PLACE: Via Videoconference

DATE: Thursday, September 9, 2021

TIME: 2:00 p.m. - 4:33 p.m.

BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

G-9, Sub 722

Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC;

G-9, Sub 781

Application of Piedmont Natural Gas Company, Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina; and

G-9, Sub 786

Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs

VOLUME: 4

Noteworthy Reporting Services, LLC

A P P E A R A N C E S:

FOR PIEDMONT NATURAL GAS COMPANY, INC.:
Amanda Johnson Demopoulos, Esq.
Associate General Counsel
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

Brian S. Heslin, Esq.
Deputy General Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, North Carolina 28202

James H. Jeffries, IV, Esq.
McGuireWoods LLP
201 North Tryon Street, Suite 3000
Charlotte, North Carolina 28202

CAROLINA UTILITY CUSTOMERS ASSOCIATION:
Marcus Trathen, Esq.
Craig D. Schauer, Esq.
Brooks Pierce
150 Fayetteville Street, Suite 1700
Raleigh, North Carolina 27601

A P P E A R A N C E S (Continued):

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES IV:

Christina D. Cress, Esq.
Patrick T. Buffkin, Esq.
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR DUKE ENERGY CAROLINAS, LLC:

Robert W. Kaylor, Esq.
Law Office of Robert W. Kaylor, P.A.
353 East Six Forks Road, Suite 260
Raleigh, North Carolina 27609

FOR FAYETTEVILLE PUBLIC WORKS COMMISSION:

James West, Esq.
General Counsel
Dustin Doty, Esq.
Staff Counsel
955 Old Wilmington Road
Fayetteville, North Carolina 28301

A P P E A R A N C E S (Continued):

FOR THE USING AND CONSUMING PUBLIC AND THE STATE OF NORTH CAROLINA AND ITS CITIZENS:

Margaret A. Force, Esq.
Special Deputy Attorney General
Teresa L. Townsend, Esq.
Special Deputy Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602

FOR THE USING AND CONSUMING PUBLIC:

Elizabeth D. Culpepper, Esq.
Megan Jost, Esq.
Lucy E. Edmondson, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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P R O C E E D I N G S

CHAIR MITCHELL: All right. It's 2:00, so let's go back on the record, please. We are still with the Company. Mr. Heslin, I don't see Mr. Jeffries. We'll have one last witness to call?

MR. JEFFRIES: Sorry, Chair Mitchell, I was a little slow on the button there.

CHAIR MITCHELL: That's okay.

MR. JEFFRIES: So, Chair Mitchell, if we're ready to proceed, the Company has concluded the presentation of its direct case. We have Mr. Long, who filed rebuttal and supplemental testimony slated for rebuttal, and then we have Mr. Barkley on reserve, but otherwise, our case in chief is complete.

CHAIR MITCHELL: Okay. And, Mr. Jeffries, just so I'm clear, you intend to hold Mr. Long until subsequent to the intervenors' testimony?

MR. JEFFRIES: That was our original intent. I think that's the plan. If you have a different preference, we could probably accommodate that as long as he's on the call.

CHAIR MITCHELL: That works on our end.

All right. Well, at this point, any other preliminary matters for my attention before we go ahead and get started?

(No response.)

CHAIR MITCHELL: All right. I'm not hearing any, so let's move forward. Let's see, I have CUCA.

MR. KAYLOR: Madam Chair, this is Robert Kaylor. I think we might be next in line.

CHAIR MITCHELL: Okay. I'm working off two different lists here. I'm gonna work off the list that Piedmont filed as of yesterday. So DEC, Mr. Kaylor, you can go ahead and proceed.

MR. KAYLOR: Thank you, Madam Chair, members of the Commission. We'll call our witness Lee Mitchell.

CHAIR MITCHELL: All right. Mr. Mitchell, let's see, where are you, sir. There you are. Just for what it's worth, Lee Mitchell is the name of my father as well, so when I saw you pop up on my screen, I thought, oh, my gosh, it's Lee Mitchell. All right. Mr. Mitchell, raise your right hand, please.

Whereupon,

HERBERT LEE MITCHELL, IV,
having first been duly affirmed, was examined
and testified as follows:

CHAIR MITCHELL: All right. Thank you, sir.

DIRECT EXAMINATION BY MR. KAYLOR:

Q. State your name and business address for the record, please.
A. My full name is Herbert Lee Mitchell, IV. My business address 526 South Church Street, Charlotte, North Carolina.
Q. By whom are you employed and what position?
A. Duke Energy Carolinas, director of fuel strategy and planning.
Q. And in connection with this hearing, did you cause to be prefiled, nine pages of direct testimony?
A. I did.
Q. If I ask you those same questions today, would the answers be the same?
A. Yes, sir.
Q. So you have no additions or corrections to that prefiled testimony; is that correct?
A. That is correct.
Q. And portions of this direct testimony are

confidential; is that correct?

A. That is correct.

Q. So in addition to the nine pages, we do have a cover page.

MR. KAYLOR: At this time, Madam Chair, I would ask that the prefiled direct testimony of Mr. Mitchell be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Mr. Kaylor, hearing no objection to your motion, the testimony of DEC witness Mitchell filed in the docket on August 11, 2021, shall be copied into the record as if given orally from the stand.

(Whereupon, the prefiled direct testimony of Herbert Lee Mitchell, IV was copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
DOCKET NO. G-9, SUB 722	)	
	)	
In the Matter of	)	
Consolidated Natural Gas Construction and	)	
Redelivery Services Agreement Between	)	
Piedmont Natural Gas Company, Inc., and	)	
Duke Energy Carolinas, LLC	)	
	)	
DOCKET NO. G-9, SUB 781	)	
	)	
In the Matter of	)	
Application of Piedmont Natural Gas	)	**DIRECT TESTIMONY OF**
Company, Inc., for an Adjustment of Rates,	)	**H. LEE MITCHELL, IV**
Charges, and Tariffs Applicable to Service	)	
in North Carolina	)	
	)	
DOCKET NO. G-9, SUB 786	)	
	)	
In the Matter of	)	
Application of Piedmont Natural Gas	)	
Company, Inc., for Modification to Existing	)	
Energy Efficiency Program and Approval of	)	
New Energy Efficiency Programs	)	
	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is H. Lee Mitchell IV. My business address is 526 S. Church St., Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Carolinas, LLC ("DEC" or the "Company") as a Director of Fuel Strategy and Planning. My responsibilities include providing leadership on enterprise fuel strategy and developing the corporate direction on strategic fuel matters for all regulated Duke Energy electric subsidiaries. Specifically, I support Duke Energy's generation transition away from coal to cleaner burning fuels, such as natural gas and other developing alternatives. This includes the management of long-term fuel planning, implementation of near-term strategic fuel initiatives, developing strategies to improve fuel security and supply, and helping advance a roadmap to fuel Zero-Emitting Load-Following Resources ("ZELFRs") through coordination with internal and external stakeholders.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I obtained a Bachelor of Science in Business Administration from the University of Richmond and a Master of Science in Natural Gas Engineering and Management from the University of Oklahoma. After five years trading wholesale petroleum products, I started my career with Duke Energy in January 2013 as a Real-Time Power Trader. In this role I optimized bulk power for Duke Energy's southeast utilities. From October 2015 to May

2019 I was employed as a Natural Gas Originator, where I was responsible for physical gas procurement and gas transportation to support Duke Energy's regulated generation fleet. In May 2019, I assumed the role of Manager of Coal and Gas Origination where I oversaw the coal and natural gas origination teams responsible for fuel procurement on behalf of Duke Energy's regulated electric subsidiaries. I assumed my current position in July 2020.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No, I have not previously testified before the Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain why the Public Staff's recommendation with respect to the revised Consolidated Construction and Redelivery Services Agreement ("Redelivery Service Agreement") between Piedmont Natural Gas Company, Inc. ("Piedmont") and DEC would lead to Piedmont overearning and to DEC customers subsidizing natural gas company customers.

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE REDELIVERY SERVICE AGREEMENT.

A. DEC and Piedmont negotiated an arms-length Redelivery Service Agreement related to the construction of new incremental natural gas facilities and the provision of redelivery service by Piedmont to DEC through these facilities at DEC's Lincoln Combustion Turbine ("CT") Plant. These incremental facilities serve the new Lincoln CT Plant Unit 17, for which the Commission issued a Certificate of Public Convenience and Necessity on December 7, 2017 in Docket No. E-7, Sub 1134. Piedmont filed the Redelivery Service Agreement on April 23, 2018 to supersede, replace, and expand upon a previous agreement which had been filed in Docket No. G-9, Sub 491. To address concerns of the Public Staff, Piedmont recommended to DEC the inclusion of additional volumetric charges for gas flows on the incremental facilities. Therefore, a volumetric charge was negotiated and then filed in a revised Redelivery Service Agreement on November 16, 2018, that also included an updated construction schedule and cost projections for the incremental facilities involved in the project. In this revised Redelivery Service Agreement, DEC agreed to carry forward the Existing Facilities Demand Charge per month and the Existing Facilities Volumetric Rate per dekatherm ("Dth") for CT Units 1-16 and to add an Incremental Facilities Volumetric Rate for Lincoln CT Unit 17 in addition to the Fixed Demand Charge for these Incremental Facilities. To protect DEC's customers from Piedmont further overearning on the Incremental Facilities, DEC and Piedmont agreed that the annual charge of this Volumetric Rate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. DO OTHER COMMISSION-APPROVED REDELIVERY SERVICE AGREEMENTS CONTRACTED BY DEC HAVE VARIABLE OR VOLUMETRIC CHARGES?

A. Most of the Commission-approved local distribution company ("LDC") redelivery agreements contracted by DEC and Duke Energy Progress, LLC ("DEP") since the Lincoln CT Plant Agreement in 2004 included fixed demand rates in lieu of variable (or volumetric) charges. Only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** DEC or DEP combined cycle ("CC") sites have gas redelivery contracts that include a facilities volumetric charge. Indeed, this reflects an intentional and appropriate shift in response to a fundamentally different power generation market and evolving Construction and Redelivery Service Agreements. Fixed demand rates give the LDC increased certainty of not under or over earning on their cost of service model due to the unpredictability of volumetric flows. DEC does not have the visibility to LDC cost of service models as does Public Staff; however, it is understood by DEC that Piedmont uses the same cost of service model for all Special Contracts. Since the early 2000s, demand rates with no volumetric charges have been both reasonable and, in fact, common for power generation Special Contracts in North Carolina.

Q. PLEASE EXPLAIN THE PURPOSE OF VOLUMETRIC CHARGES IN GENERAL.

A. Most historical variable (or volumetric) charges are designed to partially recover cost of service and a return to the LDC and are not exclusively for system contribution. Specifically, historical variable charges have been primarily designed to account for certain administrative and general expenses

("A&G") and operations and maintenance ("O&M") for the facilities designated to provide the Redelivery Service of that Agreement. For example, volumetric charges are often used to offset variable O&M charges of compression facilities. However, the Piedmont facilities at the Lincoln site do not include any compression facilities.

Q. HOW DOES THAT RELATE TO DEC's REDELIVERY SERVICE AGREEMENT?

A. Historically speaking for the Lincoln site, volumetric charges were more logical in previous agreements with different ratemaking constructs or for facilities that have had their costs fully recovered by the LDC. For example, DEC's original Lincoln CT Agreement dated September 30, 1993 was a bundled agreement with Piedmont that included both transportation services and the physical gas commodity, in which there was a volumetric charge within the commodity pricing. This agreement recovered the costs of the original Lincoln facilities over the initial ten-year period. In the subsequent June 28, 2004 Lincoln Agreement, the commodity portion of the agreement was removed given the dated structure of the previous agreement; however, despite the cost of facilities being fully recovered, to likely help cover system overhead and O&M, a volumetric charge was retained in addition to a **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** To account for the capital required to expand the facilities for CT 17, a revised rate for incremental facilities was negotiated while preserving the rate structure of the existing service to CT 1-16. In the Redelivery Service Agreement filed April 23, 2018, in order to revise the format to be more similar to the most recent Commission-approved redelivery agreements, the A&G and O&M for the incremental facilities were accounted for as part of the Fixed Demand Rate. In response to the Public Staff's concerns, however, DEC and Piedmont negotiated and agreed to a volumetric charge with a cap. While DEC does not believe there should be any surcharges above the cost of service, given that the historical service to CT 1-16 includes a volumetric charge, DEC has agreed to a revised incremental facilities volumetric rate **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** A volumetric rate was not considered when initial planning began for Lincoln CT 17, nor was it imagined that any volumetric rate would ultimately be greater than the fixed rate yet still not be satisfactory to the Public Staff. Notwithstanding DEC's concerns with adding a volumetric charge to the Redelivery Service Agreement, in the overall structure of the renegotiated agreement, DEC supports the volumetric rate negotiated by DEC and Piedmont in this instance and requests the Commission's approval.

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S CONCERNS WITH RESPECT TO THE VOLUMETRIC CHARGE.

A. The Public Staff expressed concern that the volumetric charge was insufficient to recover Piedmont's costs related to existing infrastructure and operations and to prevent subsidization of the contract customer, i.e., DEC, by Piedmont's other customers.

Q. PLEASE EXPLAIN WHY DEC DISAGREES WITH THE PUBLIC STAFF'S PROPOSED VOLUMETRIC CHARGE.

A. DEC contends that gas transportation rates, both fixed and volumetric, should combine to enable recovery of the LDC's cost of service, plus the LDC's regulated return, and should minimize system cross-subsidization. Incremental "system support surcharge" or "system contributions" should never lead to the LDC overearning and electric utility customers subsidizing natural gas utility customers. Stated another way, punitive charges to DEC customers would create overearnings from this Redelivery Service Agreement that would ultimately reduce rates for Piedmont's other customers at the expense of electric utility customers. The Redelivery Service Agreement's revised fixed rate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** already includes an allocated share of the general system overhead costs per Piedmont's cost of service model. Any further "system support surcharge" on DEC dedicated facilities creates the forementioned electric customer subsidization of the gas customer. There also needs to be a rational, repeatable and transparent methodology for any "system support surcharge" beyond the cost of service calculation on Special Contracts. DEC is not aware that such methodology exists. The Redelivery Service Agreement for the Lincoln CT Plant will not provide any support to the Piedmont system because the pipelines and associated facilities that serve the Lincoln CT Plant are solely dedicated to serve that facility from the Transcontinental Gas Pipe Line Company LLC pipeline and do not provide natural gas service to any other customer on Piedmont's system. The pre-existing facilities at the site were fully paid for by DEC and at no time were utilized by any other Piedmont customers. Furthermore, DEC has not seen a logical or appropriate reason for any "system support surcharge" since these facilities do not rely on any of the other portion of Piedmont's system to receive service. The Public Staff's proposed volumetric charge is unreasonable and, if adopted by the Commission, would inappropriately result in cross-subsidization of Piedmont by DEC customers. Implementing a usage-based "system support surcharge" charge will cause DEC ratepayers to increase Piedmont's returns on this Redelivery Services Agreement, likely to levels above authorized limits. Equally important, the Public Staff's recommendations, if adopted, would have far reaching consequences that would unfairly harm the cost competitiveness of not only the new and efficient Lincoln CT Plant Unit 17 compared to other less efficient generators and wholesale power prices, but also disadvantage future natural gas generation facilities that could be developed in the State of North Carolina.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Q. Mr. Mitchell, did you prepare a summary of your direct testimony?

A. I did.

Q. Would you please provide that to the Commission at this time.

A. Yes, sir.

My direct testimony explains why the Public Staff's recommendation with respect to the revised consolidated construction and redelivery services agreement between Piedmont Natural Gas and Duke Energy Carolinas are related to the construction of the new incremental natural gas facilities in the provision of redelivery service by Piedmont to DEC through these facilities at DEC's Lincoln combustion turbine plant, would lead to Piedmont over-earning, and to DEC's customers subsidizing natural gas company customers.

Since the early 2000s, most redelivery agreements contracted by DEC and approved by the Commission included fixed demand rates in lieu of variable or volumetric charges. The Public Staff expressed concern that the volumetric charge in the redelivery service agreement at issue was insufficient to recover Piedmont's cost related to existing infrastructure and operations and to prevent subsidization of DEC customers by Piedmont's other customers.

It should be noted that the redelivery service agreement's revised fixed rate already includes the allocated share of the general system overhead cost per Piedmont's cost of service model. The pipelines and associated facilities that serve at Lincoln CT plant are solely dedicated to serve that facility from the Transcontinental gas pipeline and do not provide natural gas service to any other customer on Piedmont's system.

Moreover, the Public Staff's recommendation, if adopted, may have far-reaching consequences that would not only harm the cost competitiveness of the new and efficient Lincoln CT plant Unit 17, but may also disadvantage future natural gas generation facilities that could be developed in the state of North Carolina.

This concludes the summary of my testimony.

Q. Thank you, Mr. Mitchell.

MR. KAYLOR: Mr. Mitchell is available for cross examination, Madam Chair.

CHAIR MITCHELL: All right. Thank you, Mr. Kaylor. My notes indicate no cross examination has been identified for the witness, but I'll pause here to make sure that that is, in fact, the case.

(No response.)

CHAIR MITCHELL: I'm not seeing anyone indicate that they have cross, so we will proceed to questions from Commissioners.

Any Commissioners have questions for the witness?

(No response.)

CHAIR MITCHELL: All right. Mr. Mitchell, I do have a few, so I will go ahead and ask my questions for you.

EXAMINATION BY CHAIR MITCHELL:

Q. Mr. Mitchell, the original agreement, the 2004 agreement between Duke and Piedmont for gas supply at the Lincoln site, the original units, Numbers 1 through 16, are you aware of whether that original agreement was for firm or interruptible service?

A. Yes. And it should probably be noted, I know the term "original" is coined with that 2004 agreement, but there is also agreement, I believe, in 1993 or '94. That is when the units were first put into service. And that is what paid off the 10-year -- 10 years of fixed demand fees are what paid off the original facilities for those.

But to directly answer your question, it is my understanding that it's been firm transportation service since the initial units were put in service.

Q. Okay. Well, thank you for that clarification about original. So I'll refer to the -- what we have been calling the original agreement, I'll call that one the 2004 agreement, and now we know that there was a 1993 agreement that predated the 2004.

All right. Mr. Mitchell, are the -- are Units 1 through 16 at the Lincoln site used for Duke's peaking requirements? Are they peakers?

A. They are.

Q. Okay. The second revised agreement with -- between Duke and Piedmont is for Unit Number 17. Is Unit 17 also a peeking facility?

A. It is a peaking facility. It is a new and much more efficient peaking facility. I believe it's the heat rate, which is the efficiency of the unit, is approximately 30 to 35 percent more efficient than the current GE78 models at that site. And as you may know, it's serial Number 1, so it's currently being tested at the moment.

Q. Okay. Does it -- does the Unit 17 involve back-up fuel supply?

A. It does have back-up fuel on site.

Q. Is that diesel?

A. Yes.

Q. Okay. So if -- since it has back-up fuel supply, is there a reason why Duke has chosen not to contract for interruptible service? Why Duke elected firm over interruptible?

A. This lateral off Transcontinental, we're the sole customer. And, traditionally, many times when we look to do incremental facilities on dedicated laterals, since the capital investment from Piedmont will be the same since we're the sole customer, oftentimes the rate will be the same on a special agreement for firm or interruptible.

Q. And you said "oftentimes," but do you know whether that was the case here?

A. Subject to check, I believe we only requested a firm rate for this agreement.

Q. Okay. All right. Mr. Mitchell, that's all I have for you.

CHAIR MITCHELL: Any other -- I'll check in with the Commissioners one more time. Any other questions for this witness from the Commissioners?

(No response.)

CHAIR MITCHELL: Okay. I'm not hearing any. All right. We'll take questions on my questions for the witness.

Any intervening parties have questions on my questions?

(No response.)

CHAIR MITCHELL: All right. Mr. Jeffries, any questions? I'm sorry, Mr. -- now I've just gotten all confused. Mr. Kaylor, questions for the witness?

MR. KAYLOR: None from DEC.

CHAIR MITCHELL: All right. Mr. Mitchell, you are done for today. Thank you, sir, for your participation. You may step down.

THE WITNESS: Thank you.

MR. KAYLOR: And I believe he can be excused since he has no further reason to be here.

CHAIR MITCHELL: All right. Mr. Mitchell, you are excused.

MR. KAYLOR: Thank you. And that would conclude our witness.

CHAIR MITCHELL: All right. Thank you, Mr. Kaylor.

All right. Next up we have CUCA.

MR. SCHAUER: Thank you, Chair Mitchell. CUCA calls Kevin O'Donnell to the stand.

CHAIR MITCHELL: All right. Mr. O'Donnell, would you raise your right hand, please, sir.

Whereupon,

KEVIN W. O'DONNELL,

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

CHAIR MITCHELL: All right.

DIRECT EXAMINATION BY MR. SCHAUER:

Q. Mr. O'Donnell, will you please state your name and business address for the record.

A. Kevin O'Donnell. Business address is 1350 Southeast Maynard Road, Suite 101, Cary, North Carolina 27511.

Q. Did you cause to be filed in this proceeding, on August 11, 2021, direct testimony consisting of 102 pages along with 7 exhibits?

A. Yes, I did.

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

A. No, I do not.

Q. If I asked you the same questions in this prefiled submission today, would your answers be the same?

A. Yes, they would.

MR. SCHAUER: Chair Mitchell, we move that Mr. O'Donnell's direct testimony consisting of 102 pages be copied into the record as if given orally from the stand.

CHAIR MITCHELL: Okay. Hearing no objection to that motion, the testimony of CUCA witness O'Donnell filed in the docket on August 11, 2021, will be copied into the record as if given orally from the stand.

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 781

In the Matter of
Application of Piedmont Natural)
Gas Company, Inc. for General)
Rate Increase)

DIRECT TESTIMONY OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF

CAROLINA UTILITY CUSTOMERS ASSOCIATION

August 11, 2021

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I. INTRODUCTION

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

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

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

A. I am testifying on behalf of the Carolina Utility Customers Association ("CUCA"). CUCA represents industrial and manufacturing users before the North Carolina Utilities Commission ("NCUC" or "Commission").

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

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from Florida State University. I earned the designation of Chartered Financial Analyst ("CFA") in 1988. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission. I left the Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail Rates for the North Carolina Electric Membership Corporation (1994-1995), and since then in my own consulting firm.

I have been accepted as an expert witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Wisconsin Public Service Commission, the Virginia State Commerce Commission, the Minnesota Public Service Commission, the New Jersey Commission of Public Utilities, the Colorado Public Utilities Commission, the District of Columbia Public Service Commission, and the Florida Public Service Commission. In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in **Appendix A**.

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

A. The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the proper rate of return to allow Piedmont Natural Gas Company ("Piedmont" or "Company") in the current proceeding.

Q. WHAT RATE OF RETURN IS PIEDMONT REQUESTING AS PART OF THIS PROCEEDING?

A. According to the testimony of Piedmont's Witness Quynh P. Bowman, Piedmont is seeking an overall rate of return of 7.27% based on the capital structure and cost rates as set forth in **Table 1** below.

Table 1: Piedmont's Requested Cost of Capital[1]

Component	Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	47.45%	4.09%	1.94%
Short-Term Debt	0.55%	0.47%	0.00%
Common Equity	52.00%	10.25%	5.33%
Total Capitalization	**100.00%**		**7.27%**

Q. SHOULD THE COMMISSION ADOPT THE COMPANY'S COST OF CAPITAL CLAIM TO SET JUST AND REASONABLE RATES?

A. The Company's 10.25% equity cost rate is overstated when compared to my Cost of Common Equity Analyses (see **Section VII**: Cost of Common Equity). The Company determined that its equity ratio request of 10.25% was appropriate based on flawed cost of equity analyses that do not reflect market conditions (see **Section VIII**: Review of Cost of Equity Analysis of Witness D'Ascendis). As discussed in the remainder of this testimony, adoption of the Company's requested cost of capital claim would overburden ratepayers, especially in light of the current economic conditions brought on by the COVID-19 pandemic.

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

- The proper capital structure to use in this proceeding is 50.00% common equity, 49.43% long-term debt, and 0.57% short-term debt;

[1] Witness Bowman's Direct Testimony, **Exhibit QPB-7**, page 2.

- I agree that the proper embedded cost of debt to use in this proceeding is Piedmont's recommended future cost of short-term debt of 0.47% and long-term debt of 4.09%;
- The proper return on equity on which to set rates for Piedmont in this proceeding is 9.00%. This 9.00% recommendation is a market-based cost of equity which will allow the Company to access capital markets, while also ensuring that the rate is fair to the Company's captive customers; and
- The return on equity recommended by Witness D'Ascendis for Piedmont of 10.25% is excessive, unreasonable, and not indicative of current market conditions.

My recommended capital structure, ROE, and overall return are shown below within **Table 2** as based upon the results and data shown within **Exhibit KWO-1**:

Table 2: CUCA Recommended Overall Rate of Return

Component	Ratio (%)	Cost Rate (%)	Weighted Cost
Long-Term Debt	49.43%	4.09%	2.02%
Short-Term Debt	0.57%	0.47%	0.00%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.52%**

II. CURRENT STATE OF THE FINANCIAL MARKETS AND CHANGES SINCE LAST PIEDMONT RATE CASE

Q. PLEASE DESCRIBE THE CURRENT STATE OF THE FINANCIAL MARKETS.

A. The equity market has rebounded strongly since the outbreak of the COVID-19 pandemic. Just prior to the pandemic, the S&P 500 index, which represents the 500 largest companies in the United States, was 3,386 as of February 19, 2020.[2] When the severity of the pandemic sank into the market, the S&P 500 index moved sharply downward to just above 2,237[3] as of March 23, 2020, representing roughly a 1/3 loss in the index. As of July 2, 2021, the S&P 500 index closed over 4,352,[4] representing roughly a 95% gain from the low value that occurred on March 23, 2020. Clearly, investors weathered the storm and are now expecting solid growth from the US and world economies in the near future.

The debt markets have also rebounded from the impact of COVID-19. The Federal Reserve stepped in to ensure adequate liquidity to the markets and, as a result, interest rates stabilized and utilities were able to obtain adequate debt capital during the pandemic.

[2] Yahoo! Finance, *S&P 500 Historical Data*, *available at* https://finance.yahoo.com/quote/%5EGSPC/history?p=%5EGSPC (last accessed July 6, 2021).
[3] *Id.*
[4] *Id.*

Q. DESCRIBE THE KEY ELEMENTS OF PIEDMONT'S RECENT RATE CASES.

A. The Company's most recently completed base rate case was filed on April 1, 2019 under Docket No. G-9, Sub 743. In that case, the Company requested an overall rate of return of 7.68%, inclusive of a cost of equity of 10.60%, a long-term cost of debt of 2.82%, a short-term cost of debt of 4.55%, and a capital structure weighted with 52.00% common equity, 47.18% long-term debt, and 0.82% short-term debt.[5]

Ultimately, the Commission approved a settlement of Piedmont's 2019 general rate case, which allowed Piedmont to increase rates. Piedmont was allowed an overall rate of return of 7.14%, inclusive of a 9.70% cost of equity, a 4.41% long-term cost of debt, a 0.85% short-term cost of debt, and a capital structure weighted with 52.00% common equity, 47.15% long-term cost of debt, and 0.85% short-term cost of debt.[6]

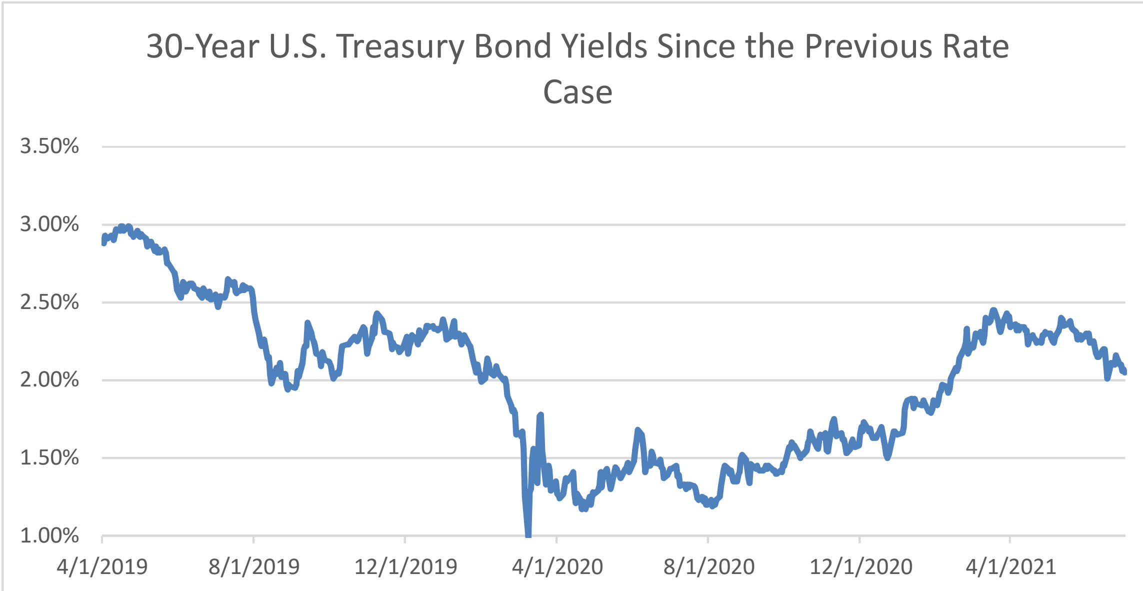
Q. HAS THE DEBT MARKET FOR PIEDMONT CHANGED SINCE THE COMPANY'S 2019 GENERAL RATE CASE?

A. Yes. The debt markets have changed since Piedmont filed its 2019 base rate case on April 1, 2019 as exhibited in **Chart 1** below. Within this chart, I have provided the change in the 30-year US Treasury Bond yields from April 1, 2019 to July 2, 2021. The maximum value over this period was 2.99%, the average value was 1.99%, and the minimum value was 0.99%. Refer to **Chart 1** below for further

[5] Direct Testimony of Witness Pia K. Powers, Docket No. G-9, Sub 743 (Apr. 1, 2019) (see Exhibit PKP-7).
[6], *Order Approving Stipulation*, Docket No. G-9, Sub 743 (Oct. 31, 2019).

details on the yield on 30-year US Treasury Bonds subsequent to the previous rate case.

Chart 1: Yield on 30-Year US Treasury Bonds[7]



Q. DOES CHART 1 ABOVE INDICATE THAT THE COMPANY'S COST OF DEBT IS HIGHER NOW THAN IT HAS BEEN HISTORICALLY?

A. No, not necessarily. When Piedmont's 2019 base rate case concluded on October 31, 2019, the yield on the 30-year US Treasury Bond was 2.17%.[8] The current yield on the 30-year US Treasury Bond yield of 2.05%, as of July 2, 2021,[9] is still significantly lower than what has been seen for the Company, and the market as a whole, in recent years. This would indicate that the cost of capital of Piedmont's

[7] U.S. Dep't of the Treasury, *Daily Treasury Yield Curves*, *available at* https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield (last accessed July 6, 2021).
[8] *Id.*
[9] *Id.*

parent company, Duke Energy Corporation, in relation to its ability to access debt markets, has still been lower on average than what has been seen in recent years.

Q. HOW ARE INTEREST RATES EXPECTED TO CHANGE OVER THE NEXT FEW YEARS?

A. The Federal Funds Rate is the interest rate that banks charge to one another to borrow or lend excess reserves on hand overnight. This rate plays an important role in the movement of interest rates, and the Federal Reserve's actions over the previous 18-months helps to showcase the steady decline in interest rates from 2018 to 2020. On March 15, 2020, in response to the COVID-19 outbreak and the disruptions to economic activity in this country across the globe, the Federal Reserve reduced the Federal Funds rate to 0.25%.[10]

The Federal Reserve has since stated that it does not expect to change the Federal Funds Rate at any time in the foreseeable future. Chairman Powell reinforced this view when he said in January 2021 that, "When the time comes to raise interest rates, we'll certainly do that, and that time, by the way, is no time soon."[11] Subsequent to the statements made by Chairman Powell in March 2021, the Federal Reserve explained that although they had sped up their overall expectation for economic growth, they continued to reinforce that they did not see

[10] *See* Commission of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Mar. 15, 2020), *available at* https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a.htm.

[11] Jeff Cox, *Powell sees no interest rate hikes on the horizon as long as inflation stays low*, CNBC News (Jan. 14, 2021), *available at* https://www.cnbc.com/2021/01/14/powell-sees-no-interest-rate-hikes-on-the-horizon-as-long-as-inflation-stays-low.html.

any interest rate hikes likely through 2023.[12] This line of thinking by the Federal Reserve then carried into July 2021 as well.[13]

As noted above, while changes within the market have raised certain interest rate benchmarks during 2021, these interest rates still remain low in relation to historical interest rates. This lower interest rate environment has continued to provide a benefit to utilities from a borrowing perspective.

Q. HOW HAS THE STOCK MARKET FOR UTILITIES CHANGED OVER THE PAST YEAR AND A HALF?

A. Utilities have always been considered a safe harbor for investors during market turbulence or uncertainty, and the COVID-19 pandemic is no different. During times of economic uncertainty, individuals and businesses still require the essential services provided by utilities. As such, the market for utilities remained strong during the past year and a half, even during the COVID-19 pandemic and the associated economic shutdown.

Chart 2, which is a double y-axis graph, shows the change in the Dow Jones Utility Average ("DJUA") since the start of 2020 (*i.e.,* 1/2/2020 – 7/6/2021), as compared to the Dow Jones Industrial Average ("DJIA") over the same period.

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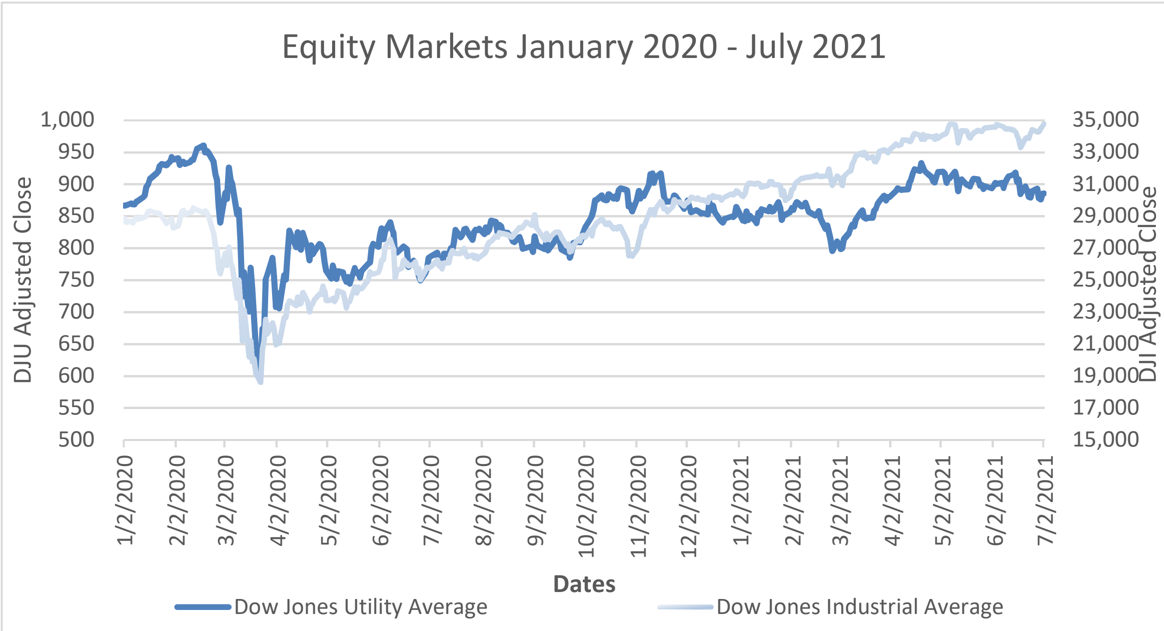
[12] Jeff Cox, *Fed sees stronger economy and higher inflation, but no rate hikes*, CNBC News (Mar. 17, 2021), *available at* https://www.cnbc.com/2021/03/17/fed-decision-march-2021-fed-sees-stronger-economy-higher-inflation-but-no-rate-hikes.html.

[13] Taylor Tepper & Benjamin Curry, *July 2021 FOMC Meeting: Fed Keeps Policy Unchanged As Pressure To Taper Increases*, Forbes Advisor (Jul. 28, 2021), *available at* https://www.forbes.com/advisor/investing/fomc-meeting-federal-reserve/.

Chart 2: DJIA to DJUA Comparison[14]



Although the DJIA is now at a level greater than that of the DJUA, the DJUA initially rebounded much more quickly than the DJIA. This further enforces the fact that the utility equity market has remained stable and consistent. Thus, although all markets were obviously impacted by the COVID-19 pandemic, utilities such as Piedmont have not had an issue accessing the capital markets. In light of this, Piedmont simply does not require a 10.25% ROE to attract and compete for capital in the current economic environment, especially given the positive market movements in 2021 as the overall economic recovery continues.

[14] Yahoo! Finance, Dow Jones Utility Average, *available at* https://finance.yahoo.com/quote/%5EDJU/components/ (last accessed July 6, 2021); Yahoo! Finance, Dow Jones Industrial Average, *available at* https://finance.yahoo.com/quote/%5EDJI/history (last accessed July 6, 2021).

Q. DO YOU HAVE ANY OTHER SUPPORT FOR HOW UTILITIES LIKE PIEDMONT WERE STILL ABLE TO ACCESS THE CAPITAL MARKETS EVEN DURING THE COVID-19 PANDEMIC?

A. Yes. On April 2, 2020, S&P Global Market Intelligence published an article entitled "US utilities demonstrate access to capital with billions in debt offerings." This article described how utilities tapped into current credit markets to obtain low-cost debt during periods of financial turbulence as noted in the excerpt below:

> Several utilities, including Xcel Energy and NextEra Energy Inc. subsidiary Florida Power & Light Co., which issued $1.1 billion in first mortgage bonds, are "*using the opportunity to take advantage of attractive borrowing costs, so there does not appear to be an inability to access capital*," they said.
>
> "*Utilities are reporting that recent deals have been significantly (7x) oversubscribed, highlighting that the capital markets are open for investment grade-rated utilities*," the analysts wrote. "*At the same time, we have also observed some utility companies that have fully drawn their bank lines as a precaution to provide them with liquidity in the event that markets seize up*," such as Duke Energy Corp. and American Electric Power Co. Inc.[15]

Additionally, during the midst of the early stages of the COVID-19 pandemic on April 29, 2020, S&P Global Market Intelligence published an article entitled "Utility sector 'far and away' least impacted by EPS estimate cuts."[16] Note that on the date that this article was published, markets were at their most volatile during

[15]Ellen Meyers, *US utilities demonstrate access to capital with billions in debt offerings*, S&P Global Market Intelligence (Apr. 2 2020), *available at* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-utilities-demonstrate-access-to-capital-with-billions-in-debt-offerings-57881534.

[16] Tom DiChristopher, *Utility sector 'far and away' least impacted by EPS estimate cuts*, S&P Global Market Intelligence (Apr. 29, 2020), *available at* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utility-sector-far-and-away-least-impacted-by-eps-estimate-cuts-58358458.

the early stages of the COVID-19 pandemic. The article provided the following observation:

> The S&P 500 utility sector has "far and away" experienced the least impact from earnings revisions since Feb. 28, the corporate bond research firm found. Despite market turmoil and the ongoing economic downturn, analysts have only cut earnings per share expectations for stocks in the utility sector by an average 1% for 2020 and 2021, according to CreditSights.
>
> By comparison, consumer staples, the next least-impacted sector, saw an average 5% decrease to EPS estimates for both years. Technology followed with a 9% estimate cut for 2020 and 2021.
>
> CreditSights pulled the data to measure the consensus view that utilities provide a safe harbor to investors. "*Water is wet, the sun will rise in the east and U.S. utilities are a defensive sector, but how defensive? Very defensive,*" CreditSights analysts Andrew DeVries and Nick Moglia wrote in an April 29 research note.[17]

The above referenced article noted the ability of utilities to continue to operate based upon the conditions of the debt and equity markets. This allowed many utilities to perform strongly even in the face of the COVID-19 pandemic as referenced in the December 9, 2020 article from S&P Global Market Intelligence, entitled "Resilient Utilities Post Notable EPS Gains, Solid ROEs Despite COVID-19 Pandemic." The S&P Global Market Intelligence article noted:

> Despite the significant challenges caused by an economy that continued to be negatively impacted by COVID-19, utilities overall posted solid earnings growth and earned returns on equity during the third quarter, illustrating the tenet that utility finances hold up comparatively well in challenging economic environments.[18]

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[17] *Id.*

[18] Dennis Sperduto, *Resilient Utilities Post Notable EPS Gains, Solid ROEs Despite COVID-19 Pandemic*, S&P Global Market Intelligence (Dec. 9, 2020), *available at* https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#news/articleabstract?id=61646964.

Although the utility sector was impacted by the COVID-19 pandemic just like the rest of the economy, utilities were much more resilient during this period than companies across other industries. The resilient performance of utilities, as well as their ability to continue to tap into debt markets, demonstrate that utilities were still able to access a variety of capital markets throughout 2020—which only continued into 2021 after the broader capital-market resurgence.

Q. WHAT HAVE BEEN THE IMPACTS ON THE EQUITY MARKETS AS A RESULT OF THE COVID-19 PANDEMIC?

A. As shown in **Chart 2**, equity markets were negatively impacted during the first two quarters of 2020, before later rebounding during the second half of 2020 and into 2021. During the majority of 2020, businesses were closed, and workers stayed home as the United States and world economies slowed dramatically prior to the beginning of phased reopening plans around the world. While I note that the economic recovery that began during the latter part of 2020 has continued into 2021, and that there is an expectation that the economy will continue its rebound throughout 2021, there is no current expectation that the economy will fully recover, or that the sustained civilian unemployment rate will reach pre-2020 levels, at any point in the near-term.

To that point, Federal Reserve Chairman Jerome Powell noted that although there was growth in the second half of 2020, the timeline for a full economic recovery across a variety of indicators remains uncertain as referenced within the following quote from December 1, 2020:

> Economic activity has continued to recover from its depressed second quarter level. The reopening of the economy led to a rapid rebound in activity, and real gross domestic product, or GDP, rose at an annual rate of 33 percent in the third quarter. In recent months, however, the pace of the improvement has moderated…The economic downturn has not fallen equally on all Americans, and those least able to shoulder the burden have been the hardest hit...The economic dislocation has upended many lives and created great uncertainty about the future…As we have emphasized throughout this pandemic, the outlook for the economy is extraordinarily uncertain….[19]

During a press conference on March 17, 2021, Chairman Powell then noted that:

> The overall recovery in economic activity since last spring is due importantly to unprecedented fiscal and monetary policy actions, which have provided essential support to households, businesses, and communities. The recovery has progressed more quickly than generally expected, and forecasts from FOMC participants for economic growth this year have been revised up notably since our December Summary of Economic Projections…As with overall economic activity, conditions in the labor market have turned up recently. Employment rose by 379,000 in February, as the leisure and hospitality sector recouped about two-thirds of the jobs that were lost in December and January. Nonetheless, employment in this sector is more than 3 million below its level at the onset of the pandemic. For the economy as a whole, employment is 9.5 million below its pre-pandemic level. The unemployment rate remains elevated at 6.2 percent in February; this figure understates the shortfall in employment, particularly as participation in the labor market remains notably below pre-pandemic levels.[20]

Chairman Powell also noted on April 12, 2021 that, "The recovery, though here, remains uneven and incomplete. <u>The burden is still falling on lower-income</u>

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[19] Jerome Powell, *Coronavirus Aid, Relief, and Economic Security Act*, Testimony before the U.S. Senate Committee on Bank, Housing, and Urban Affairs (Dec. 1, 2020), *available at* https://www.federalreserve.gov/newsevents/testimony/powell20201201a.htm.

[20] Jerome Powell, *Transcript of Chair Powell's Press Conference* (Mar. 17, 2021), *available at* https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20210317.pdf.

workers and the unemployment rate in the bottom quartile is still 20 percent."[21] Additionally, Michelle Bowman (Federal Reserve Board Governor) stated on May 5, 2021 that:

> The economic recovery is not yet complete, and the uncertain course of the pandemic still presents risks in the near term…Despite the progress to date and the signs of acceleration in the recovery, employment is still considerably short of where it was when the pandemic disrupted the economy and it is well below where it should be, considering the pre-pandemic trend.[22]

To this same point, on May 11, 2021, Lael Brainard (Federal Reserve Board Governor) also noted:

> The latest jobs report reminds us that while there are good reasons to expect the number of jobs and the number of people wanting to work will make a full recovery, it is unlikely they will recover at the same pace…Job losses are disproportionately concentrated in low-wage, high-contact sectors, suggesting that workers least able to shoulder the economic effect of job loss have faced the greatest challenges.[23]

Chairman Powell reiterated this line of thinking as recently as July 2021, when he noted that more economic improvement and sustained stability was needed before the Fed would entertain doing anything that would negatively impact

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[21] Radmilla Suleymanova, *Powell: Economy will not be confident until world is vaccinated*, Aljazeera (Apr. 8, 2021), *available at* https://www.aljazeera.com/amp/economy/2021/4/8/powell-economy-will-not-be-confident-until-world-is-vaccinated (emphasis added).

[22] Michelle W. Bowman, *The Economic Outlook and Implications for Monetary Policy* (May 5, 2021), *available at* https://www.federalreserve.gov/newsevents/speech/bowman20210505a.htm.

[23] Lael Brainard, *Patience and Progress as the Economy Reopens and Recovers* (May 11, 2021), *available at* https://www.federalreserve.gov/newsevents/speech/brainard20210511a.htm#fn13.

economic activity. Chairman Powell noted that this was the case given that the United State was still "8.5 million jobs from where we were in February of 2020."[24]

As referenced in the quotes above, although there has been considerable growth and recovery within the capital markets over the second half of 2020, and into 2021, the individuals within Piedmont's customer base that were most negatively impacted by the pandemic are still struggling with such issues. Even while economic growth within the markets has grown at a rate faster than anticipated as COVID-19 cases declined and economies began to reopen, there are key indicators (such as employment figures) that remain depressed. As such, any additional rate increases would only continue to exacerbate the negative economic circumstances encountered by this portion of Piedmont's consumer base.

Q. WHAT OTHER FACTORS SHOULD THE COMMISSION CONSIDER IN DETERMINING AN APPROPRIATE COST OF CAPITAL FOR PIEDMONT?

A. The ability of a utility to access the capital markets is just part of the determination of an appropriate cost of capital for rate setting. The Commission should also consider the position of ratepayers who must continue to make non-discretionary purchases, such as gas, electricity, or water from monopoly utilities, regardless of the impact of the COVID-19 pandemic.

Many consumers at the residential, commercial, and industrial levels have struggled to pay their utility bills as unemployment levels spiked during 2020 and

[24] Taylor Tepper & Benjamin Curry, *July 2021 FOMC Meeting: Fed Keeps Policy Unchanged As Pressure To Taper Increases*, Forbes Advisor (Jul 28, 2021), *available at* https://www.forbes.com/advisor/investing/fomc-meeting-federal-reserve/.

remained higher than average into the second half of 2020 and into 2021, with various businesses also shut down for extended time over this period.

For instance, while the financial markets began a rebound in the third quarter of 2020, the average civilian unemployment rate still exceeded what was common in prior periods. The unemployment rate was heightened at 6.77% in Q4 2020 and averaged 8.12% during the entirety of 2020.[25] For comparison purposes, the average monthly civilian unemployment rate from 2019 was 3.67%.[26] While the unemployment rate improved through the second half of 2020 and into 2021, it still averaged 6.17% for Q1 2021 and 5.93% for Q2 2021.[27]

The comparison of the unemployment rates between these time periods further reinforces that the Company's "business as usual" request is not appropriate in the current economic climate for its customers.

Q. WHY DO YOU BELIEVE THE COMPANY'S 10.25% ROE REQUEST IN THIS CASE IS NOT APPROPRIATE GIVEN THE CURRENT STATE OF THE FINANCIAL MARKETS?

A. In Piedmont's most recently concluded base rate case from 2019, Piedmont Witness Robert Hevert recommended a 10.60% market-based ROE.[28] In the current proceeding in 2021, Mr. D'Ascendis has recommended a 10.25% ROE as market-based.

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[25] U.S. Bureau of Labor Statistics, *Civilian Unemployment Rate*, *available at* https://www.bls.gov/charts/employment-situation/civilian-unemployment-rate.htm.
[26] *Id.*
[27] *Id.*
[28] *Order Approving Stipulation*, Docket No. G-9, Sub 743 (Oct. 31, 2019).

Based upon my cost of equity analyses discussed below, a market-based cost of equity for Piedmont at the end of the fully projected future test year should be no higher than 9.00%. The Commission's determination of an appropriate cost of equity must consider the needs of the consumers, and not just the interests of Piedmont. Many of Piedmont's customers are still dealing with ongoing financial struggles linked to a variety of factors, such as higher than average unemployment numbers throughout 2020 and 2021. My recommended cost of capital for Piedmont is based upon a careful analysis of current financial data, disciplined application of cost of equity models to an appropriate proxy group of natural gas utilities, and identification of an appropriate capital structure for setting rates. My cost of capital recommendation for Piedmont balances the Company's need to access the markets and the interests of consumers who will be asked to pay the rates for essential natural gas distribution utility service.

Q. ARE THERE ANY CURRENT MARKET CONDITIONS THAT WOULD GIVE RISE TO CONCERNS ABOUT THE MARKET'S OVERALL PRICING?

A. I recognize that on July 13, 2021, the Consumer Price Index ("CPI") reported that inflation results had increased by 5.4% year to date through June 2021, which was higher than anticipated by economists and the market.[29] However, this report of inflation is too early to predict whether the United States economy will seriously

[29] *Prices Pop Again, and Fed and White House Seek to Ease Inflation Fears*, N.Y. Times (July 13, 2021), *available at* https://www.nytimes.com/2021/07/13/business/economy/consumer-price-index-june-2021.html.

suffer permanently in the long term due to rising prices. In order to capture as much of this change as possible, I have examined markets as close to the testimony filing deadline as possible in this case.

III. ECONOMIC AND REGULATORY POLICY GUIDELINES FOR A JUST AND REASONABLE RATE OF RETURN

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

A. The theory of utility regulation assumes that public utilities perform functions that are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. Within the gas industry, the transmission and distribution of gas to utilities' end-use customers is still a monopolistic business and will, for the foreseeable future, be regulated. On this basis, state legislatures and state utility commissions/boards established exclusive franchised territories to public utilities in order for these utilities to provide services more efficiently and at the lowest reasonable cost. In exchange for the protection within its monopoly service area, the utility is obligated to provide service that is adequate and non-discriminatory at just and reasonable rates.

This trade-off logically leads to the question – what constitutes a just and reasonable rate? The generally accepted answer is that a prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a just and reasonable rate of return on invested capital. The just and reasonable rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators.

If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise capital on reasonable terms. As such, regulators are tasked with balancing the related interests of the interested parties (*i.e.,* the utility's equity investors, the utility itself, and the utility's customers at the varying residential, commercial, and industrial levels). This balancing act results in what regulators, analysts, and courts often refer to as setting rates within a "zone of reasonableness." Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the just and reasonable rate of return for a utility.

As I previously referenced above, Piedmont filed its previous rate case in April 2019, and its current rate case in March 2021. In the time that lapsed between these two cases, the country experienced an economic recession spurred on by a pandemic the likes of which have not been seen in this country for over a century. Accordingly, what a utility may have initially deemed as constituting just and reasonable rates during prior years may simply be construed as unreasonable today given the current economic climate absent any of the other particulars of their request.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE SUPREME COURT'S *HOPE* AND *BLUEFIELD* DECISIONS.

A. Regulatory law and policy recognize that utilities compete with other firms in the market for investor capital. The United States Supreme Court set the guidelines for a fair, just, and reasonable rate of return in two often-cited cases: *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*, 262 U.S. 679 (1923), and *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944).

In the *Bluefield* case, the U.S. Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[30]

In the above finding, the Court found that utilities are entitled to earn a return on investments of comparable risks and that a corresponding return should be

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[30] 262 U.S. at 692.

sufficient enough to support credit activities and to raise funds to carry out its mission.

In *Hope*, the U.S. Supreme Court recognized that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn. The *Hope* court stated that the return to equity owners (or shareholders) of a regulated public utility should be commensurate to returns on investments in other enterprises whose risks correspond to those of the utility being examined:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital.[31]

IV. DEVELOPMENT OF PROXY GROUP

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

A. The number of available gas utilities needed to develop a reasonably reliable comparable group is dwindling. Over the past several years, certain gas utilities have been acquired by large electric utility holding companies. These acquisitions make sense for electric utilities as they desire to grow their source of regulated earnings while, at the same time, gain natural gas infrastructure that allows them to control the distribution of natural gas.

[31] 320 U.S. at 603.

In regard to the composition of my proxy group, I opted to use the full group of gas utilities compiled and followed by *Value Line*. As such, each of the companies included by Mr. D'Ascendis within his proxy group are also included within my own proxy group. However, in contrast to Mr. D'Ascendis, I did not remove UGI Corporation from my proxy group. My reasoning for this is detailed in a below Q&A.

Additionally, unlike Mr. D'Ascendis, I have chosen to perform an analysis directly on Duke. Piedmont is a wholly owned subsidiary of Duke Energy. As such, I found it appropriate to perform a specific, singular analysis of Duke Energy, as it provides the most directly observable link between any company within the comparable proxy group and Piedmont.

Mr. D'Ascendis also opted to include a "Non-Price Regulated Companies" proxy group comprised of non-utility companies for comparison purposes to Piedmont within his Comparable Earnings Analysis as he noted that:

> Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy group if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.[32]

In contrast, I have not chosen to include a non-utility group within any of the analyses included within my testimony as, in my view, such non-regulated

[32] Witness D'Ascendis' Direct Testimony, page 42: lines 6 – 13.

companies are not truly comparable to Piedmont and should not be examined in regard to determining the proper ROE to grant a regulated utility such as Piedmont. Non-utilities are not comparable from a business risk or financial profile perspective; in particular, only regulated utilities have the ability to seek regulatory relief.

Piedmont is a regulated utility. The Company has a set of consumers at the residential, commercial, and industrial levels that are locked into purchasing natural gas distribution service from Piedmont. If Piedmont feels that they need to increase their ROE in order to result in a greater overall Rate of Return, they have the ability to request regulatory relief through a rate case in an effort to increase rates on captive customers. Unregulated entities and non-utilities do not have the ability to ask for rate relief like regulated utilities do. As such, these non-utilities operate in an unregulated environment, with a higher level of business risk, and therefore generally seek to employ a smaller amount of leverage. The ability of a utility, such as Piedmont, to seek rate relief is an integral part of the business model of a regulated utility and is not a practice that is available to any such non-utilities.

Q. WHY DID YOU CHOOSE TO INCLUDE UGI CORP WITHIN YOUR COMPARABLE GROUP, WHILE MR. D'ASCENDIS OMITTED THE COMPANY FROM HIS ANALYSIS?

A. Within his direct testimony, Mr. D'Ascendis stated that in developing his proxy group, he first began with the ten companies included in *Value Line's* Natural Gas

Utility industry.[33] However, he then subjected those ten companies to a subsequent six step screening process where he opted to remove Chesapeake Utilities and UGI Corp.

I have decided not to perform a similar removal of companies from my comparable proxy group because of the limited number of 10 companies provided for the natural gas industry through *Value Line*. Throughout my 36 years of experience providing rate of return testimony across the United States, I have always found analysts' removal of certain companies within a proxy group to be inherently subjective. In addition, removing companies from a group that is already small can result in data integrity issues. As such, I have consistently maintained that within the natural gas industry, unless a company is currently going through bankruptcy or a merger/acquisition, it should be included within a proxy group for transparency purposes.

Additionally, please note that in reference to my proxy group, I am aware UGI Corp. announced on December 30, 2020 their plan to purchase Mountaineer Gas in West Virginia.[34] As of July 21, 2021, the deal has not closed. Normally, I would not include a company in my proxy group that is in the middle of an acquisition. However, in this case, I am including UGI for the following two reasons: First, Mountaineer Gas is quite small relative to UGI (about 6% in total assets); and second, the natural gas proxy group is already small so eliminating a company may allow another entity to skew the results of the group.

[33] Witness D'Ascendis' Direct Testimony, page 14: lines 1 – 2.
[34] https://www.ugicorp.com/investors/press-releases/press-releases-details/2020/UGI-to-Acquire-Mountaineer-Gas-Company/default.aspx

Q. PLEASE EXPLAIN WHY YOU PERFORMED A COST OF EQUITY ANALYSIS SEPARATELY ON DUKE ENERGY.

A. Piedmont is owned by Duke Energy. As the owner of Piedmont, Duke therefore represents the most direct link to Piedmont, and an analysis performed specifically on Duke helps to provide a large body of knowledge of investor expectations.

V. CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE AND HOW DOES IT IMPACT THE REVENUES THAT PIEDMONT IS SEEKING?

A. The term "capital structure" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments. A company's capital structure typically includes some combination of three principal financing methods.

The first method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Common equity is comprised of all investments from investors, including common stock, retained earnings, and additional paid in capital. Returns on common equity, which in part take the form of dividends to stockholders, are not tax deductible. Therefore, on a pre-tax basis alone, common equity is about 21% more expensive than debt financing.

The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend Payments associated with preferred stock are not tax deductible.

Debt is the third major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in a year or less. Long-term debt and short-term debt, both of which are "above the line" expenses for tax purposes, represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment.

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

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

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

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

Q. WHY SHOULD THE COMMISSION BE CONCERNED ABOUT HOW THE COMPANY FINANCES ITS RATE BASE INVESTMENT?

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

The second reason the Commission should be concerned about Piedmont's capital structure is due to the tax treatment of debt versus common equity. Corporations can deduct payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds, which are more expensive than pre-tax funds. The regulatory process allows utilities to recover reasonable and prudent expenses, including taxes, within their rates. Accordingly, if a utility is allowed to use a capital structure for ratemaking purposes that is top-heavy in common stock, customers will be forced to cover the higher income tax burden, which can result in unjust, unreasonable, and unnecessarily high rates. Setting rates through the use of a capital structure that is weighted too heavily in common equity violates the fundamental principles of utility regulation: rates must be just and reasonable and only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. DOES A UTILITY SUBSIDIARY LIKE PIEDMONT SET ITS OWN CAPITAL STRUCTURE?

