PLACE: Via Videoconference



DATE: Thursday, September 9, 2021

TIME: 9:00 a.m. - 12:45 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: 3

Noteworthy Reporting Services, LLC

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

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL: Good morning. Let's come to order and go on the record, please. I'm Charlotte Mitchell, Chair of the North Carolina Utilities Commission, and with me this morning are the following Commissioners. When I announce your name, please indicate your presence.

Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I'm here.

CHAIR MITCHELL: Commissioner Gray.

COMMISSIONER GRAY: Good morning.

CHAIR MITCHELL: Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Yes, good morning.

CHAIR MITCHELL: Commissioner Duffley.

COMMISSIONER DUFFLEY: Good morning.

CHAIR MITCHELL: Commissioner Hughes.

COMMISSIONER HUGHES: Present.

CHAIR MITCHELL: And Commissioner McKissick.

COMMISSIONER McKISSICK: Good morning. Present.

CHAIR MITCHELL: All right. Present and

accounted for. All right. I now call for hearing Docket Numbers G-9, Sub 722, Sub 781, and Sub 786, in the matter of the application of Piedmont Natural Gas Company, Incorporated for an adjustment of rates, charges, and tariffs applicable to service in North Carolina. By various orders entered in this docket, the Commission has consolidated with Docket Number 781, which is the general rate case docket; Docket Number G-9, Sub 722, which is Piedmont's petition for a consolidated natural gas construction and redelivery services agreement between Piedmont and Duke Energy Carolinas -- we will refer to that one as the Lincoln agreement docket -- as well as Docket Number G-9, Sub 786, which is the application of Piedmont for modifications to existing energy efficiency programs and for the approval of new energy efficiency programs. And we will refer to that docket as the energy efficiency docket.

Okay. Before we proceed further, and as is required by the State Government Ethics Act, I remind members of the Commission of our duty to avoid conflicts of interest and inquire at this time as to whether any member of the Commission has a known conflict of interest with respect to matters coming before us in this docket.

(No response.)

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

All right. Let's go back to the beginning. On July 26, 2004, in Docket Number G-9, Sub 491, Piedmont filed an application for the approval of a multiyear gas redelivery agreement between Piedmont and Duke Power, which was a division of Duke Energy Corporation and the predecessor of Duke Energy Carolinas. This original agreement set the rates and terms by which Piedmont provided natural gas redelivery service to DEC's Lincoln County combustion turbine facility, or the Lincoln plant.

On September 3, 2004, the Commission issued an order approving the original agreement.

On April 23, 2018, the Company filed, in Docket G-9, Sub 722, for the approval of a consolidated construction and redelivery agreement between Piedmont and Duke Energy Carolinas related to service at the Lincoln plant. Piedmont stated that this agreement consolidated, superseded, and expanded upon DEC's and Piedmont's rights and responsibilities under the original agreement.

Thereafter, on November 16, 2018, Piedmont filed a second revised agreement between Piedmont and DEC in effort to address concerns that had been raised by the Public Staff regarding that revised agreement.

On January 10, 2020, Piedmont filed a request that the Commission authorize it to commence incremental service to the Lincoln plant effective February 1, 2020, on an interim basis, at the rates included in the second revised agreement. The Commission granted the request and directed the Public Staff to review the second revised agreement.

In June 2020, the Public Staff filed its recommendations as to the second agreement, and Piedmont and DEC filed comments on the Public Staff's recommendations.

In July 2020, the Commission issued an order allowing Piedmont to continue to serve DEC at the Lincoln plant under the second revised agreement and subject to the conditions in the

Commission's orders until further order of the Commission.

All right. On February 19, 2021, Piedmont filed its notice of intent to file a general rate case application.

On March 16, 2021, the Commission issued an order consolidating the Lincoln agreement docket and the rate case docket, finding that Piedmont's general rate case is the proper forum to decide the issue of rates and terms by which Piedmont may provide natural gas service to DEC's Lincoln plant.

On March 19, 2021, Piedmont filed an application for modifications to its existing energy efficiency programs and for the approval of new programs in Docket G-9, Sub 786.

On March 22nd, Piedmont filed its application with the Commission seeking authority to increase its rates, charges and tariffs applicable to its service in North Carolina. In the application, Piedmont sought a 10.4 percent increase in annual total revenues to recover its costs. Piedmont stated that its increase is necessary primarily due to its investment of capital to expand its gas distribution system to better serve its current and future customers, and to comply with federal pipeline safety and integrity requirements.

Along with its application, Piedmont filed the testimony of its expert witnesses Bowman, Couzens, D'Ascendis, Menhorn, Newlin, Powers, Weintraub, and Weisker.

On April 13, 2021, the Commission issued an order establishing this general rate case and suspending the rates.

On April 19, 2021, Piedmont filed the direct testimony and exhibits of witnesses DeCourcey and Barkley.

Also on April 19th, the Commission issued an order finding the rate case to be the proper forum to address Piedmont's energy efficiency programs and therefore consolidating the energy efficiency docket and the rate case docket.

On May 17th, the Commission issued an order scheduling investigation and hearings, establish intervention and testimony due dates and discovery guidelines, and requiring public notice in which the Commission scheduled both public witness and expert witness hearings; establish deadlines for the submission of petitions to intervene, the filing of intervenor testimony, and Piedmont's rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

The intervention and participation of the Public Staff in this proceeding is recognized pursuant to North Carolina General Statute Section 62-15(d) and Commission Rule R1-19.

On August 2, 2021, the North Carolina Attorney General's Office provided notice of its intervention pursuant to North Carolina General Statute Section 62-20. Further, by various orders, the Commission has allowed the intervention of the following: The Fayetteville Public Works Commission, the Carolina Utilities Customer Association Incorporated, the Carolina Industrial Group for Fair Utility Rates IV, and Nucor Steel-Hertford. Duke Energy Carolinas, having been granted intervention in the docket pertaining to the Lincoln plant, has been allowed by the order of the Commission to participate in this consolidated proceeding.

In accordance with the scheduling order, the Commission held two public hearings, both remotely, on July 14th, for the purpose of hearing from Piedmont's customers.

On July 28th, Piedmont filed revised versions of the schedules required by Commission Rule R1-17 reflecting updates to its rates, revenues, rate base, cost of capital, and expenses through June 30, 2021, as well as the supplemental testimony and exhibits of witnesses Bowman and Couzens.

On August 11, 2021, the Public Staff filed the direct testimony and exhibits of witnesses Coleman, Feasel, Floyd, Hinton, Metz, Perry, Patel, as well as the joint testimony of Singer and Williamson; DEC filed the direct testimony of witness Mitchell; CUCA filed the direct testimony and exhibits of witness O'Donnell; and CIGFUR IV filed the direct testimony and exhibits of witness Phillips. The AGO, Fayetteville Public Works Commission, and Nucor did not file testimony or exhibits of any expert witnesses.

On August 16th, CIGFUR IV filed an

errata to the direct testimony of witness Phillips, and the Public Staff filed corrections to the testimony of witness Hinton.

On August 23rd, Piedmont filed a motion requesting the Commission's approval to substitute witness Kenneth Sosnick as the sponsor of the prepared direct testimony filed by witness DeCourcey. As no party objected to Piedmont's motion, the Commission granted that motion on August 31, 2021.

On August 24th, the Public Staff filed the supplemental testimony of its witness Metz.

And on August 25th, Piedmont filed the rebuttal testimony of witnesses Barkley, Bowman, Couzens, D'Ascendis, Long, Menhorn, and Newlin.

On August 26th, the Public Staff filed the amended confidential testimony and exhibits of its witness Perry.

And on September 2nd, the Company filed a notice of settlement and motion to delay the hearing, putting the Commission on notice that certain parties had settled a number of issues in principal, and requesting that the expert witness hearing be delayed until Thursday, September 9th, at 9 a.m. to allow Piedmont and the Public Staff to finalize and file a formal stipulation of settlement and the supporting testimony and exhibits. This request was granted by order of the Commission issued on September 3rd.

On September 7th, the Company filed the stipulation of partial settlement and exhibits thereto between Piedmont, the Public Staff, CUCA, CIGFUR IV; as well as the settlement testimony of Kally Couzens, the settlement testimony and exhibits of Powers, the settlement testimony and exhibit of D'Ascendis, and the supplemental testimony of Adam Long.

Also on September 7th, the Public Staff filed the settlement testimony and exhibit of Hinton and the supplemental and settlement testimony and exhibit of its witness Perry.

On August 30th, in light of the high transmission rate and spread of the delta variant of the coronavirus, the Commission issued an order holding that the expert witness hearing would be held remotely by way of Webex.

All right. Before we get started today, I must make a few points on the record in light of the fact that this hearing is being conducted remotely. This hearing has been made accessible to the public by way of a link to a video stream that's provided on the Commission's website.

As evidenced by filings made in this docket, all parties have consented to holding this expert witness hearing remotely.

In the interest of ensuring the efficient use of hearing time and minimizing the potential for technical difficulties, the Commission has afforded the parties an opportunity for a technical check-in in order to verify that they're able to access the remote technology utilized by the Commission today for this hearing.

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

Finally, and as a last request, I'll ask that all hearing participants keep their microphones muted, unless they're actively addressing the Commission in order to avoid interference with the court reporter's ability to transcribe this proceeding. Additionally, when you are addressing the Commission, you must appear on camera.

Finally, if you must speak or speak out of turn, please identify yourself first for purposes of the record and so that the court reporter knows who you are and so that I know who you are.

All right. With that, we are ready for appearances of the parties, and I will call upon counsel to announce their appearances for the record, and we'll begin with Piedmont.

All right, Mr. Jeffries?

MR. JEFFRIES: Good morning, Chair Mitchell, members of the Commission. My name is Jim Jeffries. I'm with the law firm of McGuire Woods, and I'm here on behalf of Piedmont Natural Gas today. Joining me in this docket -- in this case today are Mr. Brian Heslin and Ms. Amanda Demopoulos, who are both in-house counsel with Duke Energy Corporation. Thank you.

CHAIR MITCHELL: All right. Good morning, Mr. Jeffries, to you and your team.

All right. Public Staff?

MS. JOST: Good morning. Megan Jost with the Public Staff representing the using and consuming public. Appearing with me this morning are Elizabeth Culpepper and Lucy Edmondson.

CHAIR MITCHELL: All right. Good morning, Ms. Jost, to you and your team.

All right. Attorney General's Office?

MS. TOWNSEND: Good morning. This is Teresa Townsend. In addition to Peggy Force, we represent the using and consuming public and the citizens of this state in this matter of public interest.

CHAIR MITCHELL: All right. Good morning, Ms. Townsend and good morning, Ms. Force.

All right. DEC?

MR. KAYLOR: Good morning, Chair Mitchell. Robert Kaylor appearing on behalf of Duke Energy Carolinas and the Lincoln agreement docket which is the Sub 22 docket. I was off the air for a while, so I don't know what happened.

CHAIR MITCHELL: All right. Good morning, Mr. Kaylor, I see you and hear you now, so you are connected.

All right. Fayetteville Public Works Commission?

MR. WEST: Good morning, Madam Chair. James West appearing on behalf of the Fayetteville Public Works Commission, and joining me today is Justin Doty, who is our staff counsel. This is his first appearance at the North Carolina Utilities Commission. He was sworn in just last week to the North Carolina State Bar.

CHAIR MITCHELL: All right. Good morning, Mr. West. And, Dustin, where are you? Would you raise your hand, please, so I can see you?

MR. DOTY: Yes, Chair Mitchell, I'm here.

CHAIR MITCHELL: There you are. Good

morning and welcome.

MR. DOTY: Good morning, thank you.

CHAIR MITCHELL: And congratulations for being newly sworn in. Welcome to the profession.

All right. CUCA?

MR. SCHAUER: Good morning, Chair Mitchell. Craig Schauer on behalf of the Carolina Utility Customers Association.

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

CIGFUR?

MS. CRESS: Good morning, Chair Mitchell. Christina Cress with the law firm of Bailey & Dixon appearing on behalf of CIGFUR IV.

CHAIR MITCHELL: All right. Good morning, Ms. Cress. And I don't believe that Nucor is going to make an appearance this morning, but I will ask out of abundance of caution. I'm not hearing counsel for Nucor.

All right. Counsel, any preliminary matters we need to take up or questions that you-all have before we get started this morning?

MR. JEFFRIES: Chair Mitchell, this is Jim Jeffries. I think we have just a couple of preliminary matters. As the Chair is aware, a settlement was filed on Tuesday in this docket, and as a result of that settlement -- first of all, the Company would like to express its appreciation for all the hard work that all the parties put in to reaching that settlement. We appreciate that, particularly over -- a lot of that happened over the long holiday weekend, so I just wanted to express our appreciation for that.

But as a result of the settlement, it's impacted the hearing in two ways, from the Company's perspective. The first is that there's been a substantial reduction in the amount of reserved cross examination time for most of the witnesses, given that the majority of the parties to the settlement -- or the majority of the parties in the case are stipulating parties to the settlement and have waived cross pursuant to the settlement.

The second is it's allowed the Company to schedule and combine direct, rebuttal, supplemental, and settlement testimony for a number of its witnesses, which -- and we will -- this is all reflected on the revised witness list that was filed yesterday, but we wanted to bring it up with the Chair and make sure that our proposed approach was acceptable.

CHAIR MITCHELL: All right. Mr. Jeffries, I'm not hearing anyone objecting. I haven't heard any of the parties object to Piedmont's proposal. I'm okay with it. In the interest of ensuring an orderly record here, let's be careful and get our testimony introduced by witness such that, you know, you make sure for each witness, please have -- please be sure to introduce all testimony that that witness has sponsored as by witness, if that makes sense.

MR. JEFFRIES: It does.

CHAIR MITCHELL: Okay. That will help me, that will help our court reporter, and that hopefully will help you-all when you go back into the record.

MR. JEFFRIES: I think Mr. Heslin may have a preliminary matter he wants to bring to your attention.

CHAIR MITCHELL: Mr. Heslin?

MR. HESLIN: Thank you, Chair Mitchell. One other matter is the consumer statement that was filed with the Commission on September 2nd in this docket is a letter purportedly from a Piedmont employee dated August 26th. We were informed that the Commission wanted to address this statement possibly in the hearing. We wanted just to inform you that our second witness, Mr. Brian Weisker, is prepared to provide direct testimony on this statement, but we wanted to check with you to see if it's still the Commission's desire to address today at the hearing or if there's another way we want to address that statement.

CHAIR MITCHELL: Thank you, Mr. Heslin. Let's go ahead and have your witness address the letter in testimony this morning. And we do have questions for the witness on the letter as well, so --

MR. HESLIN: Very well.

CHAIR MITCHELL: -- we'll move forward as planned. Okay?

All right. Counsel, any other questions before we get started?

(No response.)

CHAIR MITCHELL: Okay. Well, you-all have been through this drill before of a rate case being held over video conference technology. I thought that we would be past this by this point in time, but here we are. We will -- we will take breaks as we typically do for our court reporter, and so that we can all step away from the computer for a minute. We will go for about 90 minutes to two hours, depending on where we are with testimony, and then we will take a break. And then we will also take a break for lunch. And we will go from there, depending on where we are with the hearing.

We will -- to the extent that any party needs to utilize examination exhibits that have been provided in advance of this proceeding, we will -- we all have those exhibits and we'll use them as necessary.

Please do your best to minimize interference with our court reporter's ability to hear and my ability to hear. Since we are working remotely, you-all know that, when you take yourself off mute, it can cause strange things to happen with the audio. So just be mindful of the mute button.

Okay. With that, I'll give y'all one

last chance to raise any questions or concerns before we start.

(No response.)

CHAIR MITCHELL: All right. I'm not hearing any, so, Mr. Jeffries, Mr. Heslin, the case is with you.

MR. HESLIN: Thank you, Chair Mitchell, Piedmont calls Sasha Weintraub.

MR. WEINTRAUB: Good morning.

CHAIR MITCHELL: All right. Mr. Weintraub, would you raise your right hand, please, sir.

Whereupon,

ALEXANDER J. WEINTRAUB,

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

CHAIR MITCHELL: All right, Mr. Heslin.

MR. HESLIN: Thank you.

DIRECT EXAMINATION BY MR. HESLIN:

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

A. Sure. My name is Alexander J. Weintraub. I am also known as Sasha Weintraub. I work at 4720 Piedmont Row, Charlotte, North Carolina.

Q. And for who -- whom do you work?
A. I'm the senior vice president for the natural gas business unit at Duke Energy.
Q. Are you the same Sasha Weintraub that prefiled testimony in this proceeding on March 22, 2021, consisting of 13 pages?
A. I am.
Q. And was that testimony prepared by you or at your direction?
A. It was.
Q. And do you have any corrections to your prefiled testimony?
A. I do not.
Q. If I asked you the same questions that are set forth in your prefiled testimony while you're on the stand today, would your answers be the same?
A. They would, yes.

MR. HESLIN: Chair Mitchell, at this point, we ask that Mr. Weintraub's prefiled direct testimony dated March 22, 2021, be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objections to the motion, the direct testimony of Piedmont witness Weintraub filed in the docket on

March 22, 2021, consisting of 14 pages, shall be copied into the record as if delivered orally from the stand.

(Whereupon, the prefiled direct testimony of Alexander J. Weintraub was 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

## Direct Testimony
## of
## Sasha Weintraub

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**March 22, 2021**

**Q. Please state your name and your business address.**

A. My name is Sasha Weintraub. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am Senior Vice President of the Natural Gas Business Unit at Duke Energy Corporation ("Duke Energy"). In that role, I am responsible for all utility operations and business activities of Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company").

**Q. Please describe your educational and professional background.**

A. I received a bachelor's degree in Mechanical Engineering from Rensselaer Polytechnic Institute, a master's degree in Mechanical Engineering from Columbia University and a PhD in Industrial Engineering from North Carolina State University. In 2012, I joined Duke Energy as Vice President of Fuels and Systems Optimization. In 2014, I became Senior Vice President of Customer Solutions. In November 2018, I assumed the role of Senior Vice President and Chief Commercial Officer of the Natural Gas Business Unit and I began my current role leading the Natural Gas Business Unit in October 2019.

**Q. Have you previously testified before the North Carolina Utilities Commission ("Commission") or any other regulatory authority?**

A. Yes. I have previously testified before the North Carolina Utilities Commission on a number of occasions.

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

A. My testimony supports the Petition filed by Piedmont on March 22, 2021, seeking the establishment of a general rate proceeding in this docket. In this testimony, I will provide a brief description of Piedmont and its business, summarize our request for rate relief and the reasons behind such request, and provide an overview of the other significant aspects of our business and filing.

**Q. Please describe Piedmont and its business.**

A. Piedmont is a wholly-owned subsidiary of Duke Energy Corporation with its headquarters located at 4720 Piedmont Row Drive, Charlotte, North Carolina. The Company is principally engaged in the natural gas distribution business and, as of December 31, 2020, we served more than 1.1 million customers in three states, including approximately 775,000 in North Carolina, 154,000 in South Carolina and 193,000 in Tennessee. We are fortunate to serve a growing service territory in North Carolina and anticipate continued customer growth for our system in this State of approximately 2% annually for the foreseeable future. The significant capital investments that drive the need for this general rate case facilitate Piedmont's ability to meet its obligation to serve this growing customer base under all weather conditions.

**Q. Please describe Piedmont's gas distribution business in North Carolina.**

A. Piedmont serves customers in sixty-six (66) counties across a number of cities, towns, and communities in North Carolina including Charlotte, Greensboro, Winston-Salem, High Point, Burlington, Wilmington, Hickory, Salisbury, Reidsville, Indian Trail, Fayetteville, Goldsboro, Tarboro, Elizabeth City, New Bern, Rockingham, and Spruce Pine. We also provide service to the municipal gas systems of the cities of Wilson, Greenville, and Rocky Mount, and military facilities in Fayetteville and Jacksonville, as well as multiple gas-fired electric generation facilities located throughout the State, many of which are operated by either Duke Energy Progress, LLC ("DEP") or Duke Energy Carolinas, LLC ("DEC").

