MS. FORCE: Thank you.

(AGO Powers Cross Examination Exhibit 5 was marked for identification.)

Q. Okay. I have questions for you on another matter, just for clarification in the record, and I'm going to have to pass out another exhibit for that.

(Exhibit handed out.)

COMMISSIONER BROWN-BLAND: Ms. Force, do you have a little bit more to go? I'm looking ahead to breaking for lunch.

MS. FORCE: I think it will be quick, but I can't say what the answers are. If the answers are quick, I just have about three. I just want to establish this exhibit for the record.

COMMISSIONER BROWN-BLAND: And then that will be the end of your cross?

MS. FORCE: That will be the end. So I would estimate 10 minutes.

COMMISSIONER BROWN-BLAND: All right. Let's complete the cross, and then we'll take a break for lunch.

MS. FORCE: Okay.

Q. Are you ready?

A. I am.

Q. Okay. I'd submit that this is an exhibit that compiles a few that were provided to Piedmont on Sunday when we exchanged exhibits. And I would like to make a couple of clarifying points for the record before --

MS. FORCE: First, I'd ask that this entire packet be marked as AGO Powers Cross Examination Exhibit 6.

COMMISSIONER BROWN-BLAND: Yes, it will be so identified.

(AGO Powers Cross Examination Exhibit 6 was marked for identification.)

MS. FORCE: I think it's five pages.

Thank you. The pages at the top of the -- pages after page 1 have the word "confidential," and I -- it's my understanding that these are no longer confidential. This was the form that was provided to us, so I just marked that for clarification in the record, if you could cross -- is that your preference, Mr. Jeffries, just cross through confidential?

MR. JEFFRIES: I would prefer if everyone could just line that designation out so there's not some question about it. I think it was a designation that was embedded in the cell files that were transmitted and does not apply here. We don't consider this confidential.

COMMISSIONER BROWN-BLAND: So what was identified as AGO Powers Cross Examination 6 has no confidential information?

MR. JEFFRIES: Agreed.

COMMISSIONER BROWN-BLAND: All right. Thank you.

Q. And for clarification -- let me look at my notes, because I'll say it better. I tried to make this go smoothly. The exhibit that's the top is compiled from the contents, the data that's identified in the subsequent pages; do you agree?

A. Yes.

Q. And the subsequent pages, if we look, for example, to the second page, would you agree with me that this shows pages -- page 2 is the schedule 4 of Settlement Exhibit 1?

A. Yes, it reflects the stipulation.

Q. Okay. And would you also agree that the Company provided the working spreadsheets that were used for these exhibits?

A. Yes.

Q. Okay. So -- and I believe that was also provided to Commission staff at the same time?

A. Yes.

Q. We had asked that the Company actually do the calculations. They didn't do that for us.

Do you know whether that's the case? We didn't --

A. Yes. The Company did not perform calculations in the model to reflect a position other than the stipulation.

Q. Okay. So if you look at pages 2 and 3 of this exhibit, that shows a printout of schedule 4 and schedule 5 reflecting the calculation of -- on schedule

4 of the rate of return on equity using the stipulated amount of 9.7 percent and a 52 percent equity capital structure.

And then it shows the -- after the recommended increase, if you look all the way over to the right in the bottom, it shows the net operating income after the increase; is that right?

A. Yes.

Q. And the schedule 5, then, reflects the calculation of additional gross revenue requirement under the stipulation, if you look at that total in column D on line 5, $108,796,785; is that right?

A. Yes.

Q. All right. Now, let's just look back to page 1. You'll see those same numbers that show up on line 1 in the summary, and then -- by 52 percent -- to the far left, 52 percent equity, 9.7 percent ROE. If you look one line down, it reflects the same schedules 4 and 5 changing only the rate of return on equity from 9.7 to 8.7 percent; would you agree?

A. Yes, that's what it's indicating.

Q. And do you have any reason to dispute the calculation -- the computation of those numbers?

A. I did a quick review, and I was able to come up with a number very close to that.

Q. Okay. There's rounding. I'm not sure I could explain anything else. Okay.

So when we look at pages 3 and 4 just to -- 1, 2, 3 -- the schedules 4 and 5 that appear at the end, there's a mark on them in the middle at the top that says 52 percent equity capital structure, 8.7 percent ROE.

I apologize that -- if you don't -- do you agree with me that that is reflecting the changes that we just talked about?

A. The singular change of the return on equity.

Q. Right. And we were having a good deal of difficulty making it more bold, that this is changed from the settlement. This is the best we could do working with the Excel spreadsheets.

So, then, looking at the numbers again, on the top page, would you agree with me that, when you look at the additional gross revenue requirement, that there is a change using 8.7 percent rate of return on equity from using 9.7, a reduction of $23,455,034?

A. That's where we have a little bit of a difference, but it's a very close number.

Q. So that is --

A. Yeah. So your change is $23.455 million, and I would compute it as 23.690. I feel that's probably immaterial for our discussion purposes.

Q. Okay. I think that concludes my questions for you. I appreciate your cooperation in getting that into the record, and I don't have any other questions.

COMMISSIONER BROWN-BLAND: All right. We will take our lunch break now and plan on resuming at 2:00.

(Whereupon, the hearing was adjourned at 12:37 p.m. and set to reconvene at 2:00 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

NDTCA Signed Electronic Transcript

JOANN BUNZE, RPR
Notary Public #200707300112