A. No. Piedmont's stock is owned by Duke, which is the parent holding company for several utilities.[35] Specifically, Duke owns Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida, Duke Energy Indiana, Duke Energy Ohio, and Piedmont Natural Gas.[36] As the owner of these utilities, Duke is able to set the capital structure of these utilities as it sees fit. For example, Duke, which had a common equity ratio at the conclusion of 2020 of 44.40%,[37] could issue debt and then infuse this debt into Piedmont and call it common equity. In such a circumstance, Duke could use the regulatory system to issue debt at an interest rate of approximately 3.5% and then invest those funds into Piedmont as common equity to produce a pre-tax rate of return for stockholders of over 9%. The alternative to Duke is to issue debt and then support that debt issuance with debt from Piedmont. In either event, the capital structure of Piedmont is, for the most part, at the discretion of its parent company, Duke.

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[35] Witness D'Ascendis' Direct Testimony, page 13: line 11.
[36] https://www.duke-energy.com/Our-Company/About-Us/Businesses/Regulated-Utilities
[37] *The Value Line Investment Survey*, May 14, 2021 (Electric Utilities East).

Q. HOW DOES A UTILITY'S SELECTION OF EQUITY VERSUS DEBT IMPACT RATEPAYERS?

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

If a utility issues more common equity and less debt for a certain project, the rates could potentially be set at an unbalanced debt to equity level. This could result in the ratepayer paying higher rates to support a capital structure that is neither prudent nor reasonable to support the company's current credit rating or the company's adequate access to the capital markets. It is also important to recognize how rate levels affect economic development. The reality in today's economy is that economic development opportunities for large loads occur in places where costs are lower. A utility with unduly high rates will, all else being equal, cause its service territory to lose out on economic development opportunities.

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

One role of regulation is to balance the needs of the capital markets, including utility stockholders, with the needs of ratepayers. Either too much equity or too much debt can harm both the stockholders of the corporation, as well as the consuming public.

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

A. Yes, I have.

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING IN THIS CASE?

A. Piedmont has proposed the following capital structure:

Table 3: Piedmont's Requested Capital Structure[38]

Component	Capital Structure Ratio (%)
Long-Term Debt	47.45%
Short-Term Debt	0.55%
Common Equity	52.00%
Total Capitalization	**100.00%**

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

A. **Table 4** below shows the average common equity ratio of each utility in my gas comparable company proxy group, as well as for Duke (*i.e.,* Piedmont's parent company).

[38] Witness Bowman's Direct Testimony, Exhibit QPB-7, page 2.

Table 4: Proxy Group Equity Ratio[39]

Company	2019 Ratio	2020 Ratio	2021E Ratio	2024E–2026E Ratio
Atmos Energy	62.00%	60.00%	52.00%	60.00%
Chesapeake Utilities	56.10%	57.80%	57.00%	60.00%
New Jersey Resources	50.20%	44.90%	46.00%	47.00%
NiSource Inc.	36.90%	32.90%	40.00%	40.00%
Northwest Natural	51.80%	50.80%	51.00%	57.00%
ONE Gas Inc	62.30%	58.50%	36.00%	53.00%
South Jersey Inds	40.80%	37.40%	37.00%	39.50%
Southwest Gas	52.10%	49.50%	49.50%	52.00%
Spire Inc	55.00%	51.00%	51.00%	55.00%
UGI Corp	39.80%	40.80%	43.50%	50.00%
Average	**50.70%**	**48.36%**	**46.30%**	**51.35%**
Duke Energy[40]	44.10%	44.40%	44.00%	43.50%

As can be seen in the table above, the average common equity ratio for the proxy group in 2019 was 50.70%, the average common equity ratio for 2020 was 48.36%, the average expected common equity ratio for 2021 is 46.30%, and the average expected common equity ratio from 2024–2026 is 51.35%. Additionally, the respective ratios for Duke for the same periods noted above are 44.10%, 44.40%, 44.00% and 43.50%, respectively. Each of these metrics is below the Company's requested equity ratio in this case of 52.00%

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED BY UTILITY REGULATORS FOR GAS UTILITIES ACROSS THE UNITED STATES?

[39] *The Value Line Investment Survey*, May 28, 2021 (Natural Gas Utilities).
[40] *The Value Line Investment Survey*, May 14, 2021 (Electric Utilities East).

A. Note that I have sourced the average common equity ratio values granted by utility regulators for gas utilities from across the country from *S&P Global*. In my research into these numbers, I found that four states included within the overall average value of gas utilities across the country report their allowed common equity ratios on an all capital sources basis (*i.e.,* LT Debt, ST Debt, Common Equity, Preferred Stock, Customer Deposits, Deferred Income Taxes, Investment Tax Credits). As such, I have removed these four states (*i.e.,* Arkansas, Florida, Indiana and Michigan) from these numbers to ensure that each of the states included in this average report their allowed common equity ratio percentages only on investor sources of capital (*i.e.,* LT Debt, ST Debt, Common Equity). I wanted to remove these four states from the overall average to ensure that the average represented an appropriate comparison given that Piedmont's requested equity ratio in this case of 52.00% is based solely off of investor sources of capital.

The resulting average common equity ratio granted by regulators for natural gas utilities for all states on an investor sources basis 2020 was 52.34%.[41]

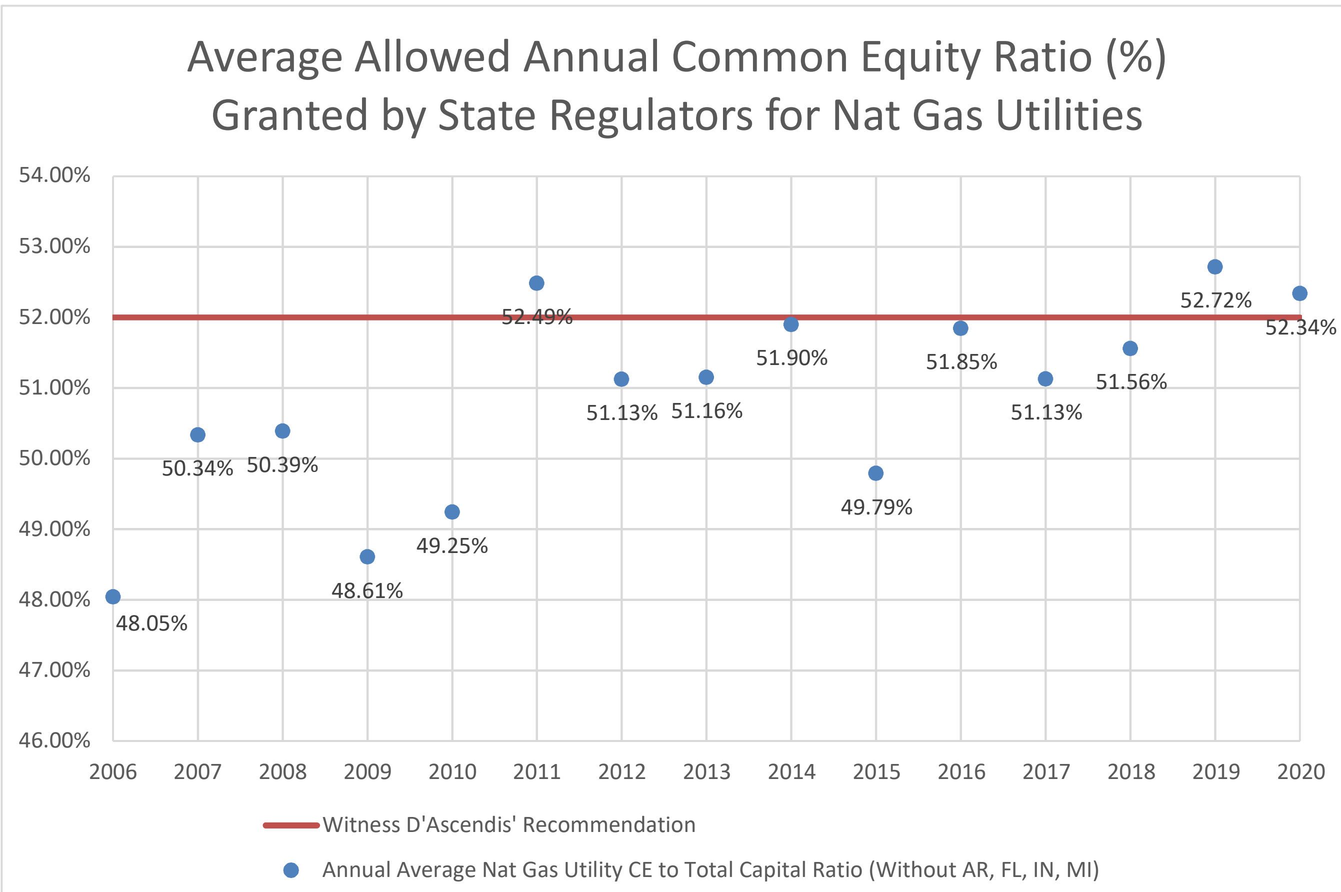
Q. WHAT COMMON EQUITY RATIOS HAVE STATE REGULATORS ACROSS THE UNITED STATES GRANTED TO NATURAL GAS UTILITIES OVER THE PAST 15 YEARS?

A. State regulators have been quite consistent in their rulings in natural gas cases for allowed common equity ratios based on investor sources of capital over the past 15 years. From 2006 through 2020, common equity ratios have ranged from 48.05%

[41] S&P Global Market Intelligence Rate Case Statistics; Date Range: 15 Years; Service Type: Natural Gas; Chart Items: Common Equity to Total Capital, Return on Equity (last accessed June 21, 2021).

to 52.71%, with an average of 50.85%. If one were to evaluate this data over the previous 12 years, the average common equity ratio over this period is 51.16%, the average ratio over the previous 10 years is 51.61%, and the average ratio over the previous 8 years is 51.56%. In **Chart 4** below I have presented the average annual common equity ratio granted by state regulators for each year over the past 15 years.

Chart 4: Common Equity Ratio Granted by State Regulators (2006–2020)[42]



[42] *Id.*

Q. WHAT IS THE CAPITAL STRUCTURE OF DUKE, THE PARENT HOLDING COMPANY OF PIEDMONT?

A. As shown in **Table 4** above, the Duke equity ratio for 2020 was 44.40%, and is expected by analysts to be at 43.50% through the 2024E-2026E time period.

Q. IS THE CAPITAL STRUCTURE OF PIEDMONT RELATED TO THE CAPITAL STRUCTURE OF DUKE?

A. Yes. Duke controls the amount of debt and equity in the Piedmont capital structure. The fact that Piedmont is asking for a 52.00% equity ratio, while Duke had a 44.40% equity ratio at the end of 2020,[43] indicates that the holding company is using double-leverage to increase profits from its regulated subsidiary, Piedmont.

Q. PLEASE EXPLAIN THE CONCEPT OF DOUBLE LEVERAGE.

A. Double leverage occurs when a utility parent company issues debt and then infuses that debt into the regulated subsidiary as common equity. The reason for such action is that equity is more expensive than debt and it is grossed up for taxes, meaning that the costs that Duke can collect from Piedmont is far greater than the cost of issuing the debt.

Q. PLEASE PROVIDE AN EXAMPLE OF DOUBLE-LEVERAGE.

A. An example would be a parent holding company issuing debt at 3.5% and then infusing the debt proceedings into the utility subsidiary as equity where the utility earns an allowed ROE of 9.0%. Keep in mind that the regulated utility is allowed to recover its income taxes so the 9.0% is actually grossed up to approximately

[43] *The Value Line Investment Survey*: 5/14/2021 (Electric Utilities East).

12.5% to pay for income taxes. As a result, through the regulatory process, Duke can issue debt at 3.5% and turn it into 12.5% through double-leverage through its relationship with its subsidiaries.

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

A. **Table 5** below provides a summary of how Piedmont's request in this case compares to the average equity ratio of the proxy group companies, the common equity ratio of Piedmont's parent company, Duke, and the average equity ratio allowed by state regulators to gas utilities across the country in 2020 and the previous 15-year period.

Table 5: Common Equity Ratio Comparison

Piedmont's Eq Ratio Request	52.00%
CUCA Eq Ratio Recommendation	50.00%
2019 O'Donnell Proxy Group Actual Eq Ratio Average	50.70%
2020 O'Donnell Proxy Group Actual Eq Ratio Average	48.36%
2021E O'Donnell Proxy Group Expected Eq Ratio Average	46.30%
2024E – 2026E O'Donnell Proxy Group Expected Eq Ratio Average	51.35%
2019 Duke Actual Eq Ratio Average	44.10%
2020 Duke Actual Eq Ratio Average	44.40%
2021E Duke Expected Eq Ratio Average	44.00%
2024E – 2026E Duke Expected Eq Ratio Average	43.50%
2020 Average Annual Regulator Nat Gas Granted Eq Ratio	52.34%
2006 – 2020 Average Annual Regulator Nat Gas Granted Eq Ratio	50.85%

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

A. No. The requested capital structure for Piedmont of 52.00% is not as reasonable as a recommended capital structure of 50.00% for ratemaking purposes. Nothing in the make-up of Piedmont suggests that it requires an equity ratio in a range that would place it higher than that of the companies within its comparable proxy group. Indeed, some of the companies in the proxy group are involved in a wider array of business activities that involve more business risk than a utility's distribution of natural gas within its monopoly service territory. As such, if anything, the financial risk (as represented by the equity ratio) of the comparable company proxy group should be higher, not lower, than a traditional gas utility such as Piedmont. Customers of Piedmont should not pay higher rates associated with a capital structure that consists of so much common equity which, as previously discussed, is more expensive than debt.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND THIS COMMISSION ADOPT FOR USE IN SETTING THE REVENUE REQUIREMENT IN THIS CASE?

A. My recommendation is for the Commission to employ a capital structure that contains an equity ratio that is more equivalent to 50%. Specifically, my recommended capital structure and embedded cost of debt is as follows:

Table 6: CUCA Recommended Capital Structure

Component	Capital Structure Ratio (%)
Long-Term Debt	49.43%
Short-Term Debt	0.57%
Common Equity	50.00%
Total Capitalization	100.00%

Note that the CUCA recommended overall debt ratio of 50% was split into a long-term debt ratio of 49.43% and short-term debt ratio of 0.57%. This split was based upon the same ratio used by the Company for its split of its recommended overall debt ratio of 48% into a long-term debt ratio of 47.45% and a short-term debt ratio of 0.55%. As such, I have used those same, specific ratios of long-term debt to total debt and short-term debt to total debt to split out CUCA's recommended overall 50% debt portion of the capital structure between short-term and long-term debt.

Q. HOW DID PIEDMONT DEVELOP ITS REQUESTED COMMON EQUITY RATIO OF 52.00%?

A. Company Witness Karl Newlin recommended that the capital structure of 52.00% and stated as follows:

> represents an appropriate amount of risk due to leverage (48% or lower) while minimizing the weighted average cost of capital…As of December 31, 2020, Piedmont's capital structure, including a thirteen-month average of natural gas inventory as a proxy for short-term debt, was 50.59% equity, 48.74% long-term debt and 0.67% short-term debt. Looking forward, the equity percentage of Piedmont's capital structure, as shown in Exhibit_(KWN-1) is projected to be 52.56% and 52.87% for year end 2021 and 2022, respectively.[44]

Q. IF THE COMMISSION ADOPTS THE COMPANY'S CAPITAL STRUCTURE FOR RATEMAKING, WHAT OTHER ADJUSTMENTS SHOULD IT MAKE?

A. Note that my specific equity recommendations in this proceeding based on the analyses performed is a capital structure weighted 50% to common equity, along

[44] Witness Newlin's Direct Testimony, page 5: lines 11 – 13, and page 6: lines 9 – 15.

with a 9.00% ROE, as shown in **Table 2**. However, if the Commission were to adopt a capital structure for Piedmont at the level requested by the Company of 52.00%, the Commission should recognize the lower financial risk applicable to Piedmont with such an equity ratio, and accordingly reduce the allowed ROE in this proceeding.

VI. COST OF DEBT

Q. DO YOU ACCEPT THE COMPANY'S COST OF DEBT?

A. Yes, I accept the Company's 4.56% overall cost of debt, based on 4.09% long-term[45] and 0.47% short-term debt cost rates.[46] If, however, there is an update to the cost of debt as we get closer to the hearing, I reserve the right to update my testimony.

VII. COST OF COMMON EQUITY

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

A. In North Carolina, as in virtually all regulatory jurisdictions, a utility's rates must be "just and reasonable."[47] Thus, regulation recognizes that utilities are entitled to an opportunity to recover the reasonable and prudent costs of providing service,

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[45] Exhibit KWN-2
[46] Exhibit KWN-3.
[47] https://www.ncuc.net/Aboutncuc.html

and the opportunity to earn a just and reasonable rate of return on the capital invested in a utility's facilities, such as natural gas distribution equipment, buildings, vehicles, and similar long-lived capital assets.

Q. HOW DO REGULATORY AUTHORITIES DETERMINE WHAT WOULD CONSTITUTE A JUST AND REASONABLE RATE OF RETURN ON EQUITY FOR A UTILITY COMPANY?

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

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

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

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

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

The CEA is based on earned returns from book equity, not market equity, as well as a comparison of what other commissions or boards across the country are awarding regulated utilities. There is no direct and immediate stockholder input into the CEA and, as a fault, that model lacks a clear and unmistaken link to stockholder expectations.

The CAPM suffers, in my opinion, from the same inherent issues as found within the CEA in that there is not a direct and immediate link from stock market prices to the CAPM result. The Beta in the CAPM can reflect changes in the ROE, but the delay can oftentimes make the CAPM results of little-or-no value.

Q. WHY DID YOU NOT USE THE RISK PREMIUM MODEL?

A. The Risk Premium Model is very similar in nature to the CAPM. In both models, one examines risk premiums, but from varying comparison points. The CAPM considers the risk premium relative to the risk-free rate whereas the risk premium model often develops the risk premium relative to utility bond yields.

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

A. No. Piedmont is ultimately a subsidiary of Duke. Note however that while Duke is classified as an electric utility by *Value Line* within their industry groupings, it is also considered to be a holding company, which owns natural gas operations as well, such as those managed by Piedmont.

A. <u>Discounted Cash Flow ("DCF") Model</u>

Q. PLEASE EXPLAIN THE DISCOUNTED CASH FLOW MODEL.

A. The DCF Model is a widely used method for estimating an investor's required return on a firm's common equity. I have worked within the utility industry since 1984. In my experience, first with the Public Staff of the North Carolina Utilities Commission, and later as a consultant, I have seen the DCF Model used much more often than any other method for estimating the appropriate return on common equity. Consumer advocate witnesses, utility witnesses and other intervenor witnesses have used the DCF Model, either by itself or in conjunction with other methods such as the CEA or the CAPM, in their analyses.

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

Let D = dividends per share in the initial future period

g = expected growth rate in dividends

k = cost of equity capital

P = price of asset (or present value of a future stream of dividends)

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

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

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

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

Solving for k yields:

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

Q. DO INVESTORS IN UTILITY COMMON STOCKS REALLY USE THE DCF MODEL IN MAKING INVESTMENT DECISIONS?

A. Yes, I believe that they do. There are two primary reasons for my conclusion. First, there is much literature that supports the fact that, while emotional or so-called "irrational" behavior in the short term may affect (and has affected) share prices, over the long term, a company's financial fundamentals drive the market.[48] Secondly, analysts give great weight to earnings, dividend, and book value growth in formulating their recommendations to clients.

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

Q. IS THE DCF FORMULA STRAIGHTFORWARD?

A. Yes. While the DCF formula as outlined above may appear complicated, it is a relatively straightforward model. To determine the total rate of return one expects from investing in a particular equity security, the investor adds the dividend yield, which they expect to receive in the future, to the expected growth in dividends over time.

Q. CAN YOU PROVIDE AN EXAMPLE?

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[48] *See*, *e.g.*, Tim Koller, Marc Goedhart, & David Wessels, *Valuation: Measuring and Managing the Value of Companies* (4th ed.); Tim Koller, Marc Goedhart, & David Wessels, *Do fundamentals—or emotions—drive the stock market?*, McKinsey & Company Inc. (Mar. 1, 2005) ("Provided that a company's share price eventually returns to its intrinsic value in the long run, managers would benefit from using a discounted-cash-flow approach for strategic decisions. What should matter is the long-term behavior of the share price of a company, not whether it is undervalued by 5 or 10 percent at any given time."), *available at* http://www.mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/do-fundamentalsor-emotionsdrive-the-stock-market (last accessed Mar. 2, 2016); *see also* Joe Weisenthal, *And Now We Know For Sure What's Really Been Driving The Market The Last Few Years...*, Business Insider (Apr. 15, 2021), *available at* http://www.businessinsider.com/what-drives-the-stock-market-2012-8 (last accessed March 2, 2016).

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

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

A. I have calculated the appropriate dividend yield by averaging the dividend yield expected to be paid over the next 12 months for each comparable company, as reported by the *Value Line Investment Survey*. The period covered is from April 16, 2021, through July 9, 2021. To study the short-term, as well as long-term, movements in dividend yields, I examined the 13-week, 4-week, and 1-week dividend yields for my comparable group. These results appear in **Exhibit KWO-2** and show an average dividend yield for the 13-week period of 3.2%, the 4-week period of 3.3%, and the 1-week period of 3.3% for the comparable company proxy group. I have also presented the results for Duke within **Exhibit KWO-2** as Piedmont's parent company. The values for Duke over these same periods were 3.9%, 3.9%, and 3.9%, respectively.

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

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

Q. HOW DID YOU DERIVE THE EXPECTED DIVIDEND GROWTH RATE?

A. I used several methods in determining the growth in dividends that investors expect. These methods are, (1) historical EPS, DPS, and BPS growth rates, (2) forecasted EPS, DPS, and BPS growth rates, and (3) the plowback ratio.

Q. PLEASE DESCRIBE THE FIRST METHOD YOU USED TO DEVELOP THE EXPECTED DIVIDEND GROWTH RATE.

A. A key component in the DCF Model is the expected growth in dividends. In analyzing the proper dividend growth rate to use in the DCF Model, the analyst must consider how dividends are created. Since over the long-term, dividends cannot be paid out without a corporation first earning the funds paid out, earnings growth is a key element in analyzing what if any growth can be expected in dividends. Similarly, what remains in a corporation after it pays its dividend is reinvested, or "plowed back," into a corporation in order to generate future growth. As a result, book value growth is another element that, in my opinion, must be considered in analyzing a corporation's expected dividend growth.

Therefore, to analyze the expected growth in dividends, I believe the analyst should also examine the historical record of past earnings, dividends, and book value. Hence, the first method I used to estimate the expected growth rate was to analyze the historical 10-year and 5-year compound annual rates of change for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BPS") as reported by *Value Line* for each of the relevant companies. My reasoning for also utilizing historical growth rates for EPS, DPS, and BPS, rather than solely relying upon forecasted growth rates is that historical growth rates capture the actual growth of the various rates over time based upon a Company's reported results. In contrast, forecasted growth rates are derived <u>entirely</u> from analyst projections, which vary from analyst to analyst, and which also have a tendency to be overstated. As such, I have always found it important to use both historical and forecasted growth rates.

Q. DO ALL ANALYSTS UTILIZE HISTORICAL GROWTH RATES WITHIN THEIR DCF MODELS?

A. No, certain analysts do not present historical growth rates in their DCF analyses. This is true for Mr. D'Ascendis, as evidenced through his DCF calculations on page 1 of his **Schedule DWD-2**, where Mr. D'Ascendis only factored forecasted growth rates from *Value Line*, *Zack's*, *Yahoo! Finance*, and *Bloomberg* into his DCF analysis.

I believe that analysts who do not present the readily available historical data fail to provide the full extent of information on which investors base their expectations. Both historical growth rates and forecasted growth rates provide valuable data for what one can expect the ultimate growth rate for an individual stock will be. To present the full breadth of the available information, both historical and forecasted growth rates should be used. I believe this to be even more important given the current economic climate and market uncertainty caused by the COVID-19 pandemic. By focusing his entire analysis on forecasted growth rates, Mr. D'Ascendis is ignoring the value in historical growth rates that are readily available.

I note that *Value Line* is the most recognized investment publication in the industry and, as such, is used by professional money managers, financial analysts, and individual investors worldwide. A prudent investor tries to examine all aspects of an enterprise's performance when making a capital investment decision. As such, it is only practical to examine historical growth rates, in addition to the forecasted growth rates, for the corporation on which the analysis is being performed.

Exhibit KWO-2 lists the historical and forecasted growth rates for the comparable company proxy group, and **Exhibit KWO-5, page 1** lists the related calculations and results for this method, with the historical and forecasted growth rate values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. Also note that **Exhibit KWO-6**, **page 1** shows these results should this analysis be performed directly on Piedmont's parent company, Duke.

Q. SHOULD ONLY EARNINGS ("EPS") GROWTH RATES BE CONSIDERED IN THE DCF METHODOLOGY?

A. No, I do not believe it is appropriate to strictly rely upon EPS growth rates on either an historical or forecasted basis. Since the DCF formula is dependent on future *dividend* growth, I believe that it would be inaccurate to use only earnings (*i.e.,* EPS) growth rates in the DCF. Doing so would produce unrealistically high return on equity numbers that cannot be sustained indefinitely, which I provide evidence for and discuss in greater detail below within **Section VII-A**: "Review of Mr. D'Ascendis' DCF Analysis."

To mitigate this problem, I have presented EPS, DPS, and BPS figures and have explained my rationale for arriving at the corresponding growth rates. I believe it is incumbent upon every analyst to present such a robust analysis.

Q. PLEASE DESCRIBE THE SECOND METHOD YOU USED TO DEVELOP THE EXPECTED DIVIDEND GROWTH RATE.

A. The second method I used was forecasted growth rates. I obtained forecasted growth rates from the following data sources:

- Forecasted compound annual rates of change for EPS, DPS, and BPS as provided by *Value Line*;
- Average "plowback" percent retained to common equity as provided by *Value Line*;
- Forecasted 3-year projected rate of change for EPS as recorded by the *Center for Financial Research and Analysis* (*i.e., CFRA*), a publication of *S&P Global Market Intelligence*; and
- Forecasted LT 3-5-year EPS growth rates, as provided by *Charles Schwab & Co (i.e., Schwab).* This forecasted rate of change is not a forecast developed solely by *Schwab*, but is, instead, a compilation of forecasts by industry analysts.

As such, the data sources referenced above all represent forecasted growth rates, but are sourced from three separate financial evaluation agencies, *Value Line, CFRA,* and *Schwab*.

Exhibit KWO-2 lists the forecasted growth rates for the comparable company proxy group and **Exhibit KWO-5, page 1** lists the related calculations & results for this method with the forecasted growth rate values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. Also note that **Exhibit KWO-6**, **page 1** shows these results should this analysis be performed directly on Piedmont's parent company, Duke. My ultimate DCF result range can be found on **Exhibit KWO-1**.

Q. PLEASE DESCRIBE THE THIRD METHOD YOU USED TO DEVELOP THE EXPECTED DIVIDEND GROWTH RATE.

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

$$g = \frac{br(2019) + br(2020) + br(2021E) + br(2024E\text{-}2026E\ Avg)}{4}$$

The plowback estimates for all companies in the comparable company proxy group can be obtained from *The Value Line Investment Survey* under the title "percent retained to common equity." **Exhibit KWO-2** and **Exhibit KWO-3** list the plowback ratios for each company in the comparable company proxy group. **Exhibit KWO-5, page 2** shows the related calculations and results for this method with the plowback values being added to the dividend yield averages for the time periods of 1-week, 4-weeks, and 13-weeks. **Exhibit KWO-6, page 2** then shows these related calculations and results for Piedmont's parent company, Duke.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS FROM A HISTORICAL GROWTH RATE PERSPECTIVE?

A. In terms of the proper dividend growth rate to employ for the comparable company proxy group in the DCF analysis, it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future.

Within **Exhibit KWO-2**, I have presented the complete set of data for the entirety of the comparable company proxy group without any of the companies removed from the comparable company proxy group as published by *Value Line*. The data and calculations shown therein at **Exhibit KWO-2** is the information that my recommendation was developed from.

An examination of the 10-year and 5-year historical growth rates for the comparable company proxy group within this exhibit show a difference between the average earnings and dividend growth rates. For the 10-year history, BPS (5.3%) grew faster than DPS (5.1%) and EPS (4.4%) in the comparable company proxy group. For the 5-year history, DPS (5.9%) grew faster than BPS (5.3%) and EPS (5.1%).

Additionally, the historical growth rates for Duke ranged from a BPS of 2.0% to a DPS of 3.0% over the 10-year historical period and a BPS of 1.0% to a DPS of 3.5% over the 5-year historical period.

These growth rates indicate that the natural gas utility industry has historically experienced solid and steady growth in earnings, dividends, and book value. The DCF results based on the set of data previously mentioned for the entirety of the proxy group can be found in **Exhibit KWO-5, pages 1-2** and the related results for Duke can be found in **Exhibit KWO-6, pages 1-2**.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS FROM A FORECASTED GROWTH RATE PERSPECTIVE?

A. The forecasted growth rates from *Value Line* for the proxy group range from 5.1% (DPS) to 7.5% (BPS). Additionally, the forecasted *Value Line* growth rates for Duke ranged from 2.0% (BPS and DPS) to 7.0% (EPS).

In addition to the above forecasted *Value Line* growth rates, the average plowback (retained to common equity) growth rate for the proxy group is 4.2% (**Exhibit KWO-2** and **Exhibit KWO-3**), the *CFRA* 3-year forecasted EPS growth rate is 6.0% (**Exhibit KWO-2**), and the *Schwab* LT Growth Rate 3-5 year forecasted EPS growth rate is 5.0% (**Exhibit KWO-2**). These values for Duke are 2.1%, 6.0%, and 5.0%, respectively.

These growth rates indicate that the natural gas utility industry is expecting solid and steady growth in earnings, dividends, and book value in the future. The

DCF results based on the set of data previously mentioned for the entirety of the proxy group can be found in **Exhibit KWO-5, pages 1-2** and the related results for Duke can be found in **Exhibit KWO-6, pages 1-2**.

Q. HOW DOES THE COVID-19 PANDEMIC IMPACT YOUR COST OF EQUITY FOR PIEDMONT IN THIS CASE?

A. I previously outlined the impacts of the COVID-19 pandemic across the overall market as a whole, as well as the utility industry, within **Section II**: "Current State of the Financial Markets."

With regard to Piedmont, the information used in my analysis herein encompasses the data from the initial onset of the COVID-19 pandemic, as well as the market's recovery that began in Q3 2020 and that continued into 2021. As a result, any change in the growth rates specific to the natural gas utility comparable group are already reflected in the growth rates utilized within my testimony, thereby recognizing that even though the recovery has begun, the US economy has significant headwinds ahead.

Q. PLEASE PROVIDE THE SPECIFIC RESULTS OF YOUR DCF ANALYSIS.

A. The average dividend yield for the comparable company proxy group for the 13-week period was 3.2%, the 4-week time period was 3.3%, and the 1-week period was 3.3%. Additionally, the average dividend yield for Duke for the 13-week period was 3.9%, the 4-week time period was 3.9%, and the 1-week time period was 3.9%. With the second portion of the DCF analysis relating to growth rates, I note that the historical growth rates range from 4.4% to 5.9% and the forecasted growth rates range from 4.2% to 7.6%. For Duke, the historical range is from 1.0% to 3.5% and the forecasted range is from 2.0% to 7.0%.

I have included both historical and forecasted growth rate figures within my analysis as previously noted as shown within both **Exhibit KWO-5** and **Exhibit KWO-6** to present the full set of growth rate information applicable within this cost of capital analysis for both my comparable proxy group, as well as Piedmont's parent company Duke. **Table 7** below showcases the Dividend Yield Range values from the 13-week, 4-week, and 1-week dividend yield periods, plus the Historical Growth Rates from *Value Line*, the Forecasted Growth Rates from *Value Line*, *CFRA*, and *Schwab*, and the Plowback Growth Rates from *Value Line* for my comparable company proxy group, as well as for Piedmont's parent company, Duke.

Table 7: DCF Results

Natural Gas DCF Results: Proxy Group (as sourced from **Exhibit KWO-5**)			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + *Value Line* Div Yield Range	8.02%	8.47%	8.80%
Forecasted Growth Rate Averages + *Value Line* Div Yield Range	8.35%	9.53%	10.84%
Value Line Plowback Growth Rate Averages + *Value Line* Div Yield Range	7.49%	7.50%	7.53%
Average (Rx)	7.95%	8.50%	9.06%
DCF Results: Duke Parent Company (as sourced from **Exhibit KWO-6**)			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + *Value Line* Div Yield Range	5.35%	6.13%	7.15%
Forecasted Growth Rate Averages + *Value Line* Div Yield Range	5.85%	8.28%	10.90%
Value Line Plowback Growth Rate Averages + *Value Line* Div Yield Range	5.93%	5.95%	5.98%
Average (Rx)	5.71%	6.78%	8.01%

As shown in **Exhibit KWO-1**, I have utilized an ultimate DCF result range of 7.50% to 9.50%. This range was determined based upon a review of the values shown in the table above. My 7.50% to 9.50% range was positioned towards the high end of the range of values shown within **Table 7** above, with the low-end of the range of 7.50% being set below the average of the minimum values for the proxy group (7.95%), and the high-end of the range of 9.50% being set above the average of the maximum values for the proxy group (9.06%). As such, I have placed my overall DCF result at 9.00%, which is above the midpoint of my 7.50% to 9.50%

range in order to take into account the higher forecasted growth rates moving forward.

B. <u>Comparable Earnings Analysis ("CEA")</u>

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

A. I have conducted two different Comparable Earnings Analyses. The first examines returns on book value equity for the comparable group. The second examines allowed natural gas utility returns over an extended period of time to evaluate the trend in returns for companies of similar risk. However, as I stated previously, I believe the CEA to be inferior to the DCF Model and that it should be given less weight in the determination of the ROE recommended in this case.

Q. PLEASE DESCRIBE YOUR FIRST COMPARABLE EARNINGS ANALYSIS.

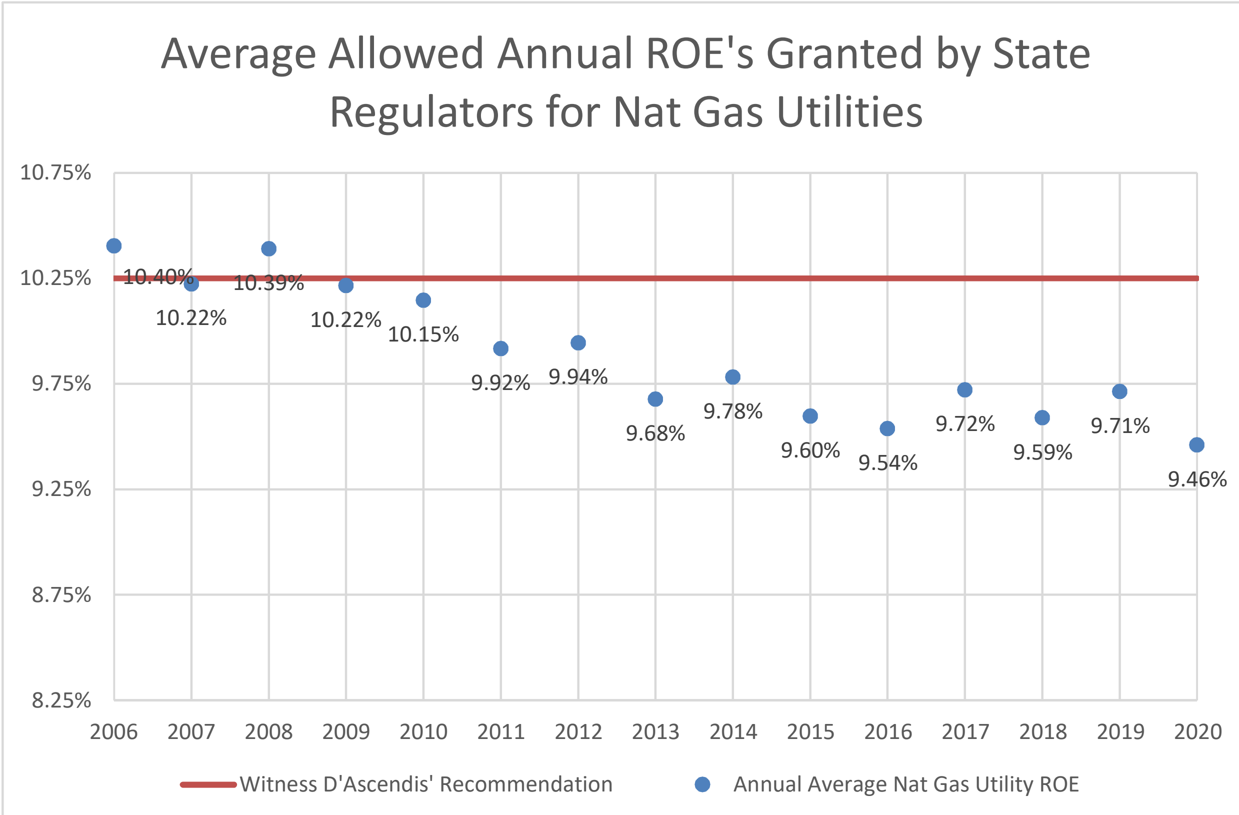
A. As noted above, an appropriate CEA should be applied to comparable companies of similar risk. **Exhibit KWO-4** presents a list of historic and forecasted earned returns *on book value equity* of the proxy group over the period from 2019 through 2026E. I picked this range to provide the Commission with at least two periods of historical returns (*i.e.,* 2019 and 2020) and a forecasted return period of at least 5 years (*i.e.,* 2021E through 2026E). As can be seen in this exhibit, the average earned returns on equity for the comparable company proxy group range from 9.2% (2019 and 2020) to 9.7% (2021E and 2024E–2026E). Additionally, for Piedmont's parent company Duke, this range was from 6.3% (2020) to 9.5% (2024E–2026E).

Q. PLEASE DESCRIBE YOUR SECOND COMPARABLE EARNINGS ANALYSIS.

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

As this Commission is likely aware, regulated ROE's have trended down over the past 15 years. Below, **Chart 5** shows the ROEs authorized for gas utilities by state regulators across the United States from 2006 through 2020, which ranges from 9.46% (2020) to 10.40% (2006).

Chart 5: Allowed ROEs 2006 – 2020[49]



As for the most recent year, 2020, the overall allowed ROE for gas utilities was 9.46%, which is the lowest figure over the previous 15-year period, significantly down from the 9.71% allowed by state regulators for gas utilities in 2019, and a notable 79-basis points below Mr. D'Ascendis' recommendation of 10.25%.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR TWO COMPARABLE EARNINGS ANALYSES?

A. Based on the above-stated findings, I believe the proper rate of return using a CEA is in the range of 9.00% to 10.00%. The 9.00% low end of this range is aligned with

[49] *S&P Global Market Intelligence* Rate Case Statistics; Date Range: 15 Years; Service Type: Natural Gas; Chart Items: Common Equity to Total Capital, Return on Equity; **Date Accessed**: June 24, 2021.

the low end of the range of the comparable company proxy group from 2019–2026E shown in **Exhibit KWO-4** for 2019 and 2020 of 9.2%. The 10.00% high end of the range is above the high end of the range of the comparable company proxy group from 2019–2026E shown in **Exhibit KWO-4** for 2021E and 2024E-2026E of 9.7%. Note that the ROE granted by state regulators in 2020 of 9.46% (see **Chart 5**) and the average ROE granted by state regulators from 2006–2020 of 9.89% fit within this 9.00% to 10.00% CEA range as well.

I have completed the Comparable Earnings Analyses as referenced above to provide the relevant data for the comparable group's book value equity. However, as previously noted, it is my opinion that the DCF Model produces the most reliable results in determining an appropriate ROE. Furthermore, given the current volatile economic climate brought on by the COVID-19 pandemic, the CEA does not appropriately capture the economic impacts of the pandemic within the output of the model. As such, I believe that the CEA should be given much less weight in the determination of the ROE recommended in this case. Additionally, I view the CAPM as a model that is more appropriate to utilize as a check on the results of the DCF Model.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE COMPARABLE EARNINGS BASED ON ALLOWED ROE'S INCLUDED IN EXHIBIT KWO-4 ARE HIGHER THAN THE RESULTS OF YOUR DCF ANALYSIS.

A. As noted above, there has been a clear declining trend in the cost of capital and return on equity figures allowed by utility regulators, and this downward trend is continuing. However, market returns are much more dynamic and change every day. Regulators may not move at the pace of the general market in terms of the decline in the market cost of capital, but regulators are, without a doubt, moving in that direction as exhibited by the decline in the annual allowed return national averages included in the Q&A's above and as exhibited in **Chart 5**.

C. <u>Capital Asset Pricing Model ("CAPM")</u>

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

A. Yes, but I have not given it as much weight in comparison to the DCF Model. I have long maintained the application of the CAPM can lead one to erroneous results when it is applied in an inaccurate manner, such as when forecasted risk premiums or forecasted interest rates are employed. However, I am aware that some commissions and boards around the country seek a review of models other than the DCF. As a result, I have included the CAPM in my analyses to supplement my DCF analysis, as well as the CEA to a lesser degree.

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL.

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

$$ROE = Rf + Beta\ [E(RM) - Rf]$$

Where:

Rf is the risk-free rate;

Beta is the risk of the studied company relative to the overall market; and

E(RM) is the expected return on the market.

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

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

ROE = Rf + (Beta * Risk Premium)

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

Q. HOW IS THE RISK-FREE RATE MEASURED?

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

Q. ARE INTEREST RATES, AT THEIR CURRENT LEVEL, EXPECTED TO CHANGE MATERIALLY IN THE FORESEEABLE FUTURE?

A. Economic forecasters, as well as the Federal Open Market Committee (FOMC), all believed in previous years that the current interest rate environment was expected to remain relatively stable for many years to come. However, the FOMC implemented rate cuts throughout the early stages of 2019 and then, in its December 2019 meeting, announced plans to keep interest rates at current levels throughout 2020.[50] This announcement occurred before the COVID-19 pandemic that played havoc on the markets throughout Q1 and Q2 2020 before the market began to rebound during Q3 and Q4 2020. In response to the impact the pandemic had on the market, on March 3, 2020 the FOMC decreased the Federal Funds Rates 50-basis points to a targeted range of between 1% and 1.25% in response to recent market conditions.[51] Additionally, on March 16, 2020 the FOMC dropped interest rates to near 0%.[52] As such, the interest rate market was unexpectedly turbulent during 2020 due largely to the COVID-19 pandemic.

Interest rates fluctuated throughout 2020 based on the overall response to the pandemic, but recently increased above 2.00% during the first half of 2021 (*i.e.,* 2.05% as of July 2, 2021). Despite these changes, the average yield value over the period beginning with the Company's most recently concluded case through the present (*i.e.,* average from April 1, 2019 through July 2, 2021) of 1.99% has still

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[50] Christopher Rugaber, *Federal Reserve leaves interest rates unchanged and foresees no moves in 2020*, PBS News Hour (Dec. 11, 2019), *available at* https://www.pbs.org/newshour/economy/federal-reserve-leaves-interest-rates-unchanged-and-foresees-no-moves-in-2020.

[51] Jeff Cox, *Fed cuts rates by half a percentage point to combat coronavirus slowdown*, CNBC News (Mar. 3, 2020), *available at* https://www.cnbc.com/2020/03/03/fed-cuts-rates-by-half-a-percentage-point-to-combat-COVID-19-slowdown.html.

[52] Federal Reserve System, *Implementation Note*, Press Release (Mar. 15, 2020), *available at* https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a1.htm.

been much lower than that at the conclusion of the Company's most recently concluded rate case prior to 2020,[53] when the 30-year US Treasury Bond Yield on that date was 2.89%.[54] Even with the rise in rates above 2.00%, rates are not expected to rise back to, and then sustain, levels near 2.89% again at any time in the near term. As such, the market remains in a low overall interest rate environment.

Q. HOW IS BETA MEASURED IN THE CAPM?

A. Beta is a statistical calculation of a company's stock price movement relative to the overall stock movement. A company whose stock price is less volatile than the overall market will have a Beta less than 1.0. A company whose stock price is more volatile than the overall market will have a Beta more than 1.0. In consideration of the fact that utilities are generally viewed as more conservative equity investments, Betas for utilities are almost always less than 1.0 under normal economic circumstances.

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

A. The development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. To gauge the historical risk premium, I turned to the Ibbotson database published by *Morningstar, Duff & Phelps,* and the *CFA Institute Research Foundation*. In **Table 8** below, I have

[53] *Order Approving Stipulation*, Docket No. G-9, Sub 743 (Oct. 31, 2019).
[54] U.S. Dep't of the Treasury, *Daily Treasury Yield Curves*, *available at* https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

presented both the long-term geometric mean and arithmetic mean returns for equities and fixed income securities and the resulting risk premiums.

Table 8: **Equity Risk Premium Calculations**[55]

Asset Class	Geometric Mean	Arithmetic Mean
Large Company Stocks	10.7%	12.1%
Long-Term Govt. Bonds	8.0%	8.7%
Resulting Risk Premium	2.7%	3.4%

Source: Ibbotson ® SBBI ®, 2020 Classic Yearbook: Stocks, Bonds, Bills and Inflation, 1972 – 2019 (Chicago: Morningstar, 2020).

Note that the data from **Table 8** above shows the statistics of annual total returns for large company stocks and long-term government bonds from 1972 to 2019. With this data being more recent than similar data provided by other sources and analysts over the period from 1926 to 2019, this data adds more credence to what a reasonable investor can expect for a return based upon more historically recent data.

Q. WHAT MARKET RETURNS ARE REPUTABLE PROFESSIONAL INVESTORS EXPECTING FOR THE FORESEEABLE FUTURE?

A. On January 20, 2021, Morningstar.com published an article entitled "Experts Forecast Stock and Bond Returns 2021 Edition."[56] This article was provided as part of Morningstar's annual stock and bond return forecast series. Note that by referring to future returns, the market experts referenced below are discussing the overall

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[55] Roger Ibbotson & James Harrington, *Stocks, Bonds, Bills, and Inflation: 2021 Summary Edition*, Duff & Phelps, *available at* https://www.cfainstitute.org/-/media/documents/book/rf-publication/2021/sbbi-summary-edition-2021.ashx.

[56] Christine Benz, *Experts Forecast Stock and Bond Returns: 2021 Edition*, Morningstar (Jan. 20, 2021), *available at* https://www.morningstar.com/articles/1018261/experts-forecast-stock-and-bond-returns-2021-edition.

total market returns, and not just the equity risk premium. Below are some of the market return forecasts from the previously referenced article:

- **Blackrock:** 5% 10-year expected nominal return from US equities.[57]
- **Grantham Mayor Van Otterloo ("GMO"):** Negative 5.8% real (inflation-adjusted) returns for US large caps over the next seven years.[58]
- **JP Morgan:** 4.1% nominal returns for US equities over a 10–15-year horizon.[59]
- **Morningstar Investment Management:** Negative 0.1% 10-year nominal returns for US stocks.[60]
- **Research Affiliates:** 2% nominal (negative 0.2% real) returns for US large caps during the next 10 years.[61]
- **Vanguard:** Nominal US equity market returns of 3.7% to 5.7% range over the next decade.[62]

The above-stated equity returns display a very large range. On the low side is *GMO*, which forecasts that US large caps will, after inflation, lose 5.8% of their value annually over the next seven years. On the more positive side is *Vanguard* that expects nominal equity market returns ranging between 3.7% and 5.7% over the next decade. Note that the above forecasts were provided in January 2021, approximately 10 months after the beginning of the pandemic in March 2020.

[57] *Id.*
[58] *Id.*
[59] *Id.*
[60] *Id.*
[61] *Id.*
[62] *Id.*

As another point of reference, Charles Schwab published an article on May 3, 2021 titled "Why Market Returns May be Lower and Global Diversification More Important in the Future."[63] This article noted that "[m]arket returns on stocks and bonds over the next decade are expected to fall short of historical averages"[64] and that Schwab's "estimates show that, over the next 10 years, stocks and bonds will likely fall short of their historical returns from 1970 to December 2020. The estimated annual expected return for U.S. large-capitalization stocks from January 2021 to December 2030 is 6.6%, for example, compared with an annualized return of 10.8% during the historical period."[65] This article also includes a chart that shows the overall market return, and overall market premium, for US large capitalization stocks are expected to be 6.6% and 4.5%, respectively, and that the same figures for US small capitalization stocks are expected to be 7.1% and 5.0%, respectively.[66]

I also note that in 2018, and prior to the COVID-19 pandemic, Duke University finance professors published equity risk premium estimates that stated the expected average risk premium exhibited by a survey of U.S. Chief Financial Officers around the country was expected to be 4.42%.[67] The study stated the following:

> During the past 18 years, we have collected almost 25,000 responses to the survey. Panel A of Table 1 presents the date that the survey

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[63] Veeru Perianan, *Why Market Returns May Be Lower and Global Diversification More Important in the Future*, Charles Schwab (May 3, 2021), *available at* https://www.schwab.com/resource-center/insights/content/why-market-returns-may-be-lower-in-the-future.
[64] *Id.*
[65] *Id.* (emphasis added).
[66] *Id.*
[67] John R. Graham and Campbell R Harvey, *The Equity Risk Premium in 2018*, Duke University (Mar. 28, 2018), at 3–4.

> window opened, the number of responses for each survey, the 10-year Treasury bond rate, as well as the average and median expected excess returns. There is relatively little time variation in the risk the historical risk premiums contained in Table 1. <u>The current premium, 4.42%, is above the historical average of 3.64%</u>. The December 2017 survey shows that the expected annual S&P 500 return is 6.79% (=4.42%+2.37%) which is slightly below the overall average of 7.11%.[68]

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

A. Using historical data, as well as ex ante (forecast) data, the evidence would suggest the equity risk premium is within the range of 4.25% to 6.25%.

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

A. I used the *Value Line* derived Beta sourced from the most recent *Value Line* editions for each company in the comparable company proxy group.

Q. WHAT WERE YOUR CAPM RESULTS?

A. The actual calculations for the CAPM for my comparable company proxy group can be seen in **Exhibit KWO-7**.

As shown above in **Chart 1**, I provided the change in the 30-year US Treasury bonds since the beginning of Piedmont's most recently concluded rate case (*i.e.,* April 1, 2019 – July 2, 2021). Note that over this period, the yield on 30-year US Treasury bonds was 2.89% as of April 1, 2019 and was 2.05% as of July 2, 2021. The Maximum value over this period was 2.99%, the Average value was

[68] *Id*. (emphasis added).

1.99%, and the Minimum value was 0.99%. **Chart 1** above provides further details on these bond yields.

The average Beta for the comparable company proxy group is 0.90 which, when multiplied by the risk premium range of 4.25% to 6.25%, produces a Beta-adjusted risk premium of 3.80% to 5.59%. The 30-year US Treasury yield ("Rf") range of 0.99% to 2.99% is next added to the Beta-adjusted risk premium range of 3.80% to 5.59% to arrive at the comparable company proxy group CAPM result range of 4.8% (3.80% + 0.99% = 4.79%) to 8.6% (5.59% + 2.99% = 8.58%, rounded to 8.6%).

Additionally, the Beta for Piedmont's parent company Duke is 0.85 which, when multiplied by the risk premium range of 4.25% to 6.25%, produces a Beta-adjusted risk premium of 3.61% to 5.31%. The 30-year US Treasury yield (Rf) range of 0.99% to 2.99% is next added to the Beta-adjusted risk premium range of 3.61% to 5.31% to arrive at Duke's CAPM result range of 4.6% (3.61% + 0.99% = 4.60%, rounded to 4.6%) to 8.3% (5.31% + 2.99% = 8.30%, rounded to 8.3%).

Based on this range of results for the CAPM, as found in **Exhibit KWO-7**, I find the proper ROE derived from the CAPM is in the range of 6.00% to 8.00%. The low-end (6.00%) of this range is above the average of the comparable company proxy group CAPM results using the 4.25% equity risk premium (5.8%) and is also above the average of Duke's results using the 4.25% equity risk premium (5.6%) as well. The high end (8.00%) of the range is positioned above the average of the comparable company proxy group CAPM results using the 6.25% equity risk premium (7.6%) and is also above the average of Duke's results using the 6.25% equity risk premium (7.3%) as well.

D. Return on Equity ("ROE") Summary

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

A. **Table 9** below lists the results of my DCF, CEA, and CAPM analyses as outlined within **Exhibit KWO-1**.

Table 9: ROE Method Results

	ROE Results	
Method	Low	High
DCF	7.50%	9.50%
CEA	9.00%	10.00%
CAPM	6.00%	8.00%

Q. WHAT IS YOUR ROE RECOMMENDATION IN THIS PROCEEDING?

A. My recommendation in this case is shown in **Exhibit KWO-1**. This exhibit shows my recommendation that the Commission grant Piedmont a return on equity of 9.00%. This 9.00% ROE recommendation is above the 8.50% mid-point of my DCF result range, below the low-end of the CEA, and above the high-end of the CAPM results.

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

A. The overall rate of return I am recommending is 6.52%, based upon a 50.00% common equity capital structure / 49.43% long-term debt / 0.57% short-term debt capital structure, and a 9.00% ROE / 4.09% long-term cost of debt / 0.47% short-term cost of debt as summarized again in **Table 10**, below.

Table 10: CUCA Recommended Overall Rate of Return

Component	Ratio (%)	Cost Rate (%)	Weighted Cost
Long-Term Debt	49.43%	4.09%	2.02%
Short-Term Debt	0.57%	0.47%	0.00%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.52%**

VIII. REVIEW OF COST OF EQUITY ANALYSIS OF WITNESS D'ASCENDIS

Q. HOW DID MR. D'ASCENDIS DEVELOP HIS LIST OF COMPARABLE COMPANIES?

A. Mr. D'Ascendis developed his comparable company proxy "Gas Group" by first determining which gas utilities were followed by *The Value Line Investment Survey*.[69] However, as previously referenced earlier within my testimony, of the ten Natural Gas Utilities followed by *Value Line*, Mr. D'Ascendis opted to remove UGI Corporation ("UGI") and Chesapeake Utilities ("Chesapeake") from his comparable company proxy group at the conclusion of his seven step proxy group screening process, leaving his comparable company proxy group comprised of eight companies.

In such industries where there are a higher number of such comparable companies (such as the electric utility industry), I have historically taken a deeper look into which companies I believe are more appropriate than others to be included

[69] Witness D'Ascendis' Direct Testimony, page 14: lines 1 – 2.

within my proxy group. However, the number of companies within the natural gas industry is dwindling due to a variety of factors that I previously explained within **Section IV**: "Development of Proxy Group." As such, given that none of the ten companies within the Natural Gas industry grouping provided by *Value Line* were undergoing any sort of bankruptcy, legal issues, restructuring, or significant merger activities at the time when this direct testimony was filed, I utilized the full ten natural gas utilities provided by *Value Line*. As for UGI, I noted above my reasoning for including that company in my comparable group.

I have been submitting ROE testimony to this Commission for over 36 years. Experience has shown me that the critical factor in determining the market required ROE is not the development of the proxy group but is, instead, the application of the various models available to the analyst. The proxy groups of Mr. D'Ascendis and I are slightly different, but our use of the various models is vastly different.

A. <u>Review of Mr. D'Ascendis' DCF Analysis</u>

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE DCF MODEL AND MR. D'ASCENDIS' APPLICATION OF THE DCF?

A. My DCF analysis in this proceeding produced a range from 7.50% to 9.50%. Mr. D'Ascendis' DCF result was 9.46%.[70] The primary difference between my application of the DCF Model and Mr. D'Ascendis' application of the DCF Model

[70] Witness D'Ascendis' Direct Testimony, **Schedule DWD-1**.

is that Mr. D'Ascendis only utilized forecasted EPS growth rates in his analysis as included within page 1 of **Schedule DWD-2**, rather than performing his analysis utilizing a variety of historical and forecasted growth rates.[71]

Q. HOW DID MR. D'ASCENDIS PERFORM THE DCF CALCULATIONS FOR HIS COMPARABLE UTILITY GROUP?

A. As I mentioned previously, a DCF calculation is largely made up of two inputs, an average dividend yield and an average growth rate. To begin his DCF calculation, Mr. D'Ascendis determined the dividend yield across his comparable group within **Schedule DWD-2**. He took the dividend at January 29, 2021 and then divided this dividend by the average closing price of the last 60 trading days ending January 29, 2021 for each company.[72] Mr. D'Ascendis then performed an adjustment to these historical dividend yields by factoring in a growth rate component equal to one-half the conclusion of the growth rate (*i.e.,* Company's Historical Dividend Yield x (1 + (½ x Company's Average Projected EPS Growth Rate)).

In contrast, I utilized forecasted annual dividend yield for each company within my proxy group across three separate time periods (*i.e.,* 13-weeks, 4-weeks, and 1-week). While Mr. D'Ascendis' dividend yield approach afforded him the use of higher dividend yield averages to use within his DCF analysis, the primary reason that his DCF result approximates the high end of my DCF result range was due to his decision to only rely upon forecasted EPS growth rates.

[71] Witness D'Ascendis' Direct Testimony, **Schedule DWD-2**.
[72] Witness D'Ascendis' Direct Testimony, **Schedule DWD-2**.

Q. DO YOU AGREE WITH MR. D'ASCENDIS' EXCLUSIVE USE OF FORECASTED GROWTH RATES IN HIS DCF MODEL AND OMISSION OF HISTORICAL GROWTH RATES?

A. No. I previously noted in this testimony that I feel that analysts should present both the historical and forecasted growth rates within their DCF analysis for transparency purposes. By omitting the use of any historical growth rates within his testimony, Mr. D'Ascendis placed his full reliance on forecasted growth rates. By not utilizing any of the historical growth rate data in conjunction with his use of forecasted growth rates, Mr. D'Ascendis has ignored an entire group of data that is readily available.

As I noted previously in this testimony within the discussion of my own DCF results, I believe that it is important for an analyst to consider historical growth rates within their DCF analysis alongside the forecasted growth rates. Historical growth rates capture the actual growth of the various rates over time based upon a Company's reported results and performance. In contrast, forecasted growth rates are derived entirely from analyst projections, which can vary from analyst to analyst, and which also tend to be overstated.

Q. ARE THERE OTHERS WITHIN THE FINANCIAL COMMUNITY THAT CALL INTO QUESTION PLACING FULL RELIANCE UPON FORECASTED GROWTH RATES?