**Q. What are Piedmont's most important business goals?**

A. We continuously strive to provide safe and reliable natural gas service to our customers at reasonable rates coupled with excellent customer service. Customer, public, and employee safety are absolutely critical to everything we do. We also want our current and future firm customers to feel certain that we will be ready to serve them on the coldest winter day. We want our customers to experience great customer service with each and every interaction. Finally, the Company seeks to exemplify excellent environmental stewardship.

**Q. Does Piedmont receive feedback on its customer service?**

A. Yes. We are rated on our provision of customer service in several ways, including ratings from J.D. Power and Cogent Reports.

**Q. What can you report about Piedmont's customer service scores?**

A. Piedmont has continued to receive positive customer satisfaction and trusted brand scores from J.D. Power and Cogent Reports. Our most recent score for J.D. Power is in the top quartile and we are ranked 6th out of 40 national natural gas utilities by Cogent. We also monitor customer satisfaction frequently by surveying our customers and using a net promoter score that includes customers that rate us highly and those that did not. Piedmont received its highest net promoter scores ever during 2020. The Company also reports monthly performance metrics concerning its call center to this Commission. The Company committed several years ago to the Commission that it would answer 80% of incoming calls within twenty (20) seconds or less, which is an exceedingly high standard for call centers to consistently achieve. Piedmont's commitment to that goal has never wavered. In fact, that goal was exceeded during the test period, with approximately 92% answered within the twenty second goal.

**Q. What is Piedmont seeking in this proceeding?**

A. In this proceeding, Piedmont seeks Commission authorization to: (1) update and increase our rates and charges to account for changes in rate base, operating expenses, and capital structure that have occurred since our last general rate case proceeding (including the roll-in of prior capital investments under our Integrity Management Rider mechanism); (2) extend our Integrity Management Rider mechanism, which has been critical to our ongoing efforts to comply with federal pipeline safety and integrity requirements; (3) amortize and collect certain deferred environmental, pipeline integrity, and other expenses that have accrued since Piedmont's last general rate case; (4) update and revise Piedmont's existing service regulations and tariffs; and (5) expand our efforts in operating customer programs that promote their efficient use of natural gas by including the proposed removal of associated program costs from base rates and the implementation of an Energy Efficiency Program rider for cost recovery. These matters are discussed in more detail either later in my testimony or in the testimony of other Company witnesses.

**Q. What else is Piedmont seeking to do in this case?**

A. In addition to our requests for specific relief, as described above, we will also: (1) provide updates to the Commission on our prior and projected capital investment activities to comply with federal safety mandates; (2) update the Commission on the status and necessity of the Robeson County Liquefied Natural Gas ("LNG") Project and certain other critical infrastructure projects the Company seeks to recover in this proceeding. These critical infrastructure projects support serving our growing customer base reliably during extreme weather conditions; (3) discuss the impact of this filing on our customers and measures that we are taking to assist customers; and (4) report on our efforts to reduce methane emissions associated with the production, transportation, and distribution of natural gas.

**Q. What is the scope of the rate changes you are requesting in this rate case?**

A. The Petition filed by the Company proposes rate changes that would produce an overall increase in annual revenues of approximately $109 million. This approximate 10% increase in annual revenues is necessary to cover the costs, including a reasonable return on investment, of providing safe, adequate and reliable natural gas service to the Company's customers in North Carolina.

**Q. Why is it necessary to file this rate case?**

A. This rate filing is prompted by an insufficient return earned during the test period ended December 31, 2020 that was driven by several factors. First, since our last general rate case, Piedmont has continued to make substantial capital investments in our system in order to (1) maintain and expand our gas distribution system for the benefit of our customers in order to accommodate system growth and service reliability, and (2) comply with ongoing federal pipeline safety and integrity requirements. With respect to the former factor, one of the primary drivers for this case is the approximately $223 million investment in the North Carolina allocated portion of the Robeson County LNG plant as well as other critical infrastructure projects that are necessary to provide service to our growing customer base under extreme weather conditions. The total amount of capital invested since our last rate case is approximately $1.65 billion, $1.15 billion of which supported system growth and $.5 billion expended in support of federal pipeline safety mandates. This rate case will allow us to roll these amounts into our base rates in order to facilitate our ability to earn a reasonable return on these investments.

I think it is important to note the customer benefits that result from our ongoing financial stability. Historically, because of its financial position, Piedmont has had the financial strength and flexibility necessary to fund its long-term capital requirements, as well as to meet short-term liquidity needs, at an economical cost to customers. As important as low cost is, ready access to capital is critical to serving our customers. Such access to capital is most assured for companies who have strong financial positions, strong investment-grade credit ratings and adequate cash flow generation to meet obligations as they become due. The financial flexibility that comes from the ability to access cost-effective capital in all market conditions serves the best interests of our customers.

**Q. Has the Company closely managed its operation and maintenance expenses since its last general rate case filing in 2019?**

A. Yes. Our operation and maintenance expenses proposed by Ms. Bowman for recovery in this proceeding exceed the amount allowed by the Commission in its order in Docket G-9, Sub 743 by less than 1%. Our management team and employees have worked to implement technology-based improvements and more efficient procedures in order to hold our expense level unchanged during a period of strong customer growth and capital additions. An example of this includes improved website functionality and customer notifications that enhance customer satisfaction while simultaneously lowering the number of calls received by our call center. The Company has also emphasized customer-related issue resolution by its customer facing personnel, allowing faster, more personal, and less costly responses. Overall, our constant focus on expense containment over the past two years has provided benefits for customers in this proceeding.

**Q. Please identify the other witnesses that will offer testimony on behalf of Piedmont in this proceeding.**

A. Brian Weisker, Senior Vice President, Chief Operations Officer Natural Gas Business, will testify as to the requirements of federal pipeline safety and integrity regulations and the incurred and projected costs of compliance with those regulations along with major system enhancements needed to provide reliable service to Piedmont's growing customer base. Karl Newlin, Senior Vice President, Corporate Development and Treasurer, will testify on our pro forma capital structure, cost of debt, and provide further perspective on the benefits to customers resulting from Piedmont's ongoing financial stability and strong credit ratings. Pia Powers, Managing Director, Gas Rates & Regulatory, will testify regarding our revenue request, its impact on customers, our robust efforts to assist customers during the pandemic and our proposed rider to recover costs associated with energy conservation programs. Quynh Bowman, Director Gas Rates & Regulatory Strategy, will testify in support of our cost of service and rate base, revenue requirement deficiency, G-1 compliance, and the proposed amortizations of deferred assets. Kally Couzens, Manager, Rates & Regulatory Strategy, will testify regarding our pro forma revenue calculations and proposed rates. In addition to these Company witnesses, we are also filing the testimonies of Dylan D'Ascendis on the cost of equity and Cynthia Menhorn on class cost of service and rate design.

**Q. Can you please provide a little more context to Piedmont's rate case filing in this docket?**

A. Yes. This rate filing occurs in the context of four significant influences impacting the natural gas industry. These influences are the maturing development of market access to plentiful new sources of shale gas, the development of corresponding environmental opposition to the extraction method for such supplies and opposition to the construction of infrastructure necessary to deliver such supplies to end-use markets, substantial and increasing federal regulations around pipeline safety and integrity that are requiring unprecedented capital investment in existing natural gas infrastructure, and the COVID-19 pandemic from which North Carolina, and the nation as a whole, is beginning to emerge. We envision further economic recovery during the period of time between the date of our filing and the date of our anticipated rate adjustment in the fall. The first factor has allowed us to maintain natural gas rates for our customers at levels that are comparable with prior periods even in the face of the substantial and ongoing capital investment required by the third factor, and the negative economic and operational implications of the second and fourth factors.

The continuing benefits of shale natural gas production have allowed us to comply with federal integrity management requirements and otherwise grow our system while preserving the essential affordability of natural gas service for our customers which will be a benefit to customers coming out of the current pandemic.

**Q. How did Piedmont respond to the pandemic?**

A. Piedmont responded by voluntarily instituting many of the measures that the Commission subsequently mandated in terms of customer disconnection policy and the assessment of late payment and other fees. The Company's call center representatives have remained attentive to customers' needs by offering flexible payment arrangements options and providing contact points for agencies with funds to assist customers with payment of their utility bills. Furthermore, the Company has and continues to proactively reach out to customers through multiple communication channels to make sure they understand the full suite of options available to support them. The Company remains committed to continuing its practice of working diligently to limit service disconnections by making flexible payment arrangements available to customers in need. Piedmont witness Powers provides additional detail on these measures.

In addition, Piedmont witness D'Ascendis recommends an ROE in the lower portion of his range in light of uncertain economic conditions and Piedmont witness Bowman notes that the Company is proposing to remove the burden of credit card fees from customers who select that payment method.

**Q. Did Piedmont propose adjustments to its cost of service to address impacts of the pandemic?**

**A.** Generally, we did not propose any specific adjustments based upon our belief that the quantification of known and measurable variances attributable to the pandemic is difficult for our particular company. Further, we believe that if such quantification were readily available, it would not result in a material adjustment to the test period cost of service based upon our financial performance. Certain cost of service items increased while others declined from levels experienced prior to the pandemic. The duration of the pandemic and the extent to which the Company's cost of service will be impacted by the pandemic in the future is also not currently determinable. The primary exception was the removal from operating expenses of a stipend paid to certain employees during the test period to help with dependent care hardships. The Company has not determined that such stipends will be paid in future periods and therefore the associated cost was removed from test period operating expenses.

**Q. Did Piedmont request any cost deferrals associated with the pandemic during the test period?**

**A.** No, we did not petition the Commission for any such deferral and believe the test period, with the exception of the stipend, represents a reasonable going level of operating expenses and revenues.

**Q. Are there any other subjects related to Piedmont's ongoing provision of natural gas sales and transportation service to its North Carolina customers that you would like to discuss?**

A. Yes. I would like to briefly mention that Piedmont is undertaking steps to eliminate methane leakage from its operations and facilities as discussed in more detail in the direct testimony of Company witness Weisker. Excellent environmental stewardship is critical to the ongoing success of Piedmont and the natural gas industry, and our goal to reach a net zero carbon emission level by 2030 reflects our commitment to the environment.

**Q. Can you please address the Robeson County LNG Facility?**

A. Yes. Mr. Weisker addresses this facility in greater detail in his direct testimony but in brief our construction of the Robeson County LNG facility was necessary in order to ensure that Piedmont is able to continue to provide firm natural gas distribution service to our customers under extreme cold weather conditions, known as a design day because we design our system to serve reliably on such day. Growing demand on our system causes us to continually evaluate the adequacy of our systems to serve heat sensitive, high-priority customers on the coldest day we may incur. The Robeson County LNG facility will provide peaking service that will ensure our continued ability to serve these customers under such conditions in a manner consistent with Piedmont's longstanding best cost approach employed to acquire natural supply, pipeline capacity, and associated system infrastructure. This facility will provide storage on our system at a critical location and that is solely under Piedmont's control. This will protect our customers from potentially life-threatening situations as were experienced earlier this year in Texas due to record cold temperatures. I also note that our Pipeline Services team constantly evaluates the resources required to ensure the provision of firm service on a design day. The additional design day capacity, on-system reliability, and operational flexibility provided by Robeson LNG allows Piedmont the opportunity to evaluate existing upstream storage and capacity contracts that deliver into the interstate pipeline system for the purpose of releasing a portion of the contracts that will be replaced with Robeson LNG. The potential release of a portion of these upstream storage or capacity contracts may serve to reduce demand gas costs paid by our customers.

**Q. Does this conclude your testimony?**

A. Yes.

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

A. I have.

MR. HESLIN: And, Chair Mitchell, before Mr. Weintraub reads his summary, there were some revisions made to his summary to add a little bit more detail since it was filed last week. We're happy to provide the court reporter with another written document if that would be easier, but he will be reading something that's a little different than what was filed last week.

CHAIR MITCHELL: Okay. All right. Well, please do get the revised summary to our court reporter as soon as you can, and you may proceed with your summary, Mr. Weintraub.

THE WITNESS: Thank you.

My name is Sasha Weintraub. I am the senior vice president of the natural gas business unit at Duke Energy Corporation. I prefiled direct testimony in this docket on March 22, 2021, in support of Piedmont’s application for a general rate increase.

My prefiled direct testimony provides a brief description of Piedmont and its business, summarizes the Company’s request for rate relief and the reasons behind such request, and provides an overview of the other significant aspects of Piedmont’s business and filing. My prefiled direct testimony also identifies the other witnesses that are offering testimony on behalf of Piedmont in this proceeding.

In my prefiled direct testimony, I explain that the Company serves more than 1.1 million customers in three states. Specifically in North Carolina, the Company serves 775,000 customers in 66 counties across the state. The Company also provides service in North Carolina to the municipal gas systems of three cities, military facilities in two cities, and multiple gas-fired electric generation facilities. I explain that the Company anticipates continued customer growth for its North Carolina system at a rate of approximately 2 percent annually for the foreseeable future.

Additionally, my prefiled direct testimony lists several factors that support Piedmont's decision to file this rate case. For example, I explain that one of the primary drivers for this rate case is the investment in the North Carolina allocated portion of the Robeson liquefied natural gas, LNG, facility, as well as other critical infrastructure projects necessary to serve the Company's growing customer base under all weather conditions.

My prefiled direct testimony also provides contextual information surrounding Piedmont's rate case filing. I explain that this rate case filing occurs in the context of the following four significant influences impacting the natural gas industry.

One, the maturing development of market access to new sources of shale gas; two, the development of corresponding environmental opposition to the extraction method and construction of infrastructure for these new sources of shale gas; substantial and increasing federal regulations concerning pipeline safety and integrity; and four, the COVID-19 pandemic.

Finally, my prefiled direct testimony explains how the Robeson LNG facility is particularly important to Piedmont and its continuing ability to provide safe and reliable service to Piedmont's customers.

This concludes the summary of my prefiled direct testimony.

MR. HESLIN: Chair Mitchell, Mr. Weintraub is available for questions by Commissioners.

CHAIR MITCHELL: All right. Let me check in with my colleagues to see if any has questions for Mr. Weintraub.

(No response.)

CHAIR MITCHELL: All right. I'm not hearing any questions for you, Mr. Weintraub. Looks like you were off easy today. Thank you, sir, for your testimony, and you may be excused.

THE WITNESS: Thank you, Chair.

CHAIR MITCHELL: All right. Piedmont, you may call your next witness.

MR. HESLIN: Piedmont calls Brian Weisker to the stand.

CHAIR MITCHELL: All right. Mr. Weisker, would you raise your right hand, please, sir.

Whereupon,

BRIAN WEISKER,

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

CHAIR MITCHELL: All right. Mr. Heslin.

DIRECT EXAMINATION BY MR. HESLIN:

Q. Mr. Weisker, please state your full name and business address for the record.

A. My name is Brian Robert Weisker. My address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. And what is your position or responsibilities at Piedmont Natural Gas?

A. I am the senior vice president and chief operations officer for Piedmont Natural Gas.

Q. And are you the same Brian Weisker that prefiled testimony in this proceeding on March 22, 2021, consisting of 16 pages and Exhibits BRW-1 and BRW-2?

A. Yes.

Q. Was that testimony and were those exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Do you have any corrections to your prefiled testimony?

A. No, I do not.

Q. If I asked you the same questions as are set forth in your prefiled testimony while you were on the stand today, would your answers be the same?

A. Yes, they would.

MR. HESLIN: Madam Chair, at this point, we would ask that Mr. Weisker's prefiled testimony be entered in the record as if given orally from the stand, and also ask that his exhibits be marked as identified BRW-1 and BRW-2.

CHAIR MITCHELL: All right. Mr. Heslin, hearing no objection to your motion, the direct testimony of witness Weisker filed in this docket on March 22, 2021, consisting of 17 pages shall be copied into the record as if delivered orally from the stand. The two exhibits shall be marked as they were when prefiled.

(Exhibits BRW-1 and BRW-2, were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony of Brian Weisker was 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

## Direct Testimony and Exhibits
## of
## Brian R. Weisker

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

March 22, 2021

**Q. Mr. Weisker, please state your name and business address.**

A. My name is Brian R. Weisker. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am a Senior Vice President and Chief Operations Officer, Natural Gas Business for Duke Energy Corporation ("Duke Energy"). In this capacity, I am responsible for the operation of Piedmont Natural Gas Company Inc.'s ("Piedmont" or "Company") natural gas system.

**Q. Please describe your educational and professional background.**

A. I received a Bachelor of Sciences degree from the United States Naval Academy in 1994 and an MBA degree from Tulane University in 2001. From 1996 through 2002, I worked in the United States Navy as a Division Officer, an Assistant Professor of Naval Science and as a Navigation/Operations Department Head. From 2002 through 2006, I worked at Cinergy as a Manager. In 2006, I joined Duke Energy as a Station Manager. In 2014, I became General Manager of Carolina West Outages & Maintenance Services. In 2015, I became Vice President of Coal Combustion Products Operations & Maintenance. In 2018, I became Vice President of Natural Gas Operational Excellence within Duke Energy's Natural Gas Business Unit. In January 2020, I assumed my current role as Senior Vice President and Chief Operating Officer of Duke Energy's Natural Gas Business Unit.

**Q. Have you previously testified before this Commission or any other regulatory authority?**

A. I have not previously testified before the North Carolina Utilities Commission but have sponsored testimony before the Tennessee Public Utility Commission and the Indiana Utility Regulatory Commission.

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

A. My testimony in this proceeding will address: (1) Piedmont's ongoing efforts and activities undertaken in compliance with the requirements of federal pipeline safety regulations promulgated by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"); (2) Piedmont's projected spending on PHMSA compliance and other capital projects over the coming years in light of changing PHMSA regulatory requirements; (3) the importance of Piedmont's Integrity Management Rider ("IMR") mechanism based upon both its past and projected capital expenditures to meet PHMSA's requirements; (4) Piedmont's capital investment in the Robeson County liquefied natural gas ("LNG") project and other large capital projects that contributed to the need for this general rate case; and (5) our continuing efforts to reduce methane leakage from our system.

**Q. Are you sponsoring any exhibits to your testimony?**

A. Yes. I am sponsoring the following four exhibits:

Exhibit __ (BRW-1): PHMSA Expenditures

Exhibit __ (BRW-2): Future PHMSA Compliance Expenditures

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

A. Yes.

## PHMSA Compliance Activities

**Q. Please provide an overview of Piedmont's recent PHMSA compliance activities.**

A. As the Commission is aware, Piedmont is subject to expansive regulatory requirements imposed by PHMSA under its Transmission Integrity Management Program ("TIMP") and Distribution Integrity Management Program ("DIMP") regulations. These regulations are issued under the authority of Subparts O and P of Part 192 of the regulations of the United States Department of Transportation and are fully binding on Piedmont as a provider of natural gas transmission and distribution services. These regulations require that Piedmont engage in extensive assessment, testing, planning, verification, record-keeping, documentation, inspection, and quality assurance activities with respect to its 2,701 miles of transmission main (and appurtenant facilities) and its 17,021 miles of distribution main (and appurtenant facilities) located in North Carolina. In compliance with these regulations, Piedmont continues to engage in a broad range of compliance activities with respect to its transmission and distribution facilities.

**Q. Please provide a summary of these recent activities.**

A. As of December 31, 2020, Piedmont has expended more than $396 million since June 30, 2019, the date through which utility plant was updated in its prior general rate case on a variety of projects designed to ensure that its system remains safe and fully compliant with applicable regulatory requirements. A summary of these projects is attached hereto as Exhibit_(BRW-1). We anticipate completing capital projects during the six months ending June 30, 2021 of an additional $137 million. The activities associated with these capital projects and related operating and maintenance ("O&M") expenditures include:

(1) the analysis and designation of High Consequence Areas ("HCAs") within Piedmont's service territory;[1]

(2) the gathering and review of Piedmont's archived engineering files on its transmission and distribution facilities;

(3) the actual survey and inspection of Piedmont's transmission lines using smart-pig technology;

(4) the mitigation or repair of flaws and defects detected through smart-pig inspections;

(5) the removal, repair, replacement, and/or upgrade of certain pipeline segments where necessary to comply with PHMSA regulations either because of administrative documentation deficiencies or because they are non-compliant with current prevailing standards for modern pipeline facilities; and

(6) pipeline casing remediation and corrosion control.