A. Yes. There are various academic articles and journals that specifically call into question the accuracy of earnings predictions and forecasts. For example, in November 2003, Louis K. C. Chan, Jason Karceski and Josef Lakonishok published an article entitled "Analysts' Conflict of Interest and Biases in Earnings Forecasts" in the *Journal of Finance*. The conclusion of the paper stated:

> [I]t is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is <u>little forecastability in earnings, and analysts' estimates tend to be overly optimistic</u>.[73]

Additionally, an article written by Professors Rocco Ciciretti, Gerald P. Dwyer, and Iftekhar Hasan, "Investment Analysts' Forecasts of Earnings," noted that "there is strong support for average and median earnings forecasts being higher than actual earnings a year before the earnings announcement"[74]; and an article published by McKinsey & Company, Strategy & Corporate Finance entitled "Equity analysts: Still too bullish" noted that "[a]nalysts, we found, were typically overoptimistic, slow to revise their earnings forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined."[75]

I recognize that there are other academic articles and journals that support the opposite viewpoint. However, given the fact that this remains a debated topic within the financial community, it is appropriate to include EPS, DPS, and BPS from both an historical and forecasted perspective, as well as plowback growth

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[73] K. Chan, L., Karceski, J., & Lakonishok, J., *The Level and Persistence of Growth Rates*, Journal of Finance (2003), at 683 (emphasis added).
[74] Ciciretti, R., P. Dwyer, G., & Iftekhar, H., *Investment Analysts' Forecasts of Earnings*, Federal Reserve Bank of St. Louis Review (2009), at 545.
[75] Goedhart, M., Raj, R., & Saxena, A., *Equity analysts: Still too bullish*, McKinsey & Company Strategy & Corporate Finance (2010).

rates, and the associated DCF results for each, within my analysis. In contrast, placing undue reliance upon forecasted EPS growth rates produces unrealistically high returns on equity numbers that cannot be sustained indefinitely.

Q. DO YOU AGREE WITH MR. D'ASCENDIS' SELECTION OF FORECASTED GROWTH RATES?

A. No. Not only did Mr. D'Ascendis rely exclusively on forecasted growth rates, Mr. D'Ascendis sourced his forecasted growth rates from a date of November 27, 2020[76] from *Value Line*, a date of January 29, 2021 for *Yahoo! Finance* and *Zacks*.[77] As such, values sourced by Mr. D'Ascendis for his forecasted growth rates were between three and four months old by the time that his testimony was filed. These forecasts fail to account for the continued changes we have seen within the markets during Q1 2021 (and prior to the Company's base rate case filing on March 22, 2021). For example, *Value Line* publishes company-specific metrics and forecasts by industry on a quarterly basis. Yet, Mr. D'Ascendis' testimony utilized data from November 2020 and was never updated for the data published by *Value Line* during February 2021 prior to the filing of his testimony at the end of March 2021.

If an analyst places full reliance on forecasted growth rates (as opposed to basing any of their analysis on historical growth rates), then the analyst should not use forecasts that are between three and four months old.

Q. WOULD MR. D'ASCENDIS' DCF ANALYSIS HAVE RETURNED A LOWER RESULT HAD HE UTILIZED BOTH HISTORICAL AND

[76] Witness D'Ascendis Direct Testimony, **Schedule DWD-2**.
[77] *Id.*

FORECASTED GROWTH RATES FROM A VARIETY OF METRICS AS OPPOSED TO SIMPLY USING HISTORICAL EPS GROWTH RATES?

A. Yes. As shown in Mr. D'Ascendis' **Schedule DWD-2**, Mr. D'Ascendis' growth rates ranged from 2.00% to 12.50% for *Value Line*, 3.10% to 24.50% for *Zack's*, 1.65% to 24.50% for *Yahoo! Finance*, and 2.96% to 13.75% for *Bloomberg*.

However, as shown within **Exhibit KWO-2**, the historical growth rates for my proxy group ranged from 4.4% to 5.9% and for Duke Energy ranged from 1.0% to 3.5% and my forecasted growth rates for my proxy group ranged from 4.2% to 7.6% and for Duke Energy ranged from 2.0% to 7.0%. Clearly the forecasted growth rates relied upon by Mr. D'Ascendis led his ultimate DCF result to approximate the absolute high end of my overall DCF result range.

B. <u>Review of Mr. D'Ascendis' CAPM Analysis</u>

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE CAPM AND MR. D'ASCENDIS' APPLICATION OF THE CAPM?

A. My CAPM analysis in this proceeding produced a range from 6.00% to 8.00%. Mr. D'Ascendis' CAPM analysis produced a range from 11.83% to 12.05%.[78] The primary differences between my application of the CAPM and Mr. D'Ascendis' application of the CAPM are the following:

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[78] Witness D'Ascendis' Direct Testimony, **Schedule DWD-1**.

- Mr. D'Ascendis utilized certain data points for his forecasted market return that inflated the overall Market Risk Premium used within his CAPM analysis;[79] and
- Mr. D'Ascendis employed the use of a Traditional CAPM and an Empirical CAPM, averaged the results of both, and then presented that value as his ultimate CAPM result.[80]

Q. PLEASE EXPLAIN HOW MR. D'ASCENDIS APPLIED THE CAPM.

A. In his analysis (as shown in **Schedule DWD-4**), Mr. D'Ascendis combined a Market Risk Premium, in conjunction with his estimated risk-free rate and company-specific Betas, to apply within his CAPM. Mr. D'Ascendis' decision to use certain forecasted market return values ultimately resulted in higher a CAPM result for his client in this proceeding.

Q WHAT IS THE RISK-FREE RATE THAT MR. D'ASCENDIS USES IN HIS CAPM ANALYSIS?

A. In his direct testimony, Mr. D'Ascendis cited various historical and forecasted interest rates and then concluded that 2.31% is a proper estimate for the risk-free rate in the CAPM.[81]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' FORECASTED RISK-FREE RATE?

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[79] Witness D'Ascendis' Direct Testimony, **Schedule DWD-4**.
[80] *Id.*
[81] Witness D'Ascendis' Direct Testimony, page 23: lines 11 – 12.

A. I do not take issue with the risk-free rate used by Mr. D'Ascendis in this proceeding of 2.31%.[82] As shown within **Exhibit KWO-7**, I have used the 30-year US Treasury Bond Yield to approximate what I deem to be appropriate to use for the risk-free rate for application within the CAPM. This yield over the period from April 1, 2019, to July 2, 2021, ranged from 0.99% to 2.99%, with an average of 1.99%.

Q. DO YOU AGREE WITH MR. D'ASCENDIS' BETAS USED WITHIN HIS CAPM ANALYSIS?

A. I do not take issue with the Beta values used by Mr. D'Ascendis in this proceeding. As shown within Mr. D'Ascendis' **Schedule DWD-4**, the average of the Mean and Median Betas sourced by Mr. D'Ascendis from Value Line and Bloomberg was 0.93.[83] As shown within **Exhibit KWO-7**, I used a 0.90 Beta as the average Beta for my comparable proxy group for application within the CAPM.

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

A. Mr. D'Ascendis utilized six different measures to determine the market premium, which, when averaged, resulted "in an average total market equity risk premium of 10.42%."[84]

To develop the six measures that Mr. D'Ascendis used to calculate his total market equity risk premium of 10.42%, he used the following data points:

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[82] *Id.*
[83] Witness D'Ascendis' Direct Testimony, **Schedule DWD-4**.
[84] Witness D'Ascendis' Direct Testimony, page 40: lines 20 – 21.

- 7.01% based on *Ibbotson* Historical Data from 1926-2019;
- 9.98% based on the application of a regression analysis applied to *Ibbotson* Historical Data from 1926-2019;
- 10.76% based on the application of a Predictive Risk Premium Model ("PRPM") to *Ibbotson* Historical Data from January 1926 – January 2021;
- 7.52% calculated from *Value Line* projected inputs;
- 11.79% calculated from Value Line and S&P 500 projected inputs; and
- 15.47% based on Bloomberg projected data.

Q. HOW DOES MR. D'ASCENDIS' FORECASTED MARKET RETURN COMPARE TO FORECASTS FROM OTHER ANALYSTS?

A. As I indicated previously, well-known entities such as Morningstar and Vanguard forecasted market returns from -0.1% to 5.7% during January 2021.[85] Additionally, Charles Schwab published an article that included a chart that showed that the overall market return, and overall market premium, for US large capitalization stocks are expected to be 6.6% and 4.5%, respectively, and that the same figures for US small capitalization stocks are expected to be 7.1% and 5.0%, respectively.[86] Mr. D'Ascendis' Forecasted Market Return of 10.42% and Forecasted Market Premium of 8.11% (*i.e.,* 10.42% Market Risk Premium - 2.31% Risk-Free Rate), as referenced above are, to say the least, unrealistic.

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[85] Christine Benz, *Experts Forecast Stock and Bond Returns: 2021 Edition*, Morningstar (Jan. 20, 2021), *available at* https://www.morningstar.com/articles/1018261/experts-forecast-stock-and-bond-returns-2021-edition.

[86] Veeru Perianan, *Why Market Returns May Be Lower and Global Diversification More Important in the Future*, Charles Schwab (May 3, 2021), *available at* https://www.schwab.com/resource-center/insights/content/why-market-returns-may-be-lower-in-the-future.

Whether the comparison is to forecasts from current day analysts or to historical returns, Mr. D'Ascendis' market return forecasts used within his CAPM analysis simply have no underlying fundamental support or reasoning.

Q. HOW DID MR. D'ASCENDIS APPLY BOTH THE TRADITIONAL CAPM AND THE ECAPM WITHIN HIS OVERALL CAPM ANALYSIS?

A. As shown in **Schedule DWD-4**, Mr. D'Ascendis utilized a both "Traditional CAPM Cost Rates" and "ECAPM Cost Rates" to derive his ultimate "Indicated Common Equity Cost Rate" through his CAPM analysis. Within his analysis, Mr. D'Ascendis explained his usage of the ECAPM where he noted:

> The empirical CAPM ("EC") reflects the reality that while the results of these tests support the notion that the Beta coefficient is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicated SML. The ECAPM reflects this empirical reality.[87]

The ECAPM pricing model makes use of a weighted Risk Premium, with the Overall Market Risk Premium weighted by a factor of 25%, and a company-specific Beta-adjusted Risk Premium based on the stocks' relative volatility being weighted by 75%.[88] Essentially, this ECAPM method is utilized when an analyst feels as though the weighted risk premium will help to correct for returns produced that were too high or too low for stocks with low Betas (*i.e.,* those stocks that are deemed to be less risky than the overall market) or high Betas (*i.e.,* those stocks that are deemed to be more risky than the overall market), respectively. I have not historically found the need to utilize the ECAPM within my analyses as I place the

[87] Witness D'Ascendis' Direct Testimony: page 36: lines 16 – 19 – page 37: line 1.
[88] Witness D'Ascendis' Direct Testimony, page 38: line 5.

most weight upon the DCF model and only utilize the CE and CAPM methodologies as a check on the reasonableness of the return generated by the DCF.

C. Review of Mr. D'Ascendis' Risk Premium Method

Q. MR. O'DONNELL, PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE RISK PREMIUM MODEL AND THE CAPM?

A. The CAPM and the Risk Premium models are both essentially risk premium models. The Risk Premium model's basis is in assuming that common stock and equity are riskier than debt, and that therefore investors would require a higher expected return on a stock in comparison to a bond. As such, in the Risk Premium model, the cost of equity is comprised of the cost of debt and a corresponding risk premium.

The primary difference between the CAPM and the Risk Premium model is that the CAPM is more company-specific due to its use of company-specific Betas to measure systematic risk. However, both models are fundamentally similar in that they compare market returns (either total market or utility markets) to bond yields.

Q. PLEASE EXPLAIN MR. D'ASCENDIS' APPLICATION OF HIS RISK-PREMIUM MODEL.

A. Mr. D'Ascendis' Risk Premium model produced a range from 9.64% to 10.11%.[89] These two results were computed as the average of two different methods, the Predictive Risk Premium Model and the Risk Premium Using an Adjusted Total Market Approach. However, each of these methods were applied against two

[89] Witness D'Ascendis' Direct Testimony, **Schedule DWD-1**.

different data sets, (1) Mr. D'Ascendis' proxy group of natural gas distribution companies using projected interest rates and (2) Mr. D'Ascendis' proxy group of natural gas distribution companies using current interest rates.

In his application of the Predictive Risk Premium Model, Mr. D'Ascendis combined the average Predictive Risk Premiums for his utility proxy group to Risk-Free Rates 2.31% on a projected interest rate basis and 1.70% on a current interest rate basis.[90] In his application of the Adjusted Total Market Approach, Mr. D'Ascendis combined Equity Risk Premiums of 6.74% and 7.13% to Adjusted Bond Yields of 3.66% and 2.94%.[91]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' PRESENTATION OF THE RISK PREMIUM MODEL?

A. No. As I noted above, I have been providing ROE testimony to this Commission and other state regulators for many years. In my nearly four decades of this work, I have never seen such a convoluted model as presented by Mr. D'Ascendis in this case. Mr. D'Ascendis Risk Premium Model reminds me of the following quote:

> ***Life is really simply, but we insist on making it complicated.***[92]

Finance is likewise very simple. I contrast all the jumps and twists of Mr. D'Ascendis in his risk premium model with the simplicity of the DCF model where one simply adds a dividend yield and a growth rate to determine the market-required rate of return. Mr. D'Ascendis Risk Premium model is overly complex

[90] Witness D'Ascendis' Direct Testimony, **Schedule DWD-3**, page 2.
[91] Witness D'Ascendis' Direct Testimony, **Schedule DWD-3**, page 3.
[92] Helen Luc, April 21, 2017, https://www.yourtango.com/2017301914/16-inspiring-life-quotes-when-things-get-complicated.

and is not an analytical tool actually used by analysts or the investing public as a whole.

D. <u>Other Adjustments Employed by Mr. D'Ascendis</u>

Q. DID MR. D'ASCENDIS' APPLY ANY ADDITIONAL ADJUSTMENTS TO HIS COST OF CAPITAL RESULTS?

A. Yes. As shown in **Schedule DWD-1**, Mr. D'Ascendis developed overall cost of capital ranges based upon his DCF, Risk Premium, and CAPM analyses. However, he then applied an upward flotation cost adjustment of 0.12% to these ranges.

Q. DO YOU AGREE WITH THIS FLOTATION COST ADJUSTMENT APPLIED BY MR. D'ASCENDIS?

A. No, I do not. Mr. D'Ascendis chose to implement this upward adjustment to compensate stockholders by ensuring their desired rate of return. However, investors are sophisticated enough to understand that flotation costs should be expected, without the need to apply an adjustment factor as an upward adjustment to the Company's overall cost of equity.

Q. DOES MR. D'ASCENDIS MAKE AN ADJUSTMENT FOR NEW EQUITY ISSUANCES?

A. Yes. As explained within his testimony, Mr. D'Ascendis explained flotation costs as "those costs associated for new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance."[93] He then later noted that his 0.12% flotation cost adjustment recognized "the actual costs of issuing

[93] Witness D'Ascendis' Direct Testimony, page 48: lines 9 – 12.

equity that were incurred by DUK in its last three equity issuances. Based on the issuance costs shown on page 1 of **Schedule DWD-8**, an adjustment of 0.12% is required to reflect the flotation costs applicable to the Utility Proxy Group."[94]

Q. WHY DO YOU NOT AGREE WITH ADJUSTING THE CALCULATED ROE FOR NEW EQUITY ISSUANCES?

A. Investors are well aware of the fact that public companies issue common stock from time-to-time. As a result, investors have factored this matter into the price they are willing to pay for that stock. Adjusting the ROE again through the machinations as proposed by Mr. D'Ascendis in this case would in effect result in double-counting for any new issuances.

Q. HAVE ANY REGULATORY BODIES PREVIOUSLY RULED UPON MR. D'ASCENDIS' FLOTATION COST ADJUSTMENT?

A. Within **CUCA Data Request No. 2-12**, Mr. D'Ascendis was asked to list all cases in which he testified in which the regulatory body accepted his recommended flotation cost adjustment. Within his response, Mr. D'Ascendis noted that he was "unaware of a regulatory body that has directly accepted his recommended flotation cost adjustment."[95] Additionally, note that the Commission previously ruled in Docket E-22, Sub 333 not to add a flotation cost in the manner as described by Mr. D'Ascendis.[96] I will agree, however, that verifiable costs, such as legal costs and brokerage costs, should be allowed to be recovered over time. Unfortunately for

[94] Witness D'Ascendis' Direct Testimony, page 51: lines 6 – 10.
[95] Witness D'Ascendis Response to **CUCA Data Request No. 2-10**.
[96] *Order Granting Partial Rate Increase*, Docket No. E-22, Subs 333 & 335 (Feb. 26, 1993), at 52.

Piedmont in this case, it did not provide such an analysis on which the Commission can base a decision.

IX. COST OF SERVICE STUDY AND RATE DESIGN

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

A. Piedmont retained the services of Witness Cynthia Menhorn for the development of its cost of service study and its proposed rate design in this case.

Q. PLEASE EXPLAIN HOW MS. MENHORN PERFORMED THE COSS PRESENTED IN THIS CASE.

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

Q. WHAT IS THE KEY COMPONENT IN PERFORMING A NATURAL GAS COST OF SERVICE STUDY?

A. The key allocation for natural gas ACOSS is how the analyst allocates distribution mains, which are pipes through which the natural gas flows from the interstate pipelines to the street level of homes and business. These distribution mains are fixed costs incurred by Piedmont in the delivery of natural gas.

Q. HOW DID MS. MENHORN ALLOCATE DISTRIBUTION MAINS WITHIN HER ACOSS?

A. Ms. Menhorm used the peak and average cost allocation method for allocating fixed gas costs in his ACOSS. In this methodology, distribution mains are allocated at the ratio of 50% of the ratio of customer class usage at the time of the annual peak demand of the utility plus 50% of the ratio of the customer class usage (throughput) as compared to the total throughout for the entire year. Hence, the peak and average allocation factor gives equal weight to customer class usage at the time of the system peak and the customer class usage throughout the entire year.

Q. WHAT ARE THE ADVANTAGES AND DISADVANTAGES OF USING THE PEAK AND AVERAGE METHODOLOGY FOR ALLOCATING DISTRIBUTION MAINS?

A. The Peak and Average ("P&A") methodology has been used by the Company and the Public Staff for quite some time. It is a methodology about which the Commission is fully aware. Along with familiarity, one advantage of the P&A is its simplicity. Adding 50% of the peak allocation and 50% of average use is a straightforward process. Another advantage is that this methodology gives weight to the peak contribution of each customer class as well as the average use of each class.

A disadvantage of the P&A methodology is that it is not, in my opinion, based on cost causation principles. Specifically, the P&A methodology does not reflect the manner in which the Piedmont gas system was constructed. The Piedmont system was built to meet peak demands, not average demands. As a result, any reliance on the use of the average throughput does not send the proper price signal to customers.

Q. ARE THERE OTHER METHODOLOGIES AVAILABLE FOR ALLOCATING MAINS IN NATURAL GAS COST OF SERVICE STUDIES?

A. Yes, since natural gas distribution systems are built to meet peak demand, another methodology that could be employed would be to allocate distribution mains on each customer class' contribution to the peak demand in a given year. This methodology is, as the name implies, the Peak methodology.

Q. WHAT ARE THE ADVANTAGES AND DISADVANTAGES OF THE PEAK METHODOLOGY FOR ALLOCATING DISTRIBUTION MAINS?

A. The advantage of the peak allocation is that it reflects the manner in which the gas distribution system is constructed. In this sense, the Peak methodology is superior to the P&A method.

Some would object to the Peak method on the grounds that it does not reflect how certain customers use the gas distribution system. Specifically, the Peak allocation methodology allocates little, if any, distribution mains expense to the two interruptible classes that take service throughout the year but have relatively little distribution mains expense allocated to that class due to the classes' interruptible nature. When a design day allocation is used, as it has been in this case, interruptible customers are not allocated distribution mains expenses.

I disagree with this objection to the Peak method. From a cost-causation, perspective, interruptive customers should pay for a small portion of the distribution mains. Piedmont constructed the distribution mains to handle peak capacity, and because the interruptive customers are subject to curtailment during peak demand, the interruptible customers contributed less to Piedmont's build out of capacity. Moreover, given that interruptive customers volunteer to be curtailed to make capacity available for other customers, interruptive customers should pay a lower-than-average rate for gas service.

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

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

Based on the above, the peak method, as opposed to the peak and average method, is a more accurate cost-allocation methodology for interruptible customers. The peak method avoids allocating distribution-mains costs to interruptible customers, who might not take service on the day of peak demand, and accurately allocates those costs to firm customers, who take service on the day of the peak demand. This is appropriate because Piedmont invested in distribution mains primarily to satisfy the demand of firm customers, not the interruptive customers. In contrast, the peak and average method assigns Piedmont's distribution-main costs to interruptible customers, despite Piedmont having made those investments primarily to serve firm customers.

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

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

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

Customer Class	Customer Class RORs (%)	
	Peak & Average	Peak Day
Residential Rate 101	5.2%	5.4%
Small GS Rate 102	8.9%	9.2%
Medium GS Rate 152	15.0%	15.8%
Firm Large GS Sales Rate 103	-2.6%	-2.6%
Large GS Transport Rate 113	-3.0%	-3.0%
Interruptible Sales Rate 104	31.1%	101.9%
Interruptible Trans Rate 114	20.5%	85.9%
Military Trans Rate T-10	-2.8%	-2.7%
Special Contracts	13.7%	13.9%
Municipal Contracts	-2.2%	-2.2%
Power Gen Contracts	3.9%	4.3%

As can be seen in the table above, with the exception of the interruptible sales and interruptible transportation classes, there is not much of a difference in the class rates per the ACOSS. The obvious reason for the huge difference in the rate of return for the interruptible classes is that, with the peak method, these two rate classes are not being allocated any fixed gas costs. This table is informative for two reasons. First, by no longer allocating these costs to the interruptible customers, the excessive level of the interruptive customers' rates is highlighted. Second, this table shows that the cost-allocation correction to interruptible customers has only a modest impact on firm customers.

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

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

Table 12: Piedmont Proposed Class Rate Increases and Rates of Return

Customer Class	Requested Rate Increase (%)[97]	Cust Class Rate of Return(%)[98]
Residential - Rate 101	11.9%	7.6%
Small GS - Rate 102	11.9%	11.7%
Medium GS - Rate 152	10.9%	18.4%
Large GS Sales - Rate 103	5.3%	-1.5%
Large GS Trans. - Rate 113	19.5%	-1.6%
Int. Sales - Rate 104	1.4%	**34.2%**
Int Trans - Rate 114	5.6%	**23.1%**
Military Trans	17.5%	-1.8%

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

Furthermore, the proposed rate design of Ms. Menhorn conflicts with a statement in her own testimony. Specifically, in her direct testimony, Ms. Menhorn states:

[97] Witness Menhorn's Direct Testimony: CAM Table 1, page 13
[98] *Id.*

> The revenue allocation described above greatly improves the IRRs of the Company's rate schedules. When the proposed revenues are entered into the cost-of-service study, the IRRs of each rate schedule moves closer to the system average or remains the same. **Additionally, the extremely over-earning and under-earning rate schedules all have made significant movement towards the system average.**[99]

The above statement is incorrect. Under Ms. Menhorn's proposed rate design, the customer class rates of return for the 104 (Interruptible Sales) increases from 31.1% to 34.2%.[100] Similarly, the 114 (Interruptible Transportation) increases from 20.8% to 23.4%. Even though the 104/114 customers are already paying rates that result in excessive rates of return, Ms. Menhorn's proposal is to increase those rates even further. Such a recommendation to this Commission defies logic, is punitive to interruptible customers, harmful to the State's economy, and should be rejected.

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

A. Yes, I am.

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

A. The basis of my rate design is the assumption that the sum of all my rate recommendations must allow Piedmont to earn my recommended overall cost of capital of 6.52%. I then made a second assumption that no customer class could sustain a rate increase or decrease of more than 10%. This last assumption is critical as, if we followed the details of the ACOSS results, interruptible sale and

[99] Witness Menhorn's Direct Testimony: page 15, lines 5-9 (emphasis added).
[100] *Id.*, CAM Table 1, page 13.

interruptible transportation customers would warrant a much greater rate reduction than 10%. My recommended rate change per customer class and the resulting class rates of return are found in **Table 13** below.

Table 13: Recommended Rate Change and Resulting Rates of Return

Customer Class	CUCA Rec Rate Increase (%)	Cust Class Rate of Return(%)
Residential - Rate 101	7.5%	7.1%
Small GS - Rate 102	-0.8%	8.7%
Medium GS - Rate 152	0.4%	15.2%
Large GS Sales - Rate 103	5.3%	-1.0%
Large GS Trans. - Rate 113	5.9%	-2.4%
Int. Sales - Rate 104	-8.4%	9.3%
Int Trans - Rate 114	-8.1%	16.0%
Military Trans	6.6%	-2.2%

In the above rate design, I attempted to balance the interests of all customer classes without allowing any one particular class to sustain excessive rate hikes while other classes enjoyed significant rate cuts. The customer class rates of return are still not cost-justified based on a risk/return basis, but the results are closer and more equitable than Ms. Menhorn's results. Indeed, the class rates of return for the interruptible customers is still well above the Piedmont overall rate of return of 6.52% and the large firm customers are below the overall rate of return. Although my proposed rate design does not fully correct the problem that I have identified, my proposal offers a balance in the rate design that is not present in Ms. Menhorn's proposed rate design.

Q. PLEASE DESCRIBE HOW MS. MENHORN TREATS CONTRACT CUSTOMERS IN THIS RATE CASE.

A. In her prefiled direct testimony, Ms. Menhorn identifies contract customers as those

> who contract for service whereby the customer commits to pay rates over a multi-year period to provide the Company an appropriate revenue stream based upon the investments made at the customers' facilities to provide that service.[101]

Ms. Menhorn also states that the contracts in which Piedmont entered were approved by the NCUC prior to the commencement of service. In reviewing Ms. Menhorn's testimony, one cannot find the class rates of return for service to the Special Contracts class, the Municipal Contracts class, or the Power Generation class. I did locate these class rates of return in Ms. Menhorn's ACOSS and noticed they had the following class rates of return:

- Special Contracts: 11.75%
- Municipal Contracts: -2.22%
- Power Generation Contracts: 5.67%

Both the Municipal Contract class and the Power Generation Contract class are earning below my recommended class overall rate of 6.52% and should realize a rate hike in this proceeding. However, Ms. Menhorn is not recommending any such rate increases.

[101] Prefiled Direct Testimony of Cynthia Menhorn, p. page 12, line 20 through page 13, line 2.

Q. WHAT REVENUE CHANGES ARE YOU RECOMMENDING FOR THESE CONTRACT CUSTOMERS?

A. My recommended rate changes and associated class rates of return for these contract customers are as follows:

Table 14: Contract Customer Recommended Rate Changes

Customer Class	Rate Change	Class Rate of Return (%)
Special Contracts	0.00%	11.80%
Municipal Contracts	7.70%	-1.70%
Power Gen Contracts	4.70%	6.30%

I realize that the Municipal and Power Generation contracts may not end at the same time as the implementation of new rates in this case. If these contracts extend out for another 2 years beyond the implementation of the new rates in this case, I recommend the revenue deficiency as noted above be spread to all remaining non-contract rates. If, however, these contracts do not terminate in 2 years, I suggest Piedmont absorb the increases in Table 13 until the contracts can be re-negotiated and more cost-based rates enacted.

Q. WHY ARE YOU RECOMMENDING NON-CONTRACT CUSTOMERS ABSORB THE RATE CHANGE FOR THESE CONTRACT CUSTOMERS FOR A PERIOD NOT-TO-EXCEED TWO YEARS?

A. Piedmont, like any utility, grows its earnings by growing its rate base through new plant investment. Piedmont, undoubtedly, knew about its ongoing plant investments when it entered into these contracts with the Municipal Contracts and Power Generation Contracts customers. If these contracts do not allow for periodic rate changes, non-contract customers should not be asked to indefinitely subsidize these customers. Piedmont should bear the risk of these contracts and absorb the revenue change itself after a period of two years.

Q. ARE YOU RECOMMENDING A RATE CHANGE FOR THE MUNICIPAL CONTRACTS AND POWER GENERATION CONTRACTS CLASSES?

A. No. A contract is a contract. If Piedmont has entered into a contract that is no longer as profitable as it first deemed feasible, it should absorb that price difference for the period of two years after the implementation of new rates in this case.

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

A. Yes, I used the SWPA ACOSS in the development of my recommended rate design. The reason is that use of the Peak Day ACOSS would not have altered my recommended rate design in any meaningful way. As noted in **Table 12** above, the class rates of return for both the SWPA ACOSS and the Peak Day ACOSS are, with the exception of interruptible sales and interruptible transportation, very close to one other. Since I limited the rate change of any customer class to +/-10%, the resulting class rates of return could not change to a point of risk/return parity amongst the customer classes.

X. <u>SUMMARY</u>

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

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

- The proper capital structure to use in this proceeding is 50.00% common equity and 50.00% long-term debt.
- I accept the Company's recommended total cost of debt of 4.56%.
- The Company's allowed ROE should be set at 9.00%.
- The overall rate of return that Piedmont should be allowed to earn in this proceeding is 6.52%.
- The Company's requested capital structure and ROE are, both, unreasonable for ratemaking purposes.
- The recommended rate changes per customer class are as follows:
  - Residential – 7.5% increase
  - Small Gen. Svc – 0.8% decrease
  - Med. Gen Svc. – 0.4% decrease
  - Large Gen. Svc – Firm Sales – 5.3% increase
  - Large Gen Svs. – Firm Transpo – 5.9% increase
  - Large Gen Svc. – Int. Sales – 8.4% decrease
  - Large Gen Svc. – Int. Transpo – 8.1% decrease
  - Military Transpo – 6.6% increase

To the extent that contractual customers have contracts that terminate within two years of the implementation of the new rates in this case, the rate changes I recommend in this rate case should be adjusted so that non-contract customers do not subsidize the contract class customers. If the contracts extend out past two years from the implementation date of the new rates, Piedmont should absorb the margin difference.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Kevin W. O'Donnell, CFA

Nova Energy Consultants, Inc. (Nova)

1350-101 SE Maynard Rd.
Cary, NC
919-461-0270
919-461-0570 (fax)
kodonnell@novaenergyconsultants.com

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

Mr. O'Donnell has experience working in the electric, natural gas, and water/sewer industries since 1984. He is very active in municipal power projects and has assisted numerous southeastern U.S. municipalities cut their wholesale cost of power by as much as 67%. On Dec. 12, 1998, ***The Wilson Daily Times*** made the following statement about O'Donnell.

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

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

Mr. O'Donnell has appeared as an expert witness in over 120 regulatory proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia Corporation Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Service Commission, the Wisconsin Public Service Commission, the Maryland Public Service Commission, the District of Columbia Public Service Commission, the Pennsylvania Public Utility Commission, the Indiana Public Utility Commission, the California Public Service Commission, and the Florida Public Service Commission. His area of expertise has included rate design, cost of service, rate of return, capital structure, asset valuation analyses, fuel adjustments, merger transactions, holding company applications, as well as numerous other accounting, financial, and utility rate-related issues.

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

MR. SCHAUER: Chair Mitchell, we also move that his Exhibits KWO-1 to KWO-7 be filed -- I'm sorry, be identified as marked.

CHAIR MITCHELL: All right. The exhibits to Mr. O'Donnell's testimony shall be marked for identification as they were when they were prefiled.

(Exhibits KWO-1 through KWO-7 were identified as they were marked when prefiled.)

MR. SCHAUER: And, Chair Mitchell, Mr. O'Donnell filed a summary with the Commission in advance of the hearing. He's prepared to read the summary, but we're also content to dispense with the summary, with lead of the Commission, and just make him available for questions.

CHAIR MITCHELL: All right. We will dispense with Mr. O'Donnell's summary and take questions for the witness. My notes indicate that there is no cross examine -- there is no cross examination for the witness. I will pause to make sure that's the case.

(No response.)

CHAIR MITCHELL: I'm not seeing any

indication that there is cross for the witness. All right.

Questions from Commissioners for this witness?

(No response.)

CHAIR MITCHELL: All right. I'm not seeing any questions from the Commissioners.

All right. Mr. O'Donnell, you are off the hook for today. Thank you, sir, for your participation in this proceeding.

THE WITNESS: Thank you all.

CHAIR MITCHELL: You may step down.

MR. SCHAUER: Chair Mitchell, if I could move his Exhibits KWO-1 to KWO-7, that they be received into evidence.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the exhibits to Mr. O'Donnell's testimony will be accepted into the record as received.

MR. SCHAUER: Thank you.

(Exhibits KWO-1 through KWO-7 were admitted into evidence.)

THE WITNESS: All right. Next up we have CIGFUR.

MS. CRESS: Thank you, Chair Mitchell. CIGFUR IV calls Nicholas Phillips, Jr. to the screen.

CHAIR MITCHELL: All right. Good afternoon, Ms. Cress. There you are, Mr. Phillips.

THE WITNESS: Good afternoon.

CHAIR MITCHELL: Would you raise your right hand, please, sir.

Whereupon,

NICHOLAS PHILLIPS, JR,

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

CHAIR MITCHELL: All right. You may proceed, Ms. Cress.

MS. CRESS: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MS. CRESS:

Q. Good afternoon, Mr. Phillips.

A. Good afternoon.

Q. Would you please state your full name for the record.

A. Nicholas Phillips, Jr.

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

A. I'm employed by Brubaker & Associates as a principal and consultant, and located in the greater Saint Louis, Missouri, area.

Q. And what is your business address within the greater Saint Louis, Missouri, area?

A. I was afraid you were gonna ask me that.

(Pause.)

THE WITNESS: It's 16690 Swingley Ridge Road, Suite 140.

Q. Thank you. And on whose behalf are you testifying in this proceeding?

A. I'm testifying on behalf of CIGFUR IV.

Q. Did you, on August 11, 2021, cause to be filed in this proceeding prefiled direct testimony consisting of 28 pages, including one appendix and six exhibits attached to your direct testimony, specifically Exhibits NP-1 through 6?

A. That is correct, I did cause to have that filed.

Q. And did you, on August 16, 2021, cause to be filed in this proceeding an errata to your direct testimony consisting of 24 pages including one appendix?

A. Yes. That errata, I believe, just corrected one number that was updated by Piedmont.

Q. Other than that correction noted in the errata testimony that you filed or caused to be filed on August 16th, do you have any other changes to your prefiled direct testimony as previously filed in this docket?

A. I do not.

Q. So if I were to ask you here today the same questions that you answered in your prefiled direct testimony, would your answers be the same as those reflected in that testimony?

A. Yes.

MS. CRESS: At this time, Chair Mitchell, CIGFUR IV would move that witness Phillips' prefiled direct testimony be admitted and copied into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the testimony of CIGFUR IV witness Phillips filed in the docket on August 11, 2021, shall be copied into the record as if given orally from the stand.

MS. CRESS: And just to clarify, Chair Mitchell, there was also an errata testimony filed on August 16th.

CHAIR MITCHELL: As well -- and the motion to move -- your motion to have his errata testimony filed or copied into the record as if delivered orally from the stand is allowed as well.

(Whereupon, the prefiled direct testimony and prefiled errata of Nicholas Phillips, Jr. was copied into the record as if given orally from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

In the Matter of **Application of Piedmont Natural Gas Company, Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina**	))))))))	**Docket No. G-9, Sub 781**

Direct Testimony and Exhibits of

Nicholas Phillips, Jr.

On behalf of

CIGFUR IV

August 4, 2021

BRUBAKER & ASSOCIATES, INC.

Project 11147

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

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**	**Docket No. G-9, Sub 781**

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 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 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. I also presented testimony in the most recent Piedmont general rate case, Docket No. G-9, Sub 743.

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 also comment on Piedmont's Integrity Management Rider ("IMR") and the proposed charges associated with the IMR to Piedmont customers. 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.

<u>Summary of Conclusions and Recommendations</u>

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, which would more accurately reflect cost causation.

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 20.79% and the rate of return under Piedmont's proposed rates would increase to 23.40%. In contrast, Piedmont's request is to earn an allowed overall rate of return of 7.27%.

4. Piedmont's proposed method of distributing the requested increase to non-contract classes makes some movement toward cost of service, but increases the subsidy provided by non-contract customers to special contract customers.

5. The Interruptible service class is paying rates far 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 22% 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 directly included in the Infrastructure Management Recovery Rider ("IMR") mechanism, but provide a credit to the IMR. There is no showing regarding the adequacy of the credit. The IMR should be borne by all customers.

8. Piedmont's request to earn a 10.4% ROE is excessive compared to the national average of authorized returns, which is approximately 9.56%. Since Piedmont has rider mechanisms in place, the national average ROE of 9.56% should be considered as an upper limit on the ROE approved in this proceeding.

9. Piedmont proposes significant increases to higher usage blocks of Rate Schedules 113 and 114, which is inappropriate. Rate Schedule 114 should be reduced, not increased. A declining block rate should be designed to collect fixed costs in the initial usage blocks and, 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 $109 million requested by Piedmont, I recommend that the higher usage blocks be lowered below current levels to reflect only variable costs.

10. 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 each class). Again, from the industrial customer’s perspective, this situation reduces the attractiveness of expansion, as well as of continued operations, because of the lessened ability to plan or predict future levels of costs or effectively respond to price signals.

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 of gas. 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 each customer class.

With respect to allocation, fixed costs should be allocated on a peak demand factor, variable costs should be allocated on a throughput factor, and customer-related costs 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 Cynthia A. Menhorn submitted 2020 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 for test year study.

Q DO YOU AGREE WITH THE ALLOCATION METHODS UTILIZED BY PIEDMONT IN ITS TEST YEAR 2020 GAS COST OF SERVICE STUDY?

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

Piedmont states that its system is designed to meet all firm customer demands under design day conditions. The allocation of costs should follow system design to reflect cost-causation. Average demand (throughput) is not relevant and the 50% weighting is unsupported by study or fact.

Q IS THE ALLOCATION OF FIXED DELIVERY COSTS BASED ON DESIGN DAY DEMAND DISCUSSED IN THE NATIONAL ASSOCIATION OF REGULATORY COMMISSIONERS ("NARUC") GAS DISTRIBUTION RATE DESIGN 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 Gas Distribution Rate Design Manual 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 equality principle.
>
> ********
>
> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate 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 Rule 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 the FERC and which comport with NARUC guidance.

Q TO YOUR KNOWLEDGE, HAVE ELECTRIC UTILITIES USED THE PEAK AND AVERAGE METHOD TO ALLOCATE TRANSMISSION OR DISTRIBUTION COSTS IN NORTH CAROLINA?

A No. To my knowledge, the peak and average method has not been used to allocate transmission or distribution costs in North Carolina. I am not aware that it has ever been proposed. The peak and average method should not be used to allocate the delivery costs for gas.

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. The results of the peak demand study are shown on Exhibit NP-2.

The peak demand study is a more correct representation of the actual cost of service associated with serving the various customer classes. 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 or rate shock to subsidized classes. The peak demand shows that certain subsidies are larger and make any corrective distribution of the requested increase even more difficult to manage in this case.

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 6-17)

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)

Duke witness Pirro presented similar testimony in the most recent Duke Energy Progress, LLC and Duke Energy Carolinas, LLC general rate cases as well. (Docket No. E-7, Sub 1214, Pirro Direct, p. 20, lines 9-18)

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. Exhibit NP-2 shows similar information based on the peak demand method.

Q WHAT DO YOU CONCLUDE?

A Piedmont's rates are not adequately based on cost of service, and Piedmont's proposed distribution of the increase only to non-contract customers results in an increase in the subsidy provided by non-contract customers to special contract customers as shown on Exhibits NP-1 and NP-2.

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. The contract classes represent approximately 22% of Piedmont's rate base (investment), and the return associated for this rate base investment requested by Piedmont in this proceeding would be borne by all other non-contract 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 22% of its investment attributable to the special contract class of customers, the Commission should not allow Piedmont to increase the rates of other non-contract 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. Certainly, affiliate transactions require additional scrutiny by the Commission.

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 chooses 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, 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 20.79% under current rates and that excessive return would increase to 23.40% under rates proposed by Piedmont based on the peak and average method. This is in contrast to Piedmont's request to earn a return of 7.27% 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 20.79%. Using the more cost-based peak demand method, the return for the interruptible service class is even higher.

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 11.9% and proposes no increase in rates to Special Contract classes. Piedmont's proposal is not adequately cost based, fair or reasonable and should be modified.

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. Another alternative is to exclude the special contract classes and their associated revenue requirement from this proceeding, preventing harm to other classes

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

A Yes. Piedmont's 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 to the special contract class with no increase to Interruptible service is shown on Exhibit NP-5. Of particular concern is that the combined Special Contract classes require a $22.7 million, or approximately 17.9%, 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 HOW DOES PIEDMONT ALLOCATE THE IMR TO CLASSES?

A Piedmont allocates the IMR to classes on the basis of margin, and includes a Special Contract Credit representing the amount provided by Special Contract customers towards the IMR. As previously stated, Special Contract customers represent 22% of Piedmont's rate base investment and Piedmont has not demonstrated that the credits cover the appropriate level of IMR costs for those customers. Customers paying margins in excess of cost are overcharged by this approach, in addition to paying for any shortfall associated with the Special Contract classes.

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

A Yes. Piedmont's proposed rate design is shown on Exhibit NP-6. Piedmont is proposing significant increases to the higher usage blocks of Rate Schedules 113 and 114, which is inappropriate and would result in harsh impacts or rate shock to higher usage customers. Rate Schedule 114 requires a reduction, not a harsh increase. A declining block rate structure should be designed to collect fixed costs in the initial usage blocks and, once fixed costs are recovered, the higher usage blocks should only be recovering variable costs. To the extent the Commission approves a lower increase than the $109 million requested, I recommend that the higher usage blocks be lowered to reflect only variable costs. The significant overpayments by Interruptible Transportation customers will continue unless addressed in the distribution of the increase to classes and the rate design, as previously discussed.

<u>Return on Equity</u>

Q IS PIEDMONT'S PROPOSED 10.40% ROE REQUEST APPROPRIATE?

A No. Piedmont's requested ROE of 10.40% is excessive and should be rejected. The Company's current authorized ROE is 9.70%, which was authorized by approving a stipulation in the Commission's Final Order in Docket No. G-9, Sub 743, issued on October 31, 2019.

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 around the country. The most recent report has been updated through March 31, 2021 and shows that the national average authorized ROE for gas utilities for the 12 months ending March 31, 2021 was 9.56%. This is 14 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 9.56%.

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 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.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722

In the Matter of:
Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC

DOCKET NO. G-9, SUB 781

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

CIGFUR IV'S ERRATA TO DIRECT TESTIMONY OF NICHOLAS PHILLIPS, JR.

NOW COMES the Carolina Industrial Group for Fair Utility Rates IV (CIGFUR IV), and respectfully submits the following errata to the Direct Testimony of Nicholas Phillips, Jr.:

1. Page 4, Line 15 should be corrected to read "Piedmont's request to earn a 10.25% ROE is excessive compared to the national"

2. Page 17, Line 15 should be corrected to read "**Q IS PIEDMONT'S PROPOSED 10.25% ROE REQUEST APPROPRIATE?**"

3. Page 17, line 16 should be corrected to read "A No. Piedmont's requested ROE of 10.25% is excessive and should be rejected. The"

Certificate of Service

I hereby certify that a copy of the Errata to Direct Testimony and Exhibits of Nicholas Phillips, Jr., filed on behalf of CIGFUR IV has been served on all parties to these proceedings.

This the 16th of August, 2021.

/s/ Christina Cress
Bailey & Dixon, LLP
P.O. Box 1351
Raleigh, NC 27602
Phone: (919) 828-0731
Email: ccress@bdixon.com
ATTORNEY FOR CIGFUR IV

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

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	)	**Docket No. G-9, Sub 781**

Errata to the Direct Testimony and Exhibits of

Nicholas Phillips, Jr.

On behalf of

CIGFUR IV

August 16, 2021

BRUBAKER & ASSOCIATES, INC.

Project 11147

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

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**	**Docket No. G-9, Sub 781**

Errata to the 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 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 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. I also presented testimony in the most recent Piedmont general rate case, Docket No. G-9, Sub 743.

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 also comment on Piedmont's Integrity Management Rider ("IMR") and the proposed charges associated with the IMR to Piedmont customers. 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, which would more accurately reflect cost causation.

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 20.79% and the rate of return under Piedmont's proposed rates would increase to 23.40%. In contrast, Piedmont's request is to earn an allowed overall rate of return of 7.27%.

4. Piedmont's proposed method of distributing the requested increase to non-contract classes makes some movement toward cost of service, but increases the subsidy provided by non-contract customers to special contract customers.

5. The Interruptible service class is paying rates far 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 22% 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 directly included in the Infrastructure Management Recovery Rider ("IMR") mechanism, but provide a credit to the IMR. There is no showing regarding the adequacy of the credit. The IMR should be borne by all customers.

8. Piedmont's request to earn a 10.25% ROE is excessive compared to the national average of authorized returns, which is approximately 9.56%. Since Piedmont has rider mechanisms in place, the national average ROE of 9.56% should be considered as an upper limit on the ROE approved in this proceeding.

9. Piedmont proposes significant increases to higher usage blocks of Rate Schedules 113 and 114, which is inappropriate. Rate Schedule 114 should be reduced, not increased. A declining block rate should be designed to collect fixed costs in the initial usage blocks and, 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 $109 million requested by Piedmont, I recommend that the higher usage blocks be lowered below current levels to reflect only variable costs.

10. 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 each class). Again, from the industrial customer's perspective, this situation reduces the attractiveness of expansion, as well as of continued operations, because of the lessened ability to plan or predict future levels of costs or effectively respond to price signals.

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 of gas. 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 each customer class.

With respect to allocation, fixed costs should be allocated on a peak demand factor, variable costs should be allocated on a throughput factor, and customer-related costs 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 Cynthia A. Menhorn submitted 2020 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 for test year study.

Q DO YOU AGREE WITH THE ALLOCATION METHODS UTILIZED BY PIEDMONT IN ITS TEST YEAR 2020 GAS COST OF SERVICE STUDY?

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

Piedmont states that its system is designed to meet all firm customer demands under design day conditions. The allocation of costs should follow system design to reflect cost-causation. Average demand (throughput) is not relevant and the 50% weighting is unsupported by study or fact.

Q IS THE ALLOCATION OF FIXED DELIVERY COSTS BASED ON DESIGN DAY DEMAND DISCUSSED IN THE NATIONAL ASSOCIATION OF REGULATORY COMMISSIONERS ("NARUC") GAS DISTRIBUTION RATE DESIGN 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 equality principle.
>
> ********
>
> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate 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 Rule 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 the FERC and which comport with NARUC guidance.

Q TO YOUR KNOWLEDGE, HAVE ELECTRIC UTILITIES USED THE PEAK AND AVERAGE METHOD TO ALLOCATE TRANSMISSION OR DISTRIBUTION COSTS IN NORTH CAROLINA?

A No. To my knowledge, the peak and average method has not been used to allocate transmission or distribution costs in North Carolina. I am not aware that it has ever been proposed. The peak and average method should not be used to allocate the delivery costs for gas.

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. The results of the peak demand study are shown on Exhibit NP-2.

The peak demand study is a more correct representation of the actual cost of service associated with serving the various customer classes. 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 or rate shock to subsidized classes. The peak demand shows that certain subsidies are larger and make any corrective distribution of the requested increase even more difficult to manage in this case.

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 6-17)

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)

Duke witness Pirro presented similar testimony in the most recent Duke Energy Progress, LLC and Duke Energy Carolinas, LLC general rate cases as well. (Docket No. E-7, Sub 1214, Pirro Direct, p. 20, lines 9-18)

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. Exhibit NP-2 shows similar information based on the peak demand method.

Q WHAT DO YOU CONCLUDE?

A Piedmont's rates are not adequately based on cost of service, and Piedmont's proposed distribution of the increase only to non-contract customers results in an increase in the subsidy provided by non-contract customers to special contract customers as shown on Exhibits NP-1 and NP-2.

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. The contract classes represent approximately 22% of Piedmont's rate base (investment), and the return associated for this rate base investment requested by Piedmont in this proceeding would be borne by all other non-contract 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 22% of its investment attributable to the special contract class of customers, the Commission should not allow Piedmont to increase the rates of other non-contract 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. Certainly, affiliate transactions require additional scrutiny by the Commission.

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 chooses 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, 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 20.79% under current rates and that excessive return would increase to 23.40% under rates proposed by Piedmont based on the peak and average method. This is in contrast to Piedmont's request to earn a return of 7.27% 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 20.79%. Using the more cost-based peak demand method, the return for the interruptible service class is even higher.

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 11.9% and proposes no increase in rates to Special Contract classes. Piedmont's proposal is not adequately cost based, fair or reasonable and should be modified.

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. Another alternative is to exclude the special contract classes and their associated revenue requirement from this proceeding, preventing harm to other classes

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

A Yes. Piedmont's 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 to the special contract class with no increase to Interruptible service is shown on Exhibit NP-5. Of particular concern is that the combined Special Contract classes require a $22.7 million, or approximately 17.9%, 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 HOW DOES PIEDMONT ALLOCATE THE IMR TO CLASSES?

A Piedmont allocates the IMR to classes on the basis of margin, and includes a Special Contract Credit representing the amount provided by Special Contract customers towards the IMR. As previously stated, Special Contract customers represent 22% of Piedmont's rate base investment and Piedmont has not demonstrated that the credits cover the appropriate level of IMR costs for those customers. Customers paying margins in excess of cost are overcharged by this approach, in addition to paying for any shortfall associated with the Special Contract classes.

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

A Yes. Piedmont's proposed rate design is shown on Exhibit NP-6. Piedmont is proposing significant increases to the higher usage blocks of Rate Schedules 113 and 114, which is inappropriate and would result in harsh impacts or rate shock to higher usage customers. Rate Schedule 114 requires a reduction, not a harsh increase. A declining block rate structure should be designed to collect fixed costs in the initial usage blocks and, once fixed costs are recovered, the higher usage blocks should only be recovering variable costs. To the extent the Commission approves a lower increase than the $109 million requested, I recommend that the higher usage blocks be lowered to reflect only variable costs. The significant overpayments by Interruptible Transportation customers will continue unless addressed in the distribution of the increase to classes and the rate design, as previously discussed.

Return on Equity

Q IS PIEDMONT'S PROPOSED 10.25% ROE REQUEST APPROPRIATE?

A No. Piedmont's requested ROE of 10.25% is excessive and should be rejected. The Company's current authorized ROE is 9.70%, which was authorized by approving a stipulation in the Commission's Final Order in Docket No. G-9, Sub 743, issued on October 31, 2019.

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 around the country. The most recent report has been updated through March 31, 2021 and shows that the national average authorized ROE for gas utilities for the 12 months ending March 31, 2021 was 9.56%. This is 14 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 9.56%.

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 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.

MS. CRESS: Thank you, Chair Mitchell. CIGFUR IV would also move for witness Phillips' exhibits attached to his prefiled direct testimony on August 11, 2021, to be identified as marked in his testimony, specifically NP-1 through NP-6.

CHAIR MITCHELL: All right. The exhibits to CIGFUR IV witness Phillips' testimony shall be marked for identification as they were when prefiled.

(Exhibits NP-1 through NP-6 were identified as they were marked when prefiled.)

MS. CRESS: Thank you, Chair Mitchell.

Q. Mr. Phillips, did you, on September 1, 2021, cause to be submitted to ncucexhibits@ncuc.net and shared with the other parties to this proceeding, a summary of your prefiled direct testimony?

A. Yes, I did.

Q. Would you please provide that summary to the Commission at this time.

A. I will.

It just starts out with my name is Nicholas Phillips, Jr., and I'm employed by Brubaker & Associates. We've been in more than 1,000 proceedings -- well more in 40 states and various provinces in Canada. We have experience with more than 350 utilities, which include electric utilities, gas pipelines, and local distribution companies. I've testified before the North Carolina Commission on numerous occasions on a variety of issues. And I filed testimony, and the case was settled, in the previous Piedmont proceeding, which was Sub 743.

I'm testifying on behalf of a group of intervenors designated as CIGFUR IV, a group of mostly industrial customers that purchase gas delivery and associated services from Piedmont. CIGFUR IV's members purchase substantial amounts of gas delivery and associated service and are major employers to the local economies where they exist. CIGFUR IV members are generally known as providing high-wage jobs in the Piedmont service area, and the economic effect of these jobs is, of course, multiplied by other businesses and jobs indirectly created because of the existence of CIGFUR IV' manufacturing operations.

Piedmont's gas rates should be based on cost of providing service to each customer class. Currently they are not. Piedmont's gas cost of service study is a form of peak and average method that allocates excessive cost to high-load-factor customers on a throughput weighted allocation as compared to a peak demand or design date peak study, which would more accurately reflect cost causation.

In addition, Piedmont's own cost of service study, that's the peak and average study, shows extreme variances in class rates of return. Interruptible service rates currently provide a rate of return of 20.79 percent under current rates, and that rate of return for that class would increase to 23.4 percent under the rates proposed by Piedmont.

In contrast, Piedmont's total requested rate of return at the ROE they are requesting is 7.27. So the rate of return provided by the interruptible class is just about triple what Piedmont is asking for. Their rates are far in excess of the cost of service, and their rates should actually be reduced in this proceeding. Certainly no rate increase to that class is warranted.

Piedmont's proposed method of distributing the requested increase to noncontract classes makes some movement toward cost of service, but actually increases the subsidy provided by noncontract customers to special contract customers. Approximately

22 percent of Piedmont's rate base is dedicated to serving its special contract classes, which do not receive any increase under Piedmont's requested rate increase and cost allocation 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 study, produces a negative rate of return, and of course it's getting no increase, so the rate of return would remain negative.

A revenue loss due to these contracts should not be borne by Piedmont's other customers. The special contract customers are also not directly included in the infrastructure management recovery rider, IMR, mechanism, but provide a credit to the IMR. However, there is no showing regarding the adequacy of this credit. Costs associated with the IMR should be borne by all customers.

Piedmont's request to earn 10.25 percent ROE is excessive compared to the national average of authorized returns, which is 9.56 percent. Since Piedmont has rider mechanisms in place, the national average should be considered as an upper limit to any

ROE approved in this proceeding.

Piedmont proposes significant increases to higher usage blocks in rate schedules 113 and 114, which is inappropriate. Rate schedule 114 should actually be reduced, not increased. A declining block rate should be designed to collect fixed cost in the initial usage blocks, and once fixed costs are recovered, the higher usage blocks need only recover variable costs. To the extent the Commission approves a lower increase than that requested by Piedmont, I recommend the higher usage blocks be lowered below current levels to reflect only variable costs.

Piedmont's parent company, Duke Energy, 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, or excess rate levels, should be reduced by 25 percent in allocating the increase to rate classes. Piedmont's existing rates deviate significantly from cost of service, and many rates are hundreds of points outside of 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 in this and future proceedings.

This concludes my summary.

Q. Thank you, Mr. Phillips. And subsequent to the submission of your witness summary, CIGFUR IV entered into a stipulation with the Company, the Public Staff, and CUCA; is that correct?

A. That is correct.

Q. And that was filed on September 7th?

A. That's my understanding.

Q. Great. And I think you may have misspoken.

You were referring to high-load-factor customers; is that right?

A. Yes.

Q. Great. Thanks.

MS. CRESS: Chair Mitchell, CIGFUR IV -- I'm sorry. The witness is now available for questioning by the Commission. Thank you.

CHAIR MITCHELL: All right. Let me check in with parties to make sure there's no cross examination for the witness.

(No response.)

CHAIR MITCHELL: All right. Seeing none, questions from Commissioners. Any Commissioner have questions for Mr. Phillips?

(No response.)

CHAIR MITCHELL: Okay. I'm not seeing any questions from Commissioners. So, Mr. Phillips, you are off the hook for the remainder of today. Thank you very much, sir, for your participation in this proceeding.

THE WITNESS: Thank you very much.

CHAIR MITCHELL: You may step down.

And, Ms. Cress, I will entertain a motion from you.

MS. CRESS: Yes. Thank you, Chair Mitchell. CIGFUR IV would move that witness Phillips' direct exhibits marked as NP-1 through NP-6 be admitted and entered into the record.

CHAIR MITCHELL: All right. Hearing no objection to the motion, the exhibits to CIGFUR IV witness Phillips' testimony will be admitted into the record of the evidence.

(Exhibits NP-1 through NP-6 were admitted into evidence.)

MS. CRESS: And to the extent that the hearing goes beyond today, may witness Phillips be excused, Chair Mitchell?

CHAIR MITCHELL: Yes. Mr. Phillips, you

are excused.

MS. CRESS: Thank you.

THE WITNESS: Thank you. I appreciate that.

CHAIR MITCHELL: All right. Thank you, sir. All right. Next up, I have Public Staff.

MS. EDMONDSON: Good afternoon, Chairman. The Public Staff now calls Bob Hinton to the stand.

CHAIR MITCHELL: All right. Mr. Hinton, let's see, where are you, sir? There you are. Mr. Hinton, would you raise your right hand, please, sir.

Whereupon,

JOHN R. HINTON,

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

CHAIR MITCHELL: All right. Ms. Edmondson, you may proceed.

DIRECT EXAMINATION BY MS. EDMONDSON:

Q. Good afternoon, Mr. Hinton. Would you please state your name and business position for the record.

A. My name is John Robert Hinton. My address is 430 North Salisbury Street, Raleigh, North Carolina, and my position is director of the economic research division.

Q. Mr. Hinton, on August 11, 2021, did you prepare and cause to be filed testimony consisting of 53 pages as well as a 3-page Appendix A, a 4-page Appendix B and 12 exhibits?

A. Yes.

Q. And you filed both a confidential and redacted version of that testimony, correct?

A. Yes.

Q. And your Exhibit 4 also contained confidential information; isn't that correct?

A. Yes, it did.

Q. And you filed an errata to your testimony on August 17, 2021, correcting errors on pages 4 and 49 of your testimony?

A. Yes.

Q. All right. And on September 7, 2021, did you cause to be filed settlement testimony consisting of eight pages and one exhibit?

A. Yes, I did.

Q. Do you have any further changes or corrections to your direct testimony, appendices, exhibits, or settlement testimony and exhibits?

A. I have a couple changes to my direct testimony. On pages 20 and 21, the word "times" is used. On page 20, line 9, the word "times" is used; however, that should read percent mark, percent symbol. Also in that table, on the same page 20, on lines 14 through line 15, there's a table there where the cash flow from operations has the word "times" there. And for each of those numbers, it should be adjacent to it the symbol percentage.

The last change is on page 21, on line 2, the word "times" should be substituted with the symbol of percentage.

Those are my changes.

Q. Mr. Hinton, with those additional changes, are there any -- is that the complete -- does that complete your testimony as if you gave it from the stand today?

A. Yes, it would be.

Q. Okay. Sorry.

MS. EDMONDSON: So, Chairman, with those additional changes, Public Staff requests that Mr. Hinton's direct and settlement testimony be admitted into evidence as if given orally from the witness stand, and his 12 direct exhibits and one settlement exhibit be marked as prefiled.

CHAIR MITCHELL: All right. The direct testimony of Public Staff witness Hinton as filed on August 11th and corrected on August 16th, and further corrected here today from the stand, shall be copied into the record as if given orally from the stand. Additionally, the settlement testimony filed by Mr. Hinton on September 7th shall be copied into the record as if given orally from the stand. The exhibits to Mr. Hinton's testimony shall be identified as they were -- shall be marked for identification as they were when prefiled.

(Hinton Exhibits 1 through 3, Confidential Hinton Exhibit 4, Hinton Exhibits 5 through 12, and Hinton Settlement Exhibit 1 were identified as they were marked when prefiled.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	TESTIMONY OF JOHN R. HINTON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

TESTIMONY OF JOHN R. HINTON

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

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

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

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

A. The purpose of my testimony is to present to the North Carolina Utilities Commission (Commission) the results of my analysis and my recommendations as to the fair rate of return to be used in establishing rates for natural gas distribution utility service provided by Piedmont Natural Gas Company, Inc. (Piedmont or the Company), and to discuss Piedmont's gas extension practices for residential and commercial customers that involve customer contribution in aid of construction (CIAC) costs.

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

A. In the last Piedmont general rate case (Docket No. G-9, Sub 743), the Commission approved an overall cost of capital of 7.414%, which is comprised of a capital structure ratio of 47.15% long-term debt, 0.85% short-term debt, and 52.00% common equity. The overall weighted cost rate includes 4.41% for long-term debt, 2.72% for short-term debt, and 9.70% cost of common equity.

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

A. Piedmont has requested an overall cost of capital or rate of return of 7.27%. This rate of return is based on a capital structure consisting of 47.45% long-term debt, 0.55% short-term debt, and 52.00% common equity as noted in the testimony of Company witness Newlin. The overall weighted cost rate includes 4.08% for long-term debt, 0.35% for short-term debt, and 10.25% cost of common equity.

Q. HOW DOES PIEDMONT WITNESS D'ASCENDIS DEVELOP HIS RECOMMENDED 10.25% COST OF EQUITY?

A. Company witness D'Ascendis utilizes three cost of equity methods: (1) the Discounted Cash Flow (DCF) model; (2) the Risk Premium method; and (3) the Capital Asset Pricing Model (CAPM). He applies these three methodologies to a proxy group of eight publicly traded natural gas distribution companies. Company witness D'Ascendis also utilizes the cost of equity applied to a proxy group of 47 domestic, non-price regulated companies (Non-Price Regulated Companies). His first method relies on the DCF model which produced a 9.46% cost rate of equity with individual company estimates ranging from 7.22% to 12.39% as shown on page 1 of Schedule DWD-2. The witness includes results from a Risk Premium Model and a similar model that encompasses a "Total Market Approach". Both the Risk Premium Model and the Total Market Approach rely on prospective and current interest rates. The average result of these two models, using prospective interest rates, is 10.11%, and the average result using current interest rates is 9.64% as shown on page 1 of Schedule DWD-3. Company witness D'Ascendis includes results from his CAPM analysis, using prospective interest rates, which generated a cost rate of 12.05%, and using current interest rates, which generated a cost rate of 11.83%, as shown on page 1 of Schedule DWD-4. With respect to witness D'Ascendis' DCF, Risk Premium, and CAPM analyses for Non-Price Regulated Companies, he concludes that a 12.18% cost rate using projected interest rates was indicative of the cost of common equity, as shown on page 1 of Schedule DWD-6 . He also opines that the cost of equity should include a 12 basis point adder for flotation costs and ultimately recommends a 10.25% cost rate for common equity based on all of his analyses.

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

A. The Public Staff recommends an overall rate of return of 6.75%. This is based on a capital structure consisting of 48.80% long-term debt, 0.67% short-term debt, and 50.53% common equity. The overall weighted cost rate includes a 4.08% cost of long-term debt, 0.20% for short-term debt, and 9.42% cost of common equity.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?

A. The remainder of my testimony is structured as follows:

I. Legal and Economic Guidelines for Fair Rate of Return

II. Current Financial Market Conditions

III. Appropriate Capital Structure and Cost Debt

IV. Cost of Common Equity Capital

V. Review of D'Ascendis' Testimony

VI. Summary and Recommendations

VII. Revisions to the Gas Extension Feasibility Model

<u>I. LEGAL AND ECONOMIC GUIDELINES FOR FAIR RATE OF RETURN</u>

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

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

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

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

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

> the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

In *Bluefield Waterworks & Improvement Co. v. Public Service Comm'n*, 262 U.S. 679, 692-93, (1923) (*Bluefield*) the United States Supreme Court stated:

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

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

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

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

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

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

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

Q. WHAT IS A FAIR RATE OF RETURN?

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

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

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

II. <u>CURRENT FINANCIAL MARKET CONDITIONS</u>

Q. CAN YOU BRIEFLY DESCRIBE CURRENT FINANCIAL MARKET CONDITIONS?

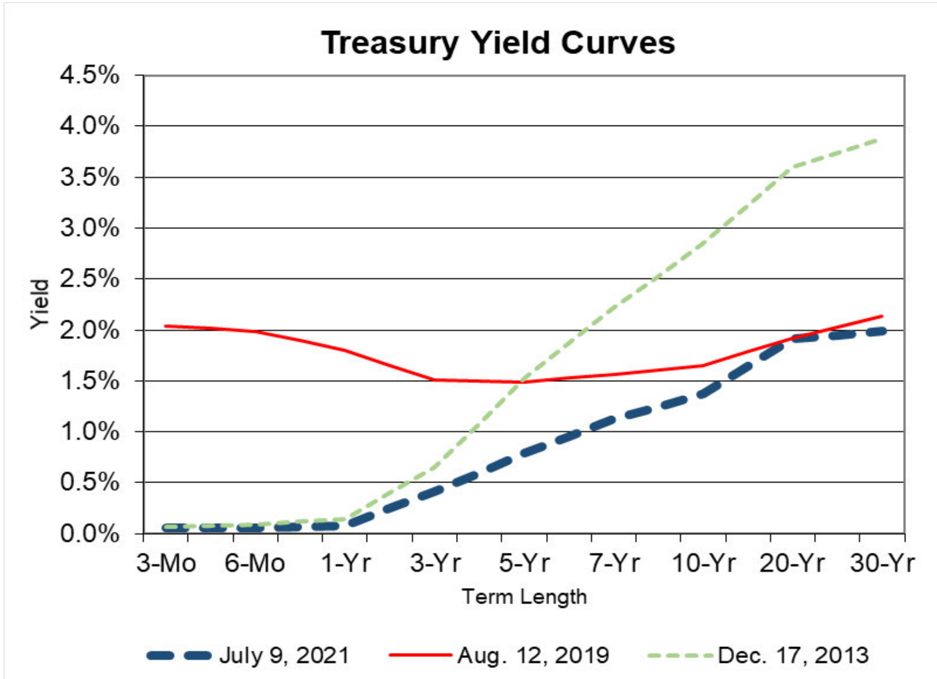
A. Yes. The cost of financing is much lower today than in the more inflationary period of the 1990s and the cost of debt capital has stayed approximately the same since Piedmont's last rate case in 2019. According to Moody's <u>Bond Survey</u>, the yield on long-term "A" rated public utility bonds, as of July 2021, is 2.95% as compared to

3.69% observed for month-ending July 2019 (when the Public Staff was in settlement discussions with Piedmont in Docket No. G-9, Sub 743). The month-ending yields on A-rated utility bonds dipped to 3.29% in August 2019, averaged 3.15% for the first quarter of 2021, and averaged 3.26% for the second quarter of 2021. This suggests that the cost of debt capital is slightly lower than it was at the time of Piedmont's last general rate proceeding.

More recently, observed annual inflation rates have increased; the overall PCE Index (Personal Consumption Expenditure Index) jumped to 4.0% in June 2021 from 1.6 in February 2021. There have been similar increases in the CPI-U (Consumer Price Index – Urban). A key question today is whether these recent increases in inflation are predictors of future inflationary trends or temporary price changes caused by pent-up consumer demand and bottlenecks in the supply chain.[1] At this time, contemporaneous increases have yet to transpire in the utility bond market, as the increases in yields have been moderated as illustrated in Hinton Exhibit I. A-rated utility bond yields have fallen by 49 basis points from their high of 3.44% in March to 2.95% in July. Since the Company's last general rate case in 2019 and, especially since the Company's 2013 rate case, there

[1] Alan S. Binder, "Don't Worry Too Much About the Inflation Surge," Wall Street Journal, July 7, 2021.

have been declines in the long-end and short-end of the yield curve shown below.[2]



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

A. No. While I believe forecasts of earnings and dividends influence investor behavior, I generally do not believe interest rate forecasts to be reliable in determining the cost of equity. Rather, I believe that current interest rates, especially in relation to yields on long-term bonds, are more appropriate for ratemaking. This is because it is reasonable to expect that as investors are pricing bonds they are basing their expected inflation-adjusted return on current interest

[2] Federal Reserve, H15 Selected Interest Rates. https://www.federalreserve.gov/releases/h15/

rates and future inflationary expectations among other factors. To suggest the current bond yields do not reflect expectations of future interest rate levels suggests that investors do not utilize projections of future interest rates in their decision making or that the bond market is not efficient. I do not think either position is true.

While I am confident in the market's ability to reasonably weight forecasts of future interest rates, I am less confident in the use of interest rate forecasts for utility rate cases because I have seen numerous interest rate forecasts that do not materialize as expected. An example of this is the reliance, in part, of cost of capital witness Hevert in Duke Energy Carolinas' 2013 rate case, Docket No. E-7, Sub 1026, relied upon predicted 30-year treasury yields published by Blue Chip Financial Forecasts[3] for his CAPM and Risk Premium analyses. The December 1, 2012 Blue Chip Financial Forecasts predicted that the average 30-year treasury yields would rise to 5.5% by 2018. However, this long-term forecast was over 200 basis points higher than the actual average 30-year treasury yields observed for 2018. In the 2017 rate case of Duke Energy Carolinas, Docket No. E-7, Sub 1146, witness Hevert used projected 30-year treasuries with a yield of 3.40%.[4] However, while the forecast errors associated

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[3] Company response to Public Staff Data Request Number 36-13. The source of the forecast is noted Tr. vol. 2, 85, Docket No. E-7, Sub 1026, pp. 85-86.

4 *See* Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-7, Sub

with these projected 30-year treasury securities were smaller, this predicted yield for 2019 was still over 140 basis points larger than the actual yields observed in 2019.

Another example is the interest rate prediction of Aqua North Carolina, Inc.'s (Aqua) rate of return witness Pauline Ahern in the 2013 Aqua rate case, Docket No. W-218, Sub 363.[5] Ms. Ahearn testified to several forecasts of 30-year Treasury bond yields that were predicted to rise to 4.3% in 2015, 4.7% in 2016, 5.2% in 2017, and 5.5% for 2020-2024.[6] As illustrated in the graph below, these forecasts significantly over-estimated the actual interest rates for 30-year Treasury bonds.

1146, at 39, (N.C.U.C. June 22, 2018), reversed on other grounds, *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (2020).

[5] In 2013, Ms. Ahern was a Principal with AUS Consultants. She is currently Executive Advisor at ScottMadden, Inc., the same firm as Piedmont witness D'Ascendis.

[6] T vol. 2, 13-14, Docket No. W-218, Sub 363.

In addition, the tendency of economists to make poor interest rate predictions in the last ten years was addressed in a December 14, 2019 Wall Street Journal article entitled, "Economists Got the Decade All Wrong. They're Trying to Figure Out Why", and attached as Hinton Exhibit 2. The foregoing examples illustrate why I tend to place more weight in current market interest rates that are inherently forward looking as they reflect investor expectations of both current and future returns on bonds, and to an extent, future rates of inflation.

III. <u>APPROPRIATE CAPITAL STRUCTURE AND COST OF DEBT</u>

Q. WHAT IS CAPITAL STRUCTURE AND HOW IS IT APPROVED FOR RATEMAKING PURPOSES AFFECTS RATES?

A. Typically, a local distribution company (LDC) obtains external capital from investors by borrowing debt and issuing common equity. However, Piedmont obtains its equity capital from its parent company Duke Energy Corporation (Duke Energy). The capital structure is simply a representation of how a utility's assets are financed. It is the relative proportions or ratios of debt and common equity to the total of these forms of capital.

Debt and equity capital have different costs. Common equity is far more expensive than debt for ratemaking purposes for two reasons. First, as mentioned earlier, there are income tax considerations. Interest on debt is deductible for purposes of calculating income taxes. The cost of common equity, on the other hand, must be "grossed up" to allow the utility sufficient revenue to pay income taxes and to earn its cost of common equity on a net or after-tax basis. Therefore, the amount of revenue the utility must collect from ratepayers to meet income tax obligations is directly related to both the common equity ratio in the capital structure and cost of common equity. A second reason for this cost difference is that the cost of common equity must be set at a marginal or current cost rate. Conversely, the cost of long-term debt is set at an embedded rate because the utility is incurring costs that are previously established in contracts with security holders.

Because the Commission has the duty to promote economical utility service, it must decide whether or not a utility's requested capital structure is appropriate for ratemaking purposes. An example of the cost difference between debt and equity can be seen in the Company's filing. Based upon the Company's requested capital cost rates, each dollar of its common equity and each dollar of its long-term debt that supports the retail rate base have the following approximate annual costs (including income tax and regulatory fee expense) to ratepayers: each dollar of common equity costs ratepayers approximately 12 cents; and each dollar of long-term debt costs ratepayers approximately four cents.

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

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

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

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

A. Company witness Newlin proposes the use of a hypothetical capital structure of 47.45% long-term debt, 0.55% short-term debt, and 52.00% common equity as shown on Exhibit KWN-1 of the Company's Application. Witness Newlin's proposal is derived by averaging the actual capital structure as of December 31, 2020, with three projected capital structures as of March 31, 2021, December 31, 2021, and December 31, 2022.

Q. DO YOU SUPPORT THE HYPOTHETICAL CAPITAL STRUCTURE PROPOSED BY COMPANY WITNESS NEWLIN?

A. No. I have concerns with the heavy reliance on projected balances of debt and equity capital, as compared to the traditional use of a historical test year capital structure. Furthermore, I am concerned that the use of a 52.00% common equity ratio and 48.00% debt ratio (combined long-term debt and short-term debt ratios) provides an excessive percentage of equity that is not necessary to maintain the Company's credit ratings, and is not reflective of Piedmont's historical capitalization ratio. As of March 31, 2021, Moody's creditworthiness metric, Cash Flow from Operations (pre-working capital) divided by Piedmont's Debt yielded a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** times, which is in alignment with Moody's expectations. Shown below are Moody's calculations of the Cash Flow metric and the Debt to Book Capitalization metric for Piedmont, both of which include the Company's long-term and short-term debt balances.

[BEGIN CONFIDENTIAL]

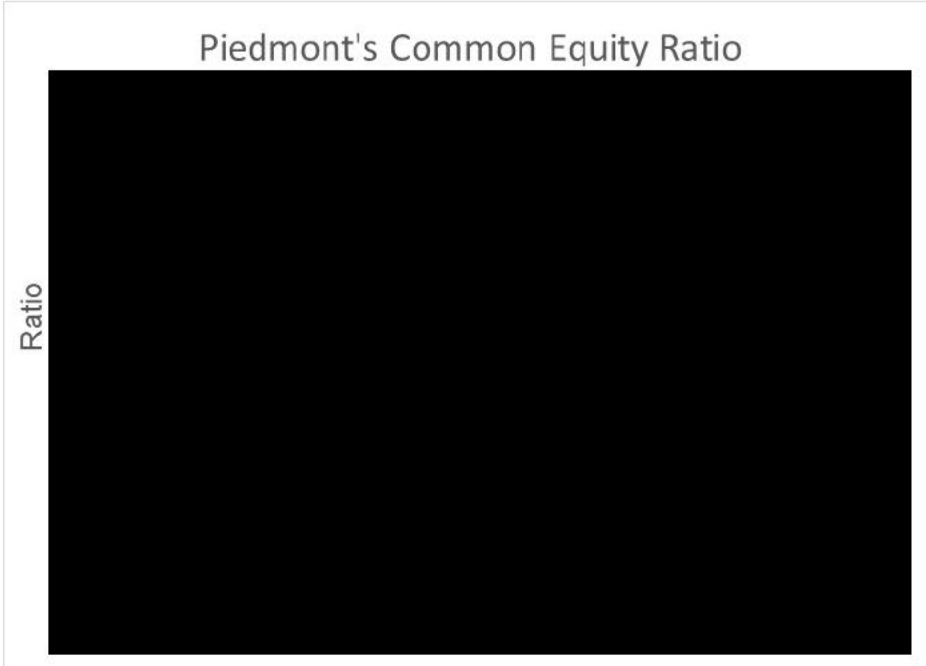
Moody's Financial Scorecard	Cash Flow from Operations / Debt	Debt / Book Capitalization
Mar. 31, 2021	[redacted] times	[redacted]%
Dec. 31, 2020	[redacted] times	[redacted]%
Dec. 31, 2019	[redacted] times	[redacted]%
Dec. 31, 2018	[redacted] times	[redacted]%

[END CONFIDENTIAL]

The fact that Piedmont's average Cash Flow metric is above **[BEGIN CONFIDENTIAL]** [redacted] [redacted] **[END CONFIDENTIAL]** suggests that Piedmont does not require a 52.00% common equity ratio in order to maintain its "A3" credit rating with a "Stable" outlook as indicated by Hinton Exhibit 3, the most current Moody's Investors Service report for Piedmont. Included in Exhibit 3, is a February 9, 2021 credit ratings report by S&P Global Ratings on the Company, which assigns an Issuer Credit Rating of BBB+.

Shown below is a graph of Piedmont's common equity ratio since its merger with Duke Energy in October 2016. The graph illustrates that the Company's average balance of equity has hovered around **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which is very close to the 13-month test year average common equity ratio.

[BEGIN CONFIDENTIAL]



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[END CONFIDENTIAL]

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

A. I recommend a capital structure for ratemaking purposes based on a 13-month historical average of long-term debt, short-term debt, and common equity, as opposed to using projected capital structure as proposed by Company witness Newlin. More specifically, to determine the capital structure, I averaged common equity, long-term debt, and short-term debt balances as of May 31, 2020, through May 31, 2021.

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

A. As shown on Page 1 of Hinton Exhibit 4, I recommend that the following capital structure be employed for ratemaking purposes in this proceeding:

Piedmont Natural Gas Capital Structure
Thirteen-Month Average as of May 31, 2021
($1,000)

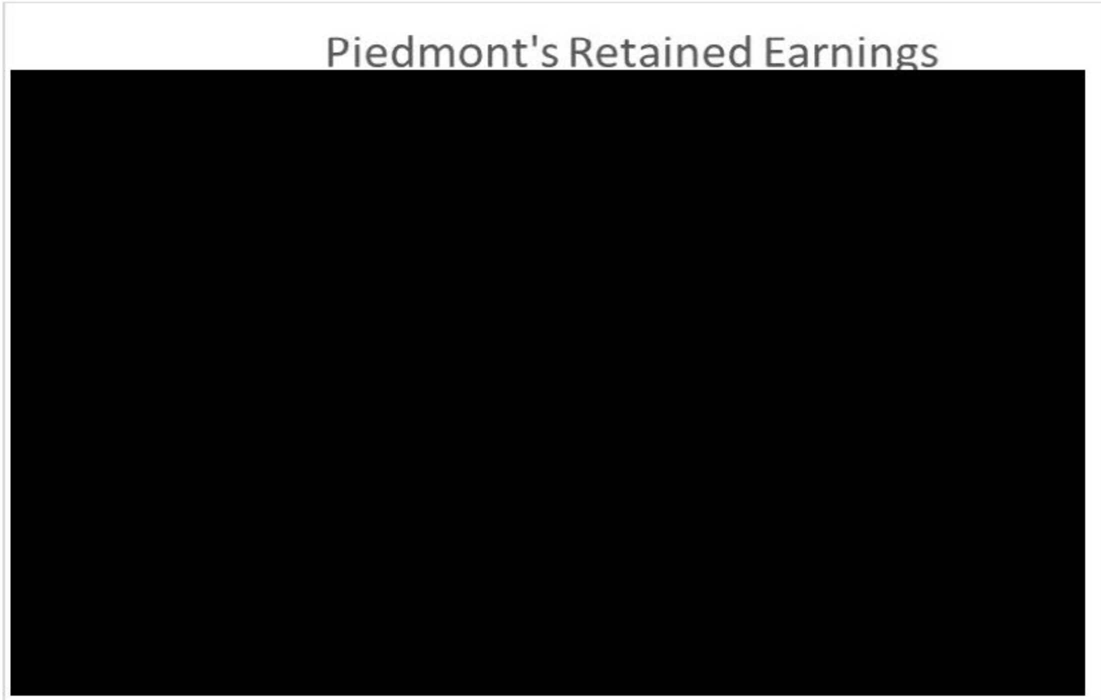
Capital Item	Amount	Ratios
Long-Term Debt	$ 2,707,488	48.81%
Short-Term Debt	37,199	0.65%
Common Equity	2,803,794	50.54%
Total Capital	$ 4,248,617	100.00%

Confidential Page 2 of Exhibit 4 presents the underlying capital account balances, the test year balance of long-term debt which is comprised of the outstanding long-term debt of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** minus the balance for the unamortized debt issuance expense throughout the 13-month period from May 31, 2020, through May 31, 2021. It is noteworthy that the balance of long-term debt includes an additional **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Hinton Exhibit 4 presents the account balances that comprise common equity. The Commission should note the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the

Company's retained earnings: from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for month-ending May 2020, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for May 2021. The Company's compound annual average growth in retained earnings over the past four years (Dec. 2016-Dec. 2020) has been approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as compared to a pre-merger growth rate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** over the four years (Dec. 2011-Dec. 2015) prior to the merger as shown below. It should be noted that the growth in retained earnings is partially explained by the absence of any dividends being paid to Duke Energy.

[BEGIN CONFIDENTIAL]



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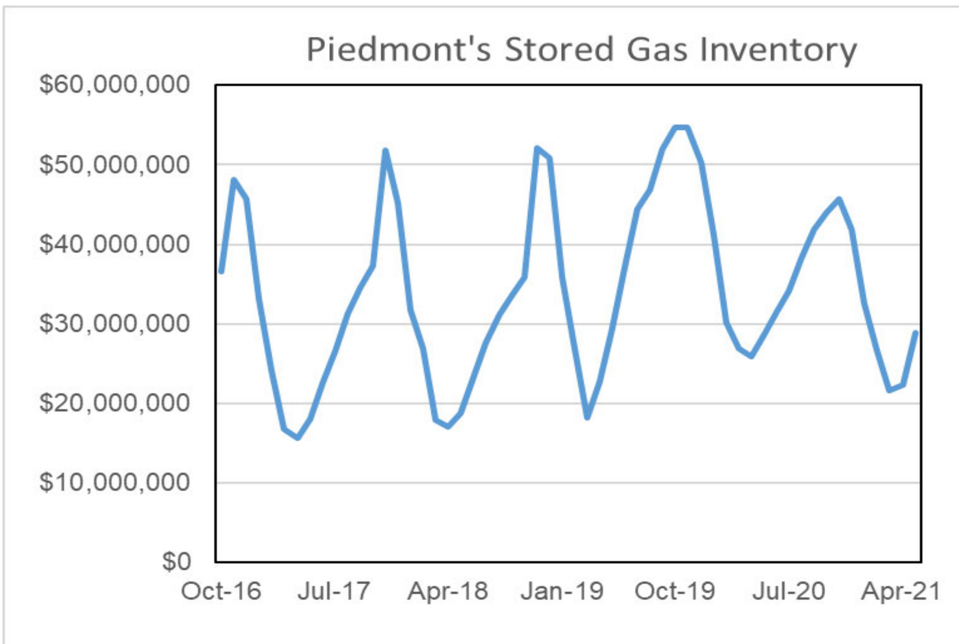
[END CONFIDENTIAL]

Piedmont's other comprehensive income played a relatively small role in the test year balance of common equity. The balance of the Company's paid in capital of includes a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Piedmont's capital structure is similar to that observed in the 2019 rate case, Docket No. G-9, Sub 743, where an issuance of long-term debt included a contemporaneous infusion of common equity.

To determine the appropriate balance of short-term debt, I recommend it be set at the Public Staff's recommended dollar value of stored gas inventory[7] to be included in rate base of \$36,227,098.[8] The graph below shows the seasonality of Piedmont's gas inventory. Since short-term debt finances gas inventory, matching the amount of short-term debt included in the capital structure to the gas inventory in the rate base establishes a reasonable amount of short-term debt for ratemaking purposes. Furthermore, this approach better aligns the actual financing cost of the gas inventory in rate base.



[7] This use of gas inventory as a proxy for short-term debt was upheld by the North Carolina Supreme Court in *State ex rel. Utilities Comm'n v. Carolina Util. Customers Ass'n*, 351 N.C. 223, 524 S.E.2d 10 (2000).

[8] As recommended by Public Staff witness Feasel, Exhibit I, Schedule 2-2.

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

A. I recommend the use of the Company's updated 4.08% cost rate of long-term debt as of May 31, 2021, and a 0.20% cost rate of short-term debt. The short-term cost is based on the 13-month average spread between the prime rate and the Company's cost of short-term debt over the 13 months ending May 31, 2021, producing an average spread of 305 basis points. I then deducted 305 basis points from the current 3.25% prime rate to produce the 0.20% cost rate of short-term debt.

IV. COST OF COMMON EQUITY CAPITAL

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

A. The cost of equity capital for a firm is the expected rate of return on common equity that investors require in order to induce them to purchase shares of the firm's common stock. The return is expected or forward-looking because the investor buys a share of the firm's common stock and does not know with certainty what his returns will be in the future. Furthermore, the cost of capital reflects opportunity costs; in that the investor foregoes the opportunity to invest in other comparable risk investments.

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

A. I used the DCF model and a regression analysis of approved returns for LDCs and diversified gas companies with local distribution utilities to determine the cost of equity. As a check method, I performed a Comparable Earnings Analysis on my group of comparable companies.

A. DCF METHOD

Q. PLEASE DESCRIBE YOUR DCF ANALYSIS.

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

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

g = expected growth rate of dividends;

k = cost of equity capital; and

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

Then,

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

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

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

Solving for k yields the DCF equation:

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

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

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

A. Since Piedmont is a wholly owned subsidiary of Duke Energy, the Company does not have any publicly traded stock. Therefore, there is no explicit market information to show what investors would pay for the stock. For this reason, I could not apply the DCF method directly to Piedmont. However, the cost of equity capital is not unique to any particular firm. Rather, it is a cost shared by firms whose equity shares are considered by investors to be risk-comparable investments. In order to estimate the required rate of return, I have identified a group of comparable companies whose market information indicates the required investor return for Piedmont.

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

A. I began my analysis by reviewing ten companies that are identified by the Value Line Investment Survey Standard Edition (Value Line) as the Natural Gas Company industry group. From this group of companies, I eliminated Nisource, Inc., due to a dividend cut in 2015. I then reviewed the diversified natural gas companies followed by Value Line and found two companies that had were identified as having distribution operations.

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

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

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

I also reviewed the S&P and Moody’s bond ratings, which are assessments of the creditworthiness of a company. Credit rating agencies focus on the creditworthiness of the particular bond issuer, which includes a detailed and thorough review of the potential areas of business risk and financial risk of the company. These and other risk measures I reviewed are shown in Hinton Exhibit 5, and are further explained in Appendix B to my testimony.

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

A. I calculated the dividend yield by using the Value Line estimate of dividends to be declared over the next 12 months, divided by the price of the stock as reported in the Value Line Summary and Index for each week of the 13-week period from April 30, 2021, through July 23, 2021. A 13-week averaging period tends to smooth out short-term variations in the stock prices. This process resulted in an average dividend yield of 3.2% for the comparable group of LDCs.

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

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

Finally, I incorporated the consensus of various analysts' forecasts of five-year EPS growth rate projections as reported in Yahoo Finance. The dividend yields and growth rates for each of the companies and for the average for the comparable group are shown in Hinton Exhibit 6.

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

A. Based on my DCF analysis, I determined that a reasonable expected dividend yield is 3.2% with an expected growth rate of 5.9% to 6.5%. As such, the analysis produces a cost of common equity for the comparable group of LDCs of 9.1% to 9.7%.

B. <u>REGRESSION ANALYSIS METHOD</u>

Q. PLEASE DESCRIBE YOUR REGRESSION ANALYSIS METHOD.

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

A strength of this approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. Thus, it is reasonable to conclude that the approved returns are good estimates for the cost of equity. The next step is to incorporate a contemporaneous cost of debt. I then use an ordinary least-squares regression model[9] that can be performed with spreadsheets that have basic statistical functionality.

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

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

A. The method I used relies on approved returns on common equity for natural gas utility companies from various public utility commissions that are published by the Regulatory Research Associates, Inc. (RRA), with S&P Global Market Intelligence and Moody's "A" rated Utility Bond Yields as shown on Page 1 of Hinton Exhibit 7. The Commission relied on this method in Docket No. G-5, Sub 327, a 1994 general rate case of Public Service Company of North Carolina, Inc.[10] The results from the regression analysis in this study and in other studies indicate that there is a high correlation between the cost of equity and utility bond yields.[11]

Q. WHAT WERE THE RESULTS OF YOUR REGRESSION ANALYSIS?

A. The results of the regression analysis indicate that the predicted cost of equity is 9.50% as shown on Page 2 of Hinton Exhibit 7. As noted, a statistical regression was performed in order to quantify the relationship of allowed equity returns and bond costs. The

[10] The regression analysis method is also used in the formula rate plans for LDCs regulated by the Mississippi Public Service Commission. *See* Mississippi Public Serve Commission, Mississippi Gas Co., Docket No. 18-UN-0139, Atmos Energy Corporation, Docket No. 05-UN-0503.

[11] *See* Brigham, E., Shome, D., and Vinson, S., 1985. "The Risk Premium Approach to Measuring a Utility's Cost of Equity." Financial Management, Spring 14: 33-45.

results of the regression analysis indicate a significant statistical relationship between the approved equity returns and bond costs such that a reduction of 10 basis points in yields corresponds to a decrease of three basis points in return on equity (ROE).[12] Therefore, the regression analysis allows the historical relationship of approved returns on equity and bond yields from 2007 through 2021 to be quantified, and then combined with six months of recent yields to derive a predicted 9.50% cost rate for common equity.

C. COMPARABLE EARNINGS METHOD

Q. PLEASE DESCRIBE YOUR COMPARABLE EARNINGS ANALYSIS THAT YOU USE AS A CHECK.

A. My comparable earnings method analysis involves reviewing earned returns on equity for my comparable group of natural gas utilities. This approach is based on the decision in the *Hope* case cited earlier in my testimony, which maintains that an investor should be able to earn a return comparable to the returns available on alternative investments with similar risks.

[12] The regression equation ROE = 0.079857 + 0.40336, indicates a significant statistical relationship between Moody's utility bond yields and approved ROEs with an adjusted R^2 = 0.90860.

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

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

Q. HOW DID YOU APPLY THE COMPARABLE EARNINGS METHOD?

A. I examined the historical earned returns and near-term predicted returns of my comparable group of LDCs as reported in Value Line, as shown in Hinton Exhibit 8.

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

A. Based on the earned rates of return, I conclude that the cost of equity using the Comparable Earnings analysis provides a reasonable check on my DCF and Regression Analysis results. Under the Comparable Earnings method, I calculated an average historical earned return of 10.0%, and a median earned return of 9.5%. In my opinion, the median calculation is a better measure of central tendency due to the 20.2% earned return by National Fuel Gas and other excessively high earned returns that exceed the Company's cost of common equity. As such, I believe the median earned return of 9.5% is more reflective of investors' expected required returns on equity.

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

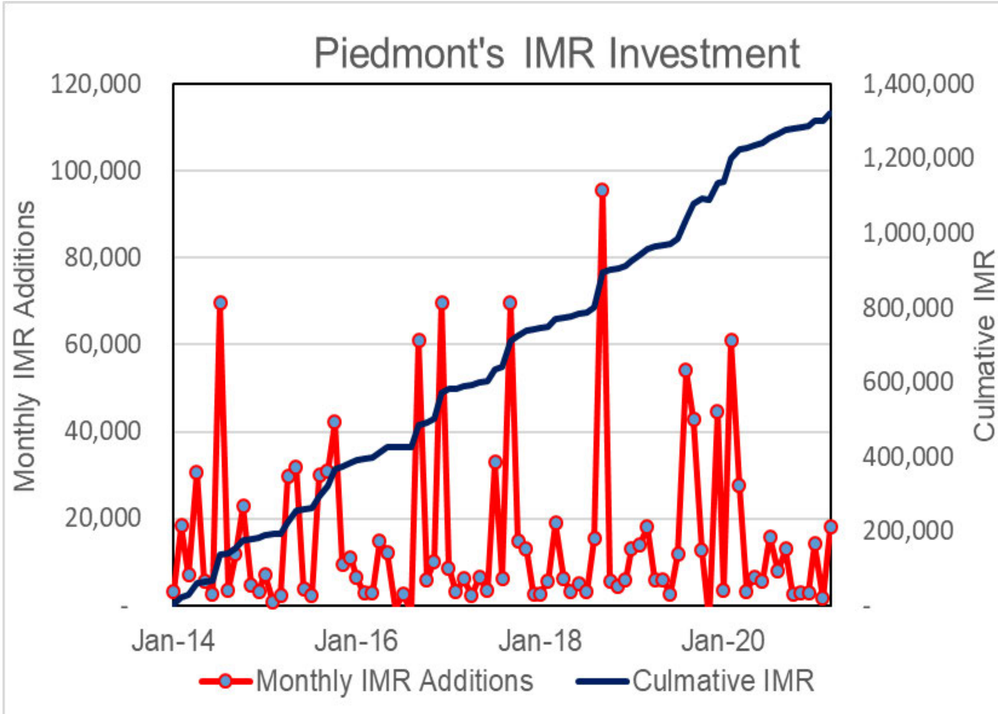
A. I recommend a 9.42% cost rate for common equity, as shown in Hinton Exhibit 9, where I average the four results of my two methods. The results of my DCF model produce a cost of equity of 9.10% using historical growth rates. If I assume that investors equally weigh historical growth and forecasts, the DCF model produces a 9.35% cost rate of equity. If I assume investors use only predicted growth rates of earnings, dividends, and book value, the

DCF model produces a 9.73% cost rate. I combined these results with my Regression Analysis result, a cost of equity of 9.50%, to yield an average cost of equity of 9.42%, which is my recommended cost of common equity for the Company.

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

A. In assessing the reasonableness of my recommendation, I considered the pre-tax interest coverage ratio produced by my cost of capital recommendation. Based on the recommended capital structure, cost of debt, and cost of equity, the pre-tax interest coverage ratio is approximately 4.1. This indicator of credit quality suggests that Piedmont has an adequate opportunity to continue to qualify for a single "A" bond rating.

My reasonableness assessment also includes acknowledging the continued role that the Integrity Management Rider (IMR) has in reducing regulatory lag, which is seen as a supportive regulatory policy by investors. The graph below shows the additional monthly plant additions associated with the Company's IMR mechanism, which as of March 31, 2021, amounted to approximately $1.3 billion of additional capital investment since its inception in January 2014.

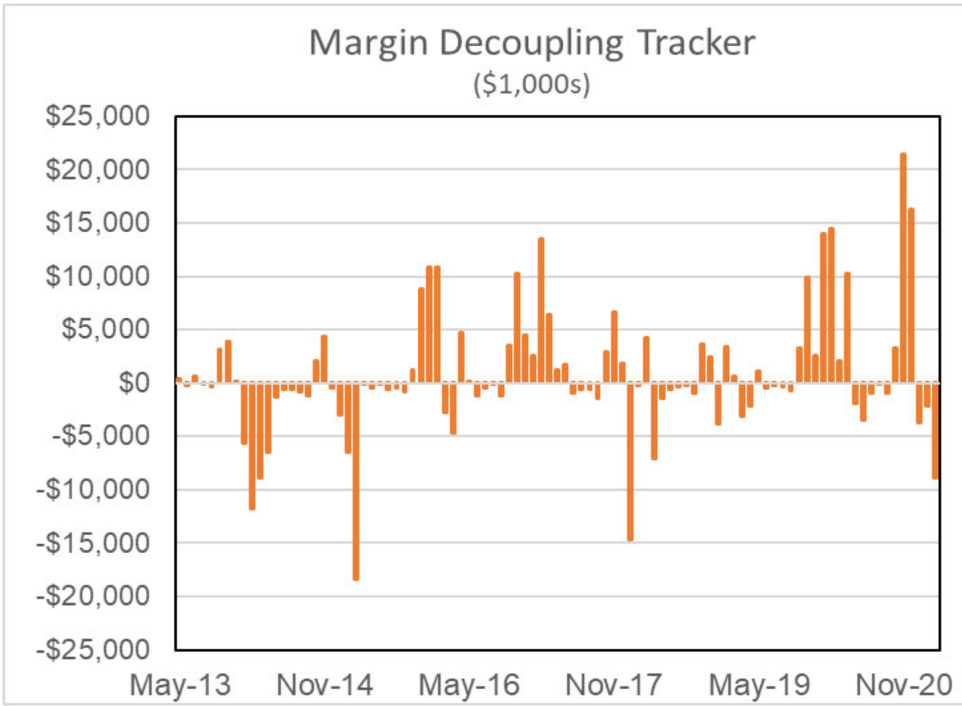


In addition, I also considered the stabilizing impact on residential and small commercial customers' revenue and on the Company's earnings of the Margin Decoupling Tracker (MDT) that was approved by the Commission in 2008 in Docket No. G-9, Sub 550.[13,14] In large part, the tracker was approved in light of declining customer usage and as a way to eliminate the Company's disincentive to promote conservation. The Commission's Order noted that the MDT would stabilize the Company's margin recovery and reduce the risk to Piedmont and its customers arising from

[13] Order Approving Partial Rate Increase and Requiring Conservation Program Filing and Reporting, *In the Matter of Application of Piedmont Natural Gas Company, Inc., for a General Increase in its Rates and Charges*, Docket No. G-9, Sub 550 (N.C.U.C. Oct. 24, 2008) (Sub 550 Order).

[14] The Company had a similar mechanism called the Customer Utilization Tracker (CUT) approved in Docket No. G-9, Sub 499.

potential variations in usage patterns.[15] The graph below shows the historical impact of the revenue adjustments associated with the MDT. The IMR leads to less regulatory lag, which lessens Piedmont's financial risk, while the MDT significantly reduces Piedmont's business risks.



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

A. I am aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an

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[15] *See* Sub 550 Order, Finding of Fact No. 24, at 18-19. The MDT affects rate schedules 101, 102, and 152.

appropriate return on equity in setting rates for a public utility. Rather, the impact of changing economic conditions nationwide is inherent in the methods and data used in my study to determine the cost of equity for utilities that are comparable to Piedmont. I have reviewed certain information on the economic conditions in the areas served by Piedmont, specifically data on the per capita personal income from the Bureau of Economic Analysis (BEA) and the Development Tier Designations published by the North Carolina Department of Commerce for Piedmont's service territory. The BEA data indicates that from 2017 to 2019, per capita total personal income grew at an annual growth rate of 3.3%, which is slightly lower than 3.7% for the whole state. While more current income data by county is not available, the statewide total personal income grew at an 18% annual growth rate as of the first quarter of 2021.[16] In addition, North Carolina's unemployment rate has fallen for the ninth consecutive month to 4.6%[17] in June 2021.

The North Carolina Department of Commerce annually ranks the State's 100 counties based on economic well-being and assigns each a Tier designation. The most distressed counties are rated a "1," and the most prosperous counties are rated a "3." The rankings examine several economic measures such as household income,

[16] Bureau of Economic Analysis, Table 1, Personal Income by State and Region, 2019: Q4-2021:Q1.
[17] Bureau of Labor Statistics, Economy at a Glance, https://www.bls.gov/eag/eag.nc.htm#

poverty rates, unemployment rates, population growth, and per capita property tax base. For 2021, the average Tier ranking for North Carolina counties in Piedmont's service territory was 1.7. However, the Tier ranking is in excess of "2" when the counties are weighted by the Company's regional resource centers; such as with the Charlotte Resource Center that serves over one third of the Company's customers.

As discussed previously, the Commission's duty is to set rates as low as reasonably possible consistent with constitutional constraints. This duty exists regardless of the customers' ability to pay. Moreover, the rate of return on common equity is only one component of the rates established by the Commission. General Statute § 62-133 sets out an intricate formula for the Commission to follow in determining a utility's overall revenue requirement. It is the combination of rate base, expenses, capital structure, and cost rates for debt and equity capital, that determines how much customers pay for utility service and investors receive in return for their investment. The Commission must exercise its best judgment in balancing the interests of both groups. My analysis of the income data and the tier rankings indicates that economic conditions are not unduly burdensome for Piedmont's customers. As shown in the income and unemployment data, overall economic conditions have significantly improved from the height of the pandemic. While this is applicable to most of the State and Piedmont's customers, it is true that the economic wellbeing of certain customers and related businesses will take years to recover from the COVID-19 pandemic. Nonetheless, I maintain that the recommended rate of return on equity will allow the Company to properly maintain its facilities, provide adequate service to its customers, attract capital on terms that are fair and reasonable to its customers and investors, and result in rates that are just and reasonable.

V. REVIEW OF D'ASCENDIS TESTIMONY

Q. HAVE YOU REVIEWED COMPANY WITNESS D'ACENDIS'S TESTIMONY?

A. Yes. My review indicates that his analyses include several inputs with which I take issue, and which I believe lead to his higher than appropriate recommended rate of return. In particular, I disagree with his exclusive use of forecasted EPS in the DCF model, his estimate of the expected market return, and the market premium used in his CAPM.

Q. WHY DO YOU DISAGREE WITH COMPANY WITNESS D'ASCENDIS'S EXCLUSIVE USE OF FORECASTED EPS IN HIS DCF ANALYSIS?

A. Company witness D'Ascendis has focused entirely on five-year EPS forecasted growth rates in estimating the long-term expected growth rate in DPS for purposes of his DCF model. He has not given any weight to historical EPS growth rates nor to historical and forecasted DPS and BPS growth rates. While I have given primary weight to forecasted growth rates of EPS, DPS, and BPS, I have also accorded some weight to actual historical performance in my recommendation. Consideration of DPS and BPS, along with EPS, provides a variety of indicative growth measures, as opposed to Mr. D'Ascendis's reliance on only one measure. Given that at least one study has found that analysts' long-term earnings growth forecasts are no more accurate at forecasting future earnings than random walk forecasts of future earnings,[18] and that other studies have found that analyst's earnings forecasts tend to have an upward bias in their projections, I find the premise that investors limit their investment decisions to forecasted growth rates in EPS to be quite questionable. Company witness D'Ascendis's DCF analysis is flawed because investors do not simply ignore the historical performance of stocks. While forecasts are generally based, in part, on a company's historical performance, it is quite a different argument to state that investors rely solely on forecasts of EPS and ignore past performance of dividends and book value.

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

In prior orders, this Commission has not been persuaded by rate of return witnesses who relied exclusively on forecasted growth rates in their use of the DCF model. In its Order in Docket No. E-22, Sub 532, the Commission said, "as stated in previous Commission general rate case orders, [the Commission] does not approve of witness Hevert's sole use of analysts' predicted earnings per share to determine the DCF growth rate.[19] Similarly, in its Order issued on December 30, 2003, in Docket No. P-100, Sub 133d, the Commission said, "The Commission is persuaded that investors consider a company's historical performance along with its forecasts when assessing its long-run growth potential."[20] In that proceeding, BellSouth's witness Billingsley gave exclusive weight to security analysts' EPS forecasts compiled by Zacks Investment Research and the Institutional Brokers Estimate System, which is comparable to witness D'Ascendis's use of earnings forecasts. This reliance on only forecasted growth is incorporated into his DCF model and his CAPM's use of a market risk premium that relies on results from his DCF model applied to the companies in the S&P 500.

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[19] *In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina,* Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation Deciding Contested Issues, and Granting Partial Rate Increase, (N.C.U.C. February 24, 2020) (*appeal filed on other grounds*) at 40.

[20] *In the Matter of General Proceeding to Determine Permanent Pricing for Unbundled Network Elements,* Order Adopting Permanent Unbundled Network Element Rates for Bellsouth Telecommunications, Inc., Docket No. P-100, Sub 133d (N.C.U.C. Dec. 30, 2003) at 73.

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

A. Company witness D'Ascendis's CAPM model based on his Total Market Approach assumes that investors are currently requiring an expected risk premium of 15.47% that is based on an investor expected return on the return of 17.78%, as shown on page 2 of Schedule DWD-4. The 17.78% market estimate is derived using a DCF model applied to each the 500 companies within the S&P 500 index. The DCF results are derived with expected dividend yields earnings forecasts from Bloomberg Professional. Then Mr. D'Ascendis weights each of the 500 DCF results by the Company's market capitalization to arrive at 17.78% return on the market. His unweighted mean DCF result for the 500 companies is 13.84% and the median DCF result is 11.03%. A concern relates to the disparity between his weighted average result of 17.78% and the lower unweighted DCF results as well as whether investor expectations are so dramatically influenced by a relative small handful of companies. The DCF results of Tesla Inc., Amazon.com Inc., Microsoft Corp., Apple, Inc., and Facebook, Inc. account for over 41% of his weighted average DCF of 17.78%. If the witness had simply taken the average of the mean and median DCF results as performed in other calculations, his estimated return on the market would generate a 12.43% expected return on the market for his CAPM and ECAPM studies, which is far more reasonable than his weighted DCF based estimate of 17.78%.

In my opinion, Company witness D'Ascendis's estimates of the expected returns on the S&P 500 are unrealistic for investors over the long run, which inflates his market premium and his CAPM and ECAPM cost of equity estimates. It is highly unlikely that the growth of the S&P 500 would over the long run exceed the growth of the general economy.[21] As such, I maintain that Mr. D'Ascendis's expected growth rates for the S&P 500 are unsustainable and his CAPM and ECAPM results that rely on a 17.78% expected return on the market are overstated.

Q. WHAT DO WELL KNOWN INVESTMENT ADVISORS BELIEVE THE FUTURE RATES OF RETURNS WILL BE FOR THE S&P 500?

A. As shown in Hinton Exhibit 10, Christine Benz of Morningstar has collected forecasts of long-term rate of returns on stocks and bonds by BlackRock Investment Institute, as well as investment professionals John Bogle with Vanguard and J.P. Morgan. In general, they expect a departure from history with lower future

[21] *Id*. at 649.

market returns on equity of 5% to 8%. In a recent article shown as Hinton Exhibit 11, Veeru Perianan, Director, Multi-Asset Research, Charles Schwab Investment Advisory, Inc., predicts that the annualized returns on large capitalized stocks over the next ten years will be 6.6% as compared to the 10.8% historical return experienced since 1970.

VI. SUMMARY AND RECOMENDATIONS

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

A. Based on the results of my analysis and study, I recommend that the appropriate overall cost of capital in this case be set at 6.75% as shown on Hinton Exhibit 12. This recommendation is derived based on a capital structure consisting of 48.80% long-term debt, 0.67% short-term debt, and 50.53% common equity, with a recommended cost of long-term debt of 4.08%, a recommended cost of short-term debt of 0.20%, and a recommended cost of common equity of 9.42%.

VII: REVISIONS TO THE GAS EXTENSION FEASIBILTY MODEL

Q. PLEASE DISCUSS THE COMPANY'S MODEL USED TO CALCULATE THE FEASIBILITY OF EXTENDING NATURAL GAS SERVICE TO ITS RESIDENTIAL AND COMMERCIAL CUSTOMERS.

A, The Company calculates the economic feasibility of providing new gas service by estimating the costs for the connection beyond the allowed 100 feet of main line and 100 feet of service line, offset by the cash flows generated by the expected gas margins associated with the customer's expected gas usage. The feasibility study follows capital budgeting practice involving the projection of the after tax cash flows over the next 20 years from this customer discounted to arrive at a net present value (NPV) and an internal rate of return (IRR). If the project has a positive present value, then the customer does not have to make a contribution in aid of construction (CIAC); however, where the costs to connect are greater than the NPV, there is a CIAC requirement.

Q. PLEASE ADDRESS YOUR CONCERNS WITH THE COMPANY'S MODEL.

A. I have three concerns based on the lack of adherence to the Commission's NPV Guidelines approved on August 4, 1999, in Docket No. G-100, Sub 75. These Guidelines were applied to projects to extend natural gas service to various unserved counties such as McDowell County in Docket No. G-5, Sub 337, Alexander County in Docket No. G-5, Sub 391, and Onslow County in Docket G-21, Sub 330. Under the Guidelines, the appropriate investment horizon is 40 years. Thus in this case, I recommend the use of 40 years or an appropriate length of time that matches the book lives of the gas plant. Second, the Guidelines directed the use of the approved net of tax discount rate employed for the NPV analysis. Third, the Guidelines required that all future cash flows be adjusted by a forecasted long-term inflation rate. The Company's current feasibility model assumes that the margins remain static over the 20-year investment horizon. As such, I recommend that the gas margins associated with the customer's gas usage be adjusted for expected inflation. At this time, I recommend the use of a 2.0% long-term inflation rate for all gas flows that generally include gas margins and O&M expense.

Q. WHAT IS THE BASIS FOR A 2% LONG-TERM INFLATION RATE?

A. While the rate is slightly below the long-term inflation rates that have been employed in recent nuclear decommissioning filings and recent electric utility integrated resource planning (IRP) proceedings, I believe it is a reasonable rate for this application where future operating and maintenance (O&M) expanses and margins are inflated over the next 40 years. Furthermore, it is my understanding that a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** inflation rate has been applied to O&M expenses for the provision of gas service to Duke Energy Carolina, LLC's combustion turbine in Lincoln County, North Carolina and other gas expansion models reviewed by the Public Staff.[22]

The Public Staff has discussed its proposed changes to the gas extension model with the Company, and it supports these three adjustments. In my opinion, these revisions will lead to a more accurate assessment of the economic value of new customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[22] Docket Nos. G-9, Sub 750 and G-9, Sub 720.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023, Docket No. E-2, Sub 1219, and similar proceedings on the level of funding for nuclear decommissioning costs in Docket Nos. E-7, Sub 1026, and E-7, Sub 1146. I have filed testimony on the Integrated Resource Plans (IRPs) filed in Docket No. E-100, Subs 114 and 125, and I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual IRPs or IRP updates.

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

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

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

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

1000, Sub 5. I have filed testimony on weather normalization of water sales in Docket No. W-274, Sub 160.

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

RISK MEASURES

SAFETY RANK[1]

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

BETA[1] (ß)

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

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

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

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

$$\text{Adjusted } ß_i = 0.35 + 0.67ß$$

FINANCIAL STRENGTH RATING[1]

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

PRICE STABILITY INDEX[1]

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

EARNINGS PREDICTABILITY INDEX[1]

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

S&P BETA[2] (ß)

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

S&P BOND RATING[2]

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

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

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

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

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

S&P STOCK RANKING[2]

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

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

Moody's Bond Rating[3]

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

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

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

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

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

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

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

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	CORRECTIONS TO THE TESTIMONY OF JOHN R. HINTON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

Mr. Hinton's testimony should be corrected as follows:

The sentence on page 4, lines 11-12 should read:

> This is based on a capital structure consisting of 48.81% long-term debt, 0.65% short-term debt, and 50.54% common equity.

The sentence on page 49, lines 12-17 should read:

> This recommendation is derived based on a capital structure consisting of 48.81% long-term debt, 0.65% short-term debt, and

50.54% common equity, with a recommended cost of long-term debt of 4.08%, a recommended cost of short-term debt of 0.20%, and a recommended cost of common equity of 9.42%.

Respectfully submitted this the 16th day of August, 2021.

PUBLIC STAFF
Christopher J. Ayers
Executive Director

Dianna W. Downey
Chief Counsel

Electronically submitted
/s/ Lucy E. Edmondson
Staff Attorney

4326 Mail Service Center
Raleigh, North Carolina 27699-4300
Telephone: (919) 733-6110
lucy.edmondson@psncuc.nc.gov

CERTIFICATE OF SERVICE

I certify that a copy of these Corrections has been served on all parties of record or their attorneys, or both, by United States mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 16th day of August, 2021.

Electronically submitted
/s/ Lucy E. Edmondson

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	)	SETTLEMENT TESTIMONY OF JOHN R. HINTON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

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

September 7, 2021

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

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

Q. ARE YOU THE SAME JOHN R. HINTON THAT FILED DIRECT TESTIMONY AND EXHIBITS ON RATE OF RETURN AND CAPITAL STRUCTURE ON AUGUST 11, 2021?

A. Yes, I am.

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

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

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

A. The Public Staff and the Company have agreed to a 6.90% cost of capital in this proceeding. The overall cost rate is comprised of a 9.60% rate of return on common equity (ROE), a 0.20% cost rate of short-term debt, a 4.08% cost rate of long-term debt, which is combined with a capital structure consisting of 51.60% common equity, 0.65% short-term debt, and 47.75% long-term debt.

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

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

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

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

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

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

I note that it remains my position that, should this be a fully litigated proceeding, I would continue to recommend a capital structure with 50.54% common equity, 0.65% short-term debt, and 48.81% long-term debt, an ROE of 9.42%, a cost of short-term debt of 0.20%, and a cost of long-term debt of 4.08%. However, given the benefits associated with entering into a settlement, it is my view that the cost of capital components of the Settlement are a reasonable resolution of otherwise contentious issues.

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

A. The average common equity ratio for natural gas utilities approved from January 1, 2018, through August 31, 2021, is 51.94% and since January 1, 2020, the average approved ratio has been 51.80%,[1] which is supportive of the Settlement common equity ratio. The Settlement capitalization ratios include a 0.65% ratio of short-term debt that is reflective of the Company's balance of gas inventory and a 48.81% ratio of long-term debt, which are comparable to the debt ratios approved in Docket No. G-9, Sub 743.

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

A. Yes, the last natural gas rate case was Piedmont's 2019 rate case (Docket No. G-9, Sub 743) where the North Carolina Utilities Commission (Commission) approved a capital structure containing 52.00% common equity. In addition, recent Commission-approved common equity ratios for other regulated utilities support the reasonableness of the Settlement common equity ratio, as shown below:

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

Company	Docket	Order Date	NCUC Approved Equity Ratio
DENC	E-22, Sub 562	2/24/2020	52.00%
DEC	E-7, Sub 1214	3/31/2021	52.00%
DEP	E-2, Sub 1219	4/16/2021	52.00%

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

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

Q. HOW DOES THE SETTLEMENT 9.60% ROE COMPARE TO THE RESULTS OF THE ANALYTICAL MODELS USED BY YOU AND BY THE COMPANY?

A. The Settlement ROE of 9.60% falls within my range of estimated cost rates for common equity of 9.10% to 9.73%, as shown in Public Staff Hinton Exhibit 9 to my originally filed testimony. The Settlement 9.60% ROE falls at the lower end of the Company's unadjusted range of 9.59% and 12.72% and slightly below its adjusted range of 9.70% to 12.83%.[2]

[2] Docket No. G-9, Sub 781, Rebuttal Testimony of Dylan W. D'Ascendis at 3.

Q. ARE THE 9.60% ROE AND THE 51.60% EQUITY RATIO A REASONABLE RESULT?

A. Yes. The Settlement 6.90% overall cost of capital is reasonable as shown in Public Staff Hinton Settlement Exhibit 1. The higher percentage of equity capital and the higher ROE contribute to increasing the pre-tax interest coverage ratio to 4.3 times, as shown in Public Staff Hinton Settlement Exhibit 1. As previously noted, the Settlement overall cost of capital represents a reasonable middle ground between the original positions of the Public Staff and the Company. In addition, the agreement on the Settlement 9.60% ROE and on capital structure occurred in the context of various other compromises by both parties on other issues.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes, it does.

MS. EDMONDSON: Thank you. In the interest of time, the Public Staff has elected not to provide witness summaries; therefore, Mr. Hinton is available for cross examination and Commission questions.

CHAIR MITCHELL: All right. Let me pause here. My notes indicate no cross for the witness, but I will make sure that is actually the case.

(No response.)

CHAIR MITCHELL: I am not seeing Mr. Jeffries or Mr. Heslin move towards their microphones. So I'll check in with Commissioners to see if Commissioners have questions for the witness.

(No response.)

CHAIR MITCHELL: All right. No questions for the witness from Commissioners. So, Mr. Hinton, you're off the hook for today. Thank you very much, sir, for your participation in this proceeding. You may step down.

And, Ms. Edmondson, is there any reason not to excuse the witness?

MS. EDMONDSON: No.

CHAIR MITCHELL: All right. Mr. Hinton you are excused.

THE WITNESS: Thank you.

MS. EDMONDSON: And if we could admit his exhibits.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the exhibits to the testimony of Public Staff witness Hinton shall be accepted into the record of evidence.

(Hinton Exhibits 1 through 3, Confidential Hinton Exhibit 4, Hinton Exhibits 5 through 12, and Hinton Settlement Exhibit 1 were admitted into evidence.)

CHAIR MITCHELL: All right. Public Staff, call your next witness.

MS. JOST: Good afternoon. The Public Staff calls Neha Patel.

CHAIR MITCHELL: All right. Ms. Patel, there you are. If you would, please raise your right hand.

Whereupon,

NEHA PATEL,

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

CHAIR MITCHELL: All right, Ms. Jost, you may proceed.

MS. JOST: Thank you.

DIRECT EXAMINATION BY MS. JOST:

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

A. My name is Neha Patel, and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I'm manager of the natural gas section of the energy division of the Public Staff, North Carolina Utilities Commission Public Staff.

Q. Thank you. On August 11, 2021, did you prepare and cause to be filed in this docket, testimony consisting of 32 pages including cover sheet and Appendix A and three exhibits?