**Q. Can you elaborate why Piedmont's compliance with PHMSA regulations results in significant costs?**

[1] Piedmont has 280 miles of HCAs in North Carolina.

A. Yes. Much of the cost is attributable to the fact that as we engage in a very granular analysis of our transmission facilities through smart-pig inspections, we often find anomalies that needed to be addressed. These are not necessarily leaks, but every time we find a dent, evidence of corrosion, a weak spot in the pipe, or a failure in cathodic protection we are required to analyze the risk associated with the anomaly and devise mitigation measures. We also do not have complete control over the costs of undertaking specific projects since much of the PHMSA compliance work is conducted by outside contractors who bid for the opportunity to do such work. Because the entire industry has ramped up to comply with PHMSA requirements over the last five years or so, competition for qualified contractors has increased, which has had an inflationary impact on the costs of this work.

**Q. Have customers benefitted from Piedmont's PHMSA compliance work?**

A. Yes, and so has the public at large. Our system is much safer and more transparent to us now than it was at the time the IMR was approved.

**Q. What has contributed the most to system safety?**

A. Any time we identify and remedy a potential physical system vulnerability, system safety is improved when that vulnerability is addressed. Our new electronic systems, as they continue to be implemented, also allow us to manage our compliance activities more efficiently with most of the data we need to engage in such management at our fingertips. This is a vast improvement from the early days of PHMSA compliance when most of our records relating to system construction, maintenance and repair were in paper format.

**Q. How does Piedmont prioritize TIMP and DIMP remediation requirements for discovered anomalies?**

A. Piedmont employs a sophisticated risk analysis system that analyzes the type of anomaly in terms of the consequences of failure versus the likelihood of failure. The Company then prioritizes mitigation measures associated with that anomaly accordingly.

**Q. Are you satisfied with the progress Piedmont is making and is Piedmont currently compliant with its obligations under PHMSA regulations?**

A. Yes. The Company has made huge progress in terms of system safety and integrity and we are currently compliant with our obligations under PHMSA. Since our last rate case, we have retrofitted more than 113 miles of our North Carolina transmission system to make it piggable, conducted in-line inspections of more than 301 miles of transmission main and uncovered 667 anomalies, all of which we have repaired or otherwise mitigated.

**Q. Does that mean the TIMP and DIMP work that Piedmont has been heavily engaged in is coming to an end?**

A. No. By design, the TIMP and DIMP requirements of PHMSA are cyclical and iterative. As such, we will continue to engage in the inspection, assessment, remediation, and documentation cycle with respect to both transmission and distribution integrity on an ongoing basis. Resulting capital costs as well as O&M expenses will continue to be difficult to predict because remediation is dependent on the inspection findings.

**Piedmont's Anticipated Ongoing PHMSA Expenditures**

**Q. Are PHMSA's regulations static or do you anticipate changes to those regulations in the future?**

A. PHMSA's regulations are subject to revision and change. In fact, they were amended as recently as October 2019 and the industry expects PHMSA to issue two additional rule modifications relating to Gas Transmission Line Safety and Gas Gathering Line Safety soon, possibly as early as this year. These amendments substantially expand obligations in effect and require maximum allowable operating pressure reconfirmation and materials verification for transmission pipelines. In addition, these amendments expand assessments outside of HCAs into Moderate Consequence Areas, significantly increasing the miles of transmission pipeline to be assessed. We anticipate that the PHMSA rules may continue to change over time and experience has shown that they are not likely to become less stringent.

**Q. Does Piedmont have a projection of the cost of PHMSA compliance activities?**

A. Yes. During the three-year period ending December 31, 2023, Piedmont expects to incur approximately $832 million of capital expenditures related to PHMSA compliance activities. A summary of this activity is attached hereto as Exhibit_(BRW-2).

**The Importance of Piedmont's IMR Mechanism and O&M Deferrals for PHMSA Compliance**

**Q. Please describe the importance of the IMR mechanism to Piedmont's efforts to ensure compliance with PHMSA pipeline safety and integrity requirements in an economical manner.**

A. As shown on Exhibit_(BRW-1) and (BRW-2), these investments in a safe and compliant system have been and will continue to be significant. Because of the accelerated cost recovery opportunity associated with these projects under the IMR, Piedmont does not face the inherent challenges created by the normal regulatory lag associated with these capital projects, allowing the Company to focus on the continuing safety and reliability of the Piedmont system.

**Q. Is the IMR the only regulatory mechanism that helps Piedmont deal with the issue of regulatory lag as it relates to PHMSA compliance spending?**

A. No. The Commission has previously allowed Piedmont to defer O&M expenditures under its TIMP and DIMP programs. These deferrals are also very important to the Company's ability to maintain its robust PHMSA compliance activities and Piedmont requests that these deferrals continue to be allowed going forward.

**Q. Why can't you build these costs into the Company's pro forma revenue requirement?**

A. Because these costs are highly variable in nature and we do not have a mechanism sufficient to formulate a reasonable estimate of what these costs will be year-to-year. Based on these facts, we continue to believe that deferral is a better and ultimately more accurate way to account for these costs.

**Capital Investments**

**Q. Has Piedmont incurred significant non-PHMSA related capital expenditures since its last general rate case filing?**

A. Yes. We estimate that our North Carolina utility plant in service will increase by more than $1.65 billion during the two-year period from the date through which plant was updated in our prior general rate case and our projected plant in service proposed for use in this proceeding as of June 30, 2021. Approximately 54% of this capital expenditure was directly related to the addition of new or expanded natural gas consumption by our customers or is being recovered timely through the IMR and therefore does not contribute significantly to the current need for general rate relief. However, the remaining 46%, $759 million, of investment was necessary to facilitate growth on our system and the continued provision of reliable service during extreme weather. The vast majority of these necessary projects will not generate a near-term increase in revenues and, therefore, are the primary drivers of Piedmont's need for rate relief at this time.

**Q. What is the largest such infrastructure project?**

A. It is the Robeson County LNG facility. We expect completion during June of this facility which will provide significant enhancements to system reliability and operational flexibility that is needed to meet our customers' demand for natural gas during periods of extreme cold weather, also known as peak demand. The tank will hold liquefied natural gas that approximates the heating value of one million dekatherms of natural gas and will be an addition to Piedmont's North Carolina plant in service of approximately $223 million.

**Q. How critical is the Robeson LNG facility for Piedmont to meet its peak demand?**

A. The Robeson County LNG plant is absolutely critical to Piedmont's ability to serve its design day demand, particularly in view of the cancellation of the Atlantic Coast Pipeline project. Without the Robeson County LNG plant, Piedmont's available natural gas supply will fall short of its peak day demand during the winter of 2022-2023. Customer growth created the need for additional natural gas supply on a peak day. The Company reviewed several options for meeting this looming shortfall including procuring additional firm transportation rights on the interstate pipeline system combined with additions to our system infrastructure. Our review indicated that the Robeson County LNG plant was the most cost-effective option to support our projected peak demand needs. It is capable of not only providing the gas supply needed for peak demand in eastern NC, but the plant also provides that gas supply at an elevated pressure that pushes the gas farther into Piedmont's system, thus alleviating the near-term need for additional infrastructure. Its location is ideal in terms of facilitating the provision of natural gas in a northeastern direction toward Fayetteville and points beyond, and also to the southeast toward the growing Wilmington area. Most of Piedmont's gas is received at a location near Charlotte and must travel a considerable distance and pass by locations of heavy natural gas consumption before reaching Robeson County and locations even farther from Charlotte. As this is a Piedmont asset, we will not be dependent on an outside third party to facilitate the movement of natural gas from the storage tank to our customers under peak conditions.

**Q. In addition to the Robeson LNG project, please provide additional capital projects that Piedmont has completed or expects to complete prior to June 30, 2021.**

A. A few examples of significant investments made to serve our growing customer base are as follows:

**Huntersville LNG** – This facility became operational in the early 1970s. Over time, the natural gas composition received at the plant has changed as more natural gas obtained from shale formations was introduced into the interstate pipeline system with different properties from the more traditional Gulf Coast supply. The composition of this new source of natural gas led to operational problems associated with the original pretreatment systems. The new pretreatment systems will be able to correctly treat the current and forecasted gas to be received at the plant for liquefaction. In addition, the Huntersville LNG Plant liquefaction system was designed to fill the LNG tank in 200 days. The current operating environment does not allow Piedmont to consistently have 200 days to fill the tank, so the new liquefaction system was designed to fill in 100 days. The new liquefaction system also uses a nitrogen-based refrigeration cycle instead of a hydrocarbon gas cycle to lower the plant's carbon footprint. The modernization of the Huntersville LNG facility is projected to add approximately $54 million to our North Carolina plant in service.

**Line 328 Extension - (Winston Salem)** Transmission pipeline extension to provide additional capacity into the high-pressure distribution system on the western side of the Winston Salem service area. The high-pressure distribution system is the primary supply pipeline from which all distribution systems are served in southwestern Forsyth and northeastern Davie Counties. Installation of this proposed pipeline will ensure the stability of the system during high demand conditions and ensure service to current and projected firm customers in those areas. Project cost is projected to be approximately $48 million.

**Dixie River Road project – (Charlotte)** Large diameter steel distribution project to serve as the primary backbone of the distribution system in West Mecklenburg County between I-485 and the Catawba River near the

Steele Creek Community. This area is one of the last remaining areas in Mecklenburg County with large tracts of developable property. Due to the current growth, the existing distribution system in the Steele Creek community had diminished to minimum design requirements in high demand conditions. This project will restore pressure and flow for both Steele Creek and the Dixie River Road area for current and projected growth in this area at a cost of approximately $16 million.

**Pender Onslow Expansion** – Approximately 35-mile distribution system expansion 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. Project cost is approximately $31 million.

**Pleasant Garden Loop Line 330 Extension – (Greensboro)** Transmission pipeline extension to provide additional capacity and associated pressure into the high-pressure distribution system in the Greensboro/South Guilford County distribution system. The high-pressure distribution system is the primary supply pipeline from which all distribution systems are served in Pleasant Garden/South Greensboro/Southern Guilford County. Installation of this pipeline will ensure the stability of the high-pressure distribution system during high demand conditions and ensure service to current and projected firm customers in those areas at a cost of approximately $20 million.

**Robeson County LNG Pipeline** – Two separate transmission lines of approximately four miles each installed to deliver natural gas to and from the newly constructed Robeson County LNG facility. The addition to North Carolina plant in service will be approximately $33 million.

**Governmental Relocations** – Piedmont is required to move its pipeline infrastructure residing in the easements it has obtained for property owned by the State of North Carolina. There is no reimbursement from the State for this type of relocation project. Such requests primarily involve road construction projects and are received from the NC Department of Transportation. Total costs during the two years ending June 30, 2021 are projected to exceed $95 million.

**Q. Does the Company anticipate a continuing need to expand facilities in Eastern North Carolina going forward?**

A. Yes. As the Commission is aware, our system in the eastern part of the state was inherited from North Carolina Natural Gas and, to a lesser degree, Eastern North Carolina Natural Gas when Piedmont purchased the facilities of these entities in 2003. In this part of the State, transmission distances tend to be longer, operating pressures lower, and our overall transmission system is not as dense or redundant as it is in the more populous parts of our service territory. In addition, Piedmont has experienced meaningful customer growth in the eastern part of the State since 2003, which has consumed much of the flexibility of our existing facilities in that region. One of the benefits that would have accrued to

Piedmont as a result of the Atlantic Coast Pipeline project is the addition of new supplies of high-pressure gas delivered to Piedmont in eastern North Carolina. Without the Atlantic Coast Pipeline project, Piedmont will now need to construct additional facilities to increase deliverability to that region from its more traditional sources of supply. Piedmont is currently in the planning phases for these system upgrades but wanted the Commission to be aware of these pending capital projects, currently anticipated for completion in the 2024-2026 time frame.

**Methane Leakage Mitigation**

**Q. Is Piedmont aware of the concerns expressed by some environmental activists that methane leakage associated with the production, transmission and distribution of natural gas negates the lower emissions benefits of natural gas as an energy source?**

A. Yes. I am very aware of these arguments.

**Q. Do you agree with those concerns?**

A. No. I disagree with the notion that natural gas is not a significant improvement over coal and fuel oil in terms of emissions and potential impacts on climate change. Having said that, the Company is continuing to take steps to reduce or eliminate the potential of methane leakage on Piedmont's system.

**Q. Please elaborate on Piedmont's efforts to reduce methane emissions.**

A. These efforts include the flaring of natural gas as part of pigging operations whenever possible rather than releasing methane directly into the atmosphere, adjusting compressor maintenance practices to limit the number of occasions when gas must be vented and reducing the amount of gas that is vented when necessary, and a continuing emphasis on reductions in third-party damages which are the largest contributors to methane releases on Piedmont's system. Additionally, we have performed two satellite flyover pilots to identify methane leaks and compare them to known leaks. In the future, we believe these flyovers may provide data to identify leaks that is practically in real time. We are also piloting a technology to capture the methane from a pipeline that is being removed from service. This technology compresses the gas and injects it back into the active portion of our system. Historically, this gas has been vented into the atmosphere. Finally, we are an active member of ONE Future, a coalition of industry members representing the entire natural gas supply chain, working together to reduce the methane intensity of the natural gas supply chain to 1% or less by 2025.

**Q. Do you have anything to add to your testimony?**

A. No, not at this time.

MR. HESLIN: Thank you, Chair Mitchell.

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

A. I have.

Q. Please provide that to the Commission.

A. My name is Brian Weisker, and I am the senior vice president and chief operations officer of the natural gas business for Duke Energy Corporation. I prefiled direct testimony in this docket on March 22, 2021, in support of Piedmont's application for a general rate increase.

My prefiled direct testimony addresses the following five topics: the efforts and activities undertaken by Piedmont in compliance with regulations of federal pipeline safety regulations promulgated by the Pipeline and Hazardous Material Safety Administration, commonly referred to as PHMSA, since Piedmont's last general rate case; Piedmont's projected spending on PHMSA compliance over the coming years in light of ongoing and projected changes to PHMSA regulatory requirements; the importance of Piedmont's integrity management rider mechanism to both its past and projected future spending on PHMSA compliance; Piedmont's capital investment in the Robeson liquefied natural gas project and other large capital projects; and Piedmont's continuing efforts to reduce methane leakage from its system.

In summary, my prefiled direct testimony demonstrates Piedmont's commitment to compliance with federal safety -- excuse me, federal pipeline safety regulations in the scope of its compliance activities. Piedmont recognizes and appreciates the Commission's willingness to support such compliance with effective regulatory mechanisms.

My prefiled direct testimony is accompanied by the following two exhibits: The first is PHMSA Expenditures, and the second is Future PHMSA Compliance Expenditures.

This concludes the summary of my prefiled direct testimony.

Q. Thank you, Mr. Weisker.

MR. HESLIN: Chair Mitchell, as we discussed prior to handing off the witness for further questioning, we are prepared to address the consumer statement that the Company filed on September 7, 2021, and identified as Weisker Direct Late-Filed Exhibit Number 1.

CHAIR MITCHELL: All right. You may

proceed.

MR. HESLIN: Thank you.

Q. Mr. Weisker, you have before you what was filed by Piedmont on September 7th and identified as Weisker Direct Late-Filed Exhibit Number 1. Do you see that?

A. Yes, I do.

Q. And that is a letter dated August 26, 2021, to the chief clerk of the NCUC, or the North Carolina Utilities Commission, specifically pertaining to Docket Number G-9, Sub 781, which is the rate case docket that the Commission is hearing today; is that correct?

A. That's correct.

Q. And the letter's one page consisting of two paragraphs and states that it is from, quote, a concerned employee and ratepayer, close quote; is that correct?

A. That is correct.

MR. HESLIN: Chair Mitchell, at this time, we ask that Weisker Direct Late-Filed Exhibit Number 1 be marked as identified.

CHAIR MITCHELL: All right. Hearing no objection, the exhibit will be marked as it was when prefiled.

(Weisker Direct Late-Filed Exhibit Number 1, was identified as it was marked when prefiled.)

MR. HESLIN: Thank you.

Q. Mr. Weisker, without reading the letter word for word, would it be fair to say that the individual claims to be an employee of Piedmont, that he alleges that Ms. Amy Presson unnecessarily mandated that the Company apply a coating called ScarGuard to the entire length of pipe on all horizontal drilling projects, presumably to run up the cost, and then questions Ms. Presson's qualifications and management?

A. That's correct. That's what the letter claims.

Q. And before we address the specific allegations, I'd like to lay a bit of context and information for the Commission here.

First, what is your position in the Company as it relates to Ms. Presson, and could you explain some of her responsibilities?

A. So I am Ms. Presson's supervisor, and some of her responsibilities include overall project management, project controls, and implementation of our major projects and transmission-level projects for the natural gas business.

Q. And can you explain to the Commission what horizontal boring or drilling is and when the Company uses that methodology?

A. So horizontal drilling, it's a construction technique that is utilized in an area where it's difficult, if not impossible, to do an open-trenching technique. So with a horizontal directional drill, a drill rig is utilized, and you end up drilling and boring underneath. It typically would be a river or an environmentally sensitive area like a wetland, and the bore -- the horizontally directional drill basically drills and bores underneath that feature at a curvature where it then comes up on the other side.

And then after you bored out that hole, you're able to take the pipe that's constructed and pull it back through that drill hole.

Q. And you mentioned the open trench or the open cut technique. What are the differences, as far as concerns between the horizontal drilling project and the open cut pipe installation?

A. So as the name basically says, with the open cut or an open trenching technique, it's literally a trench is excavated anywhere from 4 to 6 feet deep, typically, where we then lay the pipe into the trench. And so we're able to visually see the soil conditions where the pipe is laid, and we're able to also visually see the soil that's then placed back around the pipe after it's been laid. We can inspect -- visually inspect the integrity of the coating that is applied on the pipeline in order -- and the purpose of that coating is there for protection of the pipe for decades to come.

In a horizontal directional drill, as this hole has been bored and drilled through, you can't visually see that pipe once it ends up in its place where it will permanently reside, and you have to actually pull that pipe through, so you visually cannot see.

So that's -- that is the largest difference between those two techniques.

Q. What are the concerns, if any, regarding pulling the pipe through a horizontal drilling hole?

A. So it's extremely important that when you pull that pipe back through the hole that was drilled, that we maintain the integrity of the coating on the pipe; that we don't damage the coating or actually damage the coating right through the coating and damage the pipe. Because that coating, like I mentioned, it's extremely important for protecting the pipe, itself, from corrosion.

And so that -- so since you can't visually see it, it's extremely important that that is maintained once we pull the pipe back through the hole. And so we measure that via resistivity test.

Q. And to avoid confusion when you mention coating, ScarGuard is a coating that's mentioned in this letter.

What is the coating that is under the ScarGuard that you're referencing that needs to be protected?

A. So that's a fusion-bonded epoxy coating. So that is the coating that is applied on all of our steel piping that is installed. So you have the pipe, itself, that fusion-bonded epoxy, and then where needed, in a rocky setting, that's when ScarGuard is used to protect that fusion-bonded epoxy coating, or FBE coating.

Q. And what is ScarGuard and what does it actually do?

A. So ScarGuard is a -- it's an abrasive-resistant overcoat -- an ARO is what -- by abbreviation. But an abrasive-resistant overcoat that is applied to the pipe before we pull it back through. And if it's in a rocky terrain where we've had to bore through a rocky setting, and that abrasive-resistant overcoat's purpose is it hardens quickly after being applied in the field, and its job is to protect that fusion-bonded epoxy coating and the pipe from getting any damage as we pull the pipe back through the horizontal directional drill hole.

Q. What are the consequences if a pipe, in its corrosion or cathodic protection, the -- I believe the epoxy protection that you mentioned, if it's damaged when it's pulled through the horizontal hole?

A. In the short term, it would be identified via the resistivity testing. It's gonna be reworked, pulling the pipe back out, recoating, delay of the project, additional time, and additional cost. Over the long term, if there's damage done to that coating, we'll find that via our inline inspection techniques that we perform. PHMSA required inspections that are performed every seven years is the cycle for those.

And when we do an inline inspection, we can find -- if we have an area with corrosion, we'd find that via the inline inspection technique. And ultimately, the worst-case scenario is having to replace that pipe. And since this is an area where we bored, we can't excavate down to it to do a repair. The only way to fix that is doing another bore and pulling a new pipe through.

Q. The letter mentions that applying ScarGuard along the entire pipe within that horizontal drilling bore is somewhat new. Has Piedmont changed its application of ScarGuard on -- in these horizontal drilling situations?

A. We have. So this is a relatively new over the last couple of years, ScarGuard has been utilized on the weld joints of pipings of -- weld pipe typically comes in 40-feet segments, and then it's field welded. And then ScarGuard was always applied at that field weld location.

But what we have found through some of our operating experience here over the last several years, and with a couple projects where we ended up having to do rework is when we -- without applying ScarGuard across the entirety of the length of the pipe, it has been damaged when we pulled it through a bore hole.

Q. And to be clear, when we talk about applying ScarGuard across the entire pipe, that's only the pipe that is subject to the horizontal drilling bore, correct?

A. Correct. It's only the section where we actually pull the pipe through the horizontal directional drill, which is -- on all of our projects is a very small amount of the total length of the pipe that's installed.

Q. Does Piedmont apply ScarGuard along the entire pipe every time there's a horizontal drilling project?

A. No. We only install it in areas where the soil is rocky, where we have the increased risk of damaging that fusion-bonded epoxy coating in the piping, and that's in an area where it's a rocky soil. If it's sandy soil or a dirt soil, we do not install it across the lengths of the pipe that's being pulled through that horizontal directional drill hole.

Q. Who made the decision to apply ScarGuard along the entire pipe in rocky situations?

A. That decision was made by our engineering and integrity management organization within the Company.

Q. So the allegation letter that Ms. Presson was a sole decision-maker and that she initiated the mandate that ScarGuard be used all the time in HDD or horizontal drilling situations is wrong?

A. Correct. That is an incorrect statement.

Q. And you mentioned that the ScarGuard is only used on the entire pipe in horizontal drilling projects where there's rocky soil. Approximately how much of the time does Piedmont encounter a rocky soil within the North Carolina service territory where it's installing pipe?

A. So within the North Carolina -- within North Carolina, when we do perform a horizontal directional drill, it's somewhere in the range of 30 to 40 percent of those horizontal directional drills will be in a rocky setting. It's very much geography specific.

Q. What have the results been since Piedmont started utilizing ScarGuard along the entire pipe in these rocky situations?

A. So the results have been extremely positive. I mentioned before that a resistivity test is performed. After we pull the pipe back through the horizontal directional drill bore hole, through that hole, the resistivity test is performed to validate the integrity of the fusion-bonded epoxy coating.

And what we have seen since utilizing the

ScarGuard in these rocky settings, that every single one of those installations have been successful. We've had improvements in the resistivity testing results, which, in turn, will lead to long-term better performance out of that fusion-bonded epoxy over decades to come.

Q. Reference back to the exhibit Weisker Direct Late-Filed Exhibit Number 1, and I refer you to the second paragraph, seven lines down, the sentence that starts:

"No other utility does this and all the contractors can't understand why, even though they are loving the windfall."

Do you see that quote?

A. I do.

Q. Do other utilities use ScarGuard across the entire pipe like Piedmont is doing at this time?

A. Yes, they do. Other utilities have, and we've done some additional investigation to verify. Examples of other utilities that are doing this in the same scenario, in rocky settings and a horizontal directional drill, include Virginia Natural Gas, Atlanta Gas Light, Atmos, and many others within the industry.

Q. We've already discussed how Piedmont only uses ScarGuard in about 30 percent of those horizontal drilling projects, and then Piedmont has employed this practice in about the last year, couple of years, which is consistent with other utilities' usage.

What are the incremental cost of this change in usage?

A. So for a pipe that's -- a 12-inch diameter pipe, which is typically, I'll say, a standard pipe that we install throughout the North Carolina system, the incremental cost is around $100,000 for a 100-foot section of pipe. And what we've -- and as we've looked back over the past -- looking back over the past three years, looking at the average total length of pipe installed and the amount of that length that was installed via a horizontal directional drill, which it averages, just say, six miles per year. And then that 35 percent roughly of the pipe that's in a rocky setting, we're talking, on a typical year, about 2,000 -- excuse me -- two miles of pipe that's installed utilizing, you know, a horizontal directional drilling technique in a rocky setting, which is around 11,000 feet of pipe, which, in an annualized view, if that's 12-inch pipe that's installed, you're looking at about $1.1 million.

Q. And I believe, in your answer, you stated that ScarGuard costs approximately $100,000 for 100 feet of pipe?

A. Correction. It's $100,000 per 1,000 feet of pipe. Sorry about that.

Q. Thank you. Now, towards the end of this letter, the writer goes back to specifically identifying Ms. Presson, and states that she is a nuclear energy without requisite experience. He or she then goes on to state that Ms. Presson doesn't listen to her team, employs bullying tactics, and caused the best construction superintendent the Company has ever had to quit. Do you see that?

A. I do.

Q. So, first, can you explain to the Commission Ms. Presson's qualifications and her performance in her current role?

A. So Ms. Presson has 22 years of experience within the utility industry. The last 10 years of that experience has been at the director level or above leading many complex projects and implementation of projects. Ms. Presson has a bachelor of science in business administration from the University of

North Carolina Chapel Hill. She has a bachelor of science in nuclear engineering from North Carolina State University.

She's also our representative for the natural gas business unit on INGAA, Natural Gas Association of America. She has extensive experience and has demonstrated outstanding leadership leading her team here in the natural gas business unit.

Q. And in your opportunity to observe her as her manager, have you seen any of the behavior that this letter alleges?

A. I have not. Ms. Presson has demonstrated an immense level of teamwork, listening to her team, accepting feedback, implementing fleet-wide solutions. I have not seen anything that is claimed in this letter.

Q. Do you have any idea who, quote, the best construction superintendent the Company ever had, close quote, that Ms. Presson presumably caused to quit the Company?

A. Yes, I do. I know exactly who is being referred to in the letter. And this construction superintendent, he did not quit from the Company, he retired from the Company. I've maintained very close communication with him over the last several years. And his exact words were, "Ms. Presson actually empowered me to be able to retire."

Because of what he's learned and what he's done over the last several years working within the major project organizations, he had an opportunity to go somewhere else and expand his career post retirement from the Company, and he really is thankful for what Ms. Presson has done for him.

Q. Thank you, Mr. Weisker. Just a couple more questions.

What's the Company's response when it was made aware of the allegations in this letter?

A. So we investigated the response. We take any kind of an allegation seriously. We investigated both the technical merits of the work that were -- when we utilize ScarGuard. And we also investigated, I'll say, the human element of it, as far as the claims against Ms. Presson.

Q. And prior to this anonymous letter, had any employee raised these concerns with you regarding the Company's usage of ScarGuard?

A. No, they had not. But we try to instill a -- foster an environment of being able to bring up any kind of an issue, and -- but no, they have not.

Q. If the identity of this anonymous writer were learned by the Company, would Piedmont take any negative actions for the employee?

A. No, we would not. I would like the opportunity, if it was ever identified, to sit down just to have a conversation to talk through. Because there's obviously some significant technical gaps as to, you know, understanding of when we use ScarGuard, why we use ScarGuard, the importance of ScarGuard. And just really have a conversation also around, if you have concerns, please, feel free to come talk to me about your concerns or anyone within the natural gas business unit.

Q. Did representatives from Piedmont meet with members of the energy division of the Public Staff about this specific letter?

A. Yes, we did. We met with them yesterday morning.

Q. Who on your team attended the meeting and what are their positions and responsibilities?

A. So it was -- I met with the members of the Public Staff as well as Billy Wooldridge. And he is the construction superintendent within our major projects business unit or business function department. And then we had Mel Huey, who is our director of our integrity management program.

Q. And did the Public Staff ask questions?

A. They did.

Q. And just to be clear, the members of the Public Staff included accountants and engineers; is that correct?

A. That is correct.

Q. And has Piedmont also had contact with the North Carolina Utilities Commission gas pipeline safety manager, Steve Wood, about this consumer statement?

A. Yes. Mr. Wood reached out to our regulatory compliance team to investigate the matter just the past couple of days, and I'd spoken with Steve last evening as well.

Q. Thank you, Mr. Weisker.

MR. HESLIN: Chair Mitchell, Mr. Weisker is available for cross examination and questions from the Commission.

CHAIR MITCHELL: All right. Thank you, Mr. Heslin. Cross examination for the witness? I'll check in with the parties to see, beginning with the Public Staff.

MS. JOST: The Public Staff does not have any questions. Thank you.

CHAIR MITCHELL: Okay. Attorney General's Office?

MS. TOWNSEND: Yes, Commissioner, we just have a few questions for Mr. Weisker.

CROSS EXAMINATION BY MS. TOWNSEND:

Q. Good morning, Mr. Weisker.

A. Good morning.

Q. I just have a few questions, as I said. Regarding your testimony on page 16 where you testified regarding Piedmont's methane leak detection programs.

A. Yes.

Q. Okay. You mentioned that Piedmont has performed two satellite flyover pilots to identify methane leak; is that correct?

A. That's correct.

Q. And how have those satellite flyovers helped Piedmont in determining its leak detection?

A. So it's gone extremely well, I'd say. So what we were doing with the first several flyovers -- so we perform leak detection surveys where we have folks on foot that go around and identify leaks on our system that we then go out and repair.

With the flyover, two things: one, we wanted to validate, do we see the leaks that we have on our system with the satellite as well; and then also, are there any other unknown leaks that we haven't detected through our survey cycle that we would find and then be able to go out and repair as well.

So in both accounts, we were able to correlate the two, where we do have a known leak to what we see with the satellite. And we were also able to identify some leaks that we did not have on our system and we were able to go out and repair.

Q. Awesome. And do you have plans, or does the Company have plans to continue to utilize the satellite flyovers?

A. So what we have now -- we've expanded this and we're in the process of doing a pilot of this on a monthly flyover. Not in North Carolina, it's for Greenville, South Carolina. We wanted to get a pretty good size city but just continue to grow this. But our pilot right now is going to be a monthly flyover of -- you can imagine fly over, identify leaks, let's go and then fix leaks, and fly back over again with the satellite, take a snapshot to see that we were successful in repairing.

So we did a flyover back in the springtime in Greenville. What was really exciting, we've repaired about 200 leaks. And when the flyover went over just about two weeks ago, those leaks didn't show up on the flyover, they were fixed. And so our plan is to continue expand that, grow this pilot program, and hopefully that this will be something that we can continue to grow and expand as we work very diligently to reduce any kind of methane emissions from our system.

Q. Great. Awesome. Is Piedmont employing any other methods of identifying methane leaks?

A. So we have our annual -- well, I should say it's a three-year cycle of on-foot leak detection that we do across the entirety of our system. So that's where we literally walk the entire length of our system to identify leaks. We also, on a quarterly basis, utilize a helicopter to fly all of our gas transmission lines. It has a -- it's just an air detection sniffer -- a sniffer that attaches onto the helicopter, and it flies the entire length of our transmission system on a quarterly basis to identify leaks as well.

Q. Great. Has Piedmont made attempts to procure natural gas from suppliers that employ these type of methods that result in lower methane emissions?

A. I think I'm not the expert on the procurement side of our natural gas. We have others who can testify better as far as the procurement side.

Q. Okay. But there are attempts being made for that purpose, to your knowledge?

A. I think we probably need to have another one of our witnesses answer. I can't answer specifically on what the attempts are.

Q. Okay. That's fine. And that's all the questions I have. Thank you very much.

A. Thank you.

CHAIR MITCHELL: All right. Let's see, Duke Energy Carolinas? I'm not seeing Mr. Kaylor.

Fayetteville Public Works Commission?

MR. WEST: No questions, Madam Chair.

CHAIR MITCHELL: Okay. CUCA?

MR. SCHAUER: No questions.

CHAIR MITCHELL: Okay. CIGFUR?

MS. CRESS: No questions, Chair Mitchell.

CHAIR MITCHELL: All right. Questions -- actually, Mr. Heslin, redirect for your witness?

MR. HESLIN: No redirect,
Chair Mitchell. Thank you.
CHAIR MITCHELL: Okay. Questions for
the witness from Commissioners.
Commissioner McKissick?
COMMISSIONER McKISSICK: Thank you,
Madam Chair.
EXAMINATION BY COMMISSIONER McKISSICK:
Q. Just a few questions. And I had a number of them, but I think that you were able to answer most of them in your testimony today.
Can you elaborate further on Ms. Presson's role in the adoption of this policy.
A. So Ms. Presson's role in the adoption, she would -- her and her team would be the group that would implement in the field the policy that was decided upon by our engineering and technical team. So think of it as an engineering and technical team develops the standard, a construction standard, and then the team that implements those projects in the field implements that standard.
Q. Okay. And the engineering team, I mean, do you know what kind investigations they conducted or evaluations before determining that this was a policy

they wanted to adopt?

A. So we have utilized, as I mentioned, the ScarGuard technique on weld joints, but we actually, I'll say, did some testing of that. So one good project as an example where we implemented this in late 2019, early 2020 to test out putting ScarGuard on the entirety of the length of that horizontal directional drill through a rocky soil was part of our line 24 replacement project. And so in that scenario there. This was before the official policy of utilizing this in this rocky horizontal directional drill sections.

But it was used on that project, and again, saw outstanding results. No damage to the coating. Resistivity test was excellent and showed improvements. And so I'll say that field testing and implementation is what led to the implementation of the policy from our integrity management team.

Q. Okay. And at what point in time did the engineering department make this recommendation of the use of the material?

A. The formal recommendation was in November of 2020.

Q. Okay, November 2020.

Have you had a chance since that time to do any type of comparative analysis relating to the cost of implementing the policy? And I think you said that, you know, it looked like it cost -- I think was it in the range of about $1.1 million since its implementation versus what you might have incurred previously in terms of having to go back and reinstall sections of pipe that were damaged?

A. I don't -- from an overall financial analysis, I don't have -- I don't know that I can answer that right now, as far as financial analysis on the $1.1 million cost. But the whole purpose of this is to protect the asset for the long run. We are and have and had to replace sections that have been bored underneath a water body that have basically -- that the pipe life hasn't lasted as long as would have been expected. And so I think the cost very much justifies the long-term value and the long-term integrity management value.

Q. And I believe the allegation in the anonymous letter was that it added millions to the cost of each project.

Do you have any idea what has actually been spent since this new ScarGuard policy has been adopted? I mean, what has it actually worked out to, if you have

any idea of what that might be?
A. It would be in a range of that -- on an annualized look, that $1.1 million on an annualized look. But that's spread out across multiple projects. The one project I gave you the example on where we did the testing of this back in 2019 went into service in early 2020, that was a $72 million total project, and the cost of the ScarGuard was less than $300,000.
Q. Got it. And, of course, you said the ScarGuard is only used when you encounter the rocky soil condition, and that's only about 30 percent of the time; is that correct?
A. That's only about 30 to 40 percent of the time in North Carolina when we do a horizontal directional drill.
Q. Okay.
A. And realize a horizontal directional drill technique is only used on it -- over the last three years, it's only been used, on average, 8 percent. So 8 percent of the total miles installed, and then it's only been 30 to 40 percent of the time on that 8 percent of the miles installed.
Q. And Ms. Presson, I take it based upon your testimony, it was not her decision to implement the

policy at all dealing with the ScarGuard, it was made by the engineering department.

So the allegation that it was her decision and that, you know, her background was not appropriate to make that determination, I take it that that information that was provided in the letter is inaccurate?

A. Yes, that is inaccurate. It was our engineering and integrity management organization that -- technical experts who made the decision.

COMMISSIONER McKISSICK: Thank you, Madam Chair. I don't have any further questions.

THE WITNESS: Thank you.

CHAIR MITCHELL: Okay. Questions from any other Commissioners?

(No response.)

CHAIR MITCHELL: All right. I'm not seeing any. Let's go to questions on Commissioner's questions. Any of the intervening parties have questions on Commissioner's questions?

(No response.)

CHAIR MITCHELL: Okay. Piedmont, questions on Commissioner's questions?

MR. HESLIN: Chair Mitchell, just one

question.

CHAIR MITCHELL: Okay.

REDIRECT EXAMINATION BY MR. HESLIN:

Q. Mr. Weisker, given the specific pointing out of Ms. Presson and the discussion we've had, having reviewed this letter and knowing Ms. Presson as you do as her manager, do you have any concerns about her qualifications, leadership abilities, or integrity?

A. I have absolutely no concerns about her leadership abilities, integrity, and her qualifications. She's extremely qualified for the job, she's been doing an outstanding job, and she's an outstanding leader, and is someone who has a bright future ahead of her within the Company.

MR. HESLIN: Thank you. No further questions. Thank you, Chair Mitchell. Thank you, Mr. Weisker.

THE WITNESS: Thank you.

CHAIR MITCHELL: All right. Mr. Weisker, thank you for your testimony today. I do believe you are -- may be excused.

Mr. Heslin, I will take a motion from you.

MR. HESLIN: Yes. At this time, we'd

ask that exhibits marked BRW-1 and BRW-2, as well as Weisker Direct Late-Filed Exhibit 1, be accepted into evidence.

CHAIR MITCHELL: All right. I'm not hearing any objection to your motion, Mr. Heslin, so it will be allowed.

(Exhibits BRW-1, BRW-2, and Weisker Direct Late-Filed Exhibit Number 1, were admitted into evidence.)

MR. HESLIN: Thank you, Chair Mitchell. And we don't intend to recall Mr. Weisker in this hearing.

CHAIR MITCHELL: Okay. Mr. Weisker, you are excused. Thank you very much, sir.

THE WITNESS: Thank you, ma'am.

CHAIR MITCHELL: All right. Piedmont, let's go ahead and call your next witness, please.

MR. JEFFRIES: Thank you, Chair Mitchell. Piedmont would call Mr. Karl Newlin to the stand, please.

CHAIR MITCHELL: All right. Mr. Newlin, there you are. Good morning, sir, would you raise your right hand.

Whereupon,

KARL W. NEWLIN,
having first been duly affirmed, was examined
and testified as follows:

CHAIR MITCHELL: All right, Mr. Jeffries.

MR. JEFFRIES: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. Newlin, you could please state your name and business address for the record, please.

A. Karl Newlin. My business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. And do you work -- well, where do you work, Mr. Newlin?

A. I work for Duke Energy Business Services. I'm the senior vice president corporate development and treasurer. Duke Energy Business Services provides various administrative services to Piedmont Natural Gas.

Q. All right. Thank you, sir. Are you the same Karl Newlin that prefiled direct testimony in this proceeding on March 22, 2021, consisting of 18 pages and exhibits marked as KWN-1 through KWN-3?

A. I am.

Q. And are you also the same Mr. Newlin that filed rebuttal testimony in this proceeding on August 25, 2021, consisting of 13 pages and an exhibit marked as Rebuttal Exhibit KWN-1?

A. I am.

Q. And was that testimony and were those exhibits prepared by you or under your direction?

A. Yes.

Q. Mr. Newlin, do you have any corrections to your prefiled testimony or exhibits?

A. No, I do not.

Q. If I asked you the same questions that are set forth in your prefiled testimony while you were on the stand today, would your questions -- or would your answers be the same as reflected in that testimony?

A. Yes.

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

CHAIR MITCHELL: All right. Hearing no objection to your motion, Mr. Jeffries, the direct testimony of witness Newlin that was filed in this docket on March 22, 2021, shall be copied into the record as if given orally from the stand. In addition, the rebuttal testimony of witness Newlin that was filed in this docket on August 25, 2021, shall be copied into the record as if given orally from the stand.