A. Yes.

Q. Do you have any corrections to your testimony?

A. Yes, I do. Mr. Metz's modification in his supplemental testimony to the pro forma demand allocation he proposed in his original filed testimony impacted the cost of gas calculation discussed on pages 10 and 11 of my testimony and shown on Patel

Exhibit 3. The appropriate corrected cost of gas updated through June 30, 2021, including accounting for Mr. Metz's modification, is reflected in the stipulation in Settlement Exhibit I.

Q. Thank you. And with the exception of what you just discussed, if you were asked the same questions today, would your answers be the same as in your prefiled testimony?

A. Yes, they would.

MS. JOST: Chair Mitchell, I move that Ms. Patel's prefiled testimony consisting of 32 pages be copied into the record as if given orally from the stand, and that her exhibits be identified as marked when filed.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the testimony of Public Staff witness Patel filed in the docket on August 11th consisting of 31 pages shall be copied into the record as if given orally from the stand. The exhibits to that testimony shall be marked for identification as they were when prefiled.

(Patel Exhibits I through III were identified as they were marked when prefiled.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722	)	
	)	
In the Matter of	)	
Consolidated Natural Gas Construction	)	
and Redelivery Services Agreement	)	
Between Piedmont Natural Gas	)	
Company, Inc., and Duke Energy	)	
Carolinas, LLC	)	
	)	
DOCKET NO. G-9, SUB 781	)	
	)	
In the Matter of	)	TESTIMONY OF
Application of Piedmont Natural Gas	)	NEHA PATEL
Company, Inc., for an Adjustment of	)	PUBLIC STAFF – NORTH
Rates, Charges, and Tariffs Applicable	)	CAROLINA UTILITIES
to Service in North Carolina	)	COMMISSION
	)	
DOCKET NO. G-9, SUB 786	)	
	)	
In the Matter of	)	
Application of Piedmont Natural Gas	)	
Company, Inc., for Modification to	)	
Existing Energy Efficiency Program	)	
and Approval of New Energy Efficiency	)	
Programs	)	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

TESTIMONY OF NEHA PATEL

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

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

A. My name is Neha Patel. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Manager of the Natural Gas Section of the Energy Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the results of my investigation into the application of Piedmont Natural Gas Company, Inc. (Piedmont or the Company), for a general rate increase in this proceeding.

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

A. My areas of investigation in this case were: (1) determining the appropriate sales and transportation volumes and customer levels, (2) evaluating the proposed weather normalization adjustment for the test period, (3) calculating the appropriate end-of-period level of revenues, (4) updating the current cost of gas, (5) calculating the proposed updated computational factors used in the Margin Decoupling Tracker (MDT) mechanism, (6) reviewing proposed revisions to the Company's tariff, which consists of its various rate schedules and service regulations, (7) evaluating Piedmont's service quality, (8) evaluating Piedmont's request to continue its Commission-approved Integrity Management Rider (IMR) mechanism, and (9) evaluating Piedmont's programs to defer operating and maintenance (O&M) expenditures under its Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP).

WEATHER NORMALIZATION AND CUSTOMER GROWTH

Q. WHAT IS THE PURPOSE OF ADJUSTING FOR WEATHER NORMALIZATION AND CUSTOMER GROWTH?

A. Weather normalization attempts to analyze and adjust for the impacts of actual weather conditions over some specified period of time (generally, a test year) on energy consumption relative to expected "normal" weather conditions (as measured over some longer historical period of time).

The customer growth adjustment adjusts test period revenues by an amount that represents the growth in sales due to the change in the number of customers.

The Public Staff runs its own weather normalization and customer growth models and compares the results to those included in the Company's general rate case filing.

Q. PLEASE EXPLAIN HOW YOU CALCULATED YOUR WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE.

A. I calculated the weather-normalized usage by taking the test year customer data (i.e., the number of bills and consumption by month) for each Rate Schedule (RS) and comparing it with the monthly actual Heating Degree Days (HDDs) to develop a linear regression that computes both a base load (minimum usage level) and a Heat-Sensitive Factor (HSF). These base load and HSF components are then applied to the normal HDDs for the test year, resulting in a customer class usage level that would have been expected if the weather had been normal during the test year.

Q. PLEASE EXPLAIN HDDS AND HOW THEY ARE UTILIZED IN YOUR LINEAR REGRESSION.

A. HDD is a measurement used to quantify the demand for energy needed for space heating. HDDs are calculated by subtracting the average daily temperature from a base or standard temperature of 65 degrees Fahrenheit.[1] For example, a low of 20 degrees and a high of 40 degrees would yield an average of 30 degrees and an HDD of 35 degrees (65 - ((20 + 40)/2)). The normal HDDs are determined based on a 30-year historical average.

For ratemaking purposes of determining customer usage under normal weather conditions, I completed a linear regression to compare the actual customer usage to the actual HDDs to derive the baseload and the heat sensitive factors for the test year period. My completed analysis results in similar regression results to that of the Company.

Q. WHAT DATA SOURCES DID YOU USE FOR YOUR HEATING DEGREE DAY CALCULATIONS?

A. The temperatures used to calculate the HDDs were obtained from the State Climate Office of North Carolina – North Carolina State University. The Company has historically used weather data

[1] The use of 65 degrees Fahrenheit is based on an assumption that heating is not needed when the outside temperature is 65 degrees or more.

obtained on an hourly basis, whereas the Public Staff uses a daily average ((high temperature + low temperature)/2). Because Piedmont's service territory is geographically dispersed, temperature data from multiple weather stations are used. Annual therm-weighted percentages[2] for the weather stations provided by the Company in response to a data request were applied to the normal and actual degree days. The weighting percentages are determined by the heat-sensitive customer population, i.e., residential and commercial customers who need more security of service during peak (cold) days than do non-heat-sensitive customers. The final numbers for the normal HDDs and actual HDDs are the combined weighted normal HDDs and actual HDDs used to perform the linear regression analysis for the test period of the 12 months ended December 31, 2020.

Q. DOES THE COMPANY'S WEATHER NORMALIZATION ADJUSTMENT AGREE WITH THAT OF PUBLIC STAFF?

A. The Public Staff's weather normalization adjustments are comparable to the Company's although there are some minor differences. The differences are due to the fact that the Company

[2] Piedmont calculates HDDs by taking the daily average temperature for each weather station from 10:00 a.m. to 9:59 a.m. (Eastern Standard Time), which corresponds to the industry's gas day nomination cycle for gas transportation. Once each weather station's average temperature is calculated, the weather station percentages are applied to determine the North Carolina daily weighed average temperature. To calculate the HDDs, the weighted average temperature is then subtracted from 65 degrees.

uses hourly weather data, whereas the Public Staff uses daily averages, as explained above. Based on my review of the Company's weather normalization analysis, I believe it is reasonable for use in this case.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S GROWTH ADJUSTMENTS TO CUSTOMER BILLS AND CONSUMPTION.

A. Typically, the Public Staff compares actual changes in the number of customer bills between the test year and the year immediately prior, by month, to arrive at an average growth rate and then applies this average growth rate to each rate class. Due to the Commission's moratorium on disconnections for non-payment in effect during the test year in response to the COVID-19 pandemic, the Company did not disconnect service for non-payment of bills for a majority of the test period. As a result, the test period reflects a higher number of customer bills as compared to prior years. However, in consideration of the anticipated expiration of the disconnection moratorium, and with new customers being added to the system, the Public Staff applied growth to the Residential, Small General Service, and Medium General Service customer classes, and the Company used the same methodology in their June update actual growth factors from customers billed from 2018 through 2019 (when there was no disconnection moratorium in place) have been applied to the above customer classes. In addition, the Public Staff made adjustments for growth to certain large-volume customers with known and available information.

Q. WHAT TOTAL SALES AND TRANSPORTATION BILLS AND VOLUME DID YOU USE TO CALCULATE END-OF-PERIOD REVENUES?

A. Based on my analysis, I determined that the appropriate level of end-of-period sales and transportation bills is 9,311,987, and total volume is 422,497,534 dekatherms (dts), as shown in Patel Exhibit I.

Q. PLEASE PROVIDE AN EXPLANATION FOR YOUR ADJUSTMENTS SHOWN IN PATEL EXHIBIT I.

A. Columns (4) and (5) of Patel Exhibit I show the per books number of bills and the per books sales and transportation volumes segmented by rate schedule for the test year ended December 31, 2020 weather normalization, which is shown in Column (6), adjusts the volumes for the heat-sensitive customers (Rate Schedules 101, 102, and 152). The Public Staff and the Company agree on the weather normalization calculation methodology. My adjustments are comparable to that of the Company's pro forma bills and usage (dts) in their June update with some minor differences.

END-OF-PERIOD REVENUE CALCULATIONS

Q. WHAT RATES DID YOU USE TO CALCULATE THE END-OF-PERIOD PRO FORMA REVENUE LEVEL?

A. To calculate the end-of-period pro forma revenue level, I used the rates approved by the Commission in Docket No. G-9, Sub 790, Piedmont's Application for Adjustment of Its Rates and Charges to Track Changes in its Wholesale Costs of Gas that increased Piedmont's benchmark cost of gas from $2.50 to $3.25, effective July 1, 2021. I have also used the Company's updated IMR rates as approved by the Commission in Docket No. G-9, Sub 788, effective June 1, 2021. These rates exclude any temporary increments or decrements (temporaries) that were included in rates at that point in time. This calculation produces what is known as "clean rates."

Q. WHY ARE TEMPORARIES REMOVED FROM RATES FOR RATE CASE ANALYSIS?

A. Temporaries are usually associated with deferred account activities and are not related to revenue generation for the Company. The margins associated with various rate schedules are not affected by temporaries, except when temporaries are associated with fixed gas costs. Temporaries are removed when calculating end-of-period rates and proposed rates to achieve consistency and for ease of understanding. After the Commission determines the proper rates in this case, the new billing rates will be adjusted for the then current temporaries.

Q. WHAT IS YOUR END-OF-PERIOD REVENUE CALCULATION FOR THE COMPANY?

A. The Company is proposing total end-of-period revenue of $1,047,021,735, which is comprised of sale and transportation of gas revenues of $1,045,885,591 and other operating revenues of $1,136,144. I have calculated end-of-period revenues of $1,113,691,010, which is comprised of sale and transportation of gas revenues of $1,110,660,711[3] and other operating revenues as provided by Public Staff witness Julie G. Perry of $3,030,299.

Q. HOW DID YOU CALCULATE THIS END-OF-PERIOD LEVEL OF REVENUE FOR THE COMPANY?

A. I calculated the end-of-period revenue level by multiplying the number of customer bills by the facilities charge per bill, to arrive at the total facilities revenues. Similarly, the demand (for certain rate schedules) was multiplied by the demand charge per bill, to arrive at the total demand revenues. Likewise, the volume for each rate schedule was multiplied by the end-of-period rates to arrive at the

[3] Sale and Transportation of gas revenues includes the benchmark cost of gas of $3.25 as approved by the Commission in Docket No. G-9, Sub 790, as well as an updated lost and unaccounted for gas percentage as provided in the Company's response to a Public Staff data request.

total energy revenues. The total facilities charge revenue for a particular rate schedule, plus any demand revenue for that rate schedule, plus the energy revenue for that rate schedule, plus IMR revenues for that rate schedule, plus any Minimum Margin Agreement payment revenues or Compression Charge revenues for that rate schedule equals the total revenue received from customers receiving service under that rate schedule. The sum of the revenues from each rate schedule equals the total end-of-period revenue level as shown on Patel Exhibit II.

GAS COSTS

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED LEVEL OF COST OF GAS?

A. No. I have updated the commodity cost of gas using the benchmark cost of gas of $3.25 as approved by the Commission in Docket No. G-9, Sub 790, as well as an updated lost and unaccounted for gas percentage as provided in the Company's response to a Public Staff data request. My recommended commodity cost of gas is $244,251,000 as compared to the Company's level of $187,342,806.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO FIXED GAS COSTS.

A. The Company reflected annual fixed gas costs of $116,484,625. Based on recent changes in interstate pipeline and storage tariffs and secondary market credits, as provided by the Company in response to a Public Staff data request, and an allocation percentage of 83.16% as recommended by Public Staff witness Dustin R. Metz, I arrived at total fixed gas costs of $122,569,944.

I determined that the total commodity and fixed gas cost of $366,820,944, as shown on Patel Exhibit III, is appropriate for use in this proceeding.

MDT MECHANISM

Q. PLEASE EXPLAIN ANY ADJUSTMENTS REGARDING THE MDT MECHANISM.

A. In this proceeding, the Company filed MDT adjustments to the Residential, Small General Service, and Medium General Service rate schedules. I calculated the normalized usage for heat sensitive customers on a monthly basis and determined that the Public Staff's MDT revenue adjustments, the Company's adjustments and the "R" factors using data through May 31, 2021, are similar; thus, I accepted the Company's results. As stated in Piedmont witness Kally A. Couzens' testimony, this adjustment results in an increase to Residential, Small General Service, and Medium General Service total pro forma revenues.

CHANGES TO PIEDMONT'S TARIFF

Q. WHAT CHANGES IS PIEDMONT PROPOSING TO ITS NORTH CAROLINA TARIFF?

- Piedmont received approval to eliminate Standby Sales Service in its last general rate case in Docket No. G-9, Sub 743 (Sub 743 rate case) for certain rate schedules. Company witness Pia K. Powers' testimony addresses the proposal to eliminate the reference to Standby Sales Service in certain rate schedules since it no longer exists as part of RS 113.

- Piedmont proposes to add a requirement that service under RS 113 and RS 114 is contingent upon installation of telemetering equipment that reports daily consumption. Piedmont witness Powers stated in her pre-filed direct testimony that the telemetering equipment is required for Piedmont to properly operate its system, render accurate bills to customers and their agents, and enforce other provisions within its existing tariff. She further testified that customers in the affected rate classes already have the appropriate telemetering equipment, and that the tariff change is being proposed for purposes of transparency.

- Another change proposed by Piedmont is the elimination of the RS 12 and RS T-12 rate schedules since no customers were provided or billed for service under either of these two rate schedules during or after the test period, or for several years prior to the test period. The Company also proposes to remove reference to these two rate schedules under RS 143 and Appendix E. Another proposed change under RS 143 is the elimination of reference to the outdated provision for this rate schedule to remain in effect for a period of two years after which continuation of service under this rate schedule requires Commission action.

- In her testimony, Piedmont witness Powers proposes two administrative corrections to Appendix B of Piedmont's Service Regulations: one is to correct typographical errors related to a defined term and the second is to clarify the Company's internal procedures. The second change was proposed in the Sub 743 rate case and no party objected, but the change was not captured in the settlement agreement approved by the Commission.

- Witness Powers has proposed changes to update the Special Contract Credit amounts, margin percentages by rate class, allocation factors, and the annual billing determinants, etc., for the IMR mechanism in Appendix E as is necessary with each new general rate case proceeding. These changes are discussed in Public Staff witness Perry's testimony.

IMR MECHANISM

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF FEDERAL GAS PIPELINE SAFETY REQUIREMENTS.

A. Pipeline operators are required to perform integrity measures on their transmission and distribution pipelines by following certain regulatory requirements imposed by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) under its TIMP and DIMP. These PHMSA regulations are regularly amended and updated to increase the safety associated with transportation of gas. PHMSA's implementation of Integrity Management (IM) regulations for natural gas transmission and distribution pipelines is intended to improve overall pipeline safety, reliability and integrity. 49 CFR Part 192, Subpart O specifies how pipeline operators must identify, prioritize, repair, and validate the integrity of gas transmission pipelines that could affect High Consequence Areas (HCAs) within their service territories in the event of a leak or failure. HCAs, which include certain populated and occupied areas, are required to be inspected every seven years or less. Pursuant to 49 CFR Part 192, Subpart P, Piedmont is federally mandated to collect data on and have knowledge of its distribution pipelines, identify and assess existing and potential threats, evaluate and rank risk to the distribution system, identify and implement measures designed to address the risks, measure IM performance, monitor the results and evaluate effectiveness of those measures, develop and implement a process for periodic review and improvement of the program, and report results. Since these distribution lines exist largely in more populated areas while delivering gas to the end user, DIMP focuses on the Company's entire distribution system, not just the HCAs.

The TIMP and DIMP activities are cyclical, are based on timing and intervals of prior assessments, and vary from year to year.

Effective July 1, 2020, PHMSA required all pipeline operators to comply with the new Gas Transmission "Mega Rule,"[4] which provides an expansion of the IM requirements for gas transmission pipelines and aims to further increase the level of safety associated with gas transmission pipelines. A significant portion of this rule outlines documentation and requires operators to (1) Verify pipeline material properties and attributes: Operators must have information on the material strength properties for all transmission pipe; (2)

[4] https://www.federalregister.gov/documents/2019/10/01/2019-20306/pipeline-safety-safety-of-gas-transmission-pipelines-maop-reconfirmation-expansion-of-assessment

Reconfirm Maximum Allowable Operating Pressure (MAOP): this applies to those transmission pipelines where pressure test records are not traceable, verifiable and complete (TVC); and (3) Expand IM requirements outside HCA: Periodic assessments of pipelines in populated areas not designated as HCAs to Moderate Consequence Areas (MCAs).[5]

Q. PLEASE PROVIDE SOME BACKGROUND ON THE COMPANY'S IMR MECHANISM.

A. N.C. Gen. Stat. § 62-133.7A authorizes the Commission to approve a rate adjustment mechanism to enable a natural gas local distribution company (LDC) to recover its prudently incurred capital investments and associated costs of complying with federal gas pipeline safety requirements. The Commission approved an IMR mechanism as part of Piedmont's 2013 general rate case (Docket No. G-9, Sub 631) and it is contained in Appendix E to Piedmont's Service Regulations. Based on concerns raised by the Public Staff, in November 2015, the IMR mechanism was revised to provide for changes to the IMR processes and procedures, including the exclusion of certain costs from recovery through the IMR mechanism

[5] Moderate Consequence Areas (MCAs) are defined as areas within a potential impact circle containing either five or more buildings intended for human occupancy or any portion of the paved surface, including shoulders, of a designated interstate, freeway, or expressway, or principal arterial roadway with four or more lanes, as defined by the Federal Highway Administration (as compared to 20 buildings which define an HCA).

(Excluded Costs) and the allowance of bi-annual rate adjustments. The Excluded Costs percentages are intended to reduce the level of non-pipeline safety costs charged to customers through the IMR mechanism, but are still eligible for inclusion in recoverable rate base in Piedmont's next general rate case proceeding. In the Sub 743 rate case, the Commission authorized the continuation of the IMR mechanism subject to stipulated clarifications. Piedmont has included, as part of this proceeding, a proposal to continue operation of this mechanism for an additional period of four years. Public Staff witness Perry discusses the IMR mechanism.

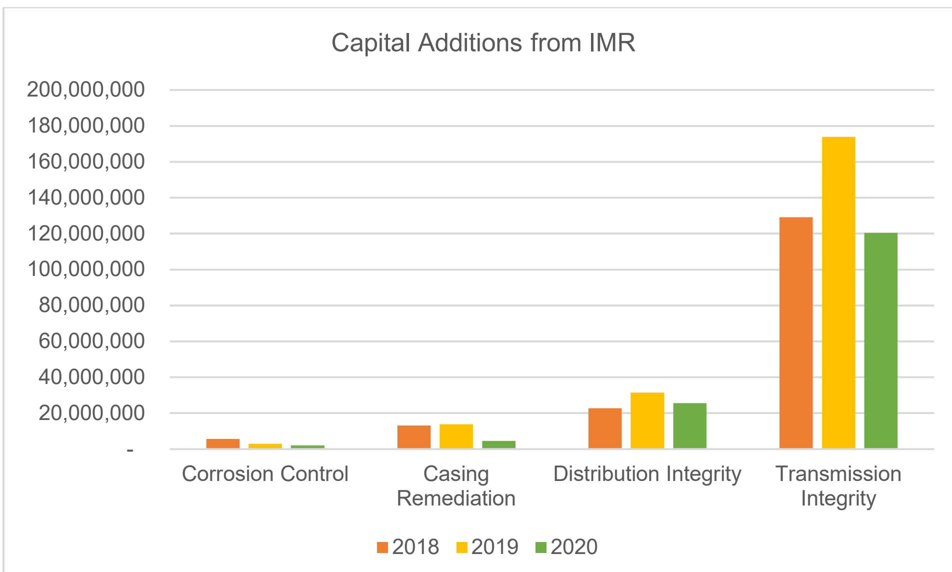
Piedmont has applied for and received Commission approval to implement rate increments to recover its Integrity Management Revenue Requirement (IMRR). Since the Sub 743 rate case, there have been five of these rate changes.

The Public Staff reviews and audits Piedmont’s monthly IMR reports filed with the Commission through data requests and follow-up conference calls with Company personnel regarding project scope, project need, actual project costs incurred, and the nature of IMR-associated costs. In addition, the Public Staff files an Annual IMR Report with the Commission every February 15th in order to discuss any issues from the monthly audits, or the IMRR, as well as summarize the completed IMR projects and the budgeted IMR projects for the next three years.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING PIEDMONT'S REQUEST TO CONTINUE THE IMR MECHANISM.

A. Patel Figure 1 below shows the Company's capital additions associated with its IMR mechanism for the period 2018 through 2020 also discussed by Public Staff witness John R. Hinton.

Patel Figure 1



Piedmont estimated in its last general rate case that it would spend approximately $173 million each year from 2019 until 2021, not including any "Mega Rule" compliance commitments. In this case, Piedmont projects it will spend approximately $277 million each year (gross plant investment) from 2021 through 2023 in addition to expenditures related to anticipated changes in the "Mega Rule."

Based on the importance of pipeline safety in complying with federal safety guidelines to protect Piedmont's customers, employees, contractors and the general public, I recommend the IMR mechanism remain in place.

REGULATORY ASSET TREATMENT FOR TIMP-RELATED O&M (PIM-T) COSTS

The Commission has approved regulatory treatment for the Company's TIMP O&M costs incurred due to the pipeline safety regulations promulgated by PHMSA. Under PHMSA, pipeline operators are mandated to identify High Consequence Areas (HCAs) or covered segments in order to identify threats to their pipelines, identify and analyze the risk to help prioritize assessments, remediate conditions found during integrity assessments, maintain records, and implement preventative and mitigative measures. Per PHMSA guidelines, operators must perform pipeline reassessments which drives up the costs added to the rate base while allowing the Company to mitigate threats and risks identified on these pipelines and ensure safely on their transmission lines. I recommend that Piedmont be allowed to continue its deferral mechanism under PIM-D until the resolution of the Company's next general rate case proceeding. I further recommend that the Company continue providing to the Commission program updates, including project scope and the budgeted and actual costs incurred, when it files its annual IMR report. While my area of investigation focused on the necessity of this mechanism, Public Staff accounting witness Feasel discusses how these costs are accounted for.

<u>REGULATORY ASSET TREATMENT FOR DIMP-RELATED O&M (PIM-D) COSTS</u>

Q. PLEASE DISCUSS YOUR REVIEW OF THE COMPANY'S REGULATORY ASSET TREATMENT FOR DIMP-RELATED O&M COMPLIANCE COSTS.

A. The Commission has approved regulatory asset treatment for Piedmont's DIMP O&M costs associated with PHMSA regulatory compliance. The DIMP primarily covers the following areas of pipeline safety:

1. Damage prevention programs: (a) legacy cross bore, (b) watch and protect, and (c) locatability investigations/repair untoneable assets;
2. Records: mapping services in the GIS; and
3. Corrosion: close interval surveys on high-pressure distribution lines.

In the Sub 743 rate case, the Company projected its five-year (2020-2024) average cost for these five programs to be approximately $11 million annually, and noted that all of the work covered by these programs would involve external contractors rather than Piedmont direct labor. However, the Company incurred lower costs than anticipated due to delayed implementation of the DIMP programs approved in the Sub 743 rate case caused by the COVID-19 pandemic.

As part of my investigation in this proceeding, I reviewed data request responses received from the Company regarding the DIMP-related O&M project scope and associated costs. Under damage prevention, I also reviewed data from 2010 to 2020[6] related to the Company's annual damage rates and the relationship to the number of locate requests. Patel Figure 1 below shows the history of locate requests and the associated damage rates per 1000 locate tickets.

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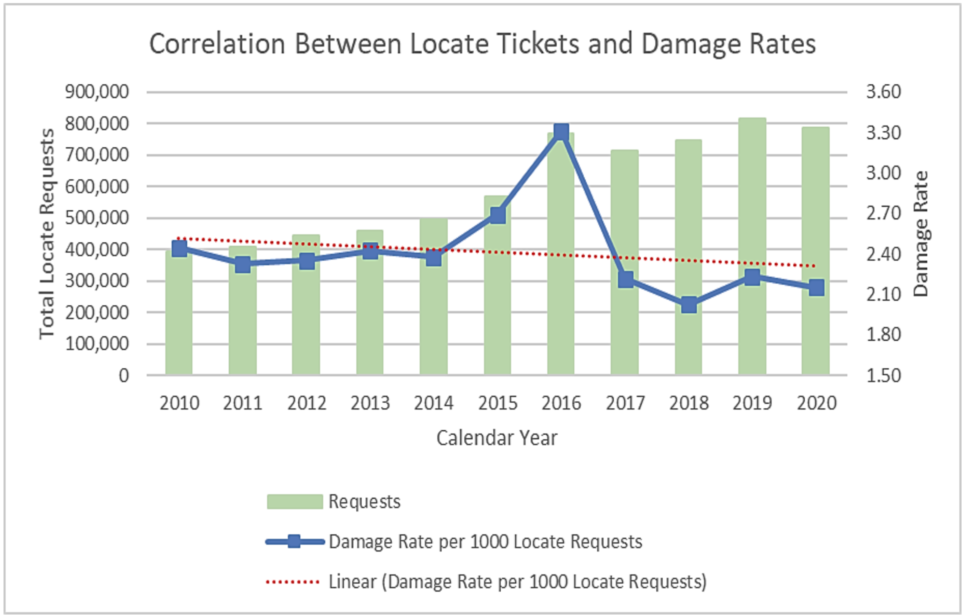
6 https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FExcavation%20Damage&Action=Navigate&col1=%22PHP%20-%20Geo%20Location%22.%22State%20Name%22&val1=%22%22

Patel Figure 2



As reflected in Patel Figure 2, from 2010 to 2014, the Company received approximately 400,000 locate requests in any given year, and the damage rate averaged 2.39 damage incidents annually. After 2014, the damage rate increased, reaching a high of about 3.3, before declining substantially over the last four years with an increase in locate requests.

The Company has implemented measures to reduce third party damages such as mailers to registered excavation companies within the Company's service territory and newspaper, billboard, and social media advertising. Beginning December 1, 2019, the Company implemented three public awareness programs to help reduce third party damage incidents. They are: (1) Risk Ranking "811" tickets, and Watch & Protect Program; (2) Untoneable Repair Program; and (3) Geofencing.

The Company received approval to defer expenses for certain programs in the Sub 743 rate case.[7] Even though these programs are relatively new, the Company states that they have already had a positive impact on the damage ratio to its infrastructure; nevertheless, the Public Staff will continue to analyze this data to assess the impacts of the programs.

In addition to the above list, the Company has adopted the Gold Shovel Standard[8] (GSS) as part of its standard practice. The GSS is a non-profit organization that promotes safe digging practices using standardized performance metrics. As a member of GSS, Piedmont requires all of its contractors to maintain Gold Shovel certification. Regardless of any programs implemented by the Company, it is still third party contractors that are key drivers behind damage events.[9] As a result, the Company emphasizes its Gas Pipeline Damage Prevention Plan, which provides for monthly interaction contractors

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[7] https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=efc328f2-5820-43c7-8390-c89ebc0df42c

[8] https://goldshovelstandard.org/

[9] https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FExcavation%20Damage&Action=Navigate&col1=%22PHP%20-%20Geo%20Location%22.%22State%20Name%22&val1=%22%22

who are repeat offenders. These meetings involve the review of the specific contractor statistics in an attempt to identify and implement corrective action measures.

Under records, mapping services in the GIS program as approved in the Sub 743 rate case help assist pipeline operators and state and federal pipeline regulators ensure the safe, reliable, and environmentally sound operation of the operator's facility. In accordance with Federal requirements, between program approval in the Sub 743 rate case and the present, the Company to date has digitally map about 15% of its distribution mains, services, and related equipment in its GIS, with an anticipated completion date of December 2024.

The Corrosion program is another program approved under the DIMP initiative during the last general and involves performing close internal surveys on high pressure distribution pipe on a five-year cycle and remediating anomalies found through the surveys.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S DEFERRED DIMP O&M EXPENSES?

The issue of pipeline safety, and specifically the testing of LDCs' systems, along with the implementation of safety programs, has come to the forefront in the past 10 to 15 years. The focus was initially on transmission systems and now includes distribution systems as well. Significant expenditures have been made to address pipeline safety and remain compliant with PHMSA regulations, which have been amended as recently as 2019 to expand obligations.[10]

Company witness Brian R. Weisker noted that much of the cost of compliance with PHMSA regulations is due to the thorough assessments the Company conducts of its transmission facilities through smart-pig inspections, which identify anomalies requiring mitigation. Witness Weisker also noted that the Company's control over the costs of undertaking specific projects is somewhat limited because much of the PHMSA compliance work is conducted by outside contractors who bid for the projects, and high demand for qualified contractors has caused the cost of PHMSA compliance work to become inflated.

The primary cost drivers impacting the Company's forecast include contracted labor to meet safety compliance and documentation per federal DIMP regulatory requirements. The Company has stated that it would be difficult to estimate these costs with much certainty and that doing so would be speculative. It is difficult to put a cost on

[10] Direct Testimony of Company witness Weisker at page 7.

pipeline safety and the prevention of property damage and personal injury or death that can occur from a natural gas incident.

As stated above, Piedmont got approval for all programs under DIMP in the last general rate case, but due to COVID there was a delay in starting all of the approved programs. The Public Staff should have the opportunity to examine the annual reports and comment on the expenditures. I recommend that Piedmont be allowed to continue its deferral mechanism under PIM-D until the resolution of the Company's next general rate case proceeding, and that the Company provide to the Commission program updates including project scope, and the budgeted and actual costs incurred when it files its annual IMR report. While my area of investigation of focused on the necessity of this mechanism, Public Staff accounting witness Feasel discusses how these costs are accounted for.

PIEDMONT'S QUALITY OF SERVICE

Q. WHAT FACTORS DID YOU CONSIDER IN YOUR EVALUATION OF PIEDMONT'S OVERALL QUALITY OF SERVICE PROVIDED TO ITS CUSTOMERS?

A. I reviewed the following information in my evaluation of Piedmont's quality of service:

- Informal complaints and inquiries from Piedmont customers received by the Public Staff's Consumer Services Division;
- Consumer statements of position filed in Docket No. G-9, Sub 781CS (Sub 781CS docket);
- Emergency response times;
- Customer Call Center Monthly Reports filed in Docket No. G-100, Sub 96PNG;
- Data on pipeline incident and damage rates (see Patel Figure 3); and
- Recent Company initiatives that impact the level of service being provided to customers.

Q. WHAT TYPES OF CUSTOMER COMPLAINTS AND INQUIRIES HAVE BEEN RECEIVED BY THE PUBLIC STAFF'S CONSUMER SERVICES DIVISION?

A. For the period January 2016 through April 2021, the Public Staff's Consumer Services Division received approximately 1,563 contacts from Piedmont customers. Of those contacts, 84% related to billing and payment issues including the establishment or modification of payment arrangements and questions about current bills. The remaining 16% involved rate, service, and meter-related issues.

Q. WHAT TYPES OF CONCERNS WERE INCLUDED IN THE CONSUMER STATEMENTS OF POSITION FILED IN THE SUB 781CS DOCKET?

A. As of August 8, 2021, approximately 47 individuals had filed consumer statements in this docket. These statements can be divided into two categories: (1) general opposition to the proposed rate increase and (2) concerns of fixed income customers regarding their ability to afford the rate increase.

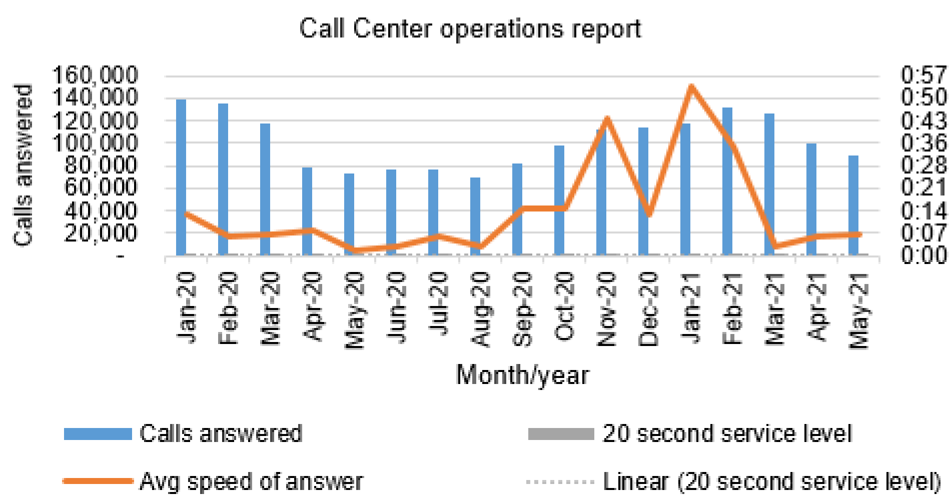
Q. PLEASE DESCRIBE THE OTHER DATA USED IN YOUR REVIEW.

A. The other data used in my review were obtained through Piedmont's Commission-required filings and responses to Public Staff data requests. I was able to analyze the Company's: (1) call center response times to customer inquiries, (2) response times to emergency response calls/events, and (3) the correlation between damage rates and the number of locate request tickets issued to the Company.

With regard to the Customer Call Center information filed in Docket No. G-100, Sub 96PNG, from January 2020 to May 2021, the Company and its third party call centers answered 1,711,719 calls with an answer rate of 98.6%. In addition to the number of calls answered by customer service representatives, the Company's

Interactive Voice Response (IVR) answering system handled an additional 1,149,579 calls during this same timeframe. Per G-100, Sub 96PNG Reports, on average, the Company's performance on the "20 second service level" to customer calls has an overall high performance of answering calls within 20 seconds (about 91%) as can be seen from Figure 3 below, while also focusing on improving call response time during the winter months.

Patel Figure 3



Q. HOW WOULD YOU RATE PIEDMONT'S SERVICE QUALITY?

A. Based on my investigation, I believe the overall quality of service provided by Piedmont to its North Carolina customers is adequate at this time.

COMPANY'S UPDATE FILING

Q. WHAT ARE YOUR COMMENTS REGARDING THE COMPANY'S UPDATE FILING MADE ON JULY 28, 2021 (JUNE UPDATE)?

A. The Public Staff is aware of the June Update; however, given the timing of the update filing and the due date of the Public Staff's testimony, the Public Staff could not reasonably perform its investigation on the Company's updated information in the short amount of time before it was due to file testimony. The Public Staff reserves the right to file supplemental testimony related to the Company's June Update once its investigation of the updated information is completed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

NEHA PATEL

I graduated from the University Of Mumbai in 1995 with a Bachelor of Science degree in Electronic Engineering. I began working as a Utilities Engineer with the Natural Gas Division of the Public Staff in the spring of 2014. In 2020, I became Manager of the Natural Gas Section of the Energy Division.

I have worked on purchased gas cost adjustment procedures, tariff filings, customer utilization trackers, special contract review and analysis, weather normalization adjustments, customer complaint resolutions, integrity management riders, franchise exchange filings, compressed natural gas special contracts, peak day demand and capacity calculations, fuel and electric usage trackers, gas resellers, annual review of gas costs proceedings, renewable natural gas filings, cost of service studies, general rate case proceedings, and rate design.

MS. JOST: Thank you. Ms. Patel is available for questions from the Commission.

CHAIR MITCHELL: All right. Just confirming there is no cross examination.

(No response.)

CHAIR MITCHELL: I'm not seeing any counsel indicate cross examination for the witness, so we will move to questions from the Commissioners.

Any Commissioner have a question for Ms. Patel?

(No response.)

CHAIR MITCHELL: All right. Ms. Patel, it looks like you too are off the hook for the remainder of the day. Thank you, ma'am, for your participation in this proceeding. You may step down.

And, Ms. Jost, any reason not to excuse the witness?

MS. JOST: No.

CHAIR MITCHELL: Okay. Ms. Patel, you may be excused.

And, Ms. Jost, you can -- I'll take a motion from you.

MS. JOST: Yes, thank you. I move that Patel Exhibits I through III be entered into evidence.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Exhibits I, II and III to the Patel testimony will be admitted into evidence.

(Patel Exhibits I through III were admitted into evidence.)

MS. JOST: Thank you.

CHAIR MITCHELL: All right. Public Staff, you may call your next witness.

MS. JOST: The Public Staff calls Dustin Metz.

CHAIR MITCHELL: All right. Mr. Metz, let's see, there you are.

Whereupon,

DUSTIN R. METZ,

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

CHAIR MITCHELL: All right. Ms. Jost.

DIRECT EXAMINATION BY MS. JOST:

Q. Good afternoon, Mr. Metz. Please state your name, business address, and present position for the record.

A. My name is Dustin Ray Metz. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I'm an engineer for the Public Staff's energy division.

Q. Thank you. On August 11, 2021, did you prepare and cause to be filed in this docket, testimony consisting of 32 pages, including a cover sheet and Appendix A, and five exhibits?

A. Yes.

Q. And for the record, Mr. Metz, is it correct that Metz Exhibit 2 is marked as confidential?

A. Yes.

Q. On August 24, 2021, did you prepare and cause to be filed in this docket, supplemental testimony consisting of four pages?

A. Yes.

Q. Do you have any corrections to either of those testimonies?

A. No.

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

A. Yes.

MS. JOST: I move that Mr. Metz's prefiled testimony consisting of 32 pages and his prefiled supplemental testimony consisting of four pages be copied into the record as if given orally from the stand, and that his exhibits be identified as marked when filed.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the 32 pages of testimony filed by Public Staff witness Metz in the docket on August 11th, and the four pages of supplemental testimony filed by Public Staff witness Metz in the docket on August 24th, shall be copied into the record as if delivered orally from the stand. The five exhibits to Mr. Metz's testimony shall be marked for identification as they were marked when prefiled.

(Metz Exhibit 1, Confidential Metz Exhibit 2, and Metz Exhibits 3 through 5 were identified as they were marked when prefiled.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722	)	
	)	
In the Matter of	)	
Consolidated Natural Gas Construction	)	
and Redelivery Services Agreement	)	
Between Piedmont Natural Gas	)	
Company, Inc., and Duke Energy	)	
Carolinas, LLC	)	
	)	
DOCKET NO. G-9, SUB 781	)	
	)	
In the Matter of	)	TESTIMONY OF
Application of Piedmont Natural Gas	)	DUSTIN R. METZ
Company, Inc., for an Adjustment of	)	PUBLIC STAFF – NORTH
Rates, Charges, and Tariffs Applicable	)	CAROLINA UTILITIES
to Service in North Carolina	)	COMMISSION
	)	
DOCKET NO. G-9, SUB 786	)	
	)	
In the Matter of	)	
Application of Piedmont Natural Gas	)	
Company, Inc., for Modification to	)	
Existing Energy Efficiency Program	)	
and Approval of New Energy Efficiency	)	
Programs	)	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

TESTIMONY OF DUSTIN R. METZ

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Section – Operations and Planning in the Public Staff's Energy Division.

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

A. The purpose of my testimony is to present the results of my investigation into the application of Piedmont Natural Gas Company, Inc. (Piedmont or the Company) for a general rate increase in this proceeding.

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

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

- General capital additions to liquefied natural gas (LNG) plant in service, including the Company's Robeson LNG facility and LNG pipeline, and the Company's Huntersville LNG facility
- Cost allocation of transmission assets
- Multiple transmission pipeline projects
- Design day margin
- Safety and regulatory compliance
- Company vehicles
- Materials and supplies
- Staffing levels for specific work groups

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. As a result of my investigation, I make the following recommendations in this case:

- That the Robeson LNG facility, Lines 456 and 457, and all of the Company's pro forma adjustments associated with the Robeson LNG project be removed from rate base at this time.
- That demand allocation factors of 83.16% and 16.84% be applied to North Carolina and South Carolina, respectively.
- That the same demand allocation factors be applied to any accounts already allocated using the 2-state jurisdictional allocators set forth in the Company's G-1, Item 5.
- That the Commission order the Company, the Public Staff, and any other interested parties, prior to the earlier of the Company's next general rate case or its 2023 annual review of gas costs proceeding (2023 Annual Review), to undertake, report on the status of, and complete a study of whether the Company's current method of allocating its transmission plant assets to North Carolina and South Carolina is fair to each state's customers in light of the fact that the Company plans for future supply and capacity resources based on a combination of both North Carolina and South Carolina demands.

- That the Commission order the Company, the Public Staff, and any other interested parties, prior to the earlier of the Company's next general rate case or its 2023 Annual Review, to initiate, report on the status of, and complete a study of an updated regression analysis to determine a more accurate breakdown of system usage among customer classes and the North Carolina and South Carolina jurisdictions.

General Capital Additions to Plant In Service

Q. PLEASE DESCRIBE THE CAPITAL ADDITIONS TO THE COMPANY'S RATE BASE THAT YOU REVIEWED IN THIS CASE.

A. In his prefiled direct testimony, Piedmont witness Brian R. Weisker discusses the addition of approximately $1.65 billion of capital plant that was either placed in service prior to the Company's filing of its application in this proceeding, or was expected to be placed in service by June 30, 2021.[1] As part of the Public Staff's investigation, I evaluated multiple categories of capital expenditures for reasonableness and prudence, and to determine whether the underlying assets were used in providing service to ratepayers.

My investigation included the following: (1) a review of the prefiled direct testimony of Piedmont witness Weisker; (2) an audit of specific expenditures (i.e., sampling of specific costs); (3) initial and follow-

[1] Direct Testimony of Piedmont witness Weisker at 9.

up discovery; (4) teleconferences between the Company and Public Staff; (5) interviews with Company witnesses and staff, including detailed discussions regarding specific aspects of certain projects; (6) a site visit to the Robeson LNG facility; and (7) a review of projects with Company management and technical staff.

<u>Specific Capital Additions</u>

Q. HAS THE NEW ROBESON LNG PLANT BEEN PLACED IN SERVICE?

A. No. Not at the time of filing of this testimony, nor by the May 31, 2021 cut-off date. The Robeson LNG facility is not complete, is not providing service to customers, and has not been closed to plant (i.e., transferred from the applicable CWIP account(s) to the applicable plant in service account(s)).

Q. WHEN DO YOU EXPECT THE ROBESON LNG FACILITY TO BE COMPLETE?

A. Based on discussions with Company staff, the Company believes the Robeson LNG facility will be in service before the end of the evidentiary hearing in this case, which is scheduled to begin September 7, 2021. However, based on my personal observations during a site visit on July 12, 2021, and on follow-up communications with the Company, I have doubts as to whether the entire Robeson

LNG plant will be completed and able to be placed in service by that time.

Q. WHAT IS THE ESTIMATED COST OF THE ROBESON LNG FACILITY?

A. It is my understanding that the final estimated cost is approximately $274M. This equates to approximately 21%[2] of the Company's proposed overall revenue requirement increase in this proceeding.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR COST DISALLOWANCE OF THE ROBESON LNG FACILITY OR ANY OTHER PROJECTS RELATED TO THE OVERALL OPERATION OF THE FACILITY?

A. Yes. At this time, I recommend that no costs related to any portion of the Robeson LNG facility be included for cost recovery. This includes any pro forma adjustments, land, and any transmission required to interconnect the facility.[3] The adjustments related to my recommendation are shown in the exhibits of Public Staff witness Perry.

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[2] Per Public Staff witness Julie G. Perry, an approximation of new plant impact to the revenue requirement would be the cost of the plant ($274M) multiplied by 0.08. This revenue requirement percentage is based on the current estimate of capital costs and excludes all other pro forma adjustments associated with the Robeson LNG facility.

[3] The Robeson LNG facility requires two transmission lines for interconnection – Lines 456 and 457 – which I discuss later in my testimony. No other customers are connected to these dedicated lines from Piedmont's existing transmission system to the LNG facility.

Allocation of Transmission Assets

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF PIEDMONT'S SYSTEM IN THE CAROLINAS.

A. Piedmont is a local distribution company (LDC) which operates in both North Carolina and South Carolina, but does not fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Piedmont's primary interstate pipeline service (capacity used to transport natural gas supply) is from Transcontinental Gas Pipeline Company, LLC (Transco). Piedmont is reliant on Transco as its capacity provider because there are currently no other interstate pipelines with significant delivery to meet Piedmont's customers' needs in the Carolinas. Piedmont has no directly owned natural gas transmission or distribution lines that connect its North Carolina and South Carolina service territories; therefore, it is reliant upon Transco as the connection between the two service territories. Metz Table 1 below summarizes the differences between the Company's North Carolina and South Carolina service territories. Metz Exhibit 1 is a graphical illustration of the Company's transmission system and service territories.

Metz Table 1

Jurisdiction	LNG Facilities[4]	Gross LNG Plant[5] ($M)	Total Transmission Piping	Gross Transmission Plant Assets ($M)	Total Customers[6]
North Carolina	3	$511	2701 Miles	$3,295	774,275
South Carolina	0	$0	79 Miles	$193	153,497

Q. MR. METZ, WHAT IS YOUR UNDERSTANDING OF HOW PIEDMONT EVALUATES AND SELECTS SUPPLY, OR FUTURE CAPACITY, AND STORAGE RESOURCES?

A. Piedmont must evaluate different options for meeting total customer demand based on the amplitude (peak maximum) and duration (total time over which the peak occurs, as well as frequency of occurrence) as part of a design day study. A detailed explanation of this evaluation can be found in Piedmont's annual gas cost reviews, which are similar in some respects to an electric utility's integrated resource plans (IRP). While there are some aspects of the

[4] This includes the soon to be completed Robeson LNG facility.

[5] Robeson LNG + Existing LNG (through June update) = ~$511M. An estimate of $274M was included in this case as a placeholder for Robeson LNG facility + gross book value of Huntersville and Bentonville LNG (based on the Company's responses to Public Staff Data Requests 110-1, 113-14, and 120-33).

[6] Total Customers are year ending 2020 values. The Company's G-1, Item 5 Pro-Forma Worksheet.

Company's annual review calculations with which I have concerns, they are outside the scope of my investigation in this case, and will instead be addressed in future annual review proceedings.

Q. DOES THE COMPANY PLAN FOR FUTURE CAPACITY AND STORAGE RESOURCES TO MEET NORTH CAROLINA AND SOUTH CAROLINA DEMAND SEPARATELY?

A. No. When the Company plans for future capacity and storage resources, it takes into account an aggregated weighted contribution of customers and customer demands in the respective service territories for both North Carolina and South Carolina. In other words, the planned-for resources are used to meet a combination of both North Carolina and South Carolina demand. In Piedmont's most recent annual review of gas costs proceeding (Docket No. G-9, Sub 771), the Robeson LNG facility was determined by the Company to be the "optimal" resource to meet the new incremental demand in both states, in combination with existing supply sources.

Q. FROM AN ANNUAL REVIEW AND SYSTEM PLANNING PERSPECTIVE, ARE EXISTING LNG FACILITIES AND EXISTING CAPACITY CONTRACTS INCLUDED IN THE ANALYSIS?

A. Yes. Piedmont's annual review lists interstate pipeline capacity and storage contracts as supply capacity in its system design day analysis filed each year. Supply capacity can be year-round firm transportation, winter only firm transportation, seasonal storage, and peaking capacity (LNG). The capacity levels and the availability of these various supply capacity contracts are included in the annual review analysis. Confidential Metz Exhibit 2 is provided to illustrate a load duration curve, produced by the Company in a recent annual review.[7] Simply stated, the load duration curve evaluates expected demands (loads) over the total days of demand that are expected to require service for the review period. Similar to how utility-scale electric generating resources are selected to meet demand, natural gas resources are selected on a "best cost" basis to supply the area under the curve (demand line).

Q. PLEASE DESCRIBE HOW LNG FACILITY COSTS ARE ALLOCATED BETWEEN NORTH CAROLINA AND SOUTH CAROLINA.

A. Because LNG facilities are built to meet the combined North Carolina and South Carolina peak demands, the associated capital and ongoing maintenance costs are allocated based on a jurisdictional (2-state) demand factor. This factor, which the Company has proposed in this case, is set out in Metz Exhibit 3, which is Attachment 1 of 2 to the Company's G-1, Item 5 Jurisdictional Allocators that was supplied in response to a Public Staff discovery request. Note (1) on the bottom

[7] Testimony of Piedmont witness Jeffrey Patton filed in Docket No. G-9, Sub 771.

of the Company's Pro Forma Design Day Allocation indicates that certain LNG-related accounts (e.g., LNG storage plant and LNG-related O&M accounts) are allocated between North Carolina and South Carolina. This Pro Forma Design Day allocation is not a demand allocation based on actual test year data, but is escalated to an "expected" demand based on a 1985 winter event, which is the coldest temperature experienced to date on Piedmont's system. In other words, these test year costs are not allocated solely on the basis of historical test year system operating data, but rather, the historical data is extrapolated to a theoretical expectation that may or may not occur again at some future time. Therefore, I have concerns regarding the usage of the Pro Forma Design Day allocation proposed by the Company that I discuss later in my testimony.

Q. HOW ARE PIEDMONT-OWNED LNG FACILITIES CONNECTED TO PIEDMONT'S SYSTEM?

A. Piedmont's three LNG facilities (Bentonville, Huntersville, and the proposed Robeson LNG) are connected to Piedmont's natural gas transmission pipelines. Similar to large utility-scale electric generating stations that provide generation (supply) to meet demand (load), natural gas supply is connected to transmission-level facilities to achieve better system efficiencies.

Q. DOES AN LNG FACILITY FUNCTION AS BOTH DEMAND AND SUPPLY WITH RESPECT TO THE GAS TRANSMISSION SYSTEM?

A. Yes. The economics and the operation of an LNG facility are similar to those of a pumped storage hydroelectric generating station. The system operator charges the facility during off-peak times to provide service during on-peak times. The economics of price arbitrage (filling the system at low prices and discharging the system at high prices) determines whether a project or supply asset is cost effective, i.e., whether the economics of price arbitrage is large enough to cover the capital and expected ongoing costs of the asset.

With the recent modification to Piedmont's Huntersville LNG facility,[8] and pending the successful commissioning of the Robeson LNG facility, Piedmont's three LNG facilities have the capability to inject (fill) over the course of the year. Each LNG facility uses the transmission system, ideally during low system loads, to convert natural gas to a liquid state and store it for future use. In addition, when the system experiences high demands or high natural gas prices, the Company can dispatch (withdraw) the LNG, converting it back to a gaseous phase, and inject it back onto the system for use. The LNG facility also withdraws daily amounts from the storage tank from the boil-off gas

[8] Prior to modification, the costs of which Piedmont seeks to recover in this rate case, the Huntersville LNG facility required 200 days to fill.

process.[9] The daily withdrawals from the LNG storage tank place small volumes of gas back onto the transmission system. During the test year, the Huntersville and Bentonville LNG plants withdrew or injected gas from the transmission system approximately 99.7% of the total days of the year.[10]

Q. DO THE COMPANY'S LNG FACILITIES PROVIDE SERVICES OTHER THAN PEAK DAY SERVICE?

A. Yes. Based on Company data request responses, the LNG facilities provide hydraulic (pressure regulation) benefits to Piedmont's overall system and are a supply resource. The LNG facilities currently in operation either inject or withdraw gas from Piedmont's transmission system nearly year-round; therefore, the hydraulic benefits and supply resource are also provided year-round to all users of the system, inclusive of North Carolina and South Carolina customers.

Q. WOULD IT BE ACCURATE TO CHARACTERIZE THE TRANSMISSION SYSTEM AS AN INTEGRAL EXTENSION OF THE LNG FACILITY?

A. Yes. In order for Piedmont's three LNG facilities, which are all located in North Carolina, to function and provide services to ratepayers,

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[9] Boil-off gas is a natural process of storage due to variations in temperatures (storage temperatures and external temperatures). The boil-off gas is removed, in part, to maintain proper storage tank pressures.

[10] Based on the Company's responses to Public Staff Data Requests 120-4 and 120-5.

including the North Carolina and South Carolina aggregate loads they were designed to meet, the transmission system must logically be considered an integral extension of the LNG facilities.

Q. DID THE ROBESON LNG FACILITY REQUIRE NEW TRANSMISSION TO INTERCONNECT TO PIEDMONT'S SYSTEM?

A. Yes. The Robeson LNG facility required two approximately four-mile-long transmission pipeline extensions to tie the LNG facility to the Company's main transmission system. Line 456 is a 24-inch gas line that is the main supply to and from the LNG facility, and Line 457 is an 8-inch line for secondary functions.

Q. HOW ARE THE TRANSMISSION COSTS CURRENTLY ALLOCATED BETWEEN NORTH CAROLINA AND SOUTH CAROLINA?

A. Currently, each state is assigned 100% of the costs of all transmission assets physically located in that state, including capital, transmission-related operations and maintenance expenses, the Integrity Management Rider costs, and the Transmission Integrity Management Program costs.

Q. ARE TRANSMISSION ASSETS BUILT SOLELY FOR LNG OPERATION?

A. Generally, no. However, dedicated lines (spurs), such as Lines 456 and 457 discussed above, are sometimes built to interconnect the

LNG facility to the transmission system. These situations are limited and are dependent upon the specific siting of the facility. Gas transmission lines are typically built and sized to meet loads, including peak loads, for all customers receiving service from that transmission line, whether directly or indirectly, which includes special contract and electric generation customers. An example would be customers such as Duke Energy Progress, LLC (DEP), whose Sutton Combined Cycle generation plant is located on the same transmission line with which the Robeson LNG facility interconnects.

Q. PLEASE EXPLAIN, ON AN OPERATIONAL BASIS, THE PEAK DAY RELATIONSHIP BETWEEN THE COMPANY'S NORTH CAROLINA AND SOUTH CAROLINA SERVICE TERRITORIES.

A. Based on responses to discovery[11] and conversations with the Company, it is the Public Staff's understanding that when LNG is withdrawn from the LNG storage tank, re-gasified, and injected into

[11] In response to Public Staff Data Request 70-4(a), the Company stated:

> The Company plans to meet its system under design day conditions [peak day event] on a combined basis for North and South Carolina and [the] Company utilizes interstate pipeline capacity, storage, and LNG to meet the supply requirements of its firm sales customers. Although the Company's North and South Carolina [service territories] are not interconnected by the Company's transmission or distribution systems, both [service territories] are interconnected with Transco. Given the Company has multiple delivery points on Transco in both North and South Carolina it is able to manage these deliveries on an **aggregated basis**. As such the Company is able to <u>utilize LNG</u> to make physical deliveries **to meet demand** in North Carolina, which the[n] reduces the Company's need for Transco deliveries in North Carolina. As a result, **this frees up or displaces** the need in North Carolina which enable deliveries in South Carolina.

(Emphasis added.)

Piedmont's transmission system, it is used to meet the aggregated load of both North Carolina and South Carolina. When LNG is injected into the transmission system, the LNG gas is a supply capacity resource that reduces the overall scheduled deliveries from Transco at the given takeoff station or node. Since all of the Company's LNG resources are located in North Carolina, the aggregate impact of LNG placed on Piedmont's system reduces the scheduled North Carolina deliveries from Transco and displaces gas on Transco for use in Piedmont's South Carolina service territory to meet total system load.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE ALLOCATION OF TRANSMISSION FACILITIES AND RELATED COSTS?

A. Yes. My recommendation takes into account the overarching consideration, and the fundamental concept of cost causation and responsibility, that users of the system should be allocated a share of total system costs incurred to optimally serve customer loads while minimizing cross-subsidization. As described in more detail above, I discovered through my investigation that Piedmont's LNG facilities are allocated on a system demand basis, yet transmission facilities and ongoing transmission costs are not. As explained above, the LNG facilities provide peaking and ancillary services (i.e. pressure regulation) which necessitate connection to the transmission system and which minimize costs to both North Carolina and South Carolina ratepayers. Therefore, it is apparent that the transmission system is an integral extension of the LNG facilities. I also would like to note that the LNG facilities utilize the transmission system throughout the entire year, and the usage of the transmission system is not isolated to a few discrete days during the winter or system peaking periods.

I believe that the results of my investigation in this proceeding warrant further investigation into whether the allocation method currently used by the Company is fair to both North Carolina and South Carolina ratepayers given that they rely on utilization of the transmission system to realize year round LNG system benefits. Therefore, I recommend that the Commission order Piedmont, the Public Staff, and any other interested parties to study this issue before the Company's next general rate case is filed. The exact scope and milestones of this study should be determined with input from all interested parties before work begins on the study itself.

Demand Allocation

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATES AND APPLIES THE DEMAND ALLOCATION TO LNG PLANT.

A. Based on my review of the workpapers supporting the Company's G-1, Item 5, Jurisdictional Allocators, as well as G-1, Item 4e, the pro forma design day study is the basis of the Company's pro forma demand allocation. My understanding of the Company's demand allocation calculations is that the Company uses an aggregate of 12 months of historic test year data and, through linear regression analyses (best R^2 fit), calculates customer class usage based on temperature. More specifically, the Company's allocation methodology evaluates the 2020 test year monthly usage for each individual customer class and then compares that usage to cumulative hours in the same month in which the weighted average temperature was less than 65 degrees (i.e., Heating Degree Days or HDDs) for the gas day. A simple regression is then performed and the base usage level (the starting point of expected usage at 65 degrees) and a heat sensitivity factor (the amount of natural gas used per customer class based on a decrease in temperature) are calculated.

Once the Company has completed the regression analyses, it applies the design day temperature (DDT), which is determined in the Company's annual review of gas costs proceeding. The starting point of the DDT calculation is the simple average of the high and low daily temperatures from a 1985 cold weather event recorded at various weather stations in the Company's service area. The simple average for each respective weather station is then applied to the total customers in the service territory represented by the weather station and a system-weighted average is derived. The weighted DDT is then subtracted from 65 degrees, as the difference is the total HDDs expected in the one extreme peak condition. The DDT calculation attempts to capture the system-weighted impact of the combined customers in both North Carolina and South Carolina given the design temperature of the one extreme peak. Based on my review, I have identified components of the Company's demand allocation methodology that appear to introduce errors into the regression analysis that relies upon a linear relationship between independent and dependent variables.