(Whereupon, the prefiled direct testimony and prefiled rebuttal testimony of Karl W. Newlin 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

## Direct Testimony and Exhibits
## of
## Karl W. Newlin

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**March 22, 2021**

**Q. Please state your name and business address.**

A. My name is Karl Newlin. My business address is 550 South Tryon Street, Charlotte, North Carolina.

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

**A.** I am employed by Duke Energy Business Services, LLC ("DEBS") as Senior Vice President, Corporate Development and Treasurer. DEBS provides various administrative and other services to Piedmont Natural Gas Company, Inc, ("Piedmont" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

**Q. Please describe your educational and professional background.**

A. I graduated from Southern Methodist University with a Bachelor of Business Administration degree in 1991. I subsequently received a Master's in Business Administration degree from UCLA's Anderson School of Management in 1998. I am also a Chartered Financial Analyst.

In November 2018, I assumed the role of Senior Vice President, Corporate Development and Treasurer for Duke Energy. Previously, I served as Senior Vice President and Chief Commercial Officer for Duke Energy's natural gas business. In this role, I was responsible for gas commercial operations, which included supply, wholesale marketing, transportation and pipeline services, field customer service, sales and delivery, and business development. I was named to this position following Duke Energy's acquisition of Piedmont in October 2016.

I joined Piedmont in 2010 to manage Piedmont's strategic planning functions, new business development activities and joint venture investments. In November 2011, I was appointed to the position of Chief Financial Officer, assuming responsibility for Piedmont's accounting, controller, finance, treasurer, investor relations, insurance, credit policy, risk management and state regulatory affairs areas. Prior to joining Piedmont, I served as Managing Director of Investment Banking for Merrill Lynch & Co. in its New York and Los Angeles offices.

**Q. Have you previously testified before this Commission or any other regulatory authority?**

A. I have recently testified before the North Carolina Utilities Commission ("NCUC" or "Commission") and have filed testimony on behalf of Duke Energy Carolinas and Duke Energy Progress in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, respectively. I have also testified before the NCUC in my prior role as Piedmont's Chief Financial Officer.

**Q. Do you have any exhibits supporting your testimony?**

A. Yes, I have three exhibits. Exhibit_(KWN-1) shows Piedmont's end of test period capital structure as well as the projection of Piedmont's capital structure in support of Piedmont's pro forma capital structure for use in this proceeding. Exhibit_(KWN-2) shows Piedmont's pro forma embedded cost of long-term debt for use in this proceeding. Exhibit_(KWN-3) shows Piedmont's pro forma embedded cost of short-term debt for use in this proceeding.

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

**supervision?**

A. Yes.

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

A. My testimony will address Piedmont's financial objectives, capital structure, and cost of capital. I will also discuss the Company's current credit ratings and forecasted capital needs. Throughout my testimony, I will emphasize the importance of Piedmont's ongoing ability to meet its financial objectives and the benefits to customers resulting from Piedmont maintaining financial stability and strong credit ratings.

**Q. Please provide an overview of your testimony.**

A. As is discussed in greater detail in my testimony, Piedmont faces substantial capital needs over the next several years in order to continue its compliance with federal pipeline safety and reliability regulations and to construct new pipeline and distribution facilities in order to serve its growing North Carolina markets. In order to meet these capital demands, the Company will compete for capital in the open market and must appeal to debt and equity investors to attract the capital it needs.

Investors have a variety of investment opportunities available to them and require a return commensurate with the risk they incur. Investors are less likely to invest in a company if they feel the expected return doesn't fairly compensate for the perceived risk of the investment. A company with lower credit quality weakens its attractiveness as an investment opportunity relative to similarly situated companies with higher credit quality. For this reason, it is critically important that a company maintain strong investment-grade credit quality, in order to assure its financial strength and flexibility and ensure access to capital on reasonable terms.

Piedmont has and will continue to make significant capital investments in order to meet its obligations under pipeline safety and integrity regulations promulgated by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") and to continue to provide cost effective, safe, and reliable natural gas service to its growing customer base within the State of North Carolina. The Company's proposed rate increase will allow the Company to recover prudently incurred costs, to compete in the capital markets for needed capital, and preserve its financial standing with both equity and debt investors as well as the credit rating agencies, to the long-term benefit of customers.

**Q. What role does capital structure and financial stability play in Piedmont's ability to provide safe, reliable, and economic natural gas service to its customers?**

A. Financial stability and consistent access to capital are necessary for Piedmont to provide safe, reliable, and economical service to its customers. Piedmont strives at all times to maintain financial stability, including investment grade credit ratings, to ensure reliable access to capital on reasonable terms. Our ability to access needed capital on reasonable terms is supported by the following specific objectives of the

Company: (a) maintaining a strong (52% or higher) equity component in our capital structure; (b) pursuing timely recovery of prudently incurred costs of providing utility service; (c) maintaining sufficient cash-flows to meet our obligations; and (d) maintaining an adequate rate of return on common equity.

**Q. What is Piedmont's proposed capital structure in this proceeding?**

A. As shown on my Exhibit_(KWN-1), I recommend a capital structure consisting of 52.00% equity, 0.55% short-term debt and 47.45% long-term debt.

**Q. Why are you recommending this pro forma capital structure?**

A. This capital structure represents an appropriate amount of risk due to leverage (48% or lower) while minimizing the weighted average cost of capital. Approval of the proposed capital structure will help Piedmont maintain its credit quality, the importance of which I will describe in subsequent sections of my testimony and is consistent with Duke Energy's target credit ratings for Piedmont. The short-term debt component of the recommended capital structure is a thirteen-month average value of Piedmont's natural gas inventory balance. Procurement of natural gas is a significant and necessary part of Piedmont's short-term indebtedness under normal operating conditions. The Commission has approved this method of calculating the short-term debt component of Piedmont's capital structure in multiple previous general rate case dockets.

**Q. Does the Company's actual financial capital structure vary over time?**

A. Yes, it does. The specific debt/equity ratio will vary over time, depending on a variety of factors, including, but not limited to, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, changes to inventory balances, equity infusions received from parent, and dividend payments made to the parent company. Achieving an approved regulatory capital structure as recommended above is consistent with the Company's financial objectives and overall plan to finance operations at favorable rates for customers. Piedmont will manage its capital structure within a reasonable range of this base. 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.

**Q. What changes in the Company's capital structure will occur after December 31, 2020, specifically over the next two years?**

A. As reflected on Exhibit_(KWN-1), Piedmont's projected equity component of the Company's regulatory capital structure will range between approximately 51% and 53% over the next two years. On March 11, 2021, Piedmont issued new long-term debt of $350 million, 10-year senior unsecured notes. Also in March 2021, Piedmont received a $325 million equity infusion from its parent. In the second quarter of 2022, Piedmont is expected to issue $300 million of long-term debt. Equity will also increase due to earnings achieved and retained in 2021 and 2022.

**Q. What pro forma cost rates did you attribute to each component of the Company's capital structure?**

A. I utilized a cost rate of 4.09% for long-term debt, 0.47% for short-term debt, and 10.25% for common equity.

**Q. How were these cost rates determined?**

A. For the Company's cost of common equity, I utilized the cost calculated and recommended by Piedmont's ROE Witness Dylan D'Ascendis in his direct testimony. For long-term debt, I used Piedmont's projected embedded cost of long-term debt as of December 31, 2021, which includes the previously referenced long-term debt offering in March 2021. For short-term debt, the rate is based on the Company's projected 2021 average borrowing rate under the Utility Money Pool Agreement. The derivation of these debt rates is shown on Exhibit_(KWN-2) and Exhibit_(KWN-3).

**Q. How does Piedmont's proposed capital structure and cost rates compare to its most recently approved capital structure?**

A. In Piedmont's rate case in 2019, the Commission approved the following capital structure, which provides part of the basis for our current rates: 47.15% long term debt, 0.85% short term debt and 52.00% common equity. The approved cost rates from that proceeding were 4.41%, 2.72% and 9.70%, respectively.

**Q. Please explain credit quality and credit ratings, and how they are determined.**

A. Credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. An assessment of Piedmont's creditworthiness is performed by two major credit rating agencies, Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"). Many qualitative and quantitative factors go into this assessment. Qualitative aspects may include an assessment of the regulatory climate in which Piedmont operates, Piedmont's record for delivering on its commitments, the strength of its management team, its operating performance, and the strength of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which Piedmont maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest and principal payments in particular) on the basis of internally-generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

**Q. What is the role of regulation in the determination of the financial strength of a utility company?**

A. Investors, investment analysts, and credit rating agencies regard constructive regulation as one of the most important factors in assessing a utility company's financial strength. These stakeholders want to be confident the Company operates in a stable regulatory environment that will allow the Company to recover prudently-incurred costs and earn a reasonable return on investments necessary to meet the demand, reliability, service, safety, and environmental requirements of its customers and service area. Important considerations include the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, and the strength of its capital structure. Positive consideration is also given for utilities operating in states where the regulatory process is streamlined, the time lag in capital investment recovery is minimized through cost recovery mechanisms such as riders and trackers, and outcomes are equitably balanced between customers and investors.

**Q. How are Piedmont's outstanding securities currently rated by the credit rating agencies?**

A. As of the date of this testimony, Piedmont's senior unsecured credit ratings and outlooks are as follows:

| Rating Agency | S&P | Moody's |
|---|---|---|
| Senior Unsecured | BBB+ | A3 |
| Outlook | Stable | Stable |

Obligations carrying a credit rating in the "A" category are considered strong, investment-grade securities subject to low credit risk for the investor. "A" rated debt is presumed to be somewhat susceptible to changes in circumstances and economic conditions; however, the debt issuer's capacity to meet its financial commitments is considered strong. By contrast, ratings in the "BBB" (one level weaker than the "A" category) category are considered adequate and have less assurance of access to the capital markets in challenging market conditions.

S&P may also modify its ratings with the use of a plus or minus sign to further indicate the relative standing within a major rating category. An "A+" credit rating is at the higher end of the "A" credit rating category and an "A-"is at the lower end of the category. Moody's credit rating assignments use the numbers "1", "2" and "3", with the numbers "1" and "3" analogous to a "+" and "-", respectively. For example, Moody's credit ratings of "A2" and "A3" would be analogous to "A" and "A-" credit ratings at S&P.

The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years). Piedmont's "Stable" outlook at S&P and Moody's is an indication the credit ratings are not likely to change at this time, however a change in outlook or rating could occur if the Company experiences a change in its business or financial risk.

**Q. Have there been any recent changes to Piedmont's credit ratings or outlooks at S&P or Moody's?**

A. Yes. On December 15, 2020, S&P revised its outlook to "negative" from "stable" on Duke Energy and subsidiaries, including Piedmont. On

January 26, 2021, S&P downgraded the senior unsecured ratings of Duke Energy and subsidiaries, including Piedmont, to "BBB+" from "A-" and returned the outlook to "stable."

S&P utilizes a family rating methodology, whereby the credit rating and outlook of the parent company, Duke Energy, is applied to each of the parent's subsidiaries. In its January 2021 Duke Energy report,[1] S&P attributed the downgrade to weaker consolidated financial metrics primarily as a result of the coal ash settlement reached at Duke Energy Carolinas and Duke Energy Progress and Duke Energy's elevated capital expenditure plan. S&P's "stable" outlook is predicated on the expectation that Duke Energy and subsidiaries will be able to manage regulatory risk while capital spending remains high as Duke Energy continues its energy transformation to reduce its carbon footprint.

**Q. What is the impact to Piedmont's expected long-term borrowing costs going forward with a one-notch downgrade by S&P at Duke Energy and its subsidiaries?**

A. Since the one-notch downgrade by S&P on January 26, 2021 to Piedmont's senior unsecured rating, there has been no material impact to Piedmont's credit spreads. With Moody's leaving its "A3" senior unsecured credit rating on Piedmont unchanged, a sophisticated investor in senior unsecured bonds will evaluate the creditworthiness of that specific

1 S&P Global Ratings, Research Update, "Duke Energy Corp. And Subsidiaries Downgraded To 'BBB+' On Coal Ash Settlement, Outlook Stable," January 26, 2021 ("January 2021 Duke Energy Corporation Report")

utility when determining the appropriate pricing level on new debt offerings. For these reasons, a one-notch downgrade at Piedmont by S&P due solely to its family rating methodology will not likely have any meaningful impact to Piedmont's cost of debt going forward.

**Q. What benefits do customers of Piedmont enjoy by being a part of the broader Duke Energy family?**

A. Customers of Piedmont enjoy several benefits derived from Piedmont's status as a subsidiary of the larger Duke Energy portfolio of utilities. Duke Energy's $8.0 billion Master Credit Facility and $6.0 billion commercial paper program provide Piedmont greater access to liquidity from highly reputable financial institutions and in the short-term money markets. In addition, the Utility Money Pool Agreement allows Piedmont to borrow short-term funds from participating entities at the "AA" Industrial Commercial Paper Composite Rate, which is a lower rate than would otherwise be available to Piedmont as a stand-alone issuer. Access to deeper pools of liquidity at lower borrowing costs have been particularly beneficial as uncertainty from the COVID-19 pandemic led to extreme market dislocation and heightened volatility in the first half of 2020. Piedmont also benefits from lower overhead costs as a result of shared corporate services.

**Q. Do Piedmont's customers benefit from the Company's strong credit ratings?**

A. Yes. To ensure reliable and cost-effective service, compliance with federal pipeline safety regulations and to fulfill its obligations to serve customers, the Company must continuously plan and execute significant capital projects. This is the nature of regulated, capital-intensive industries like natural gas utilities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. The financial markets can experience periods of volatility, and Piedmont must be able to finance its needs throughout such periods. Strong investment-grade credit ratings provide Piedmont with greater access to the capital markets on reasonable terms during such periods of volatility. Any factors that negatively impact Piedmont's credit ratings, including an inadequate allowed ROE or an inadequate equity percentage of the capital structure, have the potential to reduce the Company's access to the capital markets and to increase the cost of such access.

Approval of the Company's request in this case will support its financial objectives by allowing timely recovery of its investments in plant and equipment, providing sufficient cash flows to fund necessary capital expenditures and service debt.

**Q. What strengths and weaknesses have the credit rating agencies identified with respect to Piedmont?**

A. The rating agencies believe Piedmont operates in generally constructive regulatory environments that support long-term credit quality, and they also view the Company's customer growth profile and system integrity investments as credit supportive. However, the rating agencies have identified a number of challenges Piedmont faces in maintaining its credit ratings. In its July 2020 credit opinion, Moody's identified several factors that could adversely impact Piedmont's financial metrics (specifically, cash flow coverage ratios), which, in turn, could affect its ratings.[2]

Capital Expenditures and Tax Reform: Moody's notes elevated capital expenditures, the continued impact of federal tax reform, and the associated leverage to fund customer growth and system integrity investments will continue to pressure key credit metrics.

Environmental and Social Considerations: Moody's includes in their credit assessment of Piedmont the impact of regulations on carbon and methane through the production of energy. From a social perspective, Moody's assesses the risk the coronavirus pandemic poses to the health and safety of employees, and the potential impact the pandemic continues to have if unemployment remains elevated. Moody's states, "…financial and risk management policies including a strong financial profile are important characteristics for managing environmental and social risks."[3]

**Q. What role do equity investors play in the financing of Piedmont, and how will the outcome of this case impact these investors?**

A. Equity investors provide the foundation of a company's capitalization by providing significant amounts of capital, for which an appropriate

2 *See* Moody's Investors Service, Credit Opinion, "Piedmont Natural Gas Company, Inc. – Update to Credit Analysis," July 22, 2020 ("July 2020 Piedmont Report")
3 July 2020 Piedmont Report, p.4

economic return is required. Piedmont compensates equity investors for the risk of their investment by targeting fair and adequate returns, stable cash flows, and earnings growth - all necessary to preserve access to equity capital. Returns to equity investors are realized only after all operating expenses and fixed payment obligations (including principal and interest) of the business have been paid. Because equity investors are the last to receive surplus earnings and cash flows, their investment involves significantly more risk. For this reason, equity investors require a higher return for their investment. Equity investors in Duke Energy expect utilities like Piedmont to recover their prudently incurred costs and earn a fair and reasonable return for their investors. The Company's proposal in this proceeding supports this investor expectation.

**Q. What effect does capital structure and return on equity have on credit quality?**

A. Capital structure and return on equity are important components of credit quality. As mentioned in the previous answer, the greater the equity component of capitalization, the safer the returns are to debt investors, which translates into higher credit quality and lower borrowing costs. In addition, the allowed return on equity is a key component in the generation of earnings and cash flows. An adequate return on equity helps ensure equity investors receive fair compensation for their investment while also helping to protect the interests of debt investors. A strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. High credit quality creates financial flexibility by improving access to the capital markets on reasonable terms, and ultimately lower debt financing costs.

**Q. Do you believe Piedmont's capital structure has an adequate equity component to enable the Company to achieve its financial strength and credit quality objectives?**

A. Yes. Piedmont' requested equity component of 52% enables it to maintain current credit ratings and financial strength and flexibility. Like many utilities, Piedmont is in a period of significant capital investment necessary to provide cost-effective, safe, and reliable service to its customers in a period of rising costs, growing customer load and evolving state and federal pipeline safety and integrity requirements. The magnitude of its capital requirements dictates the need for a strong equity component of the Company's capital structure in order to assure access to capital funding at reasonable terms.

**Q. Please describe Piedmont's future capital requirements.**

A. Piedmont faces substantial capital needs over the next several years in order to comply with pipeline safety and integrity regulations, refurbish, replace and upgrade aging infrastructure, support its growing customer base, construct additional on-system storage assets, and satisfy its debt maturities.

**Q. How will Piedmont's capital requirements be funded?**

A. Piedmont's capital requirements are expected to be funded from internal cash generation, the issuance of debt, and equity contributions from its parent. It is important to remember that Duke Energy also has dividend expectations from its shareholders. Duke Energy's corporate dividend policy targets a mid-point 70 percent payout ratio, based on adjusted diluted earnings per share. Piedmont and other utility subsidiaries of Duke Energy are expected to support this dividend policy over time.

**Q. Do you anticipate Piedmont will be able to access sufficient debt and equity to support its ongoing operations without any problems?**

A. I do, but the reasonableness of the terms upon which Piedmont can access those markets depends largely on Piedmont continuing to maintain favorable credit ratings. That, in turn, depends on the regulatory treatment Piedmont receives from the state public service commissions that regulate the Company. This is particularly true for this rate case and this Commission as North Carolina accounts for over 70% the Company's rate base and earnings potential.

**Q. Can you explain?**

A. Yes. Piedmont's investors and creditors carefully evaluate how we are regulated by this Commission, including what levels of allowed return are approved in our general rate proceedings. They are aware that allowed rates of return may vary over time with changes in general economic factors, but they also believe we operate in a generally constructive regulatory environment – a conclusion with which we agree and which we believe is a significant benefit to our customers. Any change in this assessment could raise capital costs for Piedmont and its customers. This vulnerability is especially acute in light of Piedmont's significant and ongoing investments in capital projects required to meet federal safety and integrity management requirements.

The Company's management recognizes that the Commission must balance the interests of customers with those of the Company when setting rates of return and capital structure in any general rate proceeding. At the same time, it is important to consider the long-term consequences these decisions can have on the terms under which Piedmont can access capital markets.

**Q. Does this conclude your pre-filed direct testimony?**

A. Yes.

# Before the
# North Carolina Utilities Commission

## Docket No. G-9, Sub 781

## General Rate Case

## Rebuttal Testimony and Exhibit
## of
## Karl W. Newlin

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

August 25, 2021

**Q. Please state your name, business address, and occupation.**

A. My name is Karl Newlin. My business address is 550 South Tryon Street, Charlotte, North Carolina. I am employed by Duke Energy Business Services, LLC as Senior Vice President, Corporate Development and Treasurer.

**Q. Did you file direct testimony in this proceeding?**

**A.** Yes, I filed direct testimony supporting Piedmont Natural Gas Company, Inc.'s ("Piedmont" or the "Company") financial objectives, capital structure, and cost of capital.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to respond to portions of the testimony submitted by Mr. John R. Hinton, witness on behalf of the Public Staff of the North Carolina Utilities Commission ("Public Staff") and Mr. Kevin W. O'Donnell, witness on behalf of Carolina Utility Customers Association, Inc. ("CUCA"). In my testimony I will address their respective recommendations on the Company's appropriate capital structure.