The Company's methodology utilizes test year usage (demand) but escalates the usage to represent a theoretical total volume demand that assumes the reoccurrence of an event that has occurred only once, in 1985. This theoretical usage is then allocated between North Carolina and South Carolina. The Company has proposed an allocation to North Carolina of 85.39% and to South Carolina of 14.61%, with an aggregate expected firm sales usage of 1,354,754 dekatherms (dts), excluding electric generation usage.

Q. WHAT WERE THE COMPANY'S TOP FIVE FIRM SALES CUSTOMER PEAKS IN THE LAST FIVE YEARS?

A. The Company's combined North Carolina and South Carolina top five firm sales peaks for the last five years are shown in Metz Table 2 below:

Metz Table 2[12]

Date	Actual HDDs	Design Day HDDs	Difference in HDD	North Carolina (dts)	South Carolina (dts)	Total Firm Sales Sendout (dts)
1/8/2017	44.7	56.29	(11.59)	837,672.30	150,395.00	988,067.30
1/4/2018	44.2	56.29	(12.09)	865,101.50	210,781.00	1,075,882.50
1/21/2019	38.4	56.29	(17.89)	773,581.00	141,852.20	915,433.20
1/21/2020	35.3	56.29	(20.99)	719,701.40	139,553.40	859,254.80
12/25/2020	39.7	56.29	(16.59)	664,777.50	140,761.60	805,539.10

Q. WHAT IS THE ACTUAL DIVISION OF TOTAL SYSTEM USAGE BETWEEN NORTH CAROLINA AND SOUTH CAROLINA BASED ON THE COMPANY'S TOP FIVE PEAKS?

A. The actual total system usage of firm sales customers for each state, excluding power generation users on the system, is shown in Metz Table 3 below. As shown in Metz Table 3, each of the top five peaks shown for the total system usage in North Carolina is less than the 85.39% allocation recommended by the Company.

Metz Table 3

Date	NC Usage	SC Usage
1/8/2017	84.78%	15.22%
1/4/2018	80.41%	19.59%
1/21/2019	84.50%	15.50%
1/21/2020	83.76%	16.24%
12/25/2020	82.53%	17.47%

[12] The data contained in Metz Table 2 are derived from the Company's response to Public Staff Data Request No. 70-1.e.

Q. PLEASE SUMMARIZE YOUR OBSERVATIONS REGARDING THE COMPANY'S DEMAND ALLOCATION METHODOLOGY AND COMPARE IT TO THE PUBLIC STAFF'S PROPOSED ALLOCATION OF HISTORIC PEAK USAGE.

A. There is a fundamental difference between how a system is planned and how it is used. While there is merit in evaluating how 2-state usage and various customer classes contribute to a peak day planning event, the actual system usage illustrates how the planned demand allocation of test year usage can differ throughout the entire year.

One approach to cost allocation is to base it on a recent system peak[13]. Applying this methodology to data from the top five peaks in the last five years, North Carolina ratepayers should never be allocated more than that 84.78% of costs (based on a 2017 cold weather day). The benefit of this approach is that peak system usage would be more reflective of the current users of the system and rely less on linear regression estimates.

Another approach is to evaluate a weighted average of the top five peaks occurring in the last five years. The total system usage of each state across the five coldest weather peaks, weighted appropriately,

[13] This approach is consistent with the manner in which production plant and transmission plant were allocated in DEC's and DEP's most recent general rate cases, Docket No. E-7, Sub 1214, and Docket No. E-2, Sub 1219, respectively.

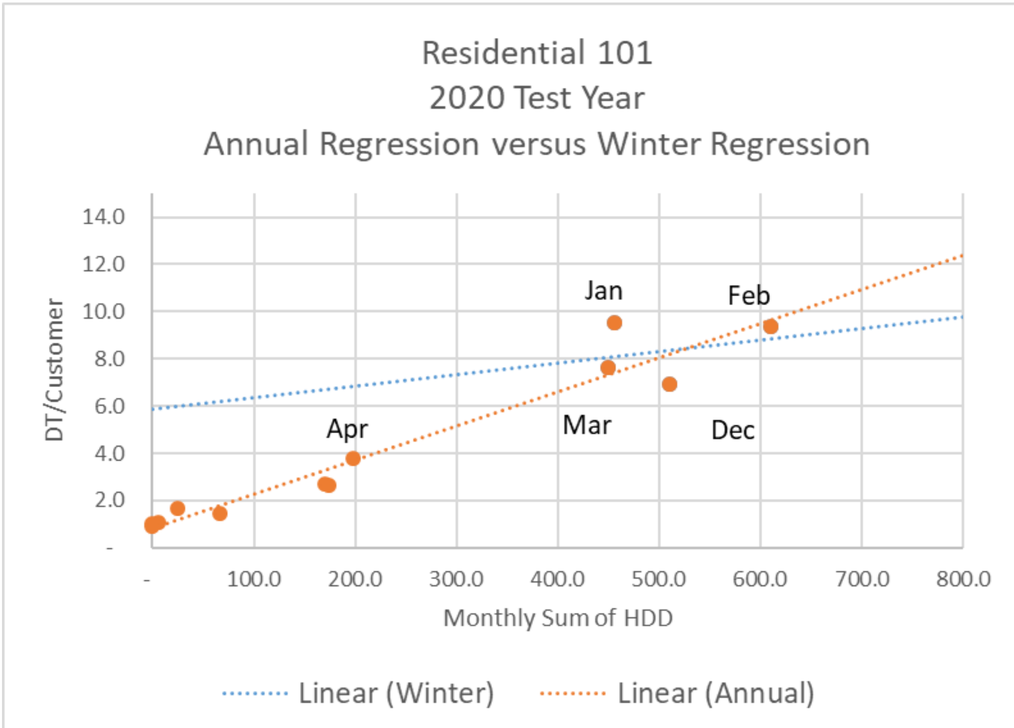
would result in an allocation of approximately 83.13% to North Carolina and approximately 16.87% to South Carolina.

A key takeaway from the above approaches to cost allocation that rely on the use of historic usage data versus a regression analysis is that there are not enough data points to feel confident with the statistical equation for the basis of a cost allocation and rate making. This is in part because improper data resolution (usage months) distorts projected loads and the relationship of base factor and heating coefficient are not consistent. Therefore, I propose an allocation methodology based on recent peak usage data, which is more reflective of how actual users of the system utilize the current plant in service.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY IMPROPER DATA FIELDS AND DISTORTION OF PROJECTED LOADS.

A. Metz Figure 1 below, which is based on data contained in the Company's G-1, Item 4(e), illustrates my point.

Metz Figure 1



The Company provided monthly data from the 15th day of one month to the 15th day of the following month (i.e., customer billing cycle). The monthly data includes usage per customer and the number of HDDs. The points on the bottom left of the graph are the summer and shoulder months and the points on the top right are winter months. The orange dotted line connecting the data points is a standard best line fit (linear regression) of all the data fields (all 12 months), which represents the regression model the Company uses to predict future usage in this general rate case proceeding. The equation that defines the linear regression trend line provides a customer coefficient (y-axis intercept), base factor, and a heating coefficient (line slope), and allows for the projection of future load. The accuracy of the projection is only as good as the correlation of system usage based on those temperatures during the test year coupled with the amount of observations (data points) used to determine the correlation. I compared the Company's annual regression based on how system loads are evaluated in the annual review. The annual review excludes non-winter months from the regression and the starting point of the regression excludes data points greater than 10 HDD (55 degrees Fahrenheit). As Metz Figure 1 shows, the slope or rate of change to temperature and per customer usage (dt/customer) is much less in the winter as compared to the annual regression. Using the Company's proposed method, as temperatures decrease and HDDs increase, the demand continues to increase at the slope or rate of change it is plotted against. The Linear Winter and Linear Annual lines on Metz Figure 1 illustrate the differences in expected demand as you project to a future HDD. The Company used the Linear Annual method in its G-1, Item 5 Jurisdictional Allocation.

The shortcomings inherent in using annual regression to determine future usage described above are further compounded when the Company attempts to assign/allocate costs from a temperature and projected usage from actual/recent system historic utilization. While the linear regression of annual per customer usage has a high R^2

value, implying a high degree of correlation, the predictive value of the model is not as strong for the winter months. For example, the R^2 value of the annual regression model is 0.94; the R^2 value of the winter months compared to the annual regression model is 0.08. The regression with the higher R^2 value (0.94) is results from multiple months with low HDDs (eight data points out of twelve) that bias the results. This relationship can be seen in Metz Figure 1, comparing the DT/Customer difference between the Winter and Annual dotted lines on an “extreme” HDD planning event, the dt/customer usage is approximately 20% higher if one uses the Annual regression compared to the Winter regression.

For example, if the temperature gets cold enough, heat produced from a natural gas source will never satisfy demand and, thus, a saturation point or plateau occurs. Colder temperatures and longer duration compound this phenomenon. Further, not all residential class customers have a gas furnace, and usage patterns may vary when all users are aggregated into one rate class. I conducted a similar analysis of the correlation between customer class usage and temperature in the Company’s last annual review. In that instance, a linear regression appeared to introduce error, and I believe another regression-type analysis could have been used to improve the correlation (e.g., polynomial regression).

Q. WHAT ALTERNATIVE METHOD DO YOU RECOMMEND FOR ALLOCATING DEMAND?

A. For purposes of this general rate case, I recommend that the demand allocation be based on two peak events occurring in 2020. The two 2020 peak events are two of the Company's five highest firm sales send out peaks over the past five years, both occurred in the test year, and they more accurately reflect the current users of the system. From an annual review perspective, the system is designed (future resources are selected) primarily for firm sales customers' demand on the overall system and is a large part of the overall planning for future resources to meet demand. I have concerns that the predictive value of the Company's proposed regression, using all 12 months of annual usage, breaks down slightly when higher numbers of HDDs are used.

My recommended demand allocation results in an assignment of 83.16% to North Carolina and 16.84% to South Carolina. The 2020 weighted average of usage between North Carolina and South Carolina is nearly identical to the same ratio of peak events over the last five years and the weighted average takes into account system usage factors, growth over those five years, and how the system is planned for cold weather (high demand) events. I have provided this allocation adjustment to Public Staff witnesses Patel and Perry, and they are reflected these witnesses' exhibits as applicable.

Further, based on my investigation, I recommend that the Commission order the Company, the Public Staff, and any other interested parties, prior to the earlier of the Company's next general rate case or its 2023 Annual Review, to initiate, report on the status of, and complete a study of an updated regression analysis to determine a more accurate breakdown of system usage among customer classes and the North Carolina and South Carolina jurisdictions.

General Findings and Observations

Q. BASED ON YOUR REVIEW OF TEST YEAR USAGE, PLEASE DESCRIBE HOW THE SYSTEM WAS USED BY CUSTOMER CLASSES.

A. Metz Exhibits 4 and 5 illustrate usage for the test year by month and customer class. Metz Exhibit 4 lists all individual North Carolina classes, and Metz Exhibit 5 groups the individual classes from Metz Exhibit 4 into three main groups for ease of identifying usage by class.

There are several observations based on my review of test year usage that I would like to bring to the Commission's attention. First, the 2020 test year was impacted by user changes in gas demand in reaction to the COVID-19 pandemic (beginning around April 2020). Second, power generation is by far the most significant user of throughput (dekatherms supplied by Piedmont's transmission and distribution system). Third, firm sales customer classes,[14] in aggregate, appear to be mostly winter peaking. Fourth, and finally, DEP's and Duke Energy Carolinas, LLC's (DEC), most recent integrated resource plans still project additional future natural gas generation, thus power generation through put may continue to increase in the future.

Based on a cursory review of system usage shown in Metz Exhibits 4 and 5 and a review of Public Staff witness Jack L. Floyd's testimony, I concur with witness Floyd's recommendation to conduct a deeper investigation into the cost of service in a future docket. Changes to the cost of service may influence other recommendations discussed in my testimony.

Q. WHAT ARE YOUR COMMENTS REGARDING THE COMPANY'S UPDATE FILING MADE ON JULY 28, 2021 (JUNE UPDATE)?

A. The Public Staff is aware of the June Update; however, given the timing of the update filing and the due date of the Public Staff's testimony, the Public Staff could not reasonably perform its investigation of the Company's updated information in the short

[14] Public Staff witness Patel identified the firm sales customer classes as: RS 101, RS 102, RS 152, RS 103, RS 143/102, RS 143/152, RS 143/103, and unique special contracts with firm sale requirements. Based on the data presented in the G-1 Item 4(e), I was not able to determine which specific special contracts were part of firm sales. For the purpose of Metz Exhibits 4 and 5, special contract load was removed because not all special contracts are firm sales.

amount of time before it was due to file testimony. The Public Staff reserves the right to file supplemental testimony related to the Company's June Update once its investigation of the updated information is completed.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009, respectively. I graduated from Central Virginia Community College, receiving Associates of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associates of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I completed engineering graduate course work in 2019 and 2020 at North Carolina State University.

I have over 12 years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, predictive statistical analysis, calibration, project planning and management, and general construction experience, including six years with direct employment with Framatome, where I provided onsite technical support, craft oversight, and engineer change packages and participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke Energy and Dominion.

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	)	SUPPLEMENTAL TESTIMONY OF DUSTIN R. METZ PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

SUPPLEMENTAL TESTIMONY OF DUSTIN R. METZ

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 24, 2021

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Section – Operations and Planning in the Public Staff's Energy Division.

Q. ARE YOU THE SAME DUSTIN R. METZ WHO FILED TESTIMONY IN THIS PROCEEDING ON AUGUST 11, 2021?

A. Yes.

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

A. The purpose of my supplemental testimony is to modify the pro forma allocation that I proposed in my original testimony.

Q. WHAT IS YOUR PROPOSED MODIFICATION?

A. For purposes of this rate case, I recommend the continued use of the Company's proposed North Carolina Allocation of 85.39% applied to the demand allocation. I have provided this correction to Public Staff witnesses Perry and Patel, and it is my understanding that both witnesses will incorporate the correction in future filings. The correction will eliminate the Design Day Allocation Change adjustment reflected on Line 8 of Perry Exhibit I, Schedule 1 filed on August 11, 2021.

Q. WHY YOU ARE NOW PROPOSING THIS CORRECTION TO YOUR ORIGINAL TESTIMONY?

A. My initial analysis evaluated firm sales (FS) customers only, based on my erroneous understanding at the time that the pro forma allocation was applied to the total "cost of gas" (both commodity and demand) and the Liquefied Natural Gas (LNG) accounts. The cost of gas, for the purposes of this allocation, should have been limited to the demand cost component. Both FS and firm transportation (FT) usage must be factored into the demand allocation, but my initial analysis excluded FT and, therefore, it was incorrect. However, I still recommend a study to review the appropriateness of the Company's "regression-based" analysis and to evaluate the possibility of using alternative methods in future rate cases.

Q. DOES THIS COMPLETE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

MS. JOST: Thank you. And Mr. Metz is available for questions from the Commission.

CHAIR MITCHELL: All right. Just confirming that there is no cross examination for the witness.

(No response.)

CHAIR MITCHELL: I'm not seeing any counsel indicate cross examination for the witness, so we'll move to questions from the Commissioners.

Any Commissioners have questions for witness Metz? I'm seeing Commissioner Duffley. You may proceed.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good afternoon, Mr. Metz. I have a question with regard to the stipulation of partial settlement language on page 28 of:

"The parties have agreed to complete a study of the current method of allocating its transmission plant assets."

And it's just a clarification question. What is included when you say "transmission plant assets"? What are you including? Is it just the transmission that's allocated 100 percent in the state, or are you also including the LNG plant as well?

A. So, currently, the LNG plant is allocated across two state, based upon the demand function.
Q. Right.
A. And so the study would evaluate how the -- also maybe how the transmission system would be impacted through a potential different allocation method, and it could also be evaluated whether or not that would also be the same factor that should be applied to LNG.
Q. Okay. So it is just related to transmission plant?
A. Yes.
Q. Okay. Thank you. And who -- what parties will be a part of the process? Will it just be the parties to this action, or do you expect to include others?
A. It could be others, I'm not opposed to including others. I haven't gotten that far into the thought process to say who or who will not be part of that conversation, but Public Staff is open to other parties being part of the study.
Q. Okay. And what specific factors will you be investigating and reviewing?
A. So an overarching concept that we evaluated

in this rate case was evaluation how the transmission system was used. And we had a few conversations with the Company along the way. So one component that we highlighted -- that I highlighted in testimony is that the LNG system -- LNG plants are connected to the transmission system. And LNG plants are built to meet both a combination of North Carolina and South Carolina load. The LNG plants are shared -- the costs are shared between North and South Carolina, but the transmission system is not.

So the component of the study would be evaluating whether that is a reasonable method to either allocate the current methodology of 100 percent per state, or in order for the LNG to function to serve both North Carolina and South Carolina load, how Piedmont studies it, would a -- could a different methodology be applied.

Q. Okay. Thank you, Mr. Metz. I have nothing further.

EXAMINATION BY CHAIR MITCHELL:

Q. Just, Mr. Metz, question for you just following on to a question from Commissioner Duffley.

So do you have any recommendations for the Commission as to who should be included in the groups that are going to be conducting these studies? Obviously, we'd like to hear the input of the Public Staff and the parties as to -- and the Company as to who should be involved. And if you don't at this time, you can simply say that. We --

A. I don't have an answer at this time. I would have to go back and internally talk and come to a larger consensus.

Q. Okay. All right.

CHAIR MITCHELL: Okay. Any additional questions for the witness from Commissioners?

(No response.)

CHAIR MITCHELL: All right. Any intervening parties have -- I'm sorry. Any parties have questions for the witness on Commissioner Duffley's questions or my question?

(No response.)

CHAIR MITCHELL: Questions from the Public Staff on our questions?

MS. JOST: No questions from the Public Staff. Thank you.

CHAIR MITCHELL: Okay. All right. Mr. Metz, you are done for today. Thank you, sir, for your participation here. You may step down.

Ms. Jost, any reason not to excuse Mr. Metz?

MS. JOST: No.

CHAIR MITCHELL: Okay. Mr. Metz, you may be excused.

And, Ms. Jost, I'll take a motion from you on his exhibits.

MS. JOST: Thank you. I move that Metz Exhibits 1 through 5 be entered into evidence.

CHAIR MITCHELL: Okay. Hearing no objection to your motion, Exhibits 1 to 5 to Public Staff witness Metz's testimony will be admitted into evidence.

(Metz Exhibit 1, Confidential Metz Exhibit 2, and Metz Exhibits 3 through 5 were admitted into evidence.)

CHAIR MITCHELL: All right. Public Staff may call its next witness.

MS. CULPEPPER: The Public Staff calls Lynn Feasel.

CHAIR MITCHELL: All right. Ms. Feasel. There you are. Raise your right hand, please, ma'am.

Whereupon,

LYNN FEASEL,
having first been duly affirmed, was examined
and testified as follows:

CHAIR MITCHELL: All right.
Ms. Culpepper, you may proceed.

DIRECT EXAMINATION BY MS. CULPEPPER:

Q. Please state your name, business address, and present position for the record.

A. My name is Lynn Feasel. The business address is 430 North Salisbury Street, Raleigh, North Carolina. My position is accountant with Public Staff accounting division.

Q. On August 11, 2021, did you prepare and cause to be filed in this docket, testimony consisting of 11 pages including a cover sheet and Appendix A?

A. Yes, I did.

Q. Do you have any corrections to your testimony?

A. No, I don't.

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

A. Yes.

MS. CULPEPPER: I move that the prefiled testimony, consisting of 11 pages, be copied into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to the motion, it will be allowed.

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	TESTIMONY OF LYNN FEASEL PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

TESTIMONY OF LYNN FEASEL

ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

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

A. My name is Lynn Feasel. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Staff Accountant with the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the results of my investigation into the application of Piedmont Natural Gas Company, Inc. (Piedmont or the Company), for a general rate increase in this proceeding.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

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

Q. PLEASE DESCRIBE THE ADJUSTMENTS YOU RECOMMEND.

A. I have recommended the following adjustments which impact rate base and operating expenses to Public Staff witness Perry to incorporate into her exhibits:

(1) Other Working Capital Updates;
(2) Deferred Transmission Pipeline Integrity Costs;
(3) Deferred Distribution Pipeline Integrity Costs;
(4) Deferred Environmental Costs; and
(5) Lead Lag Study.

OTHER WORKING CAPITAL UPDATES

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS FOR OTHER WORKING CAPITAL UPDATES.

A. With the exception of undercollection of NCUC Regulatory Fees, I have updated the other working capital items, using a 13-month average as of May 31, 2021, the Public Staff's cutoff date for post-test year plant additions in this filing.

DEFERRED TRANSMISSION PIPELINE INTEGRITY COSTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEFERRED TRANSMISSION PIPELINE INTEGRITY COSTS.

A. The Company's adjustment for deferred Pipeline Integrity Management Transmission (PIM-T) costs is composed of the unamortized balance from the last rate case in Docket No. G-9, Sub 743 (Sub 743 rate case) in addition to the amounts paid to outside vendors in connection with the PIM-T program between July 1, 2019, and December 31, 2020. The Public Staff has reviewed these charges, as well as the updated deferred PIM-T charges through May 31, 2021. The Public Staff has reflected the existing amortization from the Sub 743 rate case through November 30, 2021, the estimated effective date of rates in the current rate case, whereas the Company included the amortization expense through October 31, 2021. The Public Staff recommends that the balance of the deferred PIM-T costs, net of prior amortizations, be amortized over a four-year period consistent with the Company's proposed amortization period.

The Public Staff further recommends that the deferred balance less one full year of amortization be allowed to earn a return through its inclusion in rate base. The Public Staff also recommends that it is appropriate to continue regulatory asset treatment for PIM-T costs and to defer and treat such costs as a regulatory asset until the resolution of the Company's next general rate proceeding. In making this recommendation, the Public Staff does not intend to indicate that it believes these deferred costs to constitute used and useful property; instead, the Public Staff has included the costs in rate base as a convenient and efficient way of providing for a return on the deferred costs. The Public Staff considers the provision for a return to be reasonable in this case, but believes that the Commission's provision of such is discretionary, not obligatory, in nature.

DEFERRED DISTRIBUTION PIPELINE INTEGRITY COSTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEFERRED DISTRIBUTION PIPELINE INTEGRITY COSTS.

A. The Company's adjustment for Pipeline Integrity Management Distribution (PIM-D) costs is composed of the amounts paid to outside vendors in connection with the new PIM-D programs approved in the Sub 743 rate case between November 1, 2019, and December 31, 2020. The Public Staff has reviewed these charges, as well as the deferred PIM-D costs from January 1, 2021, through of May 31, 2021, to determine the deferred balance to be amortized. Since the Company's regulatory asset accounting treatment for certain deferred PIM-D O&M expenses was just approved in the Sub 743 rate case, there is no amortization expense to reflect from the Sub 743 rate case. The Public Staff recommends that the balance of the deferred PIM-D costs be amortized over a four-year period consistent with the Company's proposal.

The Public Staff further recommends that the deferred balance less one full year of amortization be allowed to earn a return through its inclusion in rate base. The Public Staff also recommends that it is appropriate to continue regulatory asset treatment for PIM-D costs and to defer and treat such costs as a regulatory asset until the resolution of the Company's next general rate proceeding. In making this recommendation, the Public Staff does not intend to indicate that it believes these deferred costs to constitute used and useful property; instead, the Public Staff has included the costs in rate base as a convenient and efficient way of providing for a return on the deferred costs. The Public Staff considers the provision for a return to be reasonable in this case, but believes that the Commission's provision of such is discretionary, not obligatory, in nature.

DEFERRED ENVIRONMENTAL COSTS

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO DEFERRED ENVIRONMENTAL COSTS.

A. On December 23, 1992, in Docket No. G-9, Sub 333, the Commission issued an order granting Piedmont's request to defer certain environmental assessment and clean-up costs relating to various state and federal environmental control requirements for air emissions, wastewater discharges, and solid, toxic, and hazardous waste management. In its current rate filing, the Company included the unamortized credit balance from the Sub 743 rate case in addition to the amounts paid to outside vendors in connection with the deferred environmental costs between July 1, 2019 and December 31, 2020. The Public Staff updated deferred environmental expenses from January 1, 2021, through May 31, 2021, and removed some internal labor costs that should not have been deferred. In addition, the Public Staff has reflected the existing amortization from the Sub 743 rate case through November 30, 2021, the estimated effective date of rates in the current rate case, whereas the Company included amortization expense through October 31, 2021. The Public Staff agrees with the Company's proposed four-year amortization period.

The Public Staff further recommends that the deferred balance less one full year of amortization be allowed to earn a return through its inclusion in rate base. The Public Staff also recommends that it is appropriate to continue regulatory asset treatment for environmental costs and to defer and treat such costs as a regulatory asset until the resolution of the Company's next general rate proceeding. In making this recommendation, the Public Staff does not intend to indicate that it believes these deferred costs to constitute used and useful property; instead, the Public Staff has included the costs in rate base as a convenient and efficient way of providing for a return on the deferred costs. The Public Staff considers the provision for a return to be reasonable in this case, but believes that the Commission's provision of such is discretionary, not obligatory, in nature.

LEAD LAG STUDY

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE LEAD LAG STUDY.

A. There are lag days between when the Company bills customers for payment and when payments are actually collected by the Company. The Company needs funding during this time period to maintain routine daily operations. The purpose of a lead lag study is to calculate the amount of this funding the Company requires. Piedmont's G-1, Item 26 b Attachments 1 and 2 show the supporting details for the Company's calculation of the test period and the pro forma lead/lag cash working capital for this proceeding. First, the Company divided each revenue and expense item in the Net Operating Income Schedule by 365 days to calculate the average daily cash working capital. Second, the Company multiplied each revenue item by its applicable lag days to calculate the total cash working capital to be collected. Third, the Company multiplied each expense item by its applicable lag days to calculate the total cash working capital to be reduced. Finally, the Company used the total cash working capital to be collected minus the total to be removed to calculate the net cash working capital required. The lead lag days applied in the current proceeding were approved in the Sub 743 rate case. The Public Staff agrees with the methodology the Company used to calculate net cash working capital in the lead lag study and with the calculation of lead lag days from the Company's last rate case proceeding. The Public Staff applied the same methodology to calculate net cash working capital in the lead lag study, except that the revenue and expense items the Public Staff used include its adjustments. The Company inadvertently applied an overall 84.58 per book lag days to the pro forma other operating revenues. The Public Staff has corrected it to 72.54 lag days. The Company agrees with the correction.

COMPANY'S UPDATE FILING

Q. WHAT ARE YOUR COMMENTS REGARDING THE COMPANY'S UPDATE FILING MADE ON JULY 28, 2021 (JUNE UPDATE)?

A. The Public Staff is aware of the June Update; however, given the timing of the update filing and the due date of the Public Staff's testimony, the Public Staff could not reasonably perform its investigation on the Company's updated information in the short amount of time before it was due to file testimony. The Public Staff reserves the right to file supplemental testimony related to the Company's June Update once its investigation of the updated information is completed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

LYNN FEASEL

I am a graduate of Baldwin Wallace University with a Master of Business Administration degree in Accounting. I am a Certified Public Accountant licensed in the State of North Carolina. Prior to joining the Public Staff, I was employed by Franklin International in Columbus, Ohio, from June 2011 through June 2013. Additionally, I worked for ABB Inc. from September 2013 through October 2016.

I joined the Public Staff as a Staff Accountant in November 2016. Since joining the Public Staff, I have worked on rate cases involving water and sewer utilities and natural gas utilities, filed testimony and affidavits in various general rate cases, calculated quarterly earnings for Carolina Water Service, Inc. of North Carolina and Aqua North Carolina, Inc., calculated quarterly earnings for various natural gas utilities, calculated refunds to consumers from AH4R and Progress Residential, and reviewed franchise and contiguous filings for multiple water and sewer utilities.

MS. CULPEPPER: Witness is available for cross examination and Commission questions.

CHAIR MITCHELL: All right. Let me check in with the parties to see if there is cross examination for the witness.

(No response.)

CHAIR MITCHELL: All right. I'm not seeing any counsel indicate cross examination for the witness, so we will move to questions from Commissioners.

Any Commissioner have a question for the witness?

(No response.)

CHAIR MITCHELL: All right. You are off the hook for the afternoon. Thank you, ma'am, for your participation in this proceeding. You may step down.

THE WITNESS: Thank you.

CHAIR MITCHELL: Ms. Culpepper, any reason not to excuse the witness?

MS. CULPEPPER: No.

CHAIR MITCHELL: Okay. She has already gone, so she may step down and she is excused. All right. Public Staff may call its next witness.

MS. CULPEPPER: We call Mary A. Coleman.

CHAIR MITCHELL: There are you, Ms. Coleman. Raise your right hand, please, ma'am.

Whereupon,

MARY A. COLEMAN,

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

CHAIR MITCHELL: All right, Ms. Culpepper.

DIRECT EXAMINATION BY MS. CULPEPPER:

Q. Please state your name, business address, and present position.

A. My name is Mary Annette Coleman. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina 27603.

Q. And what is your position?

A. I am a Public Staff accountant with the accounting division of the Public Staff North Carolina Utilities Commission.

Q. On August 11, 2021, did you prepare and cause to be filed in this docket, testimony consisting of nine pages, including a cover sheet and Appendix A, and one exhibit?

A. Yes, I did.

Q. Do you have any corrections to your testimony?

A. I do not.

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

A. Yes, they would.

MS. CULPEPPER: I move that the prefiled testimony consisting of nine pages be copied into the record as if given orally from the stand, and that the exhibit be identified as marked when filed.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the testimony of Public Staff witness Coleman filed the docket on August 11th consisting of nine pages shall be copied into the record as if delivered orally from the stand.

(Coleman Exhibit 1 was identified as they were marked when prefiled.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	TESTIMONY OF MARY A. COLEMAN PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

TESTIMONY OF MARY A. COLEMAN

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

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

A. My name is Mary A. Coleman. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Staff Accountant in the Accounting Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth in Appendix A.

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

A. The purpose of my testimony is to present the results of my investigation into the application of Piedmont Natural Gas Company, Inc. (Piedmont or the Company) for a general rate increase in this proceeding.

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

A. My investigation included a review of the application, testimony, exhibits, and other data filed by Piedmont. I also conducted extensive discovery in this matter, including the review of numerous responses from the Company to Public Staff data requests, and participation in virtual meetings with the Company to obtain answers to additional questions regarding North Carolina (NC) allocations, executive compensation, board of directors (BOD) expenses, and employee benefits.

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

A. I recommend adjustments in the following areas:

(1) BOD expenses
(2) Other benefits
(3) Executive compensation

BOD EXPENSES

Q. PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENT TO BOD EXPENSES.

A. I recommend an adjustment to remove 50% of the expenses associated with the BOD of Duke Energy Corporation (Duke Energy) that have been allocated to the Piedmont NC jurisdiction, as reflected in Coleman Exhibit I, Schedule 1. Piedmont does not have a separate BOD. The expense allocated to the Piedmont NC jurisdiction includes the BOD's compensation, directors' and officers' liability insurance, and other miscellaneous expenses. The first sentence of the Duke Energy Corporation Principles for Corporate Governance (Amended and Restated as of February 20, 2020),[1] states:

> An effective Board of Directors (the "Board") **will positively influence shareholder value** and enhance the reputation of Duke Energy Corporation (the "Corporation") as a constructive resource in the communities where it does business.

(Emphasis added.)

Under 1. Responsibilities of Directors, the first responsibility stated is:

> The basic responsibility of the directors is to exercise their business judgment to act in what they reasonably believe to be **in the best interests of the Corporation and its shareholders.**

(Emphasis added.)

Another stated responsibility is:

> A director should at all times discharge his or her responsibilities with the highest standards of

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[1] Retrieved from https://www.duke-energy.com/Our-Company/Investors/Corporate-Governance/Principles-Corp-Governance.

> ethical conduct, **in conformity with applicable laws and regulations, and act solely in the best interest of the Corporation's shareholders**.

(Emphasis added.)

Under 2. Director Nominations, it states that each director or director nominee should:

> Have a genuine interest in the Corporation and a recognition that, as a member of the Board, **one is accountable to the shareholders of the Corporation**, not to any particular interest group.

(Emphasis added.)

Shareholders vote on the election of directors. Unless they are shareholders, ratepayers do not have a vote. The excerpts above demonstrate that the BOD is expected to act in the best interests of the shareholders.

The average 2020 compensation of the 14 Duke Energy directors was $265,197. The test year BOD compensation allocation to the Piedmont NC jurisdiction was $721,478 as shown on Coleman Exhibit I, Schedule 1, Line 1.

This approach is consistent with the Public Staff's BOD expenses adjustment in Piedmont's last general rate case in Docket No. G-9, Sub 743 (Sub 743 rate case).

OTHER BENEFITS

Q. PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENT TO OTHER BENEFITS.

A. I recommend an adjustment of $2,570,681 to decrease the Company's proposed Other Benefits expense. The Company used budget projections as the basis for the pro forma adjustment. The Company's proposed increase to medical/dental benefits was based on a percentage of actual to budgeted projections and resulted in a pro forma level much higher than was actually incurred by the Company. The Public Staff calculated an amount based on a three-year average using actual medical/dental expenses for calendar years 2018, 2019, and 2020. The same methodology was also used to determine the Duke Energy Business Services (DEBS) medical/dental amounts. The total adjustment made to medical/dental expenses decreased the Other Benefits expense by $2,564,164.

For the Retirement Savings Plan expenses and the Basic Life and AD&D Other Benefits, the Public Staff used the test year data instead of the budgeted data since the budgeted amounts were not supported. The total adjustments maintain a reasonable ongoing level of Employee Benefits for the Company and are shown on Coleman Exhibit I, Schedule 2.

EXECUTIVE COMPENSATION

Q. PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENT TO EXECUTIVE COMPENSATION.

A. The Company made an adjustment that includes the removal of 50% of the total compensation of the top five Duke Energy executives, which is comprised of total annual salary, Short Term Incentive Plan (STIP), Long Term Incentive Plan (LTIP), and Benefits.

As shown on Coleman Exhibit I, Schedule 3, the Public Staff has updated the Company's executive compensation adjustment and identified the top five executives who have charged the highest compensation to the Piedmont NC jurisdiction. In this case, the top five are four Duke Energy executives (Chair, President and Chief Executive Officer; Executive Vice President, Energy Solutions and President, Midwest/Florida Regions and Natural Gas Business; Executive Vice President and Chief Operating Officer; and Executive Vice President and Chief Financial Officer) and Piedmont's Senior Vice President and Chief Commercial Officer, Natural Gas Business Unit.

Q. WHY DID YOU SELECT THE FOUR DUKE ENERGY EXECUTIVES AND THE PIEDMONT EXECUTIVE?

A. The Public Staff believes that basing executive compensation on the five executives who have charged the highest compensation to the

Piedmont NC jurisdiction instead of the top five Duke Energy executives is more appropriate because these positions are more closely aligned with Piedmont's efforts to minimize costs and maximize the reliability of Piedmont's service to customers than the top five Duke Energy executives selected by Piedmont.

This approach is consistent with the Public Staff's executive compensation adjustment in the Sub 743 rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

Mary A. Coleman

I am a graduate of North Carolina State University with a Bachelor of Accountancy degree and a Bachelor of Arts degree in Business Management.

Prior to joining the Public Staff, I was a Financial Consultant focusing mainly on non-profit organizations from 2013 until 2017. I was employed as a Consultant in places such as University of North Carolina-Chapel Hill, North Carolina State University, City of Raleigh-Community Development Office, Neuro Community Care, and the Carolina Center for Medical Excellence. Before I became a Consultant, I was the Chief Financial Officer for several organizations, including the North Carolina Justice Center where I worked for ten years.

I joined the Public Staff as a Staff Accountant in December 2017. Since joining the Public Staff I have assisted on natural gas, electric, and water proceedings.

MS. CULPEPPER: The witness is available for cross examination and Commission questions.

CHAIR MITCHELL: All right. Any questions -- any cross examination for the witness from the parties?

(No response.)

CHAIR MITCHELL: All right. I am not seeing any counsel indicate that they have cross examination for the witness, so I'll move to questions from Commissioners.

Commissioners, any questions for the witness?

(No response.)

CHAIR MITCHELL: All right. No questions for the witness from Commissioners either. So, Ms. Coleman, you may -- you are off the hook -- you too are off the hook for today. You may step down.

Ms. Culpepper, any reason not to excuse your witness?

MS. CULPEPPER: No reason not to.

CHAIR MITCHELL: All right. You may step down. You may be excused, Ms. Coleman.

And, Ms. Culpepper, you may have moved

that the exhibit to her testimony be marked for identification it was when prefiled.

MS. CULPEPPER: We would move it into evidence.

CHAIR MITCHELL: I will grant your initial motion, and I will grant te motion that it be admitted into evidence having heard no objection to that motion.

MS. CULPEPPER: Thank you.

(Coleman Exhibit 1 was admitted into evidence.)

CHAIR MITCHELL: All right. Public Staff may call its next witness.

MS. CULPEPPER: We call Julie G. Perry.

CHAIR MITCHELL: All right. Ms. Perry, raise your right hand, please, ma'am.

Whereupon,

JULIE G. PERRY,

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

CHAIR MITCHELL: All right. You have to go off mute. Unfortunately for you we've got some questions for you.

THE WITNESS: I was.

CHAIR MITCHELL: Okay. Now we can hear you. All right.

THE WITNESS: Okay. Well, I do.

CHAIR MITCHELL: Okay.

DIRECT EXAMINATION BY MS. CULPEPPER:

Q. Please state your name, business address and present position for the record.

A. My name is Julie G. Perry. My business address is 430 North Salisbury Street, Raleigh, North Carolina. My present position is accounting manager of natural gas and transportation in the accounting division of the Public Staff.

Q. On August 11, 2021, did you prepare and caused to be filed in this docket confidential and redacted versions of your testimony consisting of 31 pages including a cover sheet and Appendix A and eight exhibits?

A. Yes, I did. Is it on?

Q. It is now.

A. Okay.

Q. And for the record, portions of the testimony on page 22 are marked confidential; is that correct?

A. Yes.

Q. And Exhibits IV, VI, and VIII are marked confidential; is that correct?

A. Are you not hearing me?

Q. No. Not when --

A. I'm sorry.

Q. Did you say they're marked confidential?

A. Yes.

Q. Do you have any corrections to your testimony?

A. No, I do not. Sorry.

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

A. Yes, they would.

Q. Can you move closer, maybe, to your microphone?

A. Sure. Is that better?

Q. Yes.

MS. CULPEPPER: I move that the prefiled testimony consisting of 31 pages be copied into the record as if given orally from the stand. And I request that the confidentiality designations on page 22 of the testimony be preserved in the record as marked.

CHAIR MITCHELL: All right. Hearing no objection to that motion, it will be allowed, noting the confidentiality of portions of her testimony.

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	TESTIMONY OF JULIE G. PERRY PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

TESTIMONY OF JULIE G. PERRY

ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

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

A. My name is Julie G. Perry. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Accounting Manager of the Natural Gas & Transportation Section in the Accounting Division of the Public Staff.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth in Appendix A.

Q. WHAT IS THE NATURE OF THE APPLICATION IN THIS RATE CASE?

A. Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed an application with the Commission on March 22, 2021, in Docket No. G-9, Sub 781, with a test period ended December 31, 2021, seeking authority for: (i) a general increase in and revisions to the rates and charges for customers served by the Company; (ii) continuation of Piedmont's Integrity Management Rider (IMR) mechanism; (iii) continued regulatory asset treatment for certain incremental Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) operations and maintenance (O&M) expenses, and certain incremental environmental cleanup and remediation O&M expenses; (iv) continued utilization of the depreciation rates for the Company's North Carolina and joint property assets approved in Docket No. G-9, Sub 743, the Company's most recent general rate case in 2019 (Sub 743 rate case); (v) revised and updated amortizations and recovery of certain regulatory assets accrued since the Sub 743 rate case; (vi) utilization of the lead-lag study filed by Piedmont in the 743 rate case; (vii) adoption of a rider mechanism to allow Piedmont to recover the costs of its approved energy efficiency (EE) programs from customers on a commensurate basis with the electric utilities with whom Piedmont competes or, in the alternative, authorization to defer costs associated with Piedmont's approved energy efficiency programs pending amortization at the Commission's discretion at some later date; and (viii) other updates and revisions to Piedmont's rate schedules and service regulations.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's accounting and ratemaking adjustments and to incorporate the adjustments recommended by other Public Staff witnesses who work in the Accounting, Energy, and Economic Research Divisions. The Public Staff has made its adjustments based on its investigation of the revenue, expenses, and rate base presented by the Company in support of its request for an annual revenue requirement increase of approximately $109 million in this proceeding. In addition to this amount, the application also provides for continued decreases related to the remaining years of the approved Excess Deferred Income Taxes (EDIT) riders.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

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

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

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

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

A. Schedule 1 of Perry Exhibit I presents a reconciliation of the difference between the Company's requested revenue increase of $109,025,725 and the Public Staff's recommended decrease of ($462,808). In addition, the Public Staff has recommended decreases to the revenue requirement associated with the refund of the remaining EDIT riders approved in the Company's Sub 743 rate case.

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

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

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

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

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

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

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

(2) The recommendation of Public Staff witness Patel regarding the following items:

(a) Cost of Gas; and

(b) End-of-Period Revenues and Bills.

(3) The recommendation of Public Staff witnesses Singer and Williams regarding EE Programs.

(4) The recommendations of Public Staff witness Metz regarding the following items:

(a) Robeson LNG facility; and
(b) Design Day Allocator.

(5) The recommendations of Public Staff witness Feasel regarding the following items:

(a) Other Working Capital Updates;
(b) Deferred Transmission Pipeline Integrity Costs;
(c) Deferred Distribution Pipeline Integrity Costs;
(d) Deferred Environmental Costs; and
(e) Lead Lag Study.

(6) The recommendations of Public Staff witness Coleman regarding the following items:

(a) Board of Directors Expenses;
(b) Other Benefits; and
(c) Executive Compensation.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.

A. The accounting and ratemaking adjustments that I will discuss relate to the following items:

(1) Plant in Service
(2) Accumulated Depreciation
(3) Accumulated Deferred Income Taxes (ADIT)
(4) Depreciation Expense
(5) Property Tax
(6) Special Contract Adjustment
(7) Deferred Eastern NCNG Costs
(8) Deferred Undercollection of NCUC Regulatory Fee
(9) Other Operating Revenues
(10) Payroll
(11) Short-Term and Long-Term Incentive Plans (STIP and LTIP)
(12) Pension, Other Post-Employment Benefits (OPEB) and Long Term Disability (LTD) Expense

(13) Rate Case Expenses
(14) Regulatory Fee Expense
(15) Aviation Expenses
(16) Uncollectibles
(17) Advertising
(18) Lobbying
(19) Sponsorship and Dues
(20) Inflation
(21) COVID-19 Related Expenses
(22) Customer Payment Fees
(23) Non-utility Adjustment
(24) Interest on Customer Deposits
(25) Excess Deferred Income Taxes (EDIT) Riders
(26) Integrity Management Rider (IMR) mechanism and tariff
(27) EE Program Mechanism
(28) Duke Lincoln Contract and Commission questions

PLANT IN SERVICE AND ACCUMULATED DEPRECIATION

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PLANT IN SERVICE AND ACCUMULATED DEPRECIATION.

A. I have updated plant in service and accumulated depreciation for known and actual changes through May 31, 2021, the Public Staff's cutoff date for post-test year plant additions in this filing, and which effectively removed estimated additions for June 2021, as reflected by the Company.[1] I have also made an end-of-period depreciation adjustment to accumulated depreciation for the difference between the annual depreciation expense per the Public Staff and the book depreciation expense for the 12 months ended May 31, 2021. Perry

[1] As discussed later in this testimony, the Public Staff plans to consider the Company's June 2021 update in supplemental testimony.

Exhibit I Schedule 2-1 and all of its backup schedules reflect the calculation of and adjustments to plant in service and accumulated depreciation by the Public Staff.

In addition, I have made an adjustment to remove the Robeson LNG land and dedicated transmission lines closed to plant as of May 31, 2021 based on the recommendation of Public Staff witness Metz since the LNG facility is not yet in service.

ADIT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ADIT.

A. I have updated accumulated deferred income taxes to the amount recorded on the Company's books as of May 31, 2021, the Public Staff's cutoff date for post-test year plant additions in this filing.

DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. I made adjustments to (1) correct various depreciation rates that were approved in the depreciation study included in the Sub 743 rate case, and (2) apply the approved rates to present an annualized amount of depreciation expense based on the actual plant in service as of May 31, 2021. Perry Exhibit I, Schedule 2-1 and all of its backup schedules reflect the calculation of and adjustments to depreciation expense by the Public Staff.

PROPERTY TAX

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPERTY TAX.

A. Based on data request responses, the Company revised the property tax rate used to calculate property tax expense in this proceeding. I have applied the revised property tax rate to the net plant in service balance as of May 31, 2021, in order to calculate property tax expense. Perry Exhibit I, Schedule 2-1 and all of its backup schedules reflect the calculation of and adjustments to property tax made by the Public Staff.

SPECIAL CONTRACT ADJUSTMENT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SPECIAL CONTRACTS.

A. I have removed the estimated plant and accumulated depreciation associated with the initial Duke Lincoln contract since Duke Energy Carolinas, LLC (DEC), previously paid Piedmont for the entire cost of the pipeline serving the Duke Lincoln plant. I have made this adjustment using the Sub 743 rate case adjustment data because the Company did not provide this information in response to a Public Staff data request.

EASTERN NCNG DEFERRED O&M EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO EASTERN NCNG DEFERRED O&M EXPENSES.

A. The Company updated the amortization amount in the cost of service consistent with the Sub 743 rate case treatment. During its investigation in this proceeding, the Public Staff found some incorrect assumptions in the calculations that were approved in the Sub 743 rate case and has corrected them in this case. The Public Staff recommends that the revised principal and interest balances be amortized over the Company's proposed four-year amortization period in this case at the net of tax overall rate of return approved in this case.

DEFERRED UNDERCOLLECTION OF NCUC REGULATORY FEE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEFERRED UNDERCOLLECTION OF NCUC REGULATORY FEE EXPENSE.

A. The Public Staff updated this adjustment consistent with the balance approved in the Sub 743 rate case order and reflected amortizations through November 30, 2021, to estimate the expected date of rates in this proceeding, whereas the Company updated amortizations through October 31, 2021. I have amortized the remaining balance over four years consistent with the Company's adjustment.

The Public Staff further recommends that the deferred balance less one full year of amortization be allowed to earn a return in rate base. In making this recommendation, the Public Staff does not intend to indicate that it believes these deferred costs to constitute used and useful property; instead, the Public Staff has included the costs in rate base as a convenient and efficient way of providing for a return on the deferred costs. The Public Staff considers the provision for a return to be reasonable in this case, but believes that the Commission's provision of such is discretionary, not obligatory, in nature.

OTHER OPERATING REVENUES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO OTHER OPERATING REVENUES.

A. The Company reflected the test year level of other operating revenues in its application, which were extremely low. The Company stated that it continues to be subject to the Commission requirement in Docket No. M-100, Sub 158 to forgo assessing late payment charges on customer accounts and is uncertain as to when the Commission will lift this moratorium on the Company's ability to assess late payment charges on customer accounts. I have determined an ongoing reasonable level of Late Payment Revenues, Miscellaneous Service Revenues, and Rent from Gas Properties by utilizing a five-year average of these other operating revenues. This methodology recognizes the extremely low test year levels along with higher years in determining a reasonable, ongoing level once the COVID-19 restrictions have been lifted.

PAYROLL EXPENSE

Q. PLEASE EXPLAIN YOUR PROPOSED PAYROLL EXPENSE ADJUSTMENT.

A. I updated the annualized payroll expense to a level that reflects pay rates and employees as of May 31, 2021, excluding temporary positions, which resulted in a reduction to the Company's pro forma level of payroll expense as reflected in Perry Exhibit I, Schedule 3-1.

INCENTIVE PLANS

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

A. The Company offers two incentive plans to its employees: the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). The STIP is offered to all employees, including executives. The LTIP is comprised of two programs: the Executive LTI Plan and the Restricted Stock Units (RSU) Plan. Employees that are members of the Executive Leadership Team participate in the Executive LTI Plan.

The STIP consists of goals set and approved by the Board of Directors (BOD) of Duke Energy Corporation (Duke Energy) for a one-year term. In 2020, the test year in this case, the goals consisted of Earnings per Share (EPS), Operational Excellence, Customer Satisfaction, as well as team and individual goals. The LTIP consists of Performance Shares, which are further categorized between EPS and Total Shareholder Return (TSR), and RSU. The LTIP goals are set and approved by the BOD for a three-year period.

I have adjusted the Company's STIP pro forma level to exclude the amounts that were based on the EPS metric for only the top executives that are also included in the LTIP. The Public Staff believes that the incentives related to EPS should be excluded because they provide a direct benefit to shareholders, rather than to ratepayers. It should be further noted that the EPS portion of the STIP accounts for 50% of the executive level employee accrual.

I have adjusted Company's STIP pro forma level to exclude the EPS and TSR metrics. The Public Staff believes that the incentives related to EPS and TSR should be excluded because they provide a direct benefit to shareholders, rather than to ratepayers. Therefore, these costs should be borne by shareholders. This treatment is consistent with incentive adjustments approved by the Commission in the last general rate cases of DEC in Docket No. E-7, Sub 1214 (DEC Sub

1214 rate case) and Duke Energy Progress, LLC (DEP), in Docket No. E-2, Sub 1219 (DEP Sub 1219 rate case). My adjustment is shown on Perry Exhibit I, Schedule 3-2.

PENSION, OPEB AND LTD EXPENSE

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO THE COMPANY'S PENSION EXPENSE.

A. In the current rate case filing, the Company proposed an increase to its ongoing annual pension, OPEB, and LTD expense based on the Company's 2021 projection. The Public Staff decreased the expense amounts by using an annualized ongoing expense amount on Piedmont's books as of May 31, 2021, to compute its adjustment as shown on Perry Exhibit I, Schedule 3-3.

RATE CASE EXPENSES

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO DEFERRED RATE CASE EXPENSES.

A. The Company proposed that the unamortized balance of rate case expenses plus the estimate of rate case expenses for the current general rate case be amortized over a four-year period. The Public Staff has reviewed the actual invoices paid as of June 30, 2021, and the contracts related to the various consultants. I included an expense level that reflects an average of the difference between the

Company's proposed amount and actual payments to determine the rate case expenses. The Public Staff did allow actual payments for regulatory notices.

The Public Staff did not include the unamortized balance of rate case expenses from the Sub 743 rate case in its adjustment since the Company has not been allowed deferred accounting treatment for rate case expenses. This treatment is consistent with the treatment of rate case expenses adjustments approved by the Commission in the DEC Sub 1214 rate case and the DEP Sub 1219 rate case, since the Commission has not approved regulatory asset treatment for rate case expenses for a gas or electric utility.

ADJUSTMENT TO REGULATORY FEE EXPENSE

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO THE NCUC REGULATORY FEE.

A. In its Order Decreasing Regulatory Fee Effective July 1, 2019 (issued June 18, 2019, in Docket No. M-100, Sub 142), the Commission ordered that the regulatory fee for noncompetitive jurisdictional revenues shall be set at 0.13% effective July 1, 2019. The Public Staff made an adjustment to update the regulatory fee expense as needed for adjustments that impact revenues in this rate case.

AVIATION EXPENSES

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

A. The Company made an adjustment to remove 50% of aviation expenses; however, the Public Staff made an additional adjustment after investigating the aviation expenses charged to Piedmont's North Carolina (NC) jurisdiction during the test year. Aviation expenses are allocated to Piedmont through Duke Energy's service company, Duke Energy Business Services LLC (DEBS), and then are apportioned to Piedmont's NC operations through a North Carolina jurisdictional allocation factor. Since corporate aircraft are available for use by Duke Energy's officers, I reviewed the flight logs to determine whether the flights charged to Piedmont should be recoverable from ratepayers. Based on this review, I recommend that certain expenses allocated to Piedmont's NC jurisdiction be removed due to fact that most of the flights do not appear to have anything to do with providing natural gas utility service. I also recommend that 50% of expenses related to BOD flights be disallowed consistent with the BOD expense adjustment recommended by the Public Staff. My adjustment is shown on Perry Exhibit I, Schedule 3-16.

UNCOLLECTIBLES EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UNCOLLECTIBLES EXPENSES.

A. The Company made an adjustment to increase uncollectibles expenses for the test period ended December 31, 2020, by excluding the 2020 test period due to the COVID-19 pandemic and using the highest two years of net write-offs expense as compared to the last five years, which reflected a much higher-than-average uncollectibles percentage and expense level.

Pursuant to its Purchased Gas Adjustment procedures, Piedmont recovers the gas cost portion of uncollectible account write-offs by charging the actual amounts to its Gas Cost Deferred Account. Therefore, the only portion of uncollectibles that should be included in O&M expenses in a rate case proceeding is the non-gas cost, also known as “margin,” portion of customer bills.

My adjustment uses the NC charge-offs based on a five-year average of net NC charge-offs to sales and transportation revenues. Even though the Company’s net charges-offs for 2020 were low, I recommend taking a five-year average since the other recent years reflect very high uncollectible data due to cold weather events. Therefore, my adjustment resulted in a decrease in uncollectibles expense while reflecting an ongoing reasonable level as shown on Perry Exhibit I, Schedule 3-4.

ADVERTISING EXPENSES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO ADVERTISING EXPENSES.

A. I first requested a detailed listing of all advertising expenses for the test period. From this listing, I reviewed expenses from each advertising account and also requested documentation to support the expenses.

My adjustment, which is shown in Perry Exhibit I, Schedule 3, is consistent with Commission Rule R12-13 and the Public Staff's position in all of Piedmont's previous general rate case proceedings.

LOBBYING EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LOBBYING EXPENSES.

A. I have adjusted O&M expenses to remove lobbying activities charged to Piedmont during the test period consistent with the Public Staff's positions in the Sub 743 rate case, DEC Sub 1214 rate case, and the DEP Sub 1219 rate case. I adjusted lobbying expenses to remove O&M expenses associated with Stakeholder Strategy and Federal Government Affairs that were recorded above the line during the test period. I recommend that test year lobbying expenses be adjusted as shown in Perry Exhibit I, Schedule 3-17.

SPONSORSHIPS AND DUES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SPONSORSHIPS AND DUES.

A. I have decreased O&M expenses to remove amounts charged for sponsorships and dues. These expenses should be disallowed because they were not incurred in order to provide natural gas service to Piedmont's customers. My recommended adjustment is shown in Perry Exhibit I, Schedule 3-18.

INFLATION

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR INFLATION.

A. The Company made an adjustment to test period non-labor, non-fuel O&M costs to reflect an increase in O&M expenses from the test year that have not been adjusted elsewhere in the Company's filing. I made an adjustment to inflation by first adjusting the base level of O&M expenses used in the calculation to remove test year customer growth-related expense accounts that the Company did not adjust for in its filing due to higher than normal growth during the 2020 test year. I have removed the customer billing expenses that are typically removed since these expenses are most likely already unusually higher than normal if growth was higher than normal during the test period. Next, I have removed the test year expenses for additional adjustments that the Public Staff is recommending, such as to advertising, lobbying, and sponsorships and dues. Lastly, I have reflected an updated inflation factor recommended to me by Public Staff witness Hinton that uses the same methodology as the Company, updated for 2021 and was applied to the remaining base level of O&M expenses. These adjustments resulted in a Public Staff adjustment as shown on Perry Exhibit I, Schedule 3-15.

COVID-19 RELATED EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO COVID-19 RELATED EXPENSES.

A. The Company incurred approximately $2.5 million of COVID-19 related expenses during the test period. The Company removed approximately $600,000 as non-recurring expenses for employee stipends and walk-in fees from the test period and additionally requested recovery of customer payment fees of approximately $863,000. The remaining $953,000 was not supported as being an ongoing level of expense and, therefore, the Public Staff made an adjustment to remove it.

CUSTOMER PAYMENT FEES

Q. PLEASE DESCRIBE PIEDMONT'S CONVENIENCE FEES.

A. Piedmont's residential customers who are assisted by a customer service representative to make a payment over the telephone by credit card, debit card or bank draft (ACH) are assessed a $3.50 convenience fee by the credit card payment vendor, Speedpay, Inc. (Speedpay). These convenience fees have never been included in the cost of service. Residential customers do not incur any direct transaction fee for using their credit card, debit card, or ACH for payment of bills through any of the other payment channels currently offered by Piedmont; however, the fees paid by Piedmont for these transactions are included in the cost of service.

Q. HOW IS PIEDMONT PROPOSING TO HANDLE CONVENIENCE FEES FOR CUSTOMER SERVICE REPRESENTATIVE ASSISTED PAYMENTS FOR RESIDENTIAL CUSTOMERS IN THIS PROCEEDING?

A. During the period of April through December 2020 (nine months of the test period in this proceeding), the Company waived the convenience fee for customer service representative assisted payments for residential customers and paid the third-party vendor directly. The Company made a pro forma adjustment in this case to include in the cost of service Speedpay convenience fees for residential customers making payments over the telephone and stated in response to a Public Staff data request that Piedmont would no longer charge customers for using the payment method. The Company is requesting that it be allowed to recover an annualized level of these fees on an ongoing basis from all customers.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO CUSTOMER PAYMENT EXPENSE?

A. The Public Staff believes that the inclusion of the costs for payments over the telephone with a customer service representative based on a fee of $3.50 per transaction is excessive. The contract with Speedpay was entered into in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and the Public Staff believes the convenience fee may be outdated. In comparison, the Public Staff has found that a convenience fee of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

The Public Staff recommends that the Company seek to renegotiate a lower transaction fee for customer service representative assisted payments in its contract with Speedpay. Alternatively, Piedmont could **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

In lieu of removing the total pro forma expense amount, the Public Staff recommends an adjustment based on a lesser per transaction fee as shown in Perry Exhibit I, Schedule 3-7.

NON-UTILTY ADJUSTMENT

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NON-UTILITY ADJUSTMENT?

A. The Company did not allocate a proportionate share of its general administrative costs to its merchandising and jobbing (M&J) operations and none to its equity investment affiliates. The Public Staff applied revised non-utility factors to certain administrative and general (A&G) senior level salaries, other corporate O&M expense accounts, and general plant accounts. The revised factors incorporate investment, revenues, and payroll in equity companies at December 31, 2020. Based on Piedmont's response to a Public Staff data request, I had a difficult time determining how certain charges from DEBS were being handled as far as the equity investment companies owned by Piedmont. I, therefore, included some but not all of the equity investment companies in my calculation of the non-utility factors.