**Q. Do you have any exhibits to your rebuttal testimony?**

A. Yes. I have one exhibit, marked as Rebuttal Exhibit KWN-1, attached to my rebuttal testimony.

**Q. Was this exhibit prepared by you or under your direction?**

A. Yes.

**Q. Please summarize the key points made by witness Hinton and witness O'Donnell regarding your recommendation that the Company's appropriate equity ratio be 52% equity.**

A. The key points are as follows:

- Witness Hinton claims that the Company's recommended equity ratio of 52% is excessive, is not necessary to maintain Piedmont's credit ratings, and does not reflect Piedmont's historical capital structure. Instead, witness Hinton recommends the Commission reduce the Company's equity ratio from 52% (as currently approved under Docket G-9, Sub 743) to 50.54% based on a 13-month historical average of Piedmont's capital structure as of May 31, 2021.
- Witness O'Donnell recommends a 50% equity ratio. To support his recommendation, Mr. O'Donnell points to the following three comparative equity ratios:
    1. The "average" capital structure calculated for the companies he utilized as "proxy" companies for the purposes of calculating Piedmont's Return on Equity ("ROE");
    2. Duke Energy Corporation's ("Duke Energy") average equity ratio based on the concept of double leverage; and
    3. The 2020 and 15-year (2006-2020) historical average allowed annual common equity ratio granted by state regulators for natural gas companies.

**Q. Witness Hinton suggests that Piedmont's 52% equity ratio is excessive and is not necessary in order to maintain the Company's "A3" credit rating and "stable" outlook by Moody's. Do you agree with witness Hinton?**

A. No. Mr. Hinton points to Piedmont's average Cash Flow from Operations pre-working capital to Debt (CFO pre-WC to Debt) metric of 14.1% as the basis for his argument that Piedmont's 52% equity ratio is excessive. Below is the table from page 20 of witness Hinton's testimony with Moody's CFO pre-WC to Debt metrics utilized in his average calculation.

| Moody's Financial Scorecard | Cash Flow from Operations / Debt | Debt / Book Capitalization |
|---|---|---|
| Mar. 31, 2021 | 14.9 times | 43.6% |
| Dec. 31, 2020 | 13.4 times | 48.6% |
| Dec. 31, 2019 | 16.3 times | 48.3% |
| Dec. 31, 2018 | 11.9 times | 47.8% |

Moody's Investors Service states in its July 16, 2021 Credit Opinion that Piedmont's credit metrics "…are weak and have been adversely impacted by the negative cash flow impact of tax reform and increased leverage due to a large capital program." In the same credit opinion, citing what "Factors that could lead to a downgrade," Moody's states "…if we expect the CFO pre-WC to debt ratio to be below 14% for an extended period…"[1] This clearly demonstrates that Moody's downgrade threshold

1 *See* Moody's Investors Service, Credit Opinion, "Piedmont Natural Gas Company, Inc. – Update to Credit Analysis," July 16, 2021 ("July 2021 Piedmont Report")

for Piedmont's "A3" credit rating is 14% for the Company's CFO pre-WC to debt metric. Piedmont's average CFO pre-WC to Debt of 14.1%, as calculated by witness Hinton, is only 10 basis points above Moody's downgrade threshold and shows the Company is already operating with very minimal cushion. Any reduction to the Company's currently approved equity ratio of 52% would result in higher long-term leverage, higher interest expense, and lower CFO pre-WC. This combination of lower CFO pre-WC and higher debt would weaken the Company's already strained CFO pre-WC to debt ratio.

Witness Hinton further states that "the fact that Piedmont's average Cash Flow metric is above 14 times [sic] suggests that Piedmont does not require a 52.00% common equity ratio in order to maintain its "A3" credit rating…" However, Moody's in its July 16, 2021 opinion wrote that "[g]oing forward, on average, we expect Piedmont's ratio of CFO pre-WC to debt to be between 15% and 16%."[2] Clearly, 14% is not within 15% - 16% as Moody's expects, therefore a lowering of the equity component of capital structure as witness Hinton suggests would be detrimental to credit quality, Moody's expectations and potentially the A3 rating.

**Q. Do you agree with witness Hinton's recommendation that a 50.54% equity ratio is appropriate for Piedmont's regulatory capital structure?**

A. No, I do not. Witness Hinton's recommended 50.54% equity ratio is

2 July 2021 Piedmont Report, p. 2

based on a 13-month historical average as of May 31, 2021. However, in March 2021, Piedmont received a $325 million equity infusion from Duke Energy to help fund the Company's capital needs for the year. Since this equity infusion was performed in March, it is only included in three of the thirteen months used in Mr. Hinton's historical average capital structure calculation. Thus, on its face, Mr. Hinton's calculation does not account for significant equity increases currently underlying Piedmont's capitalization. As I will describe next, Piedmont's projected capital structure shown in Exhibit_(KWN-1) to my direct testimony fully accounts for this equity infusion and is a more accurate reflection of the Company's actual capital structure.

Piedmont's regulatory capital structure as of December 31, 2020, consisted of 50.59% equity, 48.74% long-term debt and 0.67% short-term debt. To illustrate the variability of Piedmont's capital structure from December 31, 2020 to December 31, 2022, I presented three additional snapshots of projected capital structures in Exhibit_(KWN-1). This exhibit was prepared to account for planned capital markets activity including a $350 million long-term debt financing and the previously mentioned $325 million equity infusion in March 2021 and to reflect the future increases in the equity account from retained earnings generated by the Company. As illustrated in Exhibit__(KWN-1), the equity percentage is anticipated to increase to 52.56% by December 31, 2021 as a result of accumulating retained earnings over the next few months with no change in Piedmont's debt profile. Moving forward in the 2-year planning horizon, the equity ratio is projected to strengthen again to 52.87% as of December 31, 2022 as retained earnings continue to build and balance against another $300 million long-term debt financing anticipated for the second quarter of 2022 to support the capital spending requirements of the Company. This pattern of fluctuations within a reasonable band of a utility's allowed equity occurs throughout the utility industry. In the case of Piedmont, we expect this band to fall between approximately 50.5% and 53% as presented in Exhibit_(KWN-1). For this reason, the Company believes it is prudent to seek and receive a 52% equity percentage for regulatory capital structure purposes.

**Q. What is the consequence of setting Piedmont's equity ratio too low for ratemaking purposes?**

A. It increases our risk, reduces cash flow and potentially imperils our existing credit ratings. From the perspective of analysts and potential investors, it makes us a less desirable investment. These impacts would ultimately lead to higher financing costs and eventually increase customer rates.

**Q. Witness Hinton states Piedmont's average common equity ratio since its merger with Duke Energy in October 2016 was approximately 50.5%, which is very close to the 13-month average as of May 31, 2021. Do you believe this historical average is reflective of the Company's actual capital structure?**

A. No. Prior to its 2019 general rate case, the Company's regulatory approved capital structure consisted of a 50.66% equity ratio, which was set in its 2013 general rate case, Docket No. G-9, Sub 631. Piedmont's current 52% regulatory equity ratio was not approved until October 31, 2019 in Docket No. G-9, Sub 743. Piedmont seeks to manage its capital structure within a close range of its regulatory approved capital structure and plans to do so in future periods as shown in Exhibit_(KWN-1). Therefore, it is reasonable to expect the Company's capital structure from 2013 to 2019 would have closely tracked to the approved 50.66% equity ratio at the time. However, as shown in Rebuttal Exhibit KWN-1, from January 2018 through June 2021, Piedmont's monthly equity ratio fluctuated between 47.9% and 55.1% with a mid-point of 51.5% and an average equity ratio of 51.1%.

**Q. Do you agree with witness O'Donnell's recommendation that Piedmont's appropriate equity ratio is 50%?**

A. No, I do not, because the basis from which Mr. O'Donnell forms his recommendation is flawed. More specifically, most of the comparative equity ratios Mr. O'Donnell points to are not applicable to Piedmont's equity ratio for rate-setting purposes. Table 5 on page 36 of Mr. O'Donnell's testimony summarizes his findings and is used to frame his recommendation that Piedmont's requested capital structure is "not as reasonable as a recommended capital structure of 50.00% for rate making purposes."

**Q. Mr. O'Donnell first compares Piedmont's capital structure to the same proxy group utilized to calculate his recommended ROE for Piedmont. Do you have any concerns with this approach?**

A. Yes, while a proxy group average could potentially be a valid approach for comparing equity ratios, Mr. O'Donnell's proxy group is primarily comprised of utility holding companies where the equity ratios will be impacted by the consolidated capital structure of all regulated and non-regulated operations. It is inappropriate to compare the Company's capital structure to these groups. The assets obtained by Piedmont to serve customers were financed in a manner consistent with the Company's capital structure as a regulated utility, not that of a parent level holding company. Holding company capital structures differ from regulated utility operating company capital structures for a variety of reasons, and the risk profile for a consolidated entity can be very different than the risk profile of a single subsidiary. Arbitrarily imposing a holding company capital structure upon Piedmont would increase its leverage (and, therefore, risk), reduce its cash flows, and erode credit quality – all to the detriment of the Company's customers.

**Q. Company witness D'Ascendis uses holding companies for his ROE analysis. Why does that make sense for ROE but not for capital structure?**

A. Cost of Equity models require observable stock price data, which only occur at the parent level, and, therefore, those models must utilize parent company data. The appropriate capital financing structure for a given utility operating company is not dependent upon that kind of information, and there is no reason to conflate capital structure and ROE in this way.

**Q. What do you think represents an appropriate comparison group for purposes of analyzing Piedmont's capital structure?**

A. If the objective is to compare Piedmont's capital structure against those of other companies, I believe a more appropriate group of companies against which to compare is a set of regulated utility operating companies. However, a meaningful comparison may still be complicated by the unique facts and circumstances surrounding each utility capital structure. Capital structure should not be viewed in isolation; it is part of an overall structure which considers capital structure, allowed ROE, and the various mechanisms used to recover costs.

**Q. Please briefly describe witness O'Donnell's position that Piedmont's capital structure should be comparable to the capital structure of Duke Energy.**

A. Mr. O'Donnell contends that Duke Energy is using double leverage to increase the profits of Piedmont. The concept of double leverage is that of a holding company borrowing money (i.e., incurring debt) and injecting the proceeds into the subsidiary operating company. This downstream flow of money is then treated as equity by the subsidiary. The implication of the double leverage concept is that this subsidiary equity is in some part truly debt and therefore makes the subsidiary enterprise more levered than it would appear. Mr. O'Donnell compares Duke Energy's capital structure to Piedmont, and notes that Duke Energy's capital structure indicates more debt than Piedmont.

**Q. Should double leverage be considered when establishing Piedmont's capital structure?**

A. No. As I stated earlier in my testimony, Piedmont is a regulated utility operating company, not a parent-level holding company. The Company is capitalized in a manner that is consistent with similar, regulated utility operating companies, and its actual capital structure is managed around its current approved equity ratio of 52.0%. As a parent-level holding company, Duke Energy is not regulated. Duke Energy will finance its capital needs with the objective of maintaining a strong balance sheet that supports its investment grade credit ratings, while utilizing the most efficient, least cost option for raising capital.

For the same reasons that it is inappropriate to use a proxy group of holding companies, it is inappropriate to apply a holding company capital structure to Piedmont. Furthermore, arbitrarily imposing a holding company capital structure on Piedmont would have detrimental effects on the Company's credit profile and ultimately customer rates. The more debt that is put into the capital structure, the more it will dilute cash flows and weaken credit coverage ratios – the consequence of which would weaken the Company's credit profile and have a negative impact on Piedmont's credit ratings.

Since the merger with Piedmont in October 2016, Duke Energy has infused equity on several occasions to manage the Company's capital structure within a reasonable range of its regulatory approved capital structure, while ensuring Piedmont is able to meet its significant capital obligations. As shown in the tables below, however, Piedmont regularly raised capital via the equity capital markets in the five years prior to the merger – consistent with Duke Energy's equity infusions since the merger. In addition, Duke Energy, since 2017 has issued approximately $5.5 billion of common stock via discrete public offerings, Duke Energy's dividend reinvestment program (DRIP) and its at-the-market (ATM) equity program.

| Piedmont Equity Issuances<br>5 years pre-merger<br>($ Millions) | |
|---|---|
| 2012 | $22 |
| 2013 | $120 |
| 2014 | $75 |
| 2015 | $85 |
| 2016 | $139 |
| **Average** | **$88** |

| Equity Infusions from DE Corp.<br>5 years post-merger<br>($ Millions) | |
|---|---|
| 2017 | $0 |
| 2018 | $300 |
| 2019 | $150 |
| 2020 | $0 |
| 2021 | $325 |
| **Average** | **$155** |

**Q. Lastly, Mr. O'Donnell compares Piedmont's requested capital structure to the 15-year historical average and 2020 average allowed annual common equity ratios granted by state regulators for natural gas utilities. Please discuss these comparisons in more detail.**

A. Mr. O'Donnell's analysis shows that from 2006 through 2020, the average common equity ratio granted to natural gas companies over this period was 48.05%. In fact, Chart 4 of Mr. O'Donnell's testimony illustrates how common equity ratios across the country have trended over 400 basis points higher when comparing the average equity ratio in 2020 back to the average equity ratio in 2006. Mr. O'Donnell also states the 10-year historical average of allowed equity ratios is 51.61%; however, he excludes this time period from his Table 5 on page 36 of his testimony, which he uses to form his recommendation for a 50.0% equity component of the capital structure.

Of the many equity ratio comparisons in Table 5 of witness O'Donnell's testimony, the inclusion of the 2020 average equity ratio approved by regulators of 52.34% is most applicable in determining Piedmont's appropriate equity ratio. If you look at the more recent years in Chart 4 of Mr. O'Donnell's testimony, you will notice that from 2018 to 2020, the average allowed common equity ratios ranged from 51.56% to 52.34%, with a 3-year average ratio of 52.21%. This time period is significant as it is post 2017 federal tax reform, which negatively impacted Piedmont's cash flow credit metrics. In fact, Regulatory Research Associates ("RRA") Regulatory Focus, *Major Rate Case Decisions January – June 2021* notes that "the negative cash flow impact of 2017 federal tax reform raised concerns regarding utility liquidity and credit metrics…and the average authorized equity ratios adopted by utility commissions in 2019 were modestly higher than the levels in 2018 and 2017."

**Q. Do you continue to believe that 52% is the appropriate equity component for Piedmont's capital structure?**

A. Yes. As noted in my direct testimony, the specific debt/equity ratio will vary over time, depending on a variety of factors, including, among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, equity infusions from the parent company and dividend payments to the parent company. However, a regulatory capital structure comprised of 52% equity is consistent with the Company's financial objectives and overall plan to maintain its ability to finance operations at rates favorable for customers. A healthy capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. High credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs for the benefit of customers.

**Q. Does this conclude your pre-filed rebuttal testimony?**

A. Yes.

MR. JEFFRIES: And we would also request that Mr. Newlin's prefiled exhibits with his direct testimony consisting of Exhibit KWN-1 through KWN-3, and his Rebuttal Exhibit KWN-1 be identified as marked as well.

CHAIR MITCHELL: All right. Hearing no objection to the motion, the exhibits to witness Newlin's direct testimony and rebuttal testimony should be marked for identification as they were when prefiled.

MR. JEFFRIES: Thank you, Chair Mitchell.

(Exhibits KWN-1 through KWN-3 and Rebuttal Exhibit KWN-1, were identified as they were marked when prefiled.)

Q. Mr. Newlin, have you prepared a summary of your direct and rebuttal testimony?

A. I have.

Q. Could you please provide those to the Commission?

A. Yes.

My name is Karl Newlin. I am the senior vice president corporate development and treasurer for Duke Energy Business Services. I prefiled direct testimony in this docket on March 22, 2021, in support of Piedmont's application for a general rate increase. I also submitted prefiled rebuttal testimony on August 25, 2021, in this proceedings.

My prefiled direct testimony addresses Piedmont's financial objectives, capital structure, and cost of capital. I also discussed the Company's current credit ratings and forecasted capital needs. My direct testimony emphasizes the importance of Piedmont's ability to meet its financial objectives and how customers benefit from Piedmont maintaining financial stability and strong credit ratings.

My direct testimony provides an overview of Piedmont's substantial capital needs to maintain compliance with federal pipeline safety reliability regulations, and to construct new pipelines to serve its growing North Carolina markets. My direct testimony explains how the Company competes for capital in the open market, and must appeal to debt and equity investors to track the capital needs. I discuss how investors have a variety of investment opportunities available to them, and that it's critically important that a company, such as Piedmont, maintain strong investment-grade credit ratings to ensure access to capital on reasonable terms.

My direct testimony also demonstrates that the Company's proposed rate increase will allow it to recover prudently incurred costs, raise capital at competitive terms, and preserve the Company's financial standing with both equity and debt investors as well as the credit rating agencies to the long-term benefit of customers.

My direct testimony is supported by three exhibits. My first exhibit shows the calculation of Piedmont's actual and projected capital structure in this proceeding. My second exhibit shows the derivation of the pro forma embedded cost of long-term debt. My third exhibit shows the derivation of the pro forma embedded cost of short-term debt.

I also submitted prefiled rebuttal testimony in this docket on August 25, 2021, to respond to recommendations related to capital structure raised by Commission Public Staff witness John Hinton and Carolina Utility Customers Association witness Kevin O'Donnell.

My rebuttal testimony is supported by one exhibit showing Piedmont's capital structure over the past few years by month.

This concludes the summary of my prefiled direct and rebuttal testimonies.

Q. Mr. Newlin, you're aware, of course, that the Company has entered into a stipulation with the other stipulating parties in this docket, correct?

A. I am.

Q. And that stipulation contains a capital structure that is slightly different than what you recommended in your prefiled testimony, correct?

A. Correct.

Q. And is it that -- could you tell us, do you support the capital structure that was incorporated into the stipulation?

A. I do support the capital structure in the settlement. It's 51 percent -- 51.6 percent equity, 47.75 percent long-term debt, 0.65 percent short-term debt. And I believe that that capital structure will preserve credit quality in the Company and essentially enable me and my team to go out and raise funds to fund the expenditures.

Q. Thank you, Mr. Newlin. I appreciate that clarification.

MR. JEFFRIES: Chair Mitchell,

Mr. Newlin is available for cross examination and questions from the Commission.

CHAIR MITCHELL: All right. Attorney General's Office?

CROSS EXAMINATION BY MS. FORCE:

Q. Good morning, Mr. Newlin.

A. Good morning.

Q. My name is Margaret Force. I just have a few questions for you, and I'm referring to two places in your direct testimony. One is your Exhibit KWN-2 which shows the embedded cost of long-term debt. I guess that was projected for the end of 2021. And in the footnote B of that exhibit, you indicated that a new issuance of about $350 million would be issued for between 10 and 30 years.

Am I understanding your testimony correctly, on page 6, you say that there were -- that you did issue 10-year senior unsecured notes in March of '21 for $350 million?

A. Page 6, you said?

Q. Of your initial testimony.

A. That's correct.

Q. I'm having trouble hearing you.

A. That's correct.

Q. That's better, thanks. And could say what

the rate was for that issuance?
A. Projected --
CHAIR MITCHELL: Mr. Newlin, make sure you're speaking towards your microphone. It's not picking you up, so our court reporter cannot hear you.
THE WITNESS: I'm just looking for the exact rate at issue that those notes on. We projected a rate of 2.70 percent (sound failure) --
Q. I'm hearing some of what you say --
(Reporter interruption due to sound failure.)
THE WITNESS: So we have projected a 2.70 percent coupon rate, and I'm just trying to look and find the actual rate. If memory serves, I think we came in actually a little bit lower.
Q. Lower. Okay. And am I correct also that -- I think you show that the imbedded cost of debt was 4.09 in your protection, but the agreed cost of debt is 4.08, and I'm understanding it to include the newer issuance; is that right?
A. And that drove the cost of debt down with (sound failure) --
(Reporter interruption due to sound

failure.)

Q. The last answer I think you gave was that 2.70 was the projection for the coupon rate, and you think it was something lower than that?