The Company allocated a portion of its plant, accumulated depreciation, and depreciation expense to its M&J operations, and none was allocated to its equity investment affiliates. I have allocated a portion of the Company's plant, accumulated depreciation, and depreciation expense to the M&J operations and the equity investment affiliates using the revised three-factor formula method that was determined based on investment, revenues, and payroll as shown on Perry Exhibit I, Schedule 3-19.

EDIT RIDERS

Q. PLEASE DESCRIBE YOUR EDIT EXHIBIT II.

A. Perry Exhibit II, Schedule 1 presents the calculation of Federal Protected EDIT amounts in the Company's rate base and income statement based on the remaining amortization period approved in the Sub 743 rate case.

Perry Exhibit II, Schedule 2 sets forth the calculation of an annual Federal Unprotected EDIT Rider amount to be in effect for three remaining years.

Perry Exhibit II, Schedule 3 sets forth the calculation of an annual State EDIT Rider amount to be in effect for one remaining year.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO FEDERAL EDIT.

A. In the prefiled direct testimony and exhibits of Company witness Bowman, adjustments were not reflected to address the EDIT credit riders that were approved in the Sub 743 rate case. In response to Public Staff data requests, the Company stated that it was not aware of a requirement for the Company to propose a change to these settled and approved matters as a part of future general rate cases (including this current one) nor any other proceeding.

The Public Staff updated the return cost components recommended by Public Staff witness Hinton in the calculation of the levelized Federal Protected and Unprotected EDIT credits, as well as the levelized State EDIT credit and accordingly updated each credit for the remaining amortization period. In addition, the Company's responses indicated that certain reclassifications had been made between the Protected and Unprotected Federal EDIT balances. The Public Staff believes these adjustments to be reasonable for purposes of this proceeding and has recalculated the Federal Protected and Unprotected EDIT credits using the revised balances estimated at December 1, 2021, the estimated effective date of rate in this proceeding, and the remaining amortization periods approved in the Sub 743 rate case.

IMR MECHANISM AND TARIFF

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE IMR MECHANISM?

A. As discussed in the Public Staff's 2020 Annual IMR Report in Docket No. G-9, Sub 777, Piedmont and the Public Staff worked together to modify the IMRR model to address the Public Staff's concerns primarily in the determination of accumulated depreciation and ADIT during the Sub 743 rate case proceeding. During the Public Staff's review of the IMRR model since the Sub 743 rate case, we have determined that additional modifications may be needed in these areas to better align the plant and annual depreciation expense allowed in the IMR with the offsetting credits to accumulated depreciation and ADIT on a go forward basis. The Public Staff plans to send to Piedmont a template of its proposed modifications to the mechanism prior to the Company's Annual IMR filing on October 31, 2021, and will work with the Company to implement these changes.

The Public Staff will also update the tariff inputs for the margin percentages by month and by rate class, as well as the special contract credits once this hearing is complete.

ENERGY EFFICIENCY PROGRAM MECHANISM

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RECOVERY OF THE EE PROGRAMS?

A. Based on the Public Staff's recommendation to approve the Company's portfolio of programs as pilot programs for a three-year period, we have determined that the Public Staff does not oppose the implementation of an EE Rider. The structure of this Rider still remains under discussion and the final recommendation of the Public Staff will be provided in supplemental testimony.

DUKE LINCOLN CT CONTRACT

Q. **DO YOU AGREE WITH THE PUBLIC STAFF'S RECOMMENDATIONS FILED ON JUNE 1, 2020, IN DOCKET NO. G-9, SUB 722 IN RESPONSE TO THE COMMISSION'S ORDER GRANTING EXTENSION OF INTERIM AUTHORITY TO OPERATE UNDER SECOND REVISED AGREEMENT AND REQUIRING PUBLIC STAFF ACTION ISSUED APRIL 20, 2020?**

A. Yes. The Public Staff's recommendations and proposed order filed on June 1, 2020, are attached hereto as Perry Exhibit III and Confidential Perry Exhibit IV.

Q. **DO YOU ALSO AGREE WITH THE PUBLIC STAFF'S JUNE 24, 2020 FILING, WHICH CORRECTED SEVERAL PAGES OF THE PUBLIC STAFF'S RECOMMENDATIONS AND REVISED THE PROPOSED ORDER FILED ON JUNE 1, 2020?**

A. Yes. The Public Staff's corrected recommendations and revised proposed order filed on June 24, 2020, are attached hereto as Perry Exhibit V and Confidential Perry Exhibit VI.

Q. **DO YOU ADOPT THE PUBLIC STAFF'S RECOMMENDATIONS MADE ON JUNE 1, 2020, AS CORRECTED BY THE PUBLIC STAFF'S JUNE 24, 2020 FILING, AS YOUR TESTIMONY IN THIS PROCEEDING?**

A. Yes.

Q. DO YOU HAVE ANY MODIFICATIONS TO THE CORRECTED RECOMMENDATIONS?

A. No.

Q. **HAVE YOU PREPARED RESPONSES TO THE COMMISSION'S QUESTIONS IN ATTACHMENT A TO ITS ORDER CONSOLIDATING DOCKETS AND REQUIRING FILING OF TESTIMONY ISSUED MARCH 16, 2021?**

A. Yes. The responses are attached hereto as Perry Exhibit VII and Confidential Perry Exhibit VIII.

<u>COMPANY'S UPDATE FILING</u>

Q. WHAT ARE YOUR COMMENTS REGARDING THE COMPANY'S UPDATE FILING MADE ON JULY 28, 2021 (JUNE UPDATE)?

A. The Public Staff is aware of the June Update; however, given the timing of the update filing and the due date of the Public Staff's testimony, the Public Staff could not reasonably perform its investigation on the Company's updated information in the short amount of time before it was due to file testimony. The Public Staff reserves the right to file supplemental testimony related to the Company's June Update once its investigation of the updated information is completed.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JULIE G. PERRY

I graduated from North Carolina State University in 1989 with a Bachelor of Arts degree in Accounting and I am a Certified Public Accountant.

Prior to joining the Public Staff, I was employed by the North Carolina State Auditor's Office. My duties there involved the performance of financial and operational audits of various state agencies, community colleges, and Clerks of Court.

I joined the Public Staff in September 1990, and was promoted to Supervisor of the Natural Gas Section in the Accounting Division in September 2000. I was promoted to Accounting Manager – Natural Gas & Transportation effective December 1, 2016. I have performed numerous audits and/or presented testimony and exhibits before the Commission addressing a wide range of natural gas topics.

Additionally, I have filed testimony and exhibits in numerous water rate cases and performed investigations and analyses addressing a wide range of topics and issues related to the water, electric, transportation, and telephone industries.

MS. CULPEPPER: I also move that Exhibits I through VIII be identified as marked when filed and request that the confidentiality of Exhibits IV, VI, and VIII be preserved in the record as marked.

CHAIR MITCHELL: All right. The exhibits to Ms. Perry's testimony will be marked for identification as they were when prefiled with confidentiality. Certain of those exhibits will be noted.

MS. CULPEPPER: Thank you.

(Perry Exhibits I through III, Confidential Perry Exhibit IV, Perry Exhibit V, Confidential Perry Exhibit VI, Perry Exhibit VII, and Confidential Perry Exhibit VIII were identified as they were marked when prefiled.)

Q. Ms. Perry, on September 7, 2021, did you prepare and cause to be filed in this docket supplemental and settlement testimony consisting of five pages and one exhibit?

A. Yes, I did.

Q. Do you have any corrections to that testimony?

A. (Sound failure.)

(Reporter interruption due to sound failure.)

THE WITNESS: No. I don't know what's going on with this. I'm sorry.

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

A. Yes, they would.

MS. CULPEPPER: I move that the prefiled supplemental and settlement testimony consisting of five pages be copied into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to that motion, it will be allowed.

(Whereupon, the prefiled supplemental testimony and prefiled settlement testimony of Julie G. Perry were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	SUPPLEMENTAL AND SETTLEMENT TESTIMONY OF JULIE G. PERRY PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

SUPPLEMENTAL AND SETTLEMENT TESTIMONY OF
JULIE G. PERRY

ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 7, 2021

Q. MS. PERRY, WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL AND SETTLEMENT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my supplemental and settlement testimony is to support the Stipulation of Partial Settlement (Stipulation) between Piedmont Natural Gas Company, Inc. (Piedmont or the Company) and the Public Staff (collectively, the Stipulating Parties) dated September 7, 2021, and provide testimony regarding Piedmont's updates as of June 30, 2021, filed July 28, 2021.

Q. PLEASE BRIEFLY DESCRIBE THE TERMS OF THE STIPULATION.

A. The Stipulation sets forth agreement between the Stipulating Parties regarding the following revenue requirement and rate issues:

(1) Return on Equity, Capital Structure, and Debt Cost

(2) Update of revenues, cost of gas, rate base, and expenses to June 30, 2021

(3) Employee Compensation Adjustments

(4) Miscellaneous Operations and Maintenance (O&M) Expenses

(5) Uncollectibles Adjustment

(6) Board of Directors Expenses

(7) Non-Utility Adjustment

(8) Lead Lag Adjustment

(9) Amortization of Certain Regulatory Assets and Rate Case Expense

(10) Return the remaining unprotected federal excess deferred income taxes (EDIT) due to the Tax Cuts and Jobs Act to customers

(11) Return the remaining North Carolina state EDIT due to reduction in state tax rates.

(12) Continuation of the Integrity Management Rider

(13) Energy Efficiency Programs and Rider

(14) Allow the record in this case to remain open for the purpose of allowing the Company to file with the Commission the actual amounts closed to plant for determining the final impact of the Robeson LNG plant and the Pender Onslow Expansion projects on the overall revenue increase authorized in this docket.

(15) In addition to the settled issues having a revenue requirement impact in the present case, the Stipulation also settles non-revenue requirement issues involving transmission allocation, regression analysis, and rate design studies, audit and reporting obligations for Pipeline Integrity Management Transmission (PIM-T) costs, Pipeline Integrity Management Distribution (PIM-D) costs, and environmental deferrals.

The details of the agreement regarding these issues are set forth in the Stipulation.

A reconciliation of the June updates and settlement adjustments to Piedmont's filed rate increase is shown on Perry Settlement Exhibit I.

Q. WHAT BENEFITS DOES THE STIPULATION PROVIDE FOR RATEPAYERS?

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

(a) A reduction in the Company's proposed revenue increase in this proceeding.

(b) The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

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

Q. ARE THERE ANY AREAS ABOUT WHICH THE STIPULATING PARTIES DID NOT REACH AGREEMENT?

A. Yes. The Stipulating Parties reached agreement on all issues in Docket No. G-9, Subs 781 and 786; however, no issues raised by the pleadings and testimony in Docket No. G-9, Sub 722 have been resolved by the Stipulation and all such issues remain pending before the Commission for resolution.

Q. WHEN WILL THE PUBLIC STAFF PRESENT ITS CALCULATION OF THE FINAL REVENUE REQUIREMENT, INCLUDING THE IMPACTS OF THE ROBESON LNG PLANT AND THE PENDER ONSLOW EXPANSION PROJECT IN THE STIPULATION?

A. Once the Public Staff has completed the audit of Piedmont's actual costs booked to plant based on the performance metrics agreed to with the Public Staff for the Robeson LNG plant and the actual cost data closed to plant for the Pender Onslow Expansion project, the Public Staff will file schedules supporting the Public Staff's recommended revenue requirement.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. CULPEPPER: I also move that Perry Settlement Exhibit I be identified as marked when filed.

CHAIR MITCHELL: The exhibit to her testimony will be marked for identification as it were when it was prefiled.

(Perry Settlement Exhibit I was identified as they were marked when prefiled.)

MS. CULPEPPER: The witness is available for cross examination and Commission questions.

CHAIR MITCHELL: All right. Cross examination for the witness?

MR. JEFFRIES: Piedmont has cross examination for Ms. Perry, Chair Mitchell.

CHAIR MITCHELL: All right. You may proceed.

MR. JEFFRIES: Thank you. Chair Mitchell, before I begin, I hope to be brief on cross examination, and the first half of my cross I think I've been able to successfully sanitize it so we don't have to worry about disclosing confidential information, but I do have two short brief lines of questions that I'm afraid we're gonna have to go back on the phone for at the end, so I just wanted to alert you to that fact.

CHAIR MITCHELL: Okay. Well, please do what you can to avoid the use of confidential information. Ms. Perry, please do the same. To the extent that a question asked requires that you disclose confidential information, let us know before you answer the question. You know the routine.

All right. Mr. Jeffries, you may proceed.

MR. JEFFRIES: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. JEFFRIES:

Q. Good afternoon, Ms. Perry, how are you?

A. As good as I can be.

Q. Okay. This won't take long, I don't think. We've had some -- I won't say it's been confusing, but there are a number of contracts we've discussed today that relate to Piedmont's service to DEC facilities at the Lincoln plant, correct?

A. Correct.

Q. I'm making reference right now, for the next couple of questions, to the contract that was filed on

April 23, 2018, which is the current contract in Docket 722, and specifically with regard to that part of that contract that addresses service to the new Unit 17 at the Lincoln plant. So are we straight on that?

A. Straight on that. Okay.

Q. Okay. And that contract, when it was filed on April 23, 2018, was filed without any volumetric charge included, correct?

A. The first contract, yes. The first -- yes, it was. After -- yeah. But they had agreed to do a volumetric charge and hadn't, so that's -- yes, but they filed it with that one, yes.

Q. Okay. But the first one had no volumetric charge in it, right?

A. (Sound failure.)

(Reporter interruption due to sound failure.)

MR. JEFFRIES: Oh, I'm sorry.

THE WITNESS: Yes, but. Yes, but.

Q. We'll get to the "but."

That's consist with the way in which Piedmont has filed electric generation contracts over the last 15 or 16 years, correct?

A. That's the way Piedmont has filed its -- most of its combined cycle electric generation contracts. This is a CT, so we have not had that approach done with a CT yet.

Q. Right. And those other CC contracts you're referring to predate 2005, correct?

A. But.

Q. Okay.

A. Sorry. We can talk about that, but there's one. There's one --

Q. So -- so that was the original filing, no volumetric charges. And then Piedmont made a subsequent filing in November of 2018 that was based upon the Public Staff's concerns about the lack of, I think what the Public Staff refers to as a system support surcharge. And they refiled a revised agreement for Unit 17 at the DEC Lincoln plant, which included a volumetric surcharge component, correct?

A. (Sound failure.)

Q. I'm sorry, I couldn't hear you.

A. I said it did. I'm going to pull this closer. I'm sorry.

CHAIR MITCHELL: It may be that you just need to scoot as close to your microphone as you can, Ms. Perry.

THE WITNESS: Great. You guys are going to get close up.

CHAIR MITCHELL: There you go.

Q. And so then to kind of complete the cycle, on June 1, 2020, the Public Staff basically filed its own proposal which included a volumetric surcharge, but it was a larger volumetric surcharge than the one Piedmont had proposed for -- again, for service to the Unit 17 at the DEC Lincoln plant, correct?

A. So we filed because the Commission requested us to file comments with the recommendation, which we had not done yet at that point in time. So yes, we did, and that was consistent with other contracts you had, so.

Q. Okay. And are you familiar with Piedmont's feasibility model that they utilize to evaluate new projects on their system?

A. Unfortunately, I'm very familiar with everybody's feasibility model in the state.

Q. Is it your experience that Piedmont uses that model on a regular basis when they're looking at the possibility of providing service to new customers?

A. They would use it for mainly your large industrial and your special contract and your electric gen. I think they would use a different one when they're looking at residentials.

Q. And you're -- thank you for that. I think you're right about that.

The -- and you've heard Piedmont say that they apply that model in a uniform manner to all new industrial customers, correct?

A. Yes. Yes. We usually have input on that to some degree, too.

Q. Right. And you're not aware of any evidence in this case that indicates that they didn't use their standard practice in applying that model to Unit 17 at the DEC Lincoln plant, correct?

A. Well, if you're talking -- okay. So we -- they use the same model they've been using. Okay? But the assumptions that go in that model are also -- you have to look at the assumptions that are in the model, too, so -- but yes, the same model. And I duplicate their model, so I know the -- you know, I follow it, so yeah.

Q. Okay. And Piedmont's practice is that, when they file these special contracts with a fixed demand rate, that that model is actually the basis for the cost they use to establish a fixed demand rate, correct?

A. Can you, like, say that one more time?

Q. Yes, yeah. I think we've established that they use a consistent model to evaluate new industrial load on their system and that you're familiar with that, and that, you know, different assumptions may go in depending on the nature of the specific project. But I'm not now trying to take the next step, and that is the calculation of rates.

And it's my understanding, and I'm asking if it's your understanding, that Piedmont uses the results of their model to calculate fixed demand rates that go into their proposed contracts?

A. Yeah. They call it a demand charge. So it's a fixed demand charge for the term of the contract, whether it's 5, 10, 20 years, and typically it's your -- here's the magic word here -- incremental investment to connect the customer onto the Piedmont system. That's typically what -- it's the incremental capital and O&M on that project.

Q. Right. So based on those facts, is it fair to say that the Public Staff's concern in this docket is not recovery of the incremental cost of service to DEC Lincoln Unit Number 17, because that's baked into the demand charges, but it's that you are looking to add a volumetric charge to recover amounts in excess of the incremental cost?

A. So I'm looking at adding costs that would -- they would be -- let's put it nicely. They're part of the system, they're transporting gas on the system, and it's a redelivery contract. It says it's a redelivery contract. So it's actually the cost to redeliver that gas as any other transportation customer, and they're a firm transportation customer rate 113. What I'm just saying is I don't think they've assigned enough cost on the system to that contract.

And so I'm trying -- if we figure out a rate and we figure out how to assign cost, it should all net to about where we are now. But I just think we have additional costs that are not being assigned to that electric gen contract.

Q. Right. And my point is that those costs are system costs that are being incurred that you don't think are necessarily appropriately allocated, and that's what your volumetric charge is designed to recover. But it's not the incremental cost as Piedmont calculates them to provide this service?

A. It's completely separate from the incremental costs, yes.

Q. Okay. Thank you.

So as we've discussed, Piedmont's been providing service to the Lincoln facility for -- I learned something today, since 1993. I thought it was --

A. I knew that.

Q. Well, good, you're ahead of me. You weren't -- and so -- and now I'm referring to the -- what I used to call the original DEC Lincoln agreement but I now call the 2004 DEC Lincoln agreement.

And you weren't involved in the negotiation of that agreement, right?

A. Hopefully I'm not involved in negotiating anything, because I'm just the one who reviews it and approves it. I'm sure I was involved in -- when it was in front of us and the Commission. So I can tell you that some of the facts this morning were not exactly the right ones, but I'll let you go.

Q. Well, no, I was gonna ask you a question about that.

A. Uh-huh.

Q. I mean, given that you weren't -- so let me try this again.

You just indicated that you believe you were involved in reviewing that contract when it --

A. I approved it, so yeah, I should be. I approved it.

Q. Okay.

A. I recommended approval for it.

Q. All right. But that was after the contract was presented to you and it was --

A. Right.

Q. And you didn't have any involvement with it up until that point in time?

A. I don't negotiate contracts.

Q. Okay.

A. Try not to. Try not to.

Q. And you're familiar with the physical arrangement through which DEC Lincoln is and has been served on Piedmont's system, correct?

A. I am. The original one and the new one, yes.

Q. And the original one was a single transmission line. I think Mr. Barkley talked about it some earlier today.

It's a single transmission line directly connected to Transco, right?

A. The second part, yes.

Q. Right. And we'll get to that in just a second.

A. Yeah.

Q. There are no other Piedmont customers served off the original line, correct?

A. Right, correct.

Q. And it's not connected to any other part of the Piedmont system, correct?

A. As far as I can tell, yes.

Q. Okay. And as far as you know, all of that, that was true in 1993 or 2004 or whenever that arrangement was adopted, but it's also still true today, right?

A. True, yes, uh-huh.

Q. Okay. And the new incremental line is essentially in a similar situation. That line, which I think we had heard testimony earlier today, is about 1,000 feet long.

It actually connects to and extends the original line, right?

A. I think it connects -- I'm gonna just point because I like to, but I think it connects and then it connects to the old system, old units. I think it's like now a big circle, so yeah.

Q. Okay. All right. But again, there are no other Piedmont customers served off the new line, correct?

A. (Sound failure.)

Q. I'm sorry, that was a yes?

A. No, uh-uh. No other customers.

Q. And again, like the original line, it's not connected to any other part of Piedmont's distribution system, correct?

A. Part of Piedmont's system, but no.

Q. Okay. Well, I understand you contend that that is part of Piedmont's system, but what I'm asking is, it's not physically connected to any other part of Piedmont's system, correct?

A. Well, I consider their whole -- we can just agree to disagree. I consider that if it's Piedmont's monopoly and they have their CPCN and that's their territory, then that's Piedmont's system. And if Piedmont is serving them, then yes. If they have to get a contract to serve with them, then it's Piedmont's system. That's where I'm coming from, so.

Q. Yeah. No, I understand. And I think my question is really quite a bit simpler than that.

It's just, physically, there are no other interconnections of that pipeline with any other part of Piedmont's distribution --

A. True. Yes, true. And that's very similar to we have an Owens-Brockway that I've cited in my comments that we just had similar issues with, so I get it, yes.

Q. Not the only part of Piedmont's system that's configured that way?

A. Yes.

Q. Okay.

MR. JEFFRIES: Madam Chair, I think I've exhausted the sanitized version of my questions for Ms. Perry. I do have probably about an equal amount of questions that I think we need to go on the phone for.

CHAIR MITCHELL: All right. Before we leave the video conference and go on the phone line, I want to check in to see if any other party has cross examination for this witness that we can handle in open setting.

(No response.)

CHAIR MITCHELL: All right. I'm not seeing any. All right, so let's leave the video conference now and get on the phone line, and I'll take a roll of Commissioners once we're on the phone line.

(Due to the proprietary nature of the testimony found on pages 427 to 445, it was filed under seal.)

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CHAIR MITCHELL: All right. So just checking back in with you, Mr. Jeffries. You -- just confirming that you completed all cross examination of Ms. Perry; is that correct?

MR. JEFFRIES: I have, Chair Mitchell. Thank you.

CHAIR MITCHELL: Okay. And there is no redirect for the witness, Ms. Culpepper, remaining on nonconfidential information; is that correct?

MS. CULPEPPER: That is correct.

CHAIR MITCHELL: Okay. All right. And just checking in with my colleagues. No questions from Commissioners that they've held back for the open setting?

(No response.)

CHAIR MITCHELL: All right, Commissioner Duffley?

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Just one general question regarding the EE rider mechanism.

In general terms, what does the Public Staff consider when it determines that the creation of a rider mechanism during a general rate case proceeding will result in just and reasonable rates?

A. (Sound failure.)

Q. You're on mute.

A. I'm sorry, once again. I think, in this case, we don't have a law, we don't have a Senate Bill 3, you know, kind of dictating how we do it. So I think we have done riders in rate cases, as far as the integrity rider. IMR was done in the last -- two rate cases ago. So I think, because we removed the cost out of this rate case, they were doing their conservation energy efficiency programs in base rates up until now, so we agreed to move them into a rider to -- because I think their costs are gonna start increasing, they're gonna have -- our energy engineers are gonna be requiring a lot EM&D, you know, just different things that they are gonna be requiring them to do. So I think they need that flexibility and oversight and the transparency of what's going on. So I'm gonna leave a lot of that to your EE guys that are coming on after me, but I think we have a history of being able to do a rider in the rate case with the IMR.

COMMISSIONER DUFFLEY: Thank you. I have nothing further.

EXAMINATION BY CHAIR MITCHELL:

Q. All right, Ms. Perry, I do have one question for you following up on Commissioner Duffley's line. Piedmont has asked for a deferral of the cost associated with its EE programs in the event the Commission doesn't grant its request for a rider mechanism.

Has the Public Staff given thought to whether the costs associated with these programs here would meet the test the Commission has historically applied to deferral requests?

A. I don't think we really went that route. I really don't even think we considered that route, to be honest with you. I know we've done it for other -- it made sense, maybe, for the other, the pipeline integrity. You know, some of the things that are going on and on and on, but these I think we can really want to monitor them more so on an annual basis and see what's going on in the recovery part, because if it's not -- if it's not a good program, they want them to stop it and go to something else. So I think there -- I think the -- I don't think we really identified deferring this as something we wanted to -- a route we wanted to go, if that makes sense.

CHAIR MITCHELL: Okay. All right.

COMMISSIONER HUGHES: Chair Mitchell, I

have one question that is open that I didn't ask before.

CHAIR MITCHELL: Commissioner Hughes, you may proceed.

EXAMINATION BY COMMISSIONER HUGHES:

Q. If -- you probably heard when there were statements several times today about over-earning under your proposed contract terms.

If there was over-earning on paper from a revenue requirement calculation -- not cost, but just from a revenue requirement calculation, as I think is the issue -- even if it was just until the next rate case, do you have -- the Public Staff or do you have any opinions about where that paper over-earnings should go? Should it go to ratepayers or shareholders?

A. So, typically -- and I think -- and Bruce -- Mr. Barkley -- I mean, we've all been in the same boat, as far as how these special contracts are running through the revenues. And I wish I had shown them. Typically, I will break them out in my schedules. I'll do sales and transportation, special contracts, electric gen, and you can kind of see all the different components of them and where the increase and decrease goes.

If you have an over- or an under-earning on both, I mean, it's going to go to the firm market. I mean, if it's an over-earning, it's gonna go -- it's gonna go to their bottom line, but after they pay all their bills. After they pay all their expenses and their taxes. I mean -- and that's just what they -- that's just the nature of the increase and decrease. If some of the contracts are beneficial to the system, that's gonna benefit the firm -- I mean the tariff customers as well. So I think it goes both ways on that. Does that help at all.

Q. Yes.

A. That's not a cost of service answer. That's a revenue -- that's the accounting answer. That's not necessarily your cost of service witness answers, but yeah. So, I mean, I think what you'll see is a lot of times you will have -- expenses are gonna go up and down between rate cases anyway. So if I put $1 million in, you know, for payroll, and, you know, they retired half the staff -- which they're not doing, I'm just kidding -- that stays in play until the next rate case. That difference will go to the bottom line or whatever. So expenses do change between rate cases. You can't track everything, so. Does that help at all?

Q. Absolutely. Thanks.
A. Sorry.
CHAIR MITCHELL: All right. Commissioner Brown-Bland?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. All right. Ms. Perry, I'm trying to get it, and I think that I'm not asking you anything about dollar value, so I think I'm safe not in confidential.
So it's the Public Staff's position -- and I'm repeating this to see if I have it right -- that there are systems costs that all Piedmont customers pay, and DEC is a customer, and the special contract set up to cover those system costs; is that correct?
A. Yes, that's correct. I think we always expect -- yeah, go ahead, yes.
COMMISSIONER BROWN-BLAND: Somebody's not on mute. They think they are on mute.
THE WITNESS: Okay.
CHAIR MITCHELL: All right. Let's stop right there. Mr. McCoy, will you please identify whoever that is that's talking and just make sure they are on mute.
MR. KAYLOR: Madam Chair, my phone was on, didn't realize it, and I was not on mute. I

apologize.

CHAIR MITCHELL: All right, Mr. Kaylor, put yourself on mute. All right.

THE WITNESS: Can she ask the question one more time? I don't know. That came at the very end, and I got a little bit -- could you -- Commissioner Brown-Bland, could just ask that question one more time?

Q. The Public Staff's position is --

A. Yes. Just because that sort of threw me a little bit.

Q. Is that right?

A. Yeah.

Q. There are systems costs that all customers pay, and that there is a concern that DEC is not paying that under the special contract as proposed by Piedmont?

A. Yes, ma'am, that's right.

Q. So now, if the gas -- if the gas only passes through the pipes that were specifically installed to serve DEC, would you agree that the distribution and transmission plant that are included in the special contract is at the right level?

A. So right now, none of that is in there at this point, really. We're using the rate 113 cost of service study, which is like the O&M for a firm transportation customer. So I guess it's -- it's probably a lot of those costs. And I don't know specifically, but this is what -- this is the same approach that another utility has used that is in your jurisdiction. So this is the approach I use. But I would say that, you know, we had an Owens-Brockway case years ago, and Piedmont -- you know, everybody's got a different opinion at a different decade, I think, but Piedmont's approach was, they are 300 feet from the line and they don't want to pay Piedmont a fee. And Piedmont said no, you're gonna pay us. You are on our system. We are a monopoly. This is our territory. You can't, like, go to Transco and just go directly and bypass, basically.

And it came to the Commission, and the Commission agreed with Piedmont and said, you will -- this is in our comments, by the way -- you will charge -- you will pay them something. And it was a -- in the sense, you know -- you can look up the docket and see -- and it was with a graduated rate over the five years or something, and it's still going now. But that was -- that's a good example of, it does happen, and people that are that close to Transco think, I'm not paying this.

But Piedmont, this is their CPCN. If you have to come to get the contract approved through us, that means that it is under your jurisdiction, my jurisdiction, and you are part of the Piedmont system. And I just don't believe that we ever approved an incremental -- you can be an incremental customer to the system. That's not how it's done in the electric division, because I have learned a whole lot about electric in the last three months or year, whatever. But it's just -- it's not the way I think it would be fair to the other body of ratepayers, and that's -- that's where we're coming from.

I see what they're saying, and maybe there would be a different rate. I don't have -- we never got that close -- we had some great conversation. I will tell you, Piedmont was really good about, you know, talking with us and working with us, but we just never could get there, so.

Q. So you think there are additional distribution transmission plant costs that need to be accounted for, as well as some other overhead costs?

A. I mean, you think about it, I mean, you still have to manage the system, the pressures, what's coming in on Transco, what's going off on Transco. You have got to look at -- you know, you've got all your equipment going. Okay, here's the pressure now, this person is taking this off. I mean, there is a lot of operational things that are out there for any system and how it operates as a whole.

I mean, Transco -- I mean, Transco's going right through, you know, their territories, but Piedmont is operating their system on a whole. And they always have. You know, we are not like a water company where we've got a system over here and a system over here. I mean, they're connected for a reason. And so that's kind of where we're coming from.

Q. All right. And then, on page 13, I believe, of your testimony -- but on page 13, it's filed on August 25th. I guess it goes over to 14. 13 to 14 you indicate there that, while Piedmont does not have access to the way the other electric generators have been doing it, you did and the Commission does.

A. I'm sorry, are we in my comments? Are we in the comments?

Q. I might be in the comments.

A. I'm sorry. I went to my testimony. I'm so sorry.

Q. Yes. It's in staff recommendations and proposed order.

MS. CULPEPPER: Is it Exhibit 3, Perry Exhibit 3?

COMMISSIONER BROWN-BLAND: Exhibit 4.

MS. CULPEPPER: Confidential version?

COMMISSIONER BROWN-BLAND: Yes.

THE WITNESS: Here it is. I had it up and it ran away. Okay. I'm sorry, page -- I'm sorry, Commissioner Brown-Bland.

Q. That was it, 13 to 14, and just to the point that -- really there in the paragraph 15 where there is no confidential information.

CHAIR MITCHELL: All right. Just for purposes of the record, Commissioner Brown-Bland, can you specify exactly what you're looking at? I want to make sure we're clear.

COMMISSIONER BROWN-BLAND: It was Perry Exhibit 4 to her testimony.

CHAIR MITCHELL: Okay.

Q. Is that where you found it, Ms. Perry?

A. Yes, it is. I'm sorry, yes.

Q. And so there on 13 to 14 is a paragraph 15.

A. Yes.
Q. Where it says Piedmont doesn't know, in other words, where you got your proxy.
Is your testimony your proxy comes from looking at all these other contracts; is that right?
A. My proxy comes from what they have done in the past with their CTs as well, but also -- I mean, it -- DEC knows exactly what they're paying all their different utilities, I will tell you that one thing, but anyway -- yeah. I think everyone sort of knows but they can't say they know, but yeah. But no, I'm gonna take the high road and say no. It's confidential, but I think --
Q. But your point was that you know and the Commission also has access?
A. Yes, ma'am.
Q. So, on that note, could you provide the Commission either now or in a late-filed with any of the special contracts that you're relying on that's forming the basis for your opinion for the proxy, although I'm hearing you testify your proxy is not based on that alone.
A. True. Yes, ma'am, I sure can.
Q. That can be in a late-filed, or if you have

it before we're done --

A. It would definitely be confidential.

Q. All right. Even the docket numbers?

A. No. The dockets are -- the docket numbers are actually in my comments.

Q. Okay.

A. I think --

Q. And the issue is -- so it's more here than -- you're not concerned about -- the concern is not that they are different -- that there are other contracts that have done it differently. You're not saying it needs to be done the same because there are other contracts that have done it differently. You are actually focused in on whether there are costs that need to be covered that aren't covered using just the special contract that we have in this case.

A. Yeah. And you'll see there is different rates. Some higher, some lower. Just so you know.

Q. Now, if we are look -- do these costs necessarily -- Public Staff's position that they necessarily have to be volumetric or in a variable fashion or could they be something that's determined and made to be fixed?

A. You know, that's a great question, and it's come up so much. I mean, Mr. Barkley mentioned, we talked about the earnings. You know, I just -- I had -- in good faith -- how long have I been doing this? Thirty-one years now. I can't go into a contract in front of you and say I'm gonna approve this contract, it's 18 percent return built in, or something like that, okay.

I can't, in good conscience, with no transparency, come in front of you and say that, because that's just -- that's just something I don't think would work. The overall return is, what, 6, 7, whatever it is in this case. So I wouldn't feel comfortable. That just wouldn't be something that I'm used to -- I feel comfortable doing, without having the transparency there.

And so I think that was one thing that we did discuss. I mean, I discussed that last case with their cost of service witness. So I don't know. And the fact is, if you look at the volumes that are running through the system and running through these contracts, I mean, they might be really high in the first part of the years -- and these energy engineers are teaching me a lot about these contracts, I'm telling you. But, yeah, they are gonna probably be -- they are in startup modes, there's not as many volumes, and then they are gonna probably ramp them up, and they might be ramped up for 5 or 10 years, and then something new is gonna come out. You know, a new technology is gonna come out.

And if you -- I don't want to say -- you've added in all these costs for the full 20 years, and it really isn't as effective those whole 20 years, or it's not as used the whole 20 years, then it's set and you can't change it. When you do it volumetrically, at least I feel like you're paying for what you're using. You know, you're paying as you're using it. Because -- and believe me, I don't even want to get into it, but they have the IRP dockets and all these dockets that they do, and they're looking at these units, and they're seeing what they are projecting, you know, what volume levels and what load factors. So I just thought this was a much -- this is more parallel to what a transportation customer pays on the system. I mean, every transportation customer, every residential customer pays it volumetrically.

Now, there are some fixed costs built in, and that's where the demand charge comes in. So that's why you don't pay tariff. You know, we know we would never want them to pay tariff. It's too much. But I think we may have some -- we may have some -- we may have a good agreement on the special contract part of this. We had an issue last year, so the Company and I have really come to terms on some things we're gonna try to put in writing on that one. So hopefully we are gonna have some of this out of your hair. So -- but, yeah.

Q. So if you could summarize it or help us know, so what -- does the Commission have at this moment -- have a better way of explaining it to us -- enough information that helps us to know whether we can rely on the Public Staff's number as, you know, being close, you know, in the ball park of the right amount of cost? I mean, how do we know that. There's been a lot of testimony where, you know, it suggests the cost, at the very least, arbitrary, but -- or is it just that it's close? Is that basis supposed to be just that it's close to other numbers that you have seen?

A. I don't think it's arbitrary when you are using cost of service studies and when you're using other -- the same methodology that other utilities have been using for the same type of contract, and you're looking historically at what's been done on some other similar, you know, CT-type contracts. So I don't think that's arbitrary at all. And I don't think we track every single cost in every single contract or negotiated rate we do. I mean, we have to kind of -- I mean, even right now, when I set a rate case, when we do the settlement, we set an ongoing reasonable level. We're not gonna hit everything right on it. We can't. No. That's not what a rate case is about.

Q. Would you agree that you provided us enough in this record that we can determine how you reached your number?

A. I do. And I think when you see -- I did. And I provided a data request response to the Company that had all my calculations. I don't know if you guys have that or not. But -- and then when I sent you the contracts that you were looking for, that will help you too, I think.

Q. I think that's all I have for now. Thank you.

CHAIR MITCHELL: All right. Any additional questions from Commissioners?

(No response.)

CHAIR MITCHELL: All right. Let's go to -- before we go to questions on the Commissioners' questions, we're gonna take a break for our court reporter. Let's go back on the record -- let's go off the record now. We'll go back on the record at 4:05, and we're gonna end at 5:00 today.

(At this time, a recess was taken from 3:53 p.m. until 4:05 p.m.)

CHAIR MITCHELL: All right. So we are now at questions on Commissioner's question for witness Perry. I'll start with intervening parties or Piedmont to see if there are any questions on Commissioner's questions for the witness.

MR. KAYLOR: Madam Chair, Robert Kaylor with -- representing Duke Energy. I don't have any questions -- cross examination questions, but I did say that, if it would be helpful to the Commission, we could provide a late-filed exhibit which would show the number of combustion turbine plants and combined cycles that have contracts with volumetric rates, if that would be helpful to the Commission.

CHAIR MITCHELL: All right. Please do, Mr. Kaylor.

MR. KAYLOR: We'll do that.

CHAIR MITCHELL: One additional late-filed request from -- for the Public Staff for witness Perry is, would you please provide us the work papers underlying your calculations that you reference them in your testimony in response to Commissioner Brown-Bland, the work papers supporting your calculation.

THE WITNESS: Yes, I sure will. Yes.

CHAIR MITCHELL: Okay. All right. Piedmont any questions for Ms. Perry?

MR. JEFFRIES: We have no further questions, Chair Mitchell. I -- on the Commission's last request for a late-filed exhibit, I would ask that Piedmont be provided with that as well. And we, obviously, don't care if there is any sensitive information, in terms of identifying contracting parties. That can be redacted, but we would like to see the work papers -- the substance of the work papers.

CHAIR MITCHELL: All right. The -- Mr. Jeffries, it's my expectation that the Public Staff will file in the docket, so Piedmont will get a copy of that late-filed exhibit. All right.

THE WITNESS: And they have it. You actually have it in the data request response, but you will provide it to everybody.

CHAIR MITCHELL: Okay. Ms. Culpepper, any questions for your witness on Commissioner's questions?

MS. CULPEPPER: No questions.

CHAIR MITCHELL: All right. Okay. With that, Ms. Perry, I believe you are done for the afternoon. You may -- we appreciate your participation in this proceeding. You may step down.

And, Ms. Culpepper, any reason not to excuse Ms. Perry?

MS. CULPEPPER: No reason.

CHAIR MITCHELL: All right, Ms. Perry, you are excused. Thank you very much.

MS. CULPEPPER: And I would move that Ms. Perry's exhibits be entered into evidence.

CHAIR MITCHELL: All right, Ms. Culpepper, hearing no objection to your motion, the witness' exhibits attached to her prefiled testimony will be admitted into evidence in this proceeding.

MS. CULPEPPER: Thank you.

(Perry Exhibits I through III,
Confidential Perry Exhibit IV, Perry

Exhibit V, Confidential Perry Exhibit VI, Perry Exhibit VII, Confidential Perry Exhibit VIII, and Perry Settlement Exhibit I were admitted into evidence.)

CHAIR MITCHELL: All right. Public Staff may call its next witness.

MS. EDMONDSON: Madam Chair, to the extent there are questions regarding the EE rider, we thought it might be expedient to have Mr. Floyd testify along with Mr. Singer and Williamson, since he would talk about any types of allocations, if that -- and we had checked with other parties and we have not received any objection.

CHAIR MITCHELL: Okay. So the plan is for the Public Staff to proceed with its remaining witnesses as a panel. I'm not hearing any objections. Piedmont, I just want to confirm you have no objection to that plan?

MR. JEFFRIES: That's correct, Chair Mitchell. No objection.

CHAIR MITCHELL: All right, Ms. Edmondson, are you sponsoring these? Okay. Call your witnesses.

MS. EDMONDSON: All right. The Public

Staff calls Jack Floyd, David Williamson, and James Singer to the stand.

CHAIR MITCHELL: All right, gentlemen. Good afternoon. Let's see. There you are. Would you raise your right hands, please.

Whereupon,

JACK L. FLOYD, JAMES M. SINGER,
AND DAVID M. WILLIAMSON,
having first been duly affirmed, were examined
and testified as follows:

CHAIR MITCHELL: All right. You may proceed, Ms. Edmondson.

MS. EDMONDSON: Thank you.

DIRECT EXAMINATION BY MS. EDMONDSON:

Q. All right. Let's start with Mr. Floyd.
Mr. Floyd, please state your name and business position.

A. (Jack L. Floyd.) My name is Jack Floyd. I'm manager of rates and services, and I'm also an engineer with the energy division of the Public Staff.

Q. Mr. Floyd, on August 11, 2021, did you prepare and cause to be filed testimony consisting of 17 pages and an Appendix A?

A. Yes.

Q. I didn't hear you?
A. Yes.
Q. And do you have any changes or corrections to your testimony or appendix?
A. No.
Q. And if you were asked the same questions today, would your answers be the same?
A. They would.
Q. All right. Now, let me go to Mr. Williamson.
Mr. Williamson, please state your name and business position for the record.
A. (David M. Williamson.) My name is David Williamson, and I'm an engineer with the Public Staff's energy division.
Q. Mr. Singer, please state your name and business position for the record.
A. (James M. Singer.) My name is James Matthew Singer, and I'm a utilities engineer, Public Staff energy.
Q. Mr. Williamson and Mr. Singer, on August 11, 2021, did you prepare and cause to be filed joint testimony consisting of 23 pages as well as a one-page Appendix A and a one-page Appendix B?
A. (David M. Williamson.) Yes.

A. (James M. Singer.) Yes.

Q. And do either of you have any changes or corrections to that testimony or your appendices?

A. No.

A. (David M. Williamson.) No.

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

A. (James M. Singer.) Yes.

A. (David M. Williamson.) Yes.

MS. EDMONDSON: All right. Madam Chair, we would ask that Mr. Floyd's testimony be admitted into evidence as if given orally from the witness stand; and similarly, that Mr. Williamson and Mr. Singer's joint testimony be admitted into the record as if given orally from the witness stand.

CHAIR MITCHELL: Okay. Hearing no objection to your motion, the testimony of Public Staff witness Floyd filed in the docket on August 11th shall be copied into the record as if delivered orally from the stand. In addition, the joint testimony of Public Staff witnesses Singer and Williamson filed in the docket on August 11th shall be copied into the record as if given orally from the stand.

(Whereupon, the prefiled direct testimony and Appendix A of Jack L. Floyd and the prefiled joint direct testimony and Appendix A and B of James M. Singer and David M. Williamson were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	TESTIMONY OF JACK L. FLOYD PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

TESTIMONY OF JACK L. FLOYD

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

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

A. My name is Jack L. Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Engineer and Manager of Rates and Energy Services – Electric Section of the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations concerning issues related to apportioning the base margin revenue changes that will result from this case among the various customer classes of Piedmont Natural Gas Company, Inc. (Piedmont or the Company). In my analysis, I considered class rates of return (ROR) on rate base under present rates, and principles the Public Staff has historically considered in evaluating proposed revenues in setting base rates. I also discuss issues of affordability that are affecting natural gas utility customers.

Q. WHAT DID YOU REVIEW IN DEVELOPING THE PUBLIC STAFF'S RECOMMENDATIONS?

A. The Public Staff's recommendations are based on a review of the Company's application, the testimony and exhibits of Company witnesses Pia K. Powers and Cynthia A. Menhorn, and, in particular, the Company's cost of service study (COSS) filed with Company witness Menhorn's testimony as Exhibit (CAM-2) and Exhibit (CAM-3). I also reviewed the Company's responses to pertinent Public Staff data requests.

CALCULATION OF CLASS RORS AND ASSIGNMENT OF REVENUES

Q. HOW ARE RORS USED IN DETERMINING REVENUE ASSIGNMENT?

A. RORs indicate how the revenues produced by the various customer classes cover the costs to serve those classes. They also inform how any additional revenues will be apportioned to the customer classes. An ROR that is less than the overall system or jurisdictional ROR indicates that the revenues received from a specific jurisdiction or customer class do not fully cover its share of system costs.

Conversely, an ROR that is greater than the overall system or jurisdictional ROR indicates that a jurisdiction's or class's revenues exceed the necessary cost coverage. While it is appropriate to address revenue cost recovery inequities as revealed through RORs, it is equally important to keep in mind that such an assignment is based on a snapshot in time of the Company's cost and load data. A different timeframe, test year period, or other perspective would likely yield a different representation of cost causation and revenue assignment. Due to the variability in RORs, the Public Staff has historically targeted a ±10% "band of reasonableness" for class revenue assignment in electric cases. I will discuss this in more detail later in my testimony.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S GOALS IN ASSIGNING CHANGES IN REVENUES.

A. The Public Staff believes that the assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR as determined by the COSS, and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

1. Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points

greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;

2. Maintain a ±10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;
3. Move each customer class toward parity with the overall jurisdictional ROR; and
4. Minimize subsidization of customer classes by other customer classes.

Q. HAS THE PUBLIC STAFF APPLIED SIMILAR PRINCIPLES TO NATURAL GAS UTILITIES IN PREVIOUS RATE CASES?

A. No. These revenue assignment principles have not been applied to natural gas utilities in past general rate case proceedings. I reviewed the Company's last four general rate cases (Subs 499, 550, 631, and 743), including the final order and stipulations for each. Neither the stipulations nor the final orders addressed the issue of revenue assignment and RORs in a prominent way. Intervenors representing industrial customers in those cases did discuss the disparity of class RORs. However, it is not obvious from the final orders and the resulting revenue changes in those cases that these principles were a material consideration. Similar disparities exist in this case.

Electric utility revenues and natural gas utility revenues are derived in different ways. “Sales” revenues are derived from customers who rely on the Company to secure the natural gas commodity and provide the facilities to distribute that natural gas to all customers at rates and pressures necessary to maintain an adequate level of service. “Transportation” revenues are derived from customers who secure the natural gas commodity on their own and use the Company’s transmission and distribution facilities to distribute the customer’s natural gas commodity to their respective points of delivery. Whether customers receive firm or interruptible service, or have special contracts that dictate their cost causation, each class of customers is responsible for its share of the costs to provide utility service. Those cost causation principles are typically determined through the cost functionalization, classification, and allocation processes that are associated with the Company’s COSS. This makes a COSS inextricably linked to the rate designs. Cost causation should be the first consideration when approving rates and rate designs. Once cost causation is established, then the Commission can apply its public policy objectives. While this process may result in a deviation from the Public Staff’s revenue assignment principles, both steps nevertheless conclude with a just and reasonable portfolio of rates.

Q. HOW DO THE RORS FOR THESE PAST GENERAL RATE CASES COMPARE TO THE PRESENT CASE?

A. Table 1 below summarizes the "per books" RORs from each case for each customer class that was part of that case. I used the "per books" values for the respective test year periods. This snapshot provides the best representation of the actual activities taking place in the test year. The RORs for the Large General Service (Rates 103 and 113) and the Interruptible Services (Rates 104 and 114) were each a consolidated customer class in the Sub 499, 550, and 631 proceedings. The Medium General Service (Rate 152) customer class did not exist in the Sub 499 case.

Table No. 1 Comparison of Returns on Rate Base (%s)

Customer Classes	Sub 499	Sub 631	Sub 550	Sub 743	Sub 781
Residential (Rate 101)	3.00	0.01	6.50	4.55	6.37
Small General Service (Rate 102)	11.00	9.40	9.51	8.09	11.20
Medium General Service (Rate 152)	Not included	28.84	10.35	18.86	19.03
Large General Service (Rate 103)	18.00	4.62	4.88	(4.80)	1.30
Large General Service Transportation (Rate 113)	18.00	4.62	4.88	(3.31)	(1.75)
Interruptible Sales (Rate 104)	31.00	18.40	5.80	13.05	51.71
Interruptible Transportation (Rate 114)	31.00	18.40	5.80	29.64	22.75
Military Transportation (Rate T-10)	34.00	0.15	18.91	(2.36)	(1.55)
Special Contracts	9.00	12.18	0.47	15.52	12.21
Municipal Contracts	Not included	Not included	Not included	(1.25)	(1.29)
Power Generation Contracts	Not included	Not included	14.32	4.63	6.21
Total Company	7.46	6.07	7.19	5.04	6.82

Source: Subs 499, 631, and 743 - Cost of Service Studies filed in the respective cases as Form G-1, Item 3. For Sub 550 – Normand Exhibit No. PMN-2.

Q. IS THE PUBLIC STAFF MAKING A RECOMMENDATION ON THE ASSIGNMENT OF THE REVENUE REQUIREMENT TO THE NORTH CAROLINA CUSTOMER CLASSES?

A. The Public Staff intends to update its recommended jurisdictional revenue requirement and file supplemental testimony to provide its final recommended revenue change. I will provide the Public Staff's assignment of our proposed revenue change at that time.

Q. IF THE COMMISSION ORDERS A BASE REVENUE DECREASE IN THIS PROCEEDING, WHAT RECOMMENDATIONS DOES THE PUBLIC STAFF HAVE REGARDING THE ASSIGNMENT OF THE REVENUE DECREASE TO THE CUSTOMER CLASSES?

A. In the event of a base revenue decrease, I believe it is appropriate to focus on addressing any disparities in the class RORs. In addressing disparities in RORs, any revenue decreases assigned to individual customer classes should be limited so that no other customer class sees an increase in its assigned revenue requirement simply to address a disparity in RORs. In other words, in the event of a revenue requirement decrease, no customer class should see an increase simply to bring the class ROR within 10% of the jurisdictional ROR.

Whether there is an increase or decrease in base margin revenues, Piedmont's customer classes exhibit significant differences in class

RORs. Because the process of bringing customer classes more in alignment may not be possible without creating significant rate shock to certain customer classes, strict adherence to the principles I outlined above may not be possible in this proceeding. Nevertheless, the process must begin at some level.

RATE DESIGN

Q. PLEASE DISCUSS THE RELATIONSHIP BETWEEN A COSS AND RATE DESIGN.

A. Rate design should follow the same cost causation approach underlying the COSS, such that each customer class or customer is responsible for an appropriate share of the costs that are planned for and incurred in order to serve them, including both fixed and variable costs. However, strict adherence to this cost causation principle may not always be possible if doing so would result in “rate shock” for certain customers or customer classes. In addition, and depending on the COSS methodology utilized, cost responsibility results can vary significantly due to unusual events that occur in the test year. The COSS functionalizes costs, thus providing a basis from which to start rate design, but does not necessarily dictate the final rate design. Other considerations and objectives such as undue impacts on low-usage customers must also be considered when developing rate design.

Q. DOES THE PUBLIC STAFF HAVE ANY ISSUES WITH THE COMPANY'S COSS IN THIS PROCEEDING?

A. Not for purposes of this proceeding. Due to constraints on time and resources, I was unable to complete a thorough review of the Company's COSS in this proceeding. Given the disparities in class RORs, the need to more fully understand the Company's calculations and applications of some of the allocation factors, and the degree to which interruptible customers and contract-related customers share in the recovery of fixed costs, I believe it is appropriate to conduct a deeper investigation into the COSS. I simply am not able to complete that study to my satisfaction in this case. Therefore, I do not oppose the use of the filed COSS in this proceeding. However, the Public Staff intends to work with the Company to achieve a fuller understanding of the COSS prior to the Company's next general rate case filing.

Q. WHAT SHOULD BE CONSIDERED WHEN ASSESSING THE DISPARITIES IN RATES OF RETURN FOR NATURAL GAS UTILITIES?

A. I believe there is a need to revisit the application of cost of service studies in rate design. The Commission's *Order on Remand* issued August 18, 1999, in Docket No. G-3, Sub 186,[1] has some bearing on

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1 https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=ebae180f-b78b-4cb5-b67b-5f8e180497b6

this matter. The Commission cited four points about the application of a COSS to the setting of natural gas utility rates. First, cost of service studies are highly subjective in nature notwithstanding their appearance of mathematical certainty. Different studies typically produce different results. Thus, the Commission did not believe it was appropriate to adopt a specific study when setting rates. Second, the Commission has historically allowed higher RORs on industrial and commercial customer classes. The *Order on Remand* seems to suggest these higher returns on industrial and commercial customers is justified because the percentage of revenue being derived from non-residential customers is very small. Third, the Commission did not believe that rates should be based on cost alone. Other factors such as the ability to switch fuels (gas to electric), and the ability of some large customers to acquire their own natural gas and become “transportation” customers should be considered. Fourth, the COSS methodology selected could affect the assignment of fixed gas costs to the classes. While there are similarities in the cost of service methods and calculations between electric and natural gas utilities, there may also be sufficient differences that continue to justify a different approach for each. Therefore, the Public Staff recommends that the Commission require the Company to address each of these revenue assignment principles in its next general rate case filing. The Commission should also require the Company to explain why any class ROR under proposed rates that falls outside of a band of reasonableness should be allowed going forward.

AFFORDABILITY

Q. PLEASE DISCUSS THE ISSUE OF AFFORDABILITY.

A. The issue of affordability was of substantial interest to the Commission and other parties in the Electric Dockets. The Commission issued final orders in the Electric Dockets[2] that required Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (collectively the Duke Utilities) to convene a stakeholder process regarding affordability issues. The Commission directed that the collaborative should, as part of its work:

> (1) Prepare an assessment of current affordability challenges facing residential customers. The assessment should:
>
> > a. Provide an analysis of demographics of residential customers, including number of members per household, types of households (single family or multi-family), the age and racial makeup of households, household income data, and other data that would describe the types of residential customers the Company now serves. To the extent demographics vary significantly across the

[2] *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* issued March 31, 2021, in Docket No. E-7, Subs 1213, 1214, and 1187 (DEC Rate Case Order); and *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer* Notice issued April 16, 2021, in Docket No. E-2, Subs 1219 and 1193 (DEP Rate Case Order).

Company's service area, provide additional analysis of these demographic clusters.

b. Estimate the number of customers who live in households with incomes at or less than 150% of the federal poverty guidelines (FPG), and those whose incomes are at or less than 200% of the FPG.

c. For the different demographic groups identified as part of a. and b., provide an analysis of patterns and trends concerning energy usage, disconnections for nonpayment, payment delinquency histories, and account write-offs due to uncollectibility.

(2) Develop suggested metrics or definitions for "affordability" in the context of the Company's provision of service in its North Carolina service territory and explore trends in affordability. Questions to be answered include but should not be limited to:

a. How is "affordability" defined and applied in other jurisdictions, particularly for those with similar legal and regulatory frameworks, i.e., vertically integrated investor-owned utilities?

b. What criteria (both qualitative and quantitative) should the Commission consider when determining who would be eligible for different types of affordability programs?

(3) Investigate the strengths and weaknesses of existing rates, rate design, billing practices, customer assistance programs and energy efficiency programs in addressing affordability. Questions that should be addressed include:

a. What defines a "successful program" and what metrics should be monitored and presented that show the impact of programs on addressing or mitigating affordability challenges?

b. What percentage of residential customers are eligible for each existing program and what percentage of eligible customers enroll in and/or take advantage of these programs?

c. What is the impact of existing programs on the energy burden for enrolled customers?

d. Should existing programs be maintained, replaced, or terminated? If maintained, should any changes be made to improve results? If programs are replaced, what would replace them?

e. Are the following programs, in addition to any others agreed upon by the collaborative, appropriate for implementation in North Carolina and, if so, what statutory or regulatory changes are necessary to permit implementation: (1) minimum bill concepts as a substitute for fixed monthly charges; (2) income-based rate plans, such as Ohio's percentage of income payment plan; (3) segmentation of the existing residential rate class to take into account different levels of usage; (4) expanding eligibility for DEC's current SSI-based program to include additional groups of ratepayers; and (5) the inclusion of a specific component in rates to be used to fund supplemental support programs. Priority should be given to identifying affordability programs that comply with the current statutory framework, however the collaborative may describe high potential programs that have been successful in other jurisdictions but which would require statutory changes for implementation in North Carolina.

f. How do specific programs addressing affordability affect cost- causation and allowance of costs among classes?

g. How does cost-of-service allocation affect rate design and affordability of rates?

h. What, if any, practices and regulatory provisions related to disconnections for nonpayment should be modified or revised?

i. What existing utility and external funding sources are available to address affordability? Estimate the level of resources that would be required to serve additional customers

j. What are the opportunities (and challenges) of the utilities working with other agencies and organizations to collaborate and coordinate delivery of programs that affect affordability concerns?

(DEC Rate Case Order at 176-78; DEP Rate Case Order at 186.)

While not an exhaustive list, the stakeholders were given wide latitude to develop their own objectives for addressing affordability. Periodic reports were required to inform the Commission of the progress being made with a goal of making final recommendations within 12 months.

Q. DOES THE SAME ISSUE OF AFFORDABILITY EXIST IN REGARDS TO NATURAL GAS UTILITY SERVICE?

A. Yes. The Public Staff does not see a distinctive difference in natural gas utility service and electric utility service when it comes to affordability matters. Energy burden encompasses both. The Public Staff believes that if consensus can be achieved among the electric utility stakeholders delving into affordability matters, there is a high likelihood that similar consensus can be achieved among natural gas utility stakeholders. Therefore, the Public Staff recommends that either a similar stakeholder process be convened for natural gas utilities or the Company be allowed to join the Duke Utilities' affordability stakeholder process. The initial meeting was held on July 29, 2021. This is a good time for the Company to become engaged in this process.

Q. DOES THE COMPANY'S APPLICATION FOR A GENERAL RATE CASE AND DIRECT TESTIMONY ADDRESS ANY OF THE AFFORDABILITY ISSUES YOU RAISED?

A. No. Unlike the two Duke electric cases, the Commission has not requested that this issue be addressed.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING AFFORDABILITY?

A. The Public Staff recommends that the Commission consider many of the same issues of affordability for low-income residential customers it considered in the Electric Dockets, and issue an order either convening a stakeholder process separate from that involving the Duke Utilities, or alternatively, bring the Company into the same stakeholder process that is already underway.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

JACK L. FLOYD

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Chemical Engineering. I am licensed in North Carolina as a Professional Engineer. I have more than 17 years of experience in the water and wastewater treatment field, nine of which were with the Public Staff's Water Division. In addition, I have been with the Energy Division for almost 18 years.