A. I do. I believe it was lower, and that's what drove the weighted average cost of the debt to be 4.08 percent after the actual versus the 4.09 which was in the original projection.

Q. Great. Thank you. That came through loud and clear.

And is it fair to say that the rate for the cost per has been 4 percent or less for most of the recent issuances or all of them?

A. Yes.

Q. For long-term debt.

And in the last case, would you agree, and perhaps subject to check, that the cost of debt was 4.41 percent?

A. Subject to check.

Q. Embedded cost of long-term debt.

I don't have any other questions. I appreciate it, thank you.

CHAIR MITCHELL: All right. My notes indicate that no other party has cross examination for the witness, but I will pause here to see if any party has questions for the witness.

(No response.)

CHAIR MITCHELL: I'm not hearing any. All right.

Redirect for the witness?

MR. JEFFRIES: No questions, Chair Mitchell.

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

Questions from the Commission. Commissioners, any questions for the witness?

(No response.)

CHAIR MITCHELL: I'm not hearing any from the Commission either. All right. Mr. Newlin, thank you, you may step down.

And, Mr. Jeffries, I'll take a motion.

MR. JEFFRIES: Thank you, Chair Mitchell. Piedmont would move that Mr. Newlin's prefiled direct exhibits identified as KWN-1 through KWN-3, and his Rebuttal Exhibit KWN-1 be admitted into evidence.

CHAIR MITCHELL: All right. Hearing no objection to that motion, it will be allowed.

(Exhibits KWN-1 through KWN-3 and Rebuttal Exhibit KWN-1, were admitted into evidence.)

MR. JEFFRIES: Chair Mitchell, we have no intention of recalling Mr. Newlin today on rebuttal.

CHAIR MITCHELL: All right. Mr. Newlin, you may be excused. Thank you, sir.

All right. Piedmont, y'all may call your next witness.

MR. JEFFRIES: Thank you, Chair Mitchell. Piedmont would call Dylan D'Ascendis to the stand.

THE WITNESS: Hello.

CHAIR MITCHELL: All right. Good morning, Mr. D'Ascendis.

Whereupon,

DYLAN D'ASCENDIS,

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

CHAIR MITCHELL: All right, Mr. Jeffries.

MR. JEFFRIES: Thank you.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. D'Ascendis, could you state your name and business address for the record, please.

A. Yes. It's Dylan, D-Y-L-A-N, William D'Ascendis. D, apostrophe, capital A-S-C-E-N-D-I-S. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, New Jersey 08054.

Q. And where do you work, Mr. D'Ascendis?

A. I am a partner at ScottMadden, Inc.

Q. All right. And what work do you perform at ScottMadden, Inc.?

A. I offer -- I offer expert testimony on various regulatory issues, including rate return, valuation, cost of service. I also train and develop our staff, and then pretty much guide what the rate of return practice in our Company.

Q. Thank you, Mr. D'Ascendis.

Are you the same Dylan D'Ascendis that prefiled direct testimony in this proceeding on March 22, 2021, consisting of 61 pages, an Appendix A, and Schedules DWD-1 through DWD-8?

A. Yes.

Q. And you also prefiled rebuttal testimony in this proceeding on August 25, 2021, consisting of 73 pages, and Rebuttal Exhibit DWD-1, which includes

Schedules DWD-1-R through DWD-14-R; is that correct?
A. That's right.
Q. And finally, on September 7, 2021, you prefiled settlement testimony consisting of nine pages and Settlement Exhibit DWD-1; is that right?
A. Yes.
Q. And was that testimony and were those exhibits prepared by you or under your direction?
A. Yes.
Q. Do you have any corrections to your prefiled testimony or exhibits?
A. I don't.
Q. Mr. D'Ascendis, if I asked you the same questions as set forth in your prefiled testimonies while you were on the stand today, would your answers be the same?
A. They would.
MR. JEFFRIES: Chair Mitchell, we would move that Mr. D'Ascendis' prefiled direct, prefiled rebuttal, and prefiled settlement testimonies be entered into the record as if given orally from the stand.
CHAIR MITCHELL: All right.
Mr. Jeffries, hearing no objection to your motion,

the prefiled direct testimony, the prefiled rebuttal testimony, and the prefiled settlement testimony of witness -- Piedmont witness D'Ascendis shall be copied into the record as if given orally from the stand.

(Whereupon, the prefiled direct testimony and Appendix A, prefiled rebuttal testimony, and prefiled settlement testimony of Dylan D'Ascendis were copied into the record as if given orally from the stand.)

**BEFORE THE**

**NORTH CAROLINA UTILITIES COMMISSION**

# DIRECT TESTIMONY

**OF**

**DYLAN W. D'ASCENDIS, CRRA, CVA**

**ON BEHALF OF**

**PIEDMONT NATURAL GAS COMPANY, INC.**

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

March 22, 2021

# TABLE OF CONTENTS

# I. INTRODUCTION

## A. Witness Identification

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

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, NJ 08054.

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

A. I am a Director at ScottMadden, Inc.

## B. Background and Qualifications

**Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.**

A. I have offered expert testimony on behalf of investor-owned utilities before over 25 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, and one American Arbitration Association panel on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Appendix A.

## II. PURPOSE AND SUMMARY

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

A. The purpose of my testimony is to present evidence and provide a recommendation regarding Piedmont Natural Gas Company, Inc.'s ("Piedmont" or the "Company") return on common equity ("ROE").

**Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR RECOMMENDATION?**

A. Yes. I have prepared Exhibit No. __, consisting of Schedules DWD-1 through DWD-8, which were prepared by me or under my direction.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDED COMMON EQUITY COST RATE.**

A. My recommended common equity cost rate of 10.25% is summarized on page 2 of Schedule DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Piedmont. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), [3] and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of eight natural gas distribution utilities ("Utility Proxy Group") whose selection criteria will be discussed below. In addition, I applied the

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

2 *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922).

3 To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the Predictive Risk Premium Model ("PRPM"), and the second method was a risk premium model using a total market approach.

DCF model, RPM, and CAPM to a proxy group of 47 domestic, non-price regulated companies comparable in total risk to the Utility Proxy Group ("Non-Price Regulated Proxy Group"). The results derived from each are as follows:

**Table 1: Summary of Common Equity Cost Rates**

| | |
|---|---|
| Discounted Cash Flow Model | 9.46% |
| Risk Premium Model | 10.11% |
| Capital Asset Pricing Model | 12.05% |
| Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies | 12.18% |
| | |
| Indicated Range | 9.46% - 12.18% |
| Size Adjustment | 0.00% |
| Flotation Cost Adjustment | 0.12% |
| | |
| Recommended Range | 9.58% - 12.30% |
| Recommended Cost of Common Equity | 10.25% |

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 9.46% and 12.18% before any adjustment for flotation costs, which were 0.12%.[4] My Company-specific indicated range of common equity cost rates, adjusted for flotation costs, is between 9.58% and 12.30%. Given the Utility Proxy Group and Company-specific ranges of common equity cost rates, my recommended ROE for the Company is 10.25%. I have selected the lower end of my range to reflect the uncertainty surrounding the COVID-19 recovery and my

4 *See* Section VII for a detailed discussion of my flotation cost adjustment.

recommendation should be considered a conservative measure of the Company's required ROE at this time.

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

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

- Section III – Provides a summary of financial theory and regulatory principles pertinent to the development of the cost of common equity;
- Section IV – Explains my selection of the Utility Proxy Group used to develop my Cost of Common Equity analytical results;
- Section V – Describes the analyses on which my Cost of Common Equity recommendation is based;
- Section VI – Summarizes my common equity cost rate before adjustments to reflect Company-specific factors;
- Section VII – Explains my consideration of adjustments to my common equity cost rate to reflect Company-specific factors;
- Section VIII – Discusses economic conditions in North Carolina; and
- Section IX – Presents my conclusions.

## III. GENERAL PRINCIPLES

**Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 10.25%?**

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.,* the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises

> having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[5]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure their financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or

[5] *Hope*, 320 U.S. 591 (1944), at 603.

business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective as measured by their combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (*i.e.,* business risk) and financing (*i.e.,* financial risk) of the Company's North Carolina utility operations on a stand-alone basis.

**Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?**

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (*i.e.*, rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

**Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARANTEED?**

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the rate-setting process should provide the utility a reasonable opportunity to recover its return of, and return on, its prudently incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (*e.g.*, management performance, operating and maintenance expenses, etc.), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag.

### A. Business Risk

**Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.**

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, and the like, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. Therefore, it is difficult to quantify the effect of any individual risk specifically and numerically on investors' required return, *i.e.*, the cost of capital. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company as falling within a spectrum of risk. To the extent investors view a company as being exposed to high risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify.

Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

**B. Financial Risk**

**Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.**

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.,* failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors demand higher returns as compensation for bearing higher financial risk.

**Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (*I.E.*, INVESTMENT RISK)?**

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e.*, total risk) faced by bond investors.[6] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are

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[6] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, e.g., within the A category, a Moody's rating can be A1, A2 and A3.

roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

**Q. DO RATING AGENCIES ACCOUNT FOR COMPANY SIZE IN THEIR BOND RATINGS?**

A. No. Neither Standard & Poor's ("S&P") nor Moody's Investor Service ("Moody's") have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.

## IV. PIEDMONT'S OPERATIONS AND THE UTILITY PROXY GROUP

**Q. ARE YOU FAMILIAR WITH PIEDMONT'S OPERATIONS?**

A. Yes. Piedmont, a subsidiary of Duke Energy Corporation ("DUK"), provides natural gas distribution service to approximately 1,085,000 customers in North Carolina, South Carolina, and Tennessee.[7] Of this total customer base, the Company's North Carolina operations services approximately 775,000 customers.[8] Piedmont currently has senior unsecured ratings of A3 (outlook: Stable) and BBB+ (outlook: Stable) from Moody's Investor Service and Standard & Poor's Rating Services, respectively.[9]

**Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE UTILITY PROXY GROUP.**

A. The companies selected for the Utility Proxy Group met the following criteria:

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7 Duke Energy Corporation, SEC Form 8-K, February 13, 2020, at 40.
8 Company provided.
9 Source: S&P Global Market Intelligence.

(i) They were included in the Natural Gas Utility Group of *Value Line's Standard Edition* ("*Value Line*") (January 29, 2021);

(ii) They have 60% or greater of fiscal year 2019 total operating income derived from, and 60% or greater of fiscal year 2019 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (*i.e.*, one publicly-traded utility merging with or acquiring another);

(iv) They have not cut or omitted their common dividends during the five years ended 2019 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Betas;

(vi) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

(vii) They have *Value Line*, Zacks, Yahoo! Finance, or Bloomberg consensus five-year earnings per share ("EPS") growth rate projections.

The following eight companies met these criteria: Atmos Energy Corporation, New Jersey Resources Corp., NiSource Inc., Northwest Natural Gas Company, ONE Gas, Inc., South Jersey Industries, Inc., Southwest Gas Holdings, Inc., and Spire, Inc.

**Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR THE COMPANY?**

A. Because the Company is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and

*Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[10]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group indicated results.

My analyses are based on the Utility Proxy Group which is comprised of U.S. natural gas distribution utilities. As discussed earlier, utilities must compete for capital with other companies with commensurate risk (including non-utilities) and, to do so, must be provided the opportunity to earn a fair and reasonable return.

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[10] The development of the Non-Price Regulated Proxy Group is explained in more detail in Section VI.

Consequently, it is appropriate to consider the Utility Proxy Group's market data in determining the Company's ROE.

## V. COMMON EQUITY COST RATE MODELS

**Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET BASED?**

A. Yes. While a public utility such as DUK operates a regulated business within the states in which it operates, it still must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies of comparable risk, they will choose a company providing a higher return over a company providing a lower return.

**Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET BASED?**

A. Yes. The DCF model uses market prices in developing the model's dividend yield component. Regarding the RPM, the Predictive Risk Premium Model ("PRPM") uses monthly market returns in addition to expectations of the risk-free rate and the total market risk premium approach uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, Beta coefficients ("β"), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The CAPM is market based for many of the same reasons that the RPM is market based (*i.e.*, the use of expected bond yields and Betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

**Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?**

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements, and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (*i.e.,* the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

## A. Discounted Cash Flow Model

**Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?**

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; *i.e.*, the total common equity return rate expected by investors as shown below:

$$K_e = (D_0\ (1+g))/P + g$$

where:

$K_e$ = the required Return on Common Equity;
$D_0$ = the annualized Dividend Per Share;
$P$ = the current stock price; and
$g$ = the growth rate.

**Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?**

A. I used the single-stage constant growth DCF model in my analyses.

**Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE CONSTANT GROWTH DCF MODEL.**

A. The unadjusted dividend yields are based on the proxy companies' dividends as of January 29, 2021, divided by the average closing market price for the 60 trading days ended January 29, 2021.[11]

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[11] *See*, column 1, page 1 of Schedule DWD-2.

**Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.**

A. Because dividends are paid periodically (*e.g.* quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or $D_1$, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Schedule DWD-2 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

**Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.**

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, Yahoo! Finance, and Bloomberg. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' ability to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

**Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.**

A. As shown on page 1 of Schedule DWD-2, for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 9.59%, the median result is 9.32%, and the average of the two is 9.46%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF. This approach considers all the proxy utilities' results, while mitigating the high and low outliers of those individual results.

### B. The Risk Premium Model

**Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.**

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

**Q. PLEASE EXPLAIN HOW YOU DERIVED YOUR INDICATED COST OF COMMON EQUITY BASED ON THE RPM.**

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the PRPM and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

### 1. The Predictive Risk Premium Model

**Q. PLEASE EXPLAIN THE PRPM.**

A. The PRPM, published in the *Journal of Regulatory Economics,*[12] was developed

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12 Autoregressive conditional heteroscedasticity. See "A New Approach for Estimating the Equity Risk Premium for Public Utilities", Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. *The Journal of Regulatory Economics* (December 2021), 40:261-278.

from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility ("ARCH")".[13] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (*i.e.*, the variance of historical equity risk premiums).

The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term U.S. Treasury securities through January 2021. Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series[14] and a GARCH coefficient.[15] Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[16] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield

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[13] www.nobelprize.org.
[14] Illustrated on Columns 1 and 2, page 2 of Schedule DWD-3.
[15] Illustrated on Column 4, page 2 of Schedule DWD-3.
[16] Annualized Return = (1 + Monthly Return) ^12 - 1

of 2.31%[17] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from Blue Chip Financial Forecasts ("*Blue Chip").*[18] The mean PRPM indicated common equity cost rate for the Utility Proxy Group is 9.69%, the median is 9.94%, and the average of the two is 9.82%. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 9.82%.

**Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.**

A. As shown in Schedules DWD-3 and 4, the risk-free rate adopted for applications of the RPM and CAPM is 2.31%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2022, and long-term projections for the years 2022 to 2026 and 2027 to 2031.

**Q. WHY DO YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR ANALYSES?**

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate

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[17] See Column 6, page 2 of Schedule DWD-3.
[18] *Blue Chip Financial Forecasts*, December 1, 2020 at page 14 and January 1, 2021 at 2.

base to which the allowed fair rate of return (*i.e.*, cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

**Q. DID YOU INCLUDE CURRENT INTEREST RATES IN YOUR ANALYSES?**

A. Yes. Even though I do not agree with using current interest rates in a rate of return analysis, I recognize that the Commission has stated its preference for the use of current, and not projected, interest rates.[19] As such, in addition to my normal practice of relying on projected interest rates, I have also presented my ROE analyses based on current interest rates.

### 2. The Total Market Risk Premium Approach

**Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.**

A. The total market approach RPM adds a prospective public utility bond yield to an average of: 1) an equity risk premium that is derived from a Beta-adjusted total market equity risk premium, 2) an equity risk premium based on the S&P Utilities Index, and 3) an equity risk premium based on authorized ROEs for gas distribution utilities.

**Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 3.56% APPLICABLE TO THE UTILITY PROXY GROUP.**

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including

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[19] *See*, North Carolina Utilities Commission, Docket Nos. W-354, Sub 363, 364, 365, Order Granting Partial Rate Increase and Requiring Customer Notice, at 72.

common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second calendar quarter of 2022, and *Blue Chip's* long-term projections for 2022 to 2026, and 2027 to 2031. As shown on line 1, page 3 of Schedule DWD-3, the average expected yield on Moody's Aaa-rated corporate bonds is 3.06%. To derive an expected yield on Moody's A2-rated public utility bonds, I made an upward adjustment of 0.50%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds, in order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield.[20] Adding that recent 0.50% spread to the expected Aaa-rated corporate bond yield of 3.06% results in an expected A2-rated public utility bond yield of 3.56%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issuer rating is A3, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of 0.10%, which represents one-third of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the A2 prospective bond yield

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[20] As shown on line 2 and explained in note 2, page 3 of Schedule DWD-3.

applicable to an A3-rated public utility bond.[21] Adding the 0.10% to the 3.56% prospective A2-rated public utility bond yield results in a 3.66% expected bond yield applicable to the Utility Proxy Group.

**Table 2: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[22]**

| | |
|---|---|
| Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)* | 3.06% |
| Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds | 0.50% |
| Adjustment to Reflect the Utility Proxy Group's Average Moody's Bond Rating of A3 | 0.10% |
| Prospective Bond Yield Applicable to the Utility Proxy Group | 3.66% |

To develop the indicated ROE using the total market approach RPM, this prospective bond yield is then added to the average of the three different equity risk premiums described below.

***a. The Beta-Derived Risk Premium***

**Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.**

A. The components of the Beta-derived risk premium model are: 1) an expected market equity risk premium over corporate bonds, and 2) the Beta coefficient. The derivation of the Beta-derived equity risk premium that I applied to the Utility

21 As shown on line 5 and explained in note 4, page 3 of Schedule DWD-3. Moody's does not provide public utility bond yields for A3-rated bonds. As such, it was necessary to estimate the difference between A2-rated and A3-rated public utility bonds. Because there are three steps between Baa2 and A2 (Baa2 to Baa1, Baa1 to A3, and A3 to A2) I assumed an adjustment of one-third of the difference between the A2-rated and Baa2-rated public utility bond yield was appropriate.

22 As shown on page 3 of Schedule DWD-3.

Proxy Group is shown on lines 1 through 9, page 8 of Schedule DWD-3. The total Beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

**Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?**

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2020 ("SBBI - 2020")[23] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2019. Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 11.83%, and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 6.05%.[24] As shown on line 1, page 8 of Schedule DWD-3, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.78%.

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23 SBBI Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2019.
24 As explained in note 1, page 9 of Schedule DWD-3.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in SBBI - 2020.[25] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

**Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.**

A. To derive the regression-based market equity risk premium of 9.30% shown on line 2, page 8 of Schedule DWD-3, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which

25 SBBI - 2020, at 10-22.

the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

**Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.**

A. I used the same PRPM approach described above as applied to the Utility Proxy Group to the historical equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through January 2021.[26] Using the previously discussed generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 9.65%.[27]

**Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* DATA FOR YOUR RPM ANALYSIS.**

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 8 of Schedule DWD-3. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from

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[26] Data from January 1928 to December 2019 is from SBBI - 2020. Data from January 2020 to January 2021 is from Bloomberg.

[27] Shown on line 3, page 8 of Schedule DWD-3.

an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended January 29, 2021, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*'s Standard Edition.[28]

The average median expected price appreciation is 35%, which translates to a 7.79% annual appreciation, and, when added to the average of *Value Line's* median expected dividend yields of 2.04%, equates to a forecasted annual total return rate on the market of 9.83%. The forecasted Moody's Aaa-rated corporate bond yield of 3.06% is deducted from the total market return of 9.83%, resulting in an equity risk premium of 6.77%, as shown on line 4, page 8 of Schedule DWD-3.

**Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.**

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 14.10%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.06% results in an 11.04% projected equity risk premium.

**Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON BLOOMBERG DATA.**

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for

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[28] As explained in detail in note 1, page 2 of Schedule DWD-3.

capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 17.78%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.06% results in a 14.72% projected equity risk premium.

**Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?**

A. I gave equal weight to all six equity risk premiums based on each source - historical, *Value Line*, and Bloomberg - in arriving at a 9.54% equity risk premium.