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

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

Currently, my duties with the Public Staff include evaluating the operation of regulated electric utilities, including rate design, cost-of-service, and demand side management and energy efficiency resources. My duties also include assisting in the preparation of reports to the North Carolina Utilities Commission; preparing testimony regarding my investigation activities; reviewing Integrated Resource Plans; and making recommendations to the Commission concerning the level of service for electric utilities.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

DOCKET NO. G-9, SUB 722 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Piedmont Natural Gas Company, Inc., and Duke Energy Carolinas, LLC DOCKET NO. G-9, SUB 781 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 DOCKET NO. G-9, SUB 786 In the Matter of Application of Piedmont Natural Gas Company, Inc., for Modification to Existing Energy Efficiency Program and Approval of New Energy Efficiency Programs	JOINT TESTIMONY OF JAMES M. SINGER AND DAVID M. WILLIAMSON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-9, SUB 722
DOCKET NO. G-9, SUB 781
DOCKET NO. G-9, SUB 786

JOINT TESTIMONY OF

JAMES M. SINGER AND DAVID M. WILLIAMSON

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

AUGUST 11, 2021

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

A. My name is James M. Singer and my business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Utilities Engineer with the Energy Division of the Public Staff - North Carolina Utilities Commission.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are attached as Appendix A to this testimony.

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

A. My name is David M. Williamson and my business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Utilities Engineer with the Energy Division of the Public Staff - North Carolina Utilities Commission.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are attached as Appendix B to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR JOINT TESTIMONY?

A. The purpose of our testimony is to present to the Commission the Public Staff's recommendations regarding Piedmont Natural Gas Company, Inc.'s (Piedmont or the Company) proposed Energy Efficiency (EE) Portfolio. Our review includes an evaluation of the following topics:

- The Company's historical operation of its EE portfolio;
- The Company's proposed new and modified programs, and current programs that were not filed for approval in this proceeding;
- The Company's cost effectiveness model and its inputs; and

- The Company's evaluation, measurement, and verification (EM&V) of its programs.

Q. WHAT GENERAL STATUTES, COMMISSION RULES, AND COMMISSION ORDERS HAVE YOU APPLIED IN YOUR REVIEW OF THE COMPANY'S APPLICATION FOR APPROVAL OF ITS PORTFOLIO OF EE PROGRAMS?

A. Since there is not a statute or Commission rule that specifically addresses natural gas EE, the Public Staff has reviewed the Company's application in a similar manner to how it would review the programs of an investor-owned electric utility (electric IOU) EE program. Commission Rule R6-95 contains guidelines for programs designed to incent the use of natural gas (both EE and non-EE related). This Commission Rule, along with N.C. Gen. Stat. § 62-133.9 and Commission Rules R8-68 and 69 were used to help guide our investigation and to create a framework by which to evaluate the Company's proposal.

The Public Staff also reviewed previous Commission orders involving natural gas EE programs, including Docket No. G-9, Subs 550A, and 743A. Within the Sub 743A docket, we reviewed the Annual Conservation Program Reports for program years 2019 and 2020.

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. With respect to the Company's natural gas EE programs, the Public Staff recommends that the Commission:

1) Approve the proposed modification to its Equipment Rebate Program.

2) Approve the proposed Commercial HVAC & Water Heating Rebate Program, Residential HVAC and Water Heating Program, Commercial Food Services Program, and Residential New Construction Program.

3) Approve the Company's proposal to remove the costs of all of its EE programs from base rates and allow the costs to be recovered through an annual rider.

4) Approve the Company's entire portfolio of natural gas EE programs, including the currently existing Residential Low-Income and School Conservation Education programs as pilot programs in order to collect operational data, perform EM&V, and assess cost-effectiveness.

5) Require the Company to conduct more rigorous EM&V during the pilot period, including both process and impact

evaluations, and to determine and include appropriate Net-to-Gross (NTG) assumptions for each program and inputs associated with avoided cost.

6) Approve these pilot programs for a period of three years, to commence within six months of the Commission's final order in this docket. At the end of the pilot period or sooner, if program performance dictates, the Company should for each program seek either approval as a full program or termination. Any petition for full approval or termination should include supporting testimony on the updated inputs for participation, savings, NTG ratio, avoided costs, program costs, and cost-effectiveness test results.

<u>The Company's Historical Gas EE Programs</u>

Q. HAS THE COMPANY OFFERED NATURAL GAS EE PROGRAMS IN THE PAST?

A. Yes. The Company has been offering the Residential Low-Income, Equipment Rebate, and School Conservation Education programs. These programs were originally approved in Docket No. G-9, Sub 550A on March 23, 2009.

Q. PLEASE DESCRIBE THESE THREE PROGRAMS.

A. The Residential Low-Income Program provides EE measures and weatherization assistance to low-income residential customers within Piedmont's North Carolina service territory.

The Equipment Rebate Program provides rebates to Piedmont's North Carolina customers who purchase and install qualifying high efficiency natural gas heating, ventilation, and air conditioning (HVAC) and water heating equipment to replace existing natural gas equipment.

The School Conservation Education Program provides interactive performances, educational lessons, and take-home activities to K-5 grade students on the importance of natural gas conservation and safety.

Q. HOW HAVE THE COSTS FOR THESE PROGRAMS BEEN RECOVERED?

A. Since program inception, the costs for these programs have been recovered from customers through the Company's base rates. Piedmont incurred $1,275,000 in 2020 for program development, marketing, rebates, and EM&V for these programs.

Q. HAS THE COMPANY FILED ANY REPORTS ON THESE PROGRAMS?

A. Yes. The Company files an annual report on the programs that cover a number of topics for each program such as the administration budget, total number of measures/rebates, satisfaction surveys, estimated annual therm reductions, and cost-effectiveness results. [1]

The Company's Proposal for Gas EE Programs

Q. WHAT CHANGES DOES THE COMPANY PROPOSE IN DOCKET NO. G-9, SUB 786 FOR ITS PORTFOLIO OF EE PROGRAMS?

A. First, the Company has not proposed any changes to its Residential Low-Income and School Conservation Education programs. The Company has indicated to the Public Staff that it did not see a need to include these programs in the subject filing because of their limited nature and societal and education aspects. As indicated in the 2021 Annual Report, these two programs have had limited participation and spending over the years and were never intended to have participation greater than what was allowed by the limited funding that was available. The Public Staff believes these programs could be modified to advance EE and to assist customers in reducing their gas utility bills.

[1] The most recent Piedmont annual report was filed in Docket No. G-9, Sub 743A, on June 15, 2021 (2021 Annual Report).

Second, the Company is proposing to update the measures offered in its Equipment Rebate program. The Company is also renaming the program as the Residential HVAC & Water Heating Program.

Last, the Company is requesting approval for three new Natural Gas EE programs: Commercial HVAC & Water Heating Rebate Program, Commercial Food Services Program, and Residential New Construction Program.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED MODIFICATIONS TO ITS EXISTING PROGRAMS AS WELL AS ITS PROPOSED NEW PROGRAMS.

A. The Commercial HVAC & Water Heating Rebate Program is a new program that includes the two measures that were part of the previous program (tankless water measures), additional HVAC and water heating measures, and a smart thermostat measure. This program is designed to provide rebates to Piedmont's North Carolina commercial customers who purchase and install qualifying high efficiency natural gas HVAC and water heating equipment to replace their existing natural gas equipment.

The Residential HVAC and Water Heating Program is virtually identical to the Commercial HVAC & Water Heating Rebate program in terms of the measures that are offered, but the target customer segment is residential customers.

The <u>Commercial Food Services Program</u> is a new program designed to provide rebates to commercial customers who purchase and install ENERGY STAR certified natural gas food service equipment.

The <u>Residential New Construction Program</u> is a new program designed to offer incentive payments to single-family home builders or designated representatives who are installing higher efficiency natural gas equipment or meeting or exceeding the whole house standards of the current North Carolina Energy Conservation Code High Energy Residential Option (HERO). Prescriptive measures offered under this program include, but are not limited to, natural gas high-efficiency furnaces, water heaters, and smart thermostats. This program will enable builders to offset a portion of the higher cost of more efficient equipment or a more energy efficient home. For the HERO measure, the incentive is $500 per home if the builder meets the requirements of the HERO code and installs a furnace with a 90% AFUE[2] or higher.

This is slightly different from the incentive structure proposed by Duke Energy Carolinas, LLC (DEC), in its proposed Residential New

[2] Annual Fuel Utilization Efficiency

Construction Program filed in Docket No. E-7, Sub 1155. Under DEC's program, the incentive is based on a dollar per kilowatt-hour saved and encompasses more whole house, building envelope measures that can reduce both electricity and gas consumption.

Cost Effectiveness

Q. PLEASE EXPLAIN HOW COST EFFECTIVENESS IS DETERMINED.

A. The cost effectiveness of measures or programs is generally measured by comparing the ratio of the costs to the benefits using four different tests: the Utility Cost test (UC), Total Resource Cost test (TRC), Participant test, and Ratepayer Impact Measure (RIM) test. Each test focuses on a different perspective and may include different costs and benefits, and as a result, a program may have a cost effectiveness score above 1.0 on one or more tests (the benefits outweigh the costs), and below 1.0 on other tests (the costs outweigh the benefits). In its review of electric EE programs and measures, the Public Staff currently uses the UC test to screen for cost-effectiveness, but also considers the TRC test. The Public Staff has used this same approach in reviewing the natural gas EE programs.

The TRC test considers the net benefit or cost of an EE program as a resource option based on the total costs of the program, including both the participants' and the utility's costs, as well as the benefits of the program, typically measured using the utility's avoided costs. The UC test likewise measures benefits and costs, but on the cost side only takes into account the costs incurred by the utility. A UC test result greater than 1.0 indicates that the program is cost beneficial to the utility (the overall system benefits are greater than the utility's costs, including incentives paid to participants), thus lowering the aggregate cost (and revenue requirement) of providing utility service. The Participant test is used to evaluate the benefits and costs specific to those ratepayers who participate in a program, looking at the impact of participants' bills. The RIM test is used to understand how ratepayers who do not participate in a program will be impacted by the program.

Q. WHAT TEST DID THE COMPANY USE TO DETERMINE COST EFFECTIVENESS FOR ITS PORTFOLIO OF NATURAL GAS EE PROGRAMS?

A. The Company utilized the UC test as the primary test for its determination of program cost effectiveness of its new EE portfolio.

Q. HOW DID THE COMPANY ANALYZE THE COST EFFECTIVENESS OF ITS PROGRAMS?

A. The Company contracted the services of Nexant, Inc. (Nexant) to perform the cost effectiveness modeling for the Company's portfolio of Natural Gas EE programs.

Q. PLEASE DESCRIBE THE RESULTS OF THE COST EFFECTIVENESS ANALYSIS AS CONTAINED IN THE COMPANY'S APPLICATION.

A. The Company's cost effectiveness results are:

Programs	TRC	UC	Participant	RIM
Residential HVAC & Water Heating Rebates	1.04	2.04	3.37	0.34
Residential New Construction	0.68	1.06	2.43	0.30
Commercial HVAC & Water Heating Rebates	0.97	1.49	3.38	0.39
Commercial Food Services Rebates	0.71	2.05	1.79	0.42
Totals	**0.80**	**1.34**	**2.87**	**0.32**

Based on the Company's analysis, each program passes the UC and Participant tests, but only the Residential HVAC & Water Heating Program passes the TRC.

Q. BASED ON YOUR REVIEW OF THE COMPANY'S COST EFFECTIVENESS ANALYSIS, DO YOU HAVE ANY CONCERNS?

A. For purposes of this proceeding, the Public Staff believes that the Company's calculations and cost-effectiveness test results are sufficient for approval of the programs as part of a pilot. However, we do have concerns with some of the inputs that feed into the calculations, and these inputs should be carefully reviewed as part of the evaluation of the pilot.

Q. WHAT ARE YOUR CONCERNS WITH THE INPUTS TO THE COST EFFECTIVENESS ANALYSIS?

A. As stated above, the Company has been offering three EE programs to its customers for over a decade (Equipment Rebate, Residential Low-Income, and School Conservation Education programs). Over that time, outside of the limited data provided in the annual reports, it does not appear that the Company has updated its analysis or the inputs to the analysis of the cost effectiveness of its programs. The only program that has had any EM&V or other assessment is the Equipment Rebate program. The Public Staff's review of the Equipment Rebate program evaluation has revealed two major concerns with some of the inputs currently used.

First, in the *Order Approving Conservation Programs*, the original program approval order, issued March 23, 2009, in Docket No. G-9, Sub 550A (Sub 550A Order), the Commission noted the following:

> In response to Duke's contention that Piedmont's cost-effectiveness analysis failed to take into account free-ridership, Piedmont asserted that its consultants analyzed the likelihood of free-ridership based on up-to-date data available from the New York State Energy [Research] and Development Authority (NYSERDA), National Grid, and Wisconsin Focus on Energy, and recommended an initial net-to-gross ratio of 1.0 for Piedmont's programs.

(Sub 550A Order at 6.)

Over ten years have elapsed since the issuance of the Sub 550A Order and it does not appear that the Company has performed any analysis to update its original assumptions regarding an NTG ratio. The Company continues to use a NTG ratio of 1.0 for each program measure included in the proposed EE portfolio.

In response to a Public Staff data request, the Company provided an Equipment Rebate Program Evaluation report performed by Cadmus where data was collected for calendar year 2019 (Cadmus Report). Some of the results in this report show the potential for a NTG ratio of less than 1.0. Namely, when asked how influential the PNG rebate offer was in the decision to purchase a high-efficiency measure, 38% of survey respondents replied the rebate was "not influential at all." This degree of non-influence demonstrates a potential for free ridership. Free ridership connotes that the participant would have implemented the measure regardless of the incentive paid (the participant incentive). Free ridership is included in the calculation of the NTG ratio, which is an input into the calculation of cost effectiveness. NTG could also include spillover, which accounts for the increase in energy savings due to additional EE measures that are adopted by participants who were motivated by the program to implement the program. However, the Cadmus Report does not indicate the existence of any spillover.

The Public Staff has significant reservations with the use of a universal NTG ratio of 1.0. Recent electric utility EM&V reports for EE programs that offer electric versions of similar measures to those offered by Piedmont's programs report a NTG ratio of less than 1.0. Given these reservations, it is appropriate to find other EM&V data that could serve as a proxy for the Company conducting its own battery of NTG-related surveys. For example, EM&V of similar EE programs offered by the electric IOUs or comparable natural gas utility programs could provide an initial estimate of NTG until the Company conducts its own EM&V, or, alternatively, be incorporated into the Company's EM&V if the participant data is shown to be comparable. The Public Staff has agreed with the use by electric membership cooperatives of EE savings and inputs from the EM&V of similar electric IOU EE programs to comply with N.C. Gen. Stat. § 62-133.8. Such proxy data suggest that overall program level NTG ratios range from 0.65-0.75.[3]

The second concern is with the application and determination of avoided cost benefits in the model. The Public Staff has significant experience with the establishment of the avoided cost benefits to be utilized in an EE program's cost benefit analysis. Over the last ten years, the electric IOUs have used avoided cost benefits in their cost

[3] *See* EM&V for the Residential and Non-Residential Smart Saver Programs, Docket No. E-7, Sub 1230, Evans Exhibit E. This EM&V report was performed by Nexant.

effectiveness evaluations that were based on their integrated resource planning and PURPA[4]-related avoided cost proceedings. However, the natural gas utilities do not have a similar proceeding to establish avoided costs, including appropriate calculation methodologies.

For this proceeding, the Company developed avoided gas commodity and avoided capacity benefits and inputs that were used to calculate the cost-effectiveness of the EE programs. The Public Staff continues to evaluate these inputs and the methodology associated with avoided cost benefits. However, for purposes of this proceeding and approving the programs as pilots, the Public Staff does not object to the Company's inputs and calculations. In future proceedings involving cost effectiveness for natural gas EE programs, the Public Staff recommends that the Commission require the Company to file testimony that explains the reasonableness of all proposed avoided costs that are included in its analysis.

Q. BASED ON YOUR CONCERNS WITH THE INPUTS TO THE COST EFFECTIVENESS MODEL, WHAT IS YOUR RECOMMENDATION AS TO APPROVAL OF THE COMPANY'S PORTFOLIO OF PROGRAMS?

[4] Public Utility Regulatory Policies Act (PURPA, Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978).

A. The Public Staff has promoted, and will continue to promote, cost effective EE that can be offered to customers through utility-sponsored programs. However, before the Public Staff can agree on a utility's portfolio of programs, it must ensure that the inputs being used to model cost effectiveness incorporate sound assumptions based on relevant and contemporaneous data applicable to the Company's service territory. Additionally, since avoided costs are the primary determinant of benefits for a program, the justification behind the sourcing of those benefits is a critical element to the review of whether a program should be considered cost effective.

Based on our conclusion that the Company's approach to modeling the programs is sound, but the inputs need to be updated to reflect more accurate data, the Public Staff recommends approval of the Company's entire portfolio of programs (those included in this filing as well as the Residential Low-Income and School Conservation Education programs) as pilot programs for a three-year period. Operating the programs as pilots will allow the Company time to conduct EM&V and use the information gathered from that effort to refine its inputs, assumptions, and calculations of cost effectiveness.

During this three-year period, the Company should work to evaluate and broaden its efforts to market and educate its customers about EE, increase participation in the programs, and evaluate the performance of the programs. The Public Staff also encourages the Company to seek approval as a full program before the end of the three-year period if participation and performance suggest that it is cost effective. Alternatively, with the exception of low-income programs, if the program is underperforming and cannot be remediated, the Company should seek to terminate the program. In other words, if the data provide a strong basis for action, the Company should not wait until the end of the three-year period to address performance and cost effectiveness.

Additionally, the Public Staff strongly encourages the Company to pursue ways to address and enhance its delivery of EE measures to residential low income customers.

<u>Evaluation, Measurement, and Verification</u>

Q. PLEASE DESCRIBE THE COMPANY'S PAST EFFORTS IN THE AREAS OF EM&V.

A. As stated earlier in our testimony, the Company currently files an annual report that provides a description of the program, summary of the measures involved along with the applicable measure efficiency standards, the number of participants for each measure, program expenditures, and therm savings. While these reports have met past Commission requirements, the Public Staff believes that as the Company expands its offerings and seeks annual recovery through a rider, the Company should increase the level of rigor in its examination of program performance.

Q. WHAT EM&V IS THE COMPANY PROPOSING FOR THESE NEW OR MODIFIED PROGRAMS?

A. In response to Public Staff discovery, the Company provided the following response regarding its EM&V plans for the programs:

> Piedmont has not yet put together an EM&V plan that would be utilized for the modified and new programs under Docket No. G-9, Sub 786. Piedmont has discussed with Nexant some potential options for developing a comprehensive EM&V plan. The objectives of the plan would try to encompass the following:
>
> - Verification of natural gas savings for the installed measures based on program planning specific data; where practicable and available.
> - Process and market evaluation to assess program implementation, customer satisfaction, contractor/builders/partners feedback and determine action items that would benefit and improve the programs.
>
> Some of the data sources that would be utilized during the EM&V evaluation could include, but are not limited to, the following:
>
> - Program participation records, including customer applications and program tracking system data.
> - Primary data collection from participating customers, including analysis of billing information and participant surveys.

> - Secondary data collection of Piedmont-specific metrics, including weather station data in Piedmont's service territory and other population data specific to Piedmont's territory.
>
> For the EM&V plan of the 5-year term of the program cycle, Piedmont has discussed some options for the scheduling of the impact and process evaluation, but the specific frequency and timing of these evaluation activities has not yet been determined.

(Response to Public Staff Data Request 90-6.f.)

Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANY'S APPROACH TO EM&V?

A. In the context of gas utility regulation, EM&V has not been as critical as it has for regulated electric utilities and unregulated utilities subject to N.C. Gen. Stat. § 62-133.8. The natural gas utilities do not receive an incentive as provided to the electric IOUs that is based on the savings achieved by their EE programs as determined through EM&V.

When the natural gas EE programs were initially approved in Docket No. G-9, Sub 550, there was little mention of how the EE programs should be evaluated. The Sub 550A Order discusses evaluation of EE programs in more detail:

> Piedmont pointed out that the amount of incentives proposed under Piedmont's conservation proposals total only $1.275 million a year in spending. Piedmont argued that if it were to commit the same dollars to the evaluation of its programs as Duke, there likely would be no money left to actually implement the programs.

> This is an argument that cannot be ignored. Testing and monitoring are not free. At the same time, there is clearly a need to ensure that money is being effectively spent. The Commission notes that the Public Staff also commented on the assumptions made by Piedmont and questioned the relevance of the Utility Cost Tests presented by Piedmont. However, the Public Staff stated that it did not oppose the implementation of these programs because of their societal benefit. Likewise, the Attorney General did not oppose the implementation of the programs as revised.

(Sub 550A Order at 8.)

> The Commission agrees with Piedmont's argument that the questions on cost-effectiveness tests raised by Duke are beyond the scope of this proceeding. Piedmont expressed a willingness to participate in a proceeding to explore the possibility of adopting generic standards for testing protocols for gas and electric conservation programs, provided that all matters relevant to gas and electric conservation programs were open to discussion and analysis. Although the methodology of Piedmont's cost-effectiveness tests and implementation plans was questioned, no party specifically opposed the implementation of these programs. The Commission concludes that Piedmont's conservation programs, as revised, should be approved.

(Sub 550A Order at 9.)

This highlights the fact that evaluation of the natural gas EE programs beyond the initial efforts to estimate the program savings and cost-effectiveness of those programs was less rigorous than that required for the electric IOUs' EE programs. Since the passage of N.C. Gen. Stat. §§ 62-133.8 and 62-133.9 in 2007, the Public Staff has become more experienced in reviewing and evaluating the performance of EE programs. The lessons learned from that experience strongly support the need for a greater level of rigor in the evaluation of gas EE programs to appropriately verify savings and cost effectiveness.

The Public Staff supports the Company's path toward EM&V planning and is committed to working with the Company to refine the process to ensure that it is able to determine "net" program savings for each program. The fact that the Company has not fully developed its evaluation plans provides further support for the Public Staff's recommendation that the programs be approved as pilots.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

JAMES M. SINGER

I am a graduate of Penn State University with a Bachelor of Science degree in Mechanical Engineering. Upon graduation, I worked as a Station Engineer at FirstEnergy Corp., responsible for maintaining, troubleshooting, and optimizing unit equipment and operations. I also held positions as a Project Engineer and as an Analyst in FirstEnergy's Commodity Operations group, where I performed benefit-cost analysis for projects throughout the company.

In 2008, I accepted a position with Progress Energy as a Boiler Engineer, responsible for operational and reliability issues for two top-tier boilers and the performance of boiler inspections across the Progress Energy fleet. After Progress Energy's merger with Duke Energy, I transitioned to a Project Manager role, focusing on gas turbine overhaul and generator repair projects.

In 2020, I worked as Consulting Engineer with Novo Nordisk in Clayton, NC, on the DAPI-US project - the largest pharmaceutical manufacturing project in the world. I was responsible for reviewing turnover documentation from the general contractor and troubleshooting operating systems.

I joined the Public Staff Energy Division in March of 2021.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

DAVID M. WILLIAMSON

I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. In August of 2020, the Electric Division merged with the Natural Gas Division to form the Energy Division, where I am a part of the Electric Section – Rates and Energy Services. My current responsibilities include reviewing applications, making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service, and interpreting and applying utility service rules and regulations. Additionally, I am currently serving as a co-chairman of the National Association of State Utility and Consumer Advocates' (NASUCA) DER and EE Committee.

My primary responsibility within the Public Staff is reviewing and making recommendations on DSM/EE filings for initial program approval, program modifications, EM&V evaluations, and ongoing program performance of DEC, DEP, and DENC's portfolio of programs. I have filed testimony in various DEC, DEP, and DENC DSM/EE rider proceedings, as well as recent general rate case proceedings.

MS. EDMONDSON: Thank you. These witnesses are available for cross examination.

CHAIR MITCHELL: All right. My notes indicate that there is no cross for these witnesses, but I want to confirm that and will ask -- will pause here to be certain that the parties have no cross for these witnesses.

(No response.)

CHAIR MITCHELL: All right. I'm not hearing any counsel speak up, so we will move on to questions from Commissioners.

Commissioners, any questions for these witnesses? All right, Commissioner Duffley?

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good afternoon. On page 4 of the joint testimony of Singer and Williamson filed on August 11th, Public Staff recommended -- or the two of you stated:

"Public Staff recommends that the Commission approve the Company's proposal to remove the cost of all of the EE programs from base rates and allow the costs to be recovered through an annual rider."

Why does the Public Staff recommend approval of the rider for these costs?

A. (David M. Williamson.) So we recommended approval of the rider to allow the Company to be able to recover costs on a more annual basis. Essentially, because they will be -- as in their proposal, they will be increasing their costs different amounts over the next several years, but still more than what has previously been in base rates. Public Staff viewed this proposal to kind of coincide with how electric IOUs are able to recover their costs for their EE riders for their EE programs.

Q. Okay. Did you hear the exchange, the questions that I asked earlier to the Company's witness?

A. (James M. Singer.) Yes.

A. (David M. Williamson.) I don't remember the conversation, sorry. Could you remind me?

Q. Between me and Mr. Powers. So I did hear Mr. Singer say yes.

Do you generally agree with what -- Ms. Powers' testimony?

A. (James M. Singer.) I do.

Q. Thank you. Nothing further.

CHAIR MITCHELL: All right. Additional

questions from Commissioners?

Commissioner Hughes, did you have questions?

COMMISSIONER HUGHES: Not right now.

CHAIR MITCHELL: Okay. All right. Any other questions from Commissioners?

(No response.)

CHAIR MITCHELL: All right. I'm not -- I am not hearing any, so I will see if there are questions on Commissioner Duffley's questions from the Company or intervenors.

(No response.)

CHAIR MITCHELL: All right. None. Any from the Public Staff?

MS. EDMONDSON: No.

CHAIR MITCHELL: Okay. All right. Gentlemen, thank you very much for your participation in this proceeding. You-all may step down.

Any reason not to excuse them, Ms. Edmondson? All right. You all are excused. Thank you very much.

All right. With that, Mr. Jeffries, we are back to you. Actually, Mr. Heslin, we are with you.

MR. HESLIN: Yes. Thanks, Chair Mitchell. The Company calls Adam Long to the stand.

CHAIR MITCHELL: All right, Mr. Long, there you are. Would you raise your right hand, please, sir.

Whereupon,

ADAM LONG,

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

CHAIR MITCHELL: All right, Mr. Heslin.

DIRECT EXAMINATION BY MR. HESLIN:

Q. Mr. Long, please state your full name and business address for the record.

A. My name is Adam long, and my business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. And what is your position and your responsibilities at Piedmont Natural Gas?

A. I'm the vice president of gas pipeline operations, having responsibility for our transmission system, control rooms, and transmission assets.

Q. And are you the same Adam Long that prefiled rebuttal testimony in this proceeding dated

August 25, 2021, consisting of 15 pages, as well as supplemental testimony on September 7, 2021, consisting of seven pages?

A. I am.

Q. And were the rebuttal and supplemental testimony prepared by you or under your direction?

A. They were.

Q. Do you have any corrections to your prefiled testimony?

A. I do not.

Q. If I asked you the same questions as are set forth in your prefiled rebuttal and supplemental testimony while you are on the stand today, would your answers be the same?

A. Yes.

MR. HESLIN: Chair Mitchell, at this point, we ask that Mr. Long's prefiled rebuttal testimony dated August 25, 2021, and his supplemental testimony dated September 7, 2021, be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the testimony of the witness will be copied into the record as if given orally from the stand.

(Whereupon, the prefiled rebuttal testimony and prefiled supplemental testimony of Adam Long were copied into the record as if given orally from the stand.)

Before the
North Carolina Utilities Commission

Docket No. G-9, Sub 781

General Rate Case

Rebuttal Testimony
of
Adam Long

On Behalf Of
Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

August 25, 2021

Q. Please state your name and business address.

A. My name is Adam Long and 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 – Gas Pipeline Operations.

Q. Have you previously testified in this proceeding?

A. No, I have not.

Q. Please describe your educational and professional background.

A. I have a BS in Mechanical Engineering from North Carolina State University, 1996. I have more than 20 years of pipeline facility and LNG experience.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses several matters raised in the direct testimony of Public Staff witness Dustin R. Metz.

Q. Which issues identified in Public Staff witness Metz's testimony are you addressing?

A. In my rebuttal testimony, I respond to witness Metz's recommendations that:

(1) All of the Robeson LNG plant and related transmission lines 456 and 457 costs should be removed from Rate Base;

(2) The Commission should order that a study of Piedmont's allocation methodology for North Carolina transmission plant be conducted prior to the earlier of the Company's next general rate case or its 2023 annual prudence review proceeding; and

(3) The Commission should order that a study of an updated regression analysis "to determine a more accurate breakdown of system usage among customer classes and the North Carolina and South Carolina jurisdictions."

Q. Are any other rebuttal witnesses addressing Mr. Metz's proposals?

A. Yes, Ms. Kally Couzens will address Mr. Metz's original proposal to change demand cost allocation factors which, as I understand it, has been superseded in supplemental testimony by Mr. Metz.

<u>Inclusion of the Robeson LNG Plant Costs in Rate Base</u>

Q. Do you agree with witness Metz's proposal to exclude all Robeson LNG related capital costs (including lines 456 and 457) from rate base in this proceeding?

A. No, I do not. One of the major drivers for this rate case was the roll-in of Robeson LNG plant costs into our rates so as to mitigate the impact of regulatory lag associated with this large investment by the Company and incorporate the facility into our rate base and rates.

Q. What is your position on Mr. Metz's conclusion that the plant is not presently in-service and has not been closed to plant from an accounting perspective and, therefore, does not qualify for treatment as rate base at this time?

A. I actually agree with Mr. Metz on this point but his conclusions in this regard do not tell the whole story.

Q. Please explain.

A. Construction of the Robeson Plant and associated facilities, including lines 456 and 457 (which connect the plant to our transmission system), has been ongoing for some time now. Substantial construction on the plant is complete and the facility has been under the operational control of Piedmont for several weeks. Our employees are currently completing the commissioning process for the plant, upon which the plant will be fully functional and capable of performing all functions integral to the operation of an LNG plant, to include liquification of natural gas, storage of that gas in the LNG tank for an indefinite period, revaporization of that gas, and redelivery of revaporized gas to our transmission system.

Q. When do you expect that state of events to be achieved?

A. We are on track for the completion of commissioning to occur on or before August 31, 2021 or 6 days from the date of this testimony. At that time, we will ask our accountants to close the LNG project to plant and the facility will be available to serve our system needs.

Q. Will the plant be completely done with all construction related activity at that time?

A. Actual construction related activity will be complete at that time but our contract with the General Contractor for this project also anticipates that testing of various systems and components of the plant will continue for several months after commissioning has concluded.

Q. Does this testing impact the availability of the plant for use to serve customers?

A. No. The testing is designed to confirm the operational parameters of the plant facilities to determine if they correspond to design parameters and to provide baseline plant performance metrics which will help us manage the operations of the plant in an efficient manner going forward. They will not preclude operation of the plant during the period they are being conducted and, in fact, the plant will be operating (primarily liquifying gas) during this period.

Q. Do you expect that the plant will engage in the large scale revaporization of gas in the next several months?

A. No. The Robeson plant is a peaking asset and it is intended to primarily be used to inject gas into our transmission system for a 5-day period in peak or near peak winter conditions. Those type of conditions will not occur in the next few months so based upon the seasonal aspects of a LNG peaking plant, there is no anticipated need to revaporize significant quantities of LNG during warm to hot weather. Further, it does not make operational sense to inject significant quantities of natural gas into our system during the summer when such additional supplies are not needed. Instead, we will focus on completing the task of filling the tank during the next few months (it is currently approximately 15% full) in order to be ready to redeliver its full capacity when it may be needed this winter. Having said that, if Piedmont needs to revaporize gas for reasons other than cold weather in the next few months, the Robeson plant will have the capability to do that and to support system operations in that regard.

Q. Do you plan to update testimony filed with the Commission to confirm the achievement of this state of events?

A. Yes, we will update our testimony to confirm achievement of the completion of commissioning, closure of project costs to plant, and the availability of the facility for service to customers to ensure the record is clear that as of the time of hearing the facilities are eligible for rate base treatment.

<u>Study of Transmission Line Allocation Factors</u>

Q. What is your position on witness Metz's suggestion that the Commission order a study of the way in which transmission assets are allocated between jurisdictions?

A. As I explain briefly below, we believe that our existing methodology for allocating transmission plant is appropriate but, as a rule, Piedmont is not opposed to the concept of studying how it allocates transmission facilities costs as suggested by Mr. Metz.

Q. What is your reaction to Mr. Metz's rationale as to why a transmission study should be conducted?

A. My sense is that Mr. Metz may be importing concepts of cost allocation from the electric side which are generally not used on the natural gas side of utility operations due to inherent differences in how those respective systems are designed and operate. For example, his testimony does not demonstrate a recognition that when we design our system and system expansions, all of our efforts are driven by the need to provide safe and reliable service to our firm heat-sensitive human needs customers in the most adverse weather conditions that can be reasonably anticipated without interruption or curtailment. We believe that we have a legal and moral obligation to achieve this goal and all of our actions in designing the construction and operations of our system are directed towards the achievement of this goal.

Q. Are electric utilities the same?

A. I don't believe that they are. While I am confident that electric utilities strive to provide reliable service, outages on electric distribution systems are common and pose no particular threat, in and of themselves, to the safety or future continuity of service to customers upon restoration of service. The same is not true of natural gas companies.

Q. Please explain.

A. If we have a system outage in the provision of natural gas, it sets up a very complicated, time consuming, and potentially dangerous set of circumstances that must be negotiated before service can be restored. Specifically, every single piece of gas-burning equipment operated by customers in the impacted area of the outage must be checked by a Piedmont employee to ensure they are ready to safely resume the receipt of gas upon restoration of service. Once that has been accomplished, and gas is again flowing on Piedmont's system, Piedmont must then revisit each and every customer to ensure that their equipment is reactivated and working properly. For a significant outage, this process can easily take weeks or even months to perform and is why Piedmont strives to never have an outage. Because of these facts, we place an enormous emphasis on anticipating possible demand from our customers in the worst weather conditions we can reasonably anticipate and we construct our system to serve that demand.

Q. What are your concerns with Mr. Metz's proposal to study transmission cost allocation?

A. I am in disagreement with several aspects of Mr. Metz's testimony including (1) his contention that demand costs should be allocated on the basis of some form of analysis of historic system usage rather than design day requirements, (2) his contention that our transmission system is designed to serve our LNG plants and therefore should be subject to allocated between North Carolina and South Carolina in the same manner that our LNG plants are allocated, and (3) his apparent conclusion that we operate our North Carolina and South Carolina systems as a unified whole which justifies allocating some portion of the North Carolina transmission system to South Carolina.

Q. Why do you disagree with the notion that system costs should not be allocated on the bases of historical usage?

A. Well, I don't disagree with it on absolute basis. For example, my understanding is that we do allocate and recover gas supply commodity costs and volumetric-based upstream gas costs across Piedmont's customers in North Carolina and South Carolina on the basis of customer usage and recover them through the purchased gas cost adjustment procedures and rates established by this Commission and by the Public Service Commission of South Carolina. My problem with using actual historic usage as an allocator for fixed costs though is, as is discussed above, the cause of incurring fixed costs is the fact that we construct our system to meet the demand of our firm customers on the coldest day reasonably foreseeable. Accordingly, we believe the costs should be recovered on that basis (i.e. fixed) rather than on the basis of some historical usage.

Q. What is your position on Mr. Metz's contention that Piedmont's "transmission system must logically be considered an integral extension of the LNG facilities."?

A. I disagree. I believe that Mr. Metz has it backwards. We built our LNG plants to support our transmission system (which pre-existed the construction of all of our LNG plants) not the other way around. Further, the existence of our LNG plants had zero effect on the size and location of our transmission assets[1] and those assets are operated completely independently from the LNG plants. Further, these assets are indifferent as to whether the gas moving through them originates from flowing gas on an interstate pipeline or from one of our LNG plants. Finally, our transmission assets in North Carolina are designed to meet the needs of our firm North Carolina customers on a design day and no part of their design is influenced by the fact they may be moving some gas that originated from one of our LNG plants. This is consistent with the fact that, from an operational perspective, LNG's primary function is to serve as a source of supplemental supply when demand is high.

Q. In support of his Transmission allocation study proposal, Mr. Metz asserts that Piedmont's LNG plants utilize its transmission system almost 100% of the days in the year and that the hydraulic benefits of

[1] Several of our plants do have short dedicated transmission lines to connect them to our transmission system which is an exception to the statement above.

LNG supply are also provided year-round. How do you respond to that?

A. I think Mr. Metz is overstating our LNG plants' actual usage of our transmission system. His conclusions rely on the inclusion of boil-off gas into his calculations and boil-off gas simply doesn't represent any kind of "use" of Piedmont's LNG facilities. Boil-off gas is an unavoidable byproduct of the storage of LNG in a tank where the ambient air temperature outside the tank is significantly higher than temperatures within the tank. It is the product of a small amount of LNG voluntarily revaporizing on its own. The daily amounts of gas that result from this process are fairly small. As a byproduct of the LNG storage process, Piedmont has to either vent this gas to the atmosphere, recapture and liquify it, or inject it into its transmission system. Piedmont utilizes the third option as it is the simplest and the most environmentally sensible solution. Excluding boil-off gas, Piedmont uses its LNG facilities to inject natural gas into the transmission system 3 to 10 days a year, depending on weather conditions, or withdraw gas into its LNG plants approximately 40 to 100 days per year.

Q. In support of his transmission allocation study suggestion, Mr. Metz states that Piedmont does not plan for future capacity and storage resources to meet North Carolina and South Carolina demand on a separate basis. Do you agree with this contention?

A. No. While that statement is true with respect to upstream capacity and storage, it is not true with respect to on-system transmission. Piedmont plans for, designs, and constructs transmission capacity for its North Carolina and South Carolina systems on a separate and independent basis.

Q. Beginning on page 15, line 10 of Mr. Metz's direct testimony he implies that Piedmont's North Carolina transmission system supports peak day deliveries in both North Carolina and South Carolina. Do you agree?

A. I do not. The North Carolina transmission system supports deliveries solely to North Carolina customers. The fact that the supplemental on-system supplies provided by Piedmont's North Carolina LNG plants allow us flexibility in regard to the scheduling of deliveries off of Transco in a way that benefits South Carolina is not facilitated by our North Carolina transmission system in any way.

Q. What is your reaction to Mr. Metz's suggestion that Piedmont's North Carolina transmission system should be allocated between North Carolina and South Carolina?

A. I believe that suggestion is contrary to how those assets were designed and operate. As I mention above, our transmission system in North Carolina is designed to serve the design day needs of our firm customers <u>in North Carolina</u>. Our North Carolina transmission system is not designed to deliver gas to customers in South Carolina and is, in fact, incapable of delivering gas outside of our North Carolina service territory as a result of the fact that Piedmont's systems in North Carolina and South Carolina (and Tennessee) are not contiguous or connected and are each wholly contained within the borders of their respective states.

Q. How does Piedmont currently allocate the costs of its transmission systems in the states in which it operates?

A. Because none of our three transmission systems are connected and because they each serve a single state and do not contribute to service provided in other states, we directly assign the costs of each of those systems to the states in which they operate.

Q. Given that your LNG plants are all in North Carolina, do you allocate their costs to just North Carolina?

A. No. Because they are a source of supply for our North Carolina system they supplement our ability to bring gas into the State from interstate pipelines like Transco. One of the incidental benefits of having LNG plants connected to our North Carolina transmission system is that it provides some flexibility in regard to scheduling deliveries off of Transco in South Carolina because gas flowing toward North Carolina can be diverted to a delivery point in South Carolina. This occurs when we are able to increase deliveries off of Transco in South Carolina because we are injecting vaporized LNG into our North Carolina system (thereby reducing our need for flowing Transco gas in North Carolina). This combination of supply assets allows us to utilize our North Carolina LNG plants in conjunction with our Transco delivery rights to benefit both States. This benefit is recognized by allocating a portion of the LNG plant costs to South Carolina. We make this allocation on the basis of the relative design day obligations between the two states (because our need for upstream capacity and peaking capacity is based upon projected design day demand in each state) and we believe that this is the proper approach for the reasons discussed above.

Q. So, Piedmont allocates supply and interstate transportation costs across the two states based upon design day analyses but retains the cost separation of the respective intrastate transmission systems?

A. Yes, that is correct and as I previously explained, the LNG facilities are considered supply assets, which allow us to leverage our scheduled deliveries from our interstate transport providers.

Q. Have the allocation methodologies you describe been approved by the North Carolina Utilities Commission?

A. I am not a regulatory expert but my understanding is that the Company's allocation methodologies as presented in this proceeding have been consistently utilized for decades and approved on numerous occasions throughout that period by both the North Carolina Utilities Commission and the Public Service Commission of South Carolina.

Q. Could you summarize your testimony on Mr. Metz's recommendation that the Commission initiate a study on the allocation of Piedmont's transmission costs?

A. Yes. I disagree with a number of the premises upon which Mr. Metz's study recommendation is based. Having said that, if the Commission reaches the conclusion that such a study is necessary, Piedmont will support and participate in that process.

<u>Study of Updated Regression Analysis</u>

Q. What is your reaction to Mr. Metz's proposal to conduct a study of Piedmont's regression analysis to determine a more accurate breakdown of system usage?

A. As was the case with his proposal to study transmission cost allocation, he has not provided a compelling case for the need for such study, particularly in light of the fact that Piedmont's existing practice has been in place for many years and has formed the basis for the calculation of rates (and allocation of costs) in both North Carolina and South Carolina for decades. As was the case with his previous suggestion for a study though, if the Commission determines that such a study is needed, Piedmont will participate fully in that process.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Before the
North Carolina Utilities Commission

Docket No. G-9, Sub 781

General Rate Case

Supplemental Testimony
of
Adam Long

On Behalf Of
Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

September 7, 2021

Q. Please state your name and business address.

A. My name is Adam Long and 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 – Gas Pipeline Operations.

Q. Have you previously testified in this proceeding?

A. Yes, I submitted prefiled rebuttal testimony in this proceeding on August 25, 2021.

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

A. In my rebuttal testimony, I explained that I would update the Commission on the status of the Robeson LNG plant prior to the hearing of this matter. The purpose of my supplemental testimony is to provide that update. I am also providing an update on the status of another significant capital project – the Pender Onslow Expansion.

Q. Before you describe the status of the Robeson LNG plant, could you explain the discussions you have had with the Public Staff and the current arrangements between the Company and the Public Staff with respect to the Robeson plant?

A. Yes. I have had several discussions with members of the Energy Division of the Public Staff regarding the progression of the Robeson Plant toward full functionality and operations. In those discussions, we have identified four areas of functionality to be achieved before the plant can be considered fully operational. These areas are: (1) the ability to receive and process natural gas into the plant; (2) the ability to liquify natural gas; (3) the ability to store LNG; and (4) the ability to vaporize LNG.

Q. How many of these functions have been demonstrated as part of the Commissioning process?

A. At this time, we have successfully demonstrated the ability to perform three out of four of these functions. The one we have not demonstrated to the Public Staff's satisfaction yet is the ability to liquify natural gas.

Q. What do you mean when you say "demonstrated to the Public Staff's satisfaction"?

A, In our discussions with the Public Staff, Piedmont suggested a three-hour liquefaction run as evidence that the plant is capable of performing that function.

Q. Have you successfully liquified natural gas at the Robeson plant?

A. Yes, we have successfully liquified natural gas on two occasions but have experienced operational issues each time which caused us to terminate the process before the three-hour mark was reached.

Q. Can you explain what happened on these two occasions?

A. Yes. As part of the initial operation and commissioning process for LNG plants, it is common practice to use enhanced filtering materials (referred to as “Socks”) inside the operational filters for liquefaction equipment. These enhanced filtering materials are intended to capture any construction debris, dirt, and dust generated by the construction process that may have been inadvertently left inside the plant’s liquefaction equipment. It is difficult to predict exactly how much of this type of material may be collected in the Socks during initial operations. If meaningful amounts of debris are collected by the Socks, then an alarm is initiated and the liquefaction process is interrupted. This involves stopping liquefaction, removing the Socks and cleaning them, placing them back into the filters, and then reinitiating liquefaction, a process that can take from 3-5 days to complete due, in part, to the extremely cold temperatures the system is operating under when the Sock alarm is sounded.

Q. Did Piedmont experience these types of alarms as it was commissioning the liquefaction equipment at the Robeson LNG plant?

A. Yes, we experienced two instances in which Sock alarms were triggered during liquefaction operations due to the collection of construction debris, dirt and dust. In each case, this caused us to have to go through the shut-down, remove, clean, replace, and reinitiate sequence for liquefaction operations.

Q. Are these types of filter issues unusual during startup of liquefaction operations?

A. Not unusual, no – but they are not predictable either. We had several similar issues when we were commissioning the Huntersville LNG plant after we completed significant renovations to that facility earlier this year.

Q. Has Piedmont experienced any other difficulties with commissioning of the Robeson LNG plant's liquefaction operations?

A. Yes, we had one additional issue that occurred after our second liquefaction run last Friday, September 3, 2021, that caused us to delay the planned liquefaction operations.

Q. What caused the problem last Friday?

A. One of our methane sensors on the refrigeration side of the heat exchanger – the equipment where natural gas is reduced in temperature to approximately 260 degrees below zero and liquified – alarmed for the presence of small quantities of methane on the refrigeration side of the circuit. Through manipulation of various valves, we were able to isolate the heat exchanger and determine that there was a small leak between the natural gas side and the refrigeration side of the heat exchanger through which methane was being introduced into the refrigeration cycle. This is dangerous and not an acceptable operating condition so we delayed the planned liquefaction run.

Q. Did you experience this alarm on any prior liquefaction runs?

A. No, we did not.

Q. What is required to remedy this leak?

A. The process for repair involves gaining access to the heat exchanger which is a rectangular steel structure roughly 81 feet high and fourteen by ten feet in internal dimensions that is heavily insulated. Once access is gained, a person will have to be inserted into the heat exchanger and will have to manually find the leak using a water and soap mixture along all the seams of the structure. Once the leak is found, the fix is a relatively simple weld to close the leak.

Q. How long will this repair process take?

A. It depends on how long it takes to find the leak. Gaining access to the heat exchanger will be fairly quick as will placing the weld to stop the leak but finding the leak could take quite a bit longer than either gaining access or repairing the leak. Our best estimate of repair time at this juncture is 5-14 days.

Q. Will you be able to achieve a three-hour liquefaction run following this repair?

A. We certainly hope so, but the Commission does not have to take that on faith. Our settlement with the Public Staff is designed to ensure that we can actually achieve functionality before this plant is included in rate base in this proceeding.

Q. **In the Stipulation with the Public Staff, the Pender Onslow Expansion project is another capital project whose inclusion in rate base is delayed. Can you explain what this project is?**

A. Yes. The Pender Onslow Expansion is an approximately 35-mile, 8-inch distribution pipeline expansion project generally paralleling Highway 17 between Wilmington and Jacksonville to support the distribution system in each city and enhance Piedmont's ability to serve customers in this growing area.

Q. **What is the status of that project?**

A. Construction on that project is complete, it is pressurized, and it is flowing gas to our customers.

Q. **Has it been closed to plant yet on Piedmont's books?**

A. Yes. This project was closed to plant on Piedmont's books as of August 31, 2021.

Q. **In your opinion, will the Robeson LNG plant and the Pender Onslow Expansion facilities be used and useful and eligible for rate base treatment upon completion of the process provided for in the Company's Settlement Agreement in this docket?**

A. Yes.

Q. **Does this conclude your supplemental testimony?**

A. Yes, it does.

MR. HESLIN: In following the others, we will waive the reading of the summary and hand over the witness for questions.

CHAIR MITCHELL: All right. My notes indicate no cross examination for this witness, but I will ask counsel once again. Any cross examination for the witness?

(No response.)

CHAIR MITCHELL: I'm not seeing -- I'm not seeing any counsel speak up. All right.

Questions for the witness from Commissioners? Commissioner McKissick?

COMMISSIONER McKISSICK: Thank you, Chair Mitchell. I have several questions.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. Mr. Long, I just want to make sure I got the characterization right dealing with some of the information provided in your testimony. The Robeson LNG facility require two approximately four-mile long transmission pipe extensions to tie the LNG facility to the Company's main transmission system, and line 456, from my understanding, is a 24-inch gas line that is the main supply to and from the LNG facility, and line 457 is an 8-inch line for secondary functions.

Now, is that a correct characterization?
A. Yes, that is.
Q. Okay. Now, do you know what the final cost of these two transmission pipeline extensions were?
A. No, Commissioner. I would have to check on those final costs that were booked to plan.
Q. All right. But you could provide that later?
A. Yes.
Q. You could do it in a late-filed exhibit? Okay.
Now, were line 456 and line 457 built for the sole purpose of supporting the Robeson LNG facility?
A. They were built and constructed to carry gas to and from the LNG facility, yes.
Q. And can you explain the benefits of the transmission lines?
A. Yes. The larger line that you mentioned does carry gas to the plant for liquefaction and carries gas away from the plant when it is vaporized from a liquid back into a gas for use in the transmission system. The smaller line, as referred to in our industry as a tail gas line. The byproducts of our processes have a small stream of natural gas at a lower pressure that leaves the plant. So that second line is to carry that

other natural gas back to a different transmission line for use by our customers.

Q. Okay. Now, if the Robeson LNG facility was not built, would the Company have installed line 456 and 457 with the same specifications in the same locations?

A. No.

Q. And if they would not have, I mean, can you explain to me what might have been done otherwise? What would the difference have been?

A. If we had not built the LNG plant at all?

Q. Yes. Well, I mean, had not built the -- are you basically saying that those lines were only built to facilitate service to the plant, itself; is that correct?

A. That is correct.

Q. Okay. All right. And you would not have dealt them under any circumstances, were it not for that plant being there; is that correct?

A. Only if we had customers in that area that requested gas.

Q. Okay. Thank you. Now, in your rebuttal testimony, you stated that, during peak demand times, Piedmont is able to increase deliveries off of Transco and South Carolina while injecting vaporized LNG into the North Carolina transmission system, and that this unique combination of supply assets allows the Company to utilize the North Carolina LNG plants in conjunction with the Company's Transco delivery rights to benefit both states, and that this benefit is recognized by allocating a portion of the LNG plant cost to South Carolina.

Do you remember making that statement?

A. I do.

Q. Now, if trans- -- I guess transmission line 456 and 457 were built for the sole purpose of serving the Robeson LNG facility, should a portion of those transmission line costs be allocated to South Carolina?

A. I would think they would not, Commissioner. And the reason is, those lines carry gas in North Carolina to only North Carolina customers. So, therefore, the sole benefit of North Carolina customers. They do not carry any gas to South Carolina. They do not serve any customers in South Carolina. They benefit North Carolina customers, as does all of the transmission pipe in North Carolina. The benefit to South Carolina is in the gas portfolio, and that is the gas storage, itself, which is the LNG plant, and that is what Piedmont shares between the two states like it does its interstate gas portfolio.

Q. Let me ask you this. In a similar vein, the Huntersville and the Bentonville LNG plants have dedicated transmission lines which were built for the sole purpose of serving LNG plants there; is that correct?

A. The Huntersville facility does, the Bentonville facility, it might be 5 feet long, but yes, I would say yes.

Q. Do you agree that a portion of those transmission line costs should be allocated to South Carolina?

A. I do not. Just like the Robinson LNG facility, those transmission lines carry gas to only North Carolina customers for the purpose of North Carolina. Only the plants, themselves, store gas that's combined with our overall portfolio.

COMMISSIONER McKISSICK: Thank you, Chair Mitchell. I don't have any further questions at this time.

CHAIR MITCHELL: All right. Any other Commissioner questions for the witness?

(No response.)

CHAIR MITCHELL: All right. Questions on the Commissioners' questions from intervenors?

(No response.)

CHAIR MITCHELL: Okay. Mr. Heslin, any questions on Commissioner McKissick's questions?

MR. HESLIN: Just a couple, Chair Mitchell.

REDIRECT EXAMINATION BY MR. HESLIN:

Q. Mr. Long, you heard the questions from Commissioner McKissick about the transmission lines that connect the -- in this case, the Robinson LNG plant to the Piedmont system; do you remember that?

A. I do.

Q. And at one point I think you agreed that the benefits of those transmission lines were to serve those LNG plants; do you recall that?

A. I do.

Q. In fact, those transmission lines facilitate the LNG plant's ability to serve peak load required on the Piedmont's North Carolina transmission and distribution system, correct?

A. That is correct.

Q. So while in warmer months the lateral transmission line allows us to liquefy and fill the tank in peak conditions, the transmission line allows the facility to send gas into the Piedmont system during extreme cold weather events, correct?

A. Into the North Carolina system, correct.

Q. Now, if there was an extreme cold weather event requiring the Robeson LNG plant access to supply, and there happened to be an outage at that plant, would that -- would that impact deliverability in South Carolina?

A. No. The only customers impacted in that scenario would be customers in North Carolina. South Carolina would have no imprints.

Q. And so when you talk about the distinction between the allocation of the cost of the LNG facility in the transmission system within the respective states, you mention the gas portfolio, correct?

A. Correct.

Q. And, in fact, the LNG plant serves as a supply asset of natural gas; is that correct?

A. That is correct.

Q. So the leveraging of supply coming off of the interstate pipeline Transco to either the South Carolina to North Carolina city gates, that is why there is this connection between the supply asset of the LNG plant when we're talking about the state-to-state allocation, correct?

A. That is correct.

Q. Whereas the transmission -- transmission facilities in each state are entirely disconnected, correct?

A. That is correct.

Q. There are no facilities that cross state lines and there are no North Carolina transmission or distribution facilities that serve any South Carolina customers, correct?

A. That is correct.

Q. And finally, the transmission system within North Carolina was built to serve North Carolina customers, correct?

A. That is correct.

Q. And to be more precise, the design of that system is based upon the needs of North Carolina customers and projected growth, if any, correct?

A. That is correct.

MR. HESLIN: I have no further questions for Mr. Long.

CHAIR MITCHELL: All right. At this point, I believe we have come to the end of the proceeding. I will take -- I will take -- let's see. I will take a motion from you, Mr. Heslin.

MR. HESLIN: Chair Mitchell, I do not believe Mr. Long had any exhibits from me to move into evidence. I do -- I do believe I entered his testimony as if read into the record.

CHAIR MITCHELL: You have. You're correct. I will take a motion from the Company on any other -- any additional documents that need to come into the record, such as the application, and other documents filed in these proceedings.

MR. HESLIN: Chair Mitchell, this is Brian Heslin on behalf of Piedmont. I do recall that Commissioner McKissick did ask for a late-filed exhibit that included the costs of the transmission lines only from the Robeson plant, and we will provide that. I just wanted to note that again for the record, and that we received that.

CHAIR MITCHELL: All right. And Commissioner McKissick, just nod your head for me that that's sufficient for your request.

COMMISSIONER McKISSICK: Yes, Chair Mitchell.

CHAIR MITCHELL: Okay. All right. I will entertain motions from the Company. I don't know if that's you, Mr. Jeffries, or you, Mr. Heslin.

MR. JEFFRIES: I will be happy to jump in there, Chair Mitchell. The Company would move that any documents that are on file with the Commission in this proceeding, including the Application and the G-1 file with the application be entered into the -- into evidence in the proceeding.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the application and supporting documentation, including G-1, will be admitted into evidence.

(Piedmont's Application, Updated Appendix 1, and G-1 Items 1 through 3, Confidential G-1 Item 4, G-1 Items 5 through 10, Confidential G-1 Items 11 and 12, G-1 Item 13, Confidential G-1 Item 14, and G-1 Items 15 through 40 were admitted into evidence.)

CHAIR MITCHELL: Any additional documents or documentation that needs to come in at this point from any other parties?

MR. KAYLOR: Chair Mitchell, I previously offered to do a late-filed exhibit, but in looking through documents that are already in the record, back in June of 26 -- June 26, 2020, DEC filed some comments, and on page 5 of that document, we list all of the plants that have volumetric rates, and so I would ask the Commission to take judicial notice of page 5 of that document that was filed on June 26, 2020, in Sub 722.

CHAIR MITCHELL: All right. Hearing no objection to that motion -- to that request, Mr. Kaylor, Commission will take judicial notice of that document.

MR. KAYLOR: Thank you.

CHAIR MITCHELL: All right. Any other -- anything further for purposes of the record before we adjourn for the day?

(No response.)

CHAIR MITCHELL: All right. We will -- it's my understanding -- counsel, I'm looking to you for some -- for some guidance here -- that parties intend to file -- at least the Public Staff and the Company intend to file some additional guidance for the Commission to take under advisement related to the energy efficiency programs; is that correct?

MR. JEFFRIES: That's correct, Chair Mitchell.

CHAIR MITCHELL: And we will -- we are expecting those within 10 days; is that correct?

MR. JEFFRIES: That's what the stipulation provides, yes.

CHAIR MITCHELL: For now we will -- we will -- as we typically do when the -- upon the notice of mailing of transcript, we will take post-hearing briefs and proposed orders within 30 days. We will keep the record open and we will be adjourned.

MR. JEFFRIES: Chair Mitchell, I apologize for interrupting, but there is also the matter -- one of the provisions of the stipulation provides for additional time for the submission of additional information and documentation on the costs of the Robeson LNG plant and the -- and the Pender Onslow project, both of which are close to plan as of the end of August, but Piedmont needs a little bit of additional time in order to provide documentation for the Public Staff for them to review that documentation, and then also there is a question of one last remaining operability issue for Robeson that we're also gonna file additional information on, and I think, at least in my mind, it might be difficult to prepare briefs and proposed orders before that information is in the record. I would just note that.

CHAIR MITCHELL: Right. Noted, Mr. Jeffries. And as I have indicated, the record will remain open pending filing of additional information by the parties in the docket. We anticipate that you-all will move quickly there so that we can go ahead and get to work wrapping this one up.

All right. With that, any additional items for the Commission's consideration before we adjourn for the time being?

(No response.)

CHAIR MITCHELL: All right. Thank you very much everybody. Thank you for your participation today, your level of preparation, and your efficiency, and your hanging in there with us as we handle this case remotely. Thank you very much, and we are adjourned for now. Thank you.

(The hearing concluded at 4:33 p.m. on September 9, 2021.)

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 13th day of September, 2021.

JOANN BUNZE, RPR

Notary Public #200707300112