**Table 3: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[29]**

| | |
|---|---|
| Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2019) | 5.78% |
| Regression Analysis on Historical Data | 9.30% |
| PRPM Analysis on Historical Data | 9.65% |
| Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields | 6.77% |
| Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields | 11.04% |
| Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields | 14.72% |
| **Average** | 9.54% |

After calculating the average market equity risk premium of 9.54%, I adjusted it by the Beta coefficient to account for the risk of the Utility Proxy Group. As discussed below, the Beta coefficient is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy

29 As shown on page 8 of Schedule DWD-3.

group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Schedule DWD-4, the average of the mean and median Beta coefficient for the Utility Proxy Group is 0.93. Multiplying the 0.93 average by the market equity risk premium of 9.54% results in a Beta-adjusted equity risk premium for the Utility Proxy Group of 8.87%.

### *b. The S&P Utility Index Derived Risk Premium*

**Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A-RATED PUBLIC UTILITY BONDS?**

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.74%, and monthly Moody's A-rated public utility bond yields of 6.53% from 1928 to 2019, to arrive at an equity risk premium of 4.21%.[30] I then used the same historical data to derive an equity risk premium of 6.83% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to January 2021 to arrive at a PRPM-derived equity risk premium of 5.59% for the S&P Utility Index.

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30 As shown on line 1, page 12 of Schedule DWD-3.

I then derived expected total returns on the S&P Utilities Index of 10.36% and 7.67% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 3.56%[31], which resulted in equity risk premiums of 6.80% and 4.11%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source (*i.e.*, historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 5.51%.

**Table 4: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[32]**

| | |
|---|---|
| Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2019) | 4.21% |
| Regression Analysis on Historical Data | 6.83% |
| PRPM Analysis on Historical Data | 5.59% |
| Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields | 6.80% |
| Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields | 4.11% |
| **Average** | 5.51% |

### c. Authorized Return-Derived Equity Risk Premium

**Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 5.83% BASED ON AUTHORIZED ROES FOR GAS DISTRIBUTION UTILITIES?**

A. The equity risk premium of 5.83% shown on line 3, page 7 of Schedule DWD-3 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A-rated public utility bonds. That analysis is shown on page 13

31 Derived on line 3, page 3 of Schedule DWD-3.
32 As shown on page 12 of Schedule DWD-3.

of Schedule DWD-3. Page 13 of Schedule DWD-3 contains the graphical results of a regression analysis of 797 rate cases for gas distribution utilities which were fully litigated during the period from January 1, 1980 through January 29, 2021. It shows the implicit equity risk premium relative to the yields on A-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[33] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds of 3.56%. Given the expected A-rated utility bond yield of 3.56%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 5.83%, which is shown on line 3, page 7 of Schedule DWD-3.

**Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?**

A. The equity risk premium I apply to the Utility Proxy Group is 6.74%, which is the average of the Beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 8.87%, 5.51%, and 5.83%, respectively.[34]

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33 *See*, *e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11 to 12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33 to 45.

34 As shown on page 7 of Schedule DWD-3.

**Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED ON THE TOTAL MARKET APPROACH?**

A. As shown on line 8, page 3 of Schedule DWD-3, I calculated a common equity cost rate of 10.40% for the Utility Proxy Group based on the total market approach RPM.

**Table 5: Summary of the Total Market Return Risk Premium Model[35]**

| | |
|---|---|
| Prospective Moody's A3-Rated Utility Bond Applicable to the Utility Proxy Group | 3.66% |
| Prospective Equity Risk Premium | 6.74% |
| Indicated Cost of Common Equity | 10.40% |

**Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE PRPM AND THE TOTAL MARKET APPROACH RPM?**

A. As shown on page 1 of Schedule DWD-3, the indicated RPM-derived common equity cost rate is 10.11%, which gives equal weight to the PRPM (9.82%) and the adjusted-market approach results (10.40%).

## C. The Capital Asset Pricing Model

**Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.**

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the Beta coefficient (β). A Beta coefficient less than 1.0 indicates lower variability than the market as a whole, while a Beta coefficient greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through

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[35] As shown on page 3 of Schedule DWD-3.

diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the Beta coefficient. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta\,(R_m - R_f)$$

Where: $R_s$ = Return rate on the common stock

$R_f$ = Risk-free rate of return

$R_m$ = Return rate on the market as a whole

$\beta$ = Adjusted Beta coefficient (volatility of the security relative to the market as a whole)

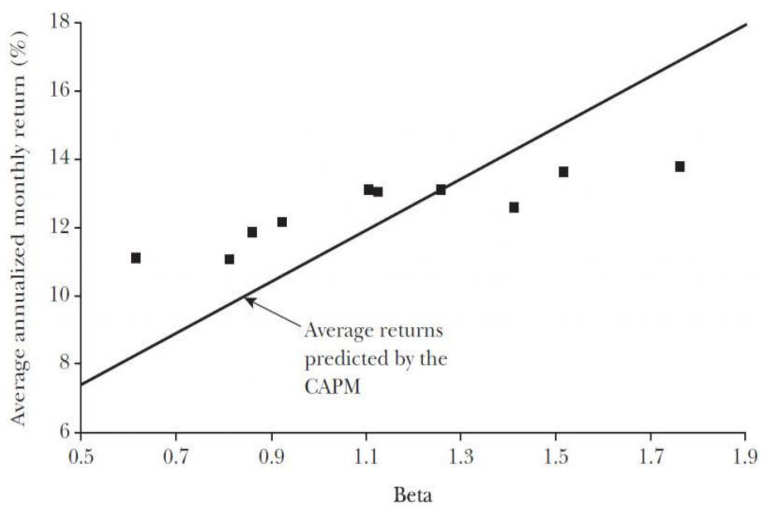
Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("EC") reflects the reality that while the results of these tests support the notion that the Beta coefficient is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[36]

36 Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 175. ("Morin")

The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[37]

*Figure 2* http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

**Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003**




In addition, Morin observes that while the results of these tests support the notion that Beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[38]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x\,\beta(R_M - R_F) + (1-x)\,\beta(R_M - R_F)$$

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

[38] Morin, at 175.

> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [39]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[40]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[41]

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

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39 Morin, at 190.
40 Fama & French, at 32.
41 *Ibid.,* at 33.

**Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM ANALYSIS?**

A. For the Beta coefficients in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg Professional Services. While both of those services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, *Value Line* calculates the Beta coefficient over a five-year period, while Bloomberg calculates it over a two-year period.

**Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.**

A. As discussed previously, the risk-free rate adopted for both applications of the CAPM is 2.31%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2022, and long-term projections for the years 2022 to 2026 and 2027 to 2031.

**Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.**

A. The basis of the market risk premium is explained in detail in note 1 on Schedule DWD-4. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.09% was deducted from the SBBI - 2020 monthly historical total market return of 12.10%, which results in an historical market equity risk premium of 7.01%.[42] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from SBBI - 2020. That regression analysis yielded a market equity risk premium of 9.98%. The PRPM market equity risk premium is 10.76% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through January 2021.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 2.31%, discussed above, from the *Value Line* projected total annual market return of 9.83%, resulting in a forecasted total market equity risk premium of 7.52%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 2.31% from the projected total return of the S&P 500 of 14.10%. The resulting market equity risk premium is 9.66%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 2.31% from the projected total return of the S&P 500 of 17.78%. The resulting market equity risk premium is 15.47%. These six measures, when averaged, result in an average total market equity risk premium of 10.42%.

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42 SBBI - 2020, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

**Table 6: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[43]**

| | |
|---|---|
| Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2019) | 7.01% |
| Regression Analysis on Historical Data | 9.98% |
| PRPM Analysis on Historical Data | 10.76% |
| Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields | 7.52% |
| Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields | 11.79% |
| Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields | 15.47% |
| **Average** | 10.42% |

**Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE UTILITY PROXY GROUP?**

A. As shown on page 1 of Schedule DWD-4, the mean result of my CAPM/ECAPM analyses is 12.09%, the median is 12.00%, and the average of the two is 12.05%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 12.05%.

43 As shown on page 2 of Schedule DWD-4.

**D. <u>Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM</u>**

**Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?**

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. 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.

**Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?**

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the Beta coefficients and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a proxy group of 47 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);
(ii) They must be domestic, non-price regulated companies, *i.e.*, not utilities;
(iii) Their Beta coefficients must lie within plus or minus two standard deviations of the average unadjusted Beta coefficients of the Utility Proxy Group; and
(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted Beta coefficients must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Beta coefficients measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar Beta coefficients <u>and</u> similar residual standard errors resulting from the same regression analyses have similar total investment risk.

**Q. HAVE YOU PREPARED A SCHEDULE WHICH SHOWS THE DATA FROM WHICH YOU SELECTED THE 47 DOMESTIC, NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?**

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Schedule DWD-5.

**Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?**

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Schedule DWD-6 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 11.97%.

Pages 3 through 5 of Schedule DWD-6 contain the data and calculations that support the 12.82% RPM common equity cost rate. As shown on line 1, page 3 of Schedule DWD-6, the consensus prospective yield on Moody's Baa-rated corporate bonds for the six quarters ending in the second quarter of 2022, and for the years 2022 to 2026 and 2027 to 2031, is 4.04%.[44]

When the Beta-adjusted risk premium of 8.78%[45] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa2-rated corporate bond yield of 4.04%, the indicated RPM common equity cost rate is 12.82%.

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[44] *Blue Chip Financial Forecasts*, December 1, 2020, at 14 and January 1, 2021, at 2.
[45] Derived on page 5 of Schedule DWD-6.

Page 6 of Schedule DWD-6 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 12.07%.

**Q. HOW IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?**

A. As shown on page 1 of Schedule DWD-6, the results of the common equity models applied to the Non-Price Regulated Proxy Group -- which group is comparable in total risk to the Utility Proxy Group -- are as follows: 11.97% (DCF), 12.82% (RPM), and 12.07% (CAPM). The average of the mean and median of these models is 12.18%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

## VI. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

**Q. WHAT ARE THE INDICATED COMMON EQUITY COST RATES BEFORE ADJUSTMENTS?**

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated range of common equity cost rates before any relative risk adjustment is between 9.46% and 12.18%. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

Based on these common equity cost rate results, I conclude that a common equity cost rate between 9.46% and 12.18% is reasonable and appropriate before any adjustments for relative risk differences between Piedmont and the Utility Proxy Group are made.[46]

## VII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

### A. Size Adjustment

**Q. DOES A COMPANY'S SIZE RELATIVE TO THE UTILITY PROXY GROUP COMPANIES IMPACT ITS BUSINESS RISK?**

A. Yes. A smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for a utility because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base.

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46 The 9.46% low end of the range represents the lowest model result. The 12.18% high end of the range is the highest model result.

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity.

**Q. HAVE YOU APPLIED A RELATIVE RISK ADJUSTMENT DUE TO PIEDMONT'S SMALL SIZE RELATIVE TO THE UTILITY PROXY GROUP?**

A. No. While Piedmont has greater relative risk than the average utility in the Utility Proxy Group as measured by its estimated market capitalization of common equity, the difference is not large enough to merit a relative risk adjustment as shown on Table 7, below.

**Table 7: Size as Measured by Market Capitalization for Piedmont and the Utility Proxy Group**

| | Market Capitalization* | Times Greater than The Company |
|---|---|---|
| | ($ Millions) | |
| Piedmont | $4,004.929 | |
| Utility Proxy Group | $4,505.920 | 1.1x |
| *From page 1 of Schedule DWD-7. | | |

Piedmont's estimated market capitalization for its North Carolina operations was $4.0 billion as of January 29, 2021,[47] compared with the market capitalization of the average company in the Utility Proxy Group of $4.5 billion as

47 $4,004.929M = $4,822.659M (requested rate base) * 52.00% (requested equity ratio) * 159.7% (market-to-book ratio of the Utility Proxy Group) as demonstrated on page 2 of Schedule DWD-7.

of January 29, 2021. The average company in the Utility Proxy Group has a market capitalization 1.1 times the size of Piedmont's estimated market capitalization.

As a result, even though there is a difference in size between Piedmont and the Utility Proxy Group, in my opinion, it is not necessary to upwardly adjust the range of indicated common equity cost rates between 9.46% to 12.18% to reflect greater risk due to smaller relative size.

**B. <u>Flotation Cost Adjustment</u>**

**Q. WHAT ARE FLOTATION COSTS?**

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (*e.g.*, underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

**Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED COMMON EQUITY COST RATE?**

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs….

> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[48]

**Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?**

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these

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[48] Morin, at 321.

expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on his or her invested $1.00 (*i.e.*, a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

**Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?**

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[49] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[50] Consequently, it

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49 Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at 342.

50 Morin, at pp. 327-30.

is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

**Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?**

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing 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.

**Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR COMPANY-SPECIFIC ADJUSTMENTS?**

A. Applying the 0.12% flotation cost adjustment to the indicated cost of common equity range of 9.46% to 12.18% results in a Company-specific cost of common equity rate range of 9.58% to 12.30%, which is my recommended common equity cost rate range. Based on that range I recommend a Company-specific cost of common equity rate of 10.25%.

## VIII. <u>ECONOMIC CONDITIONS IN NORTH CAROLINA</u>

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

A. Yes, I did. As a preliminary matter, I understand and appreciate that the Commission must balance the interests of investors and customers in setting the return on common equity. As the Commission has stated, it "…is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[51] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the *Hope* and *Bluefield* Comparable Risk, Capital Attraction, and Financial Integrity standards.

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

> … adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the "end result" test of Hope. This the Commission has done.[52]

The North Carolina Supreme Court agreed, and upheld the Commission's Order on Remand.[53] The North Carolina Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of

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

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

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

changing economic conditions on customers when determining the proper ROE for a public utility."[54] In *Cooper II*, the North Carolina Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on customers",[55] which the Commission made in its Order on Remand.[56] In light of the *Cooper II* decision and the North Carolina Supreme Court precedent that preceded it,[57] I appreciate the Commission's need to consider economic conditions in the State. As such, I have undertaken several analyses to provide such a review.

**Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.**

A. In its Order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the cost of common equity.[58] As discussed below, those relationships still hold:

- Although economic conditions in North Carolina declined significantly in the second quarter of 2020 as a result of the COVID-19 pandemic, they improved considerably in the third and fourth quarters. Notably, economic conditions in North Carolina continued to be strongly correlated to the U.S. economy;

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54 State of North Carolina ex rel. Utilities Commission v. Cooper, 758 S.E.2d 635, 642 (2014) ("Cooper II").

55 Cooper II, 758 S.E.2d at 643.

56 DNCP Remand Order, at 4-10.

57 Cooper I, 366 N.C. 484, 739 S.E.2d 541 (2013).

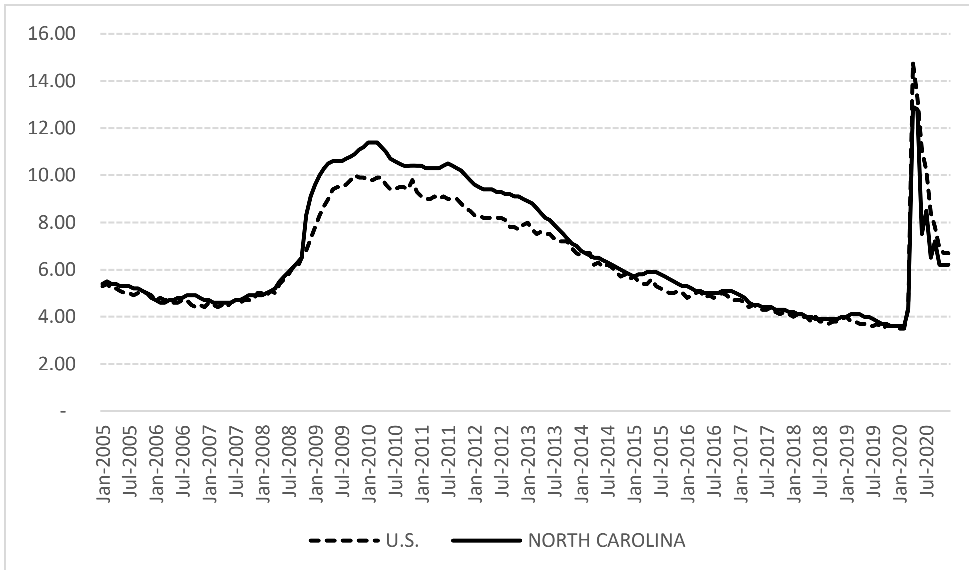
58 *See,* State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, Order on Remand, July 23, 2015, at 39.

- Unemployment at both the state and county level remains highly correlated with national rates of unemployment;
- Real Gross Domestic Product ("GDP") in North Carolina also remains highly correlated with U.S. real GDP growth; and
- Median household income in North Carolina has grown at a rate consistent with the rest of the U.S. and remains strongly correlated with national levels.

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

A. Turning first to the seasonally adjusted unemployment rate, prior to April 2020, the unemployment rate had fallen substantially in North Carolina and the U.S. since the 2008/2009 financial crisis. Although the unemployment rate in North Carolina exceeded the national rate during and after the 2008/2009 financial crisis, by the latter portion of 2013, the two were largely consistent. As the COVID-19 pandemic hit the U.S., unemployment in North Carolina and across the U.S. spiked in April 2020 as many communities closed non-essential businesses to contain the spread of the COVID-19 virus. Notably, North Carolina's unemployment rate has fared better than the overall U.S., even as both fell considerably by the end of 2020 (*see* Chart 1, below).

**Chart 1: Unemployment Rate (Seasonally Adjusted)[59]**



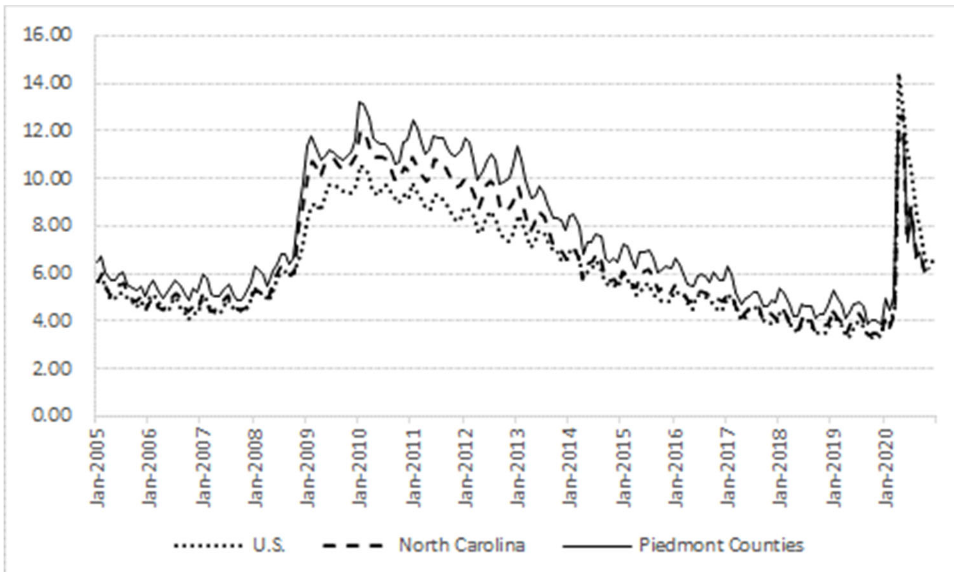

Between 2005 and 2020, the correlation between North Carolina's unemployment rate and the national rate was 96.66%, indicating the two are highly correlated.

Second, I reviewed (seasonally unadjusted) unemployment rates in the counties served by Piedmont. As with the seasonally adjusted statistics described above, the unemployment rate in those counties spiked in April 2020 at 11.58% (0.92% below the state-wide average), but by November 2020 it had fallen substantially to 6.26%, somewhat above the rate statewide in North Carolina (6.10%) and below the overall rate in the U.S. (6.40%). From 2005 through November 2020, the correlation in unemployment rates between the counties served by Piedmont and the U.S., as well as North Carolina, were approximately 93.76% and 98.91%, respectively. In summary, county-level unemployment has

59 Source: Bureau of Labor Statistics.

fallen considerably since it recently spiked in April 2020, is similar to the U.S. and statewide unemployment rates, and is highly correlated to state and national unemployment rates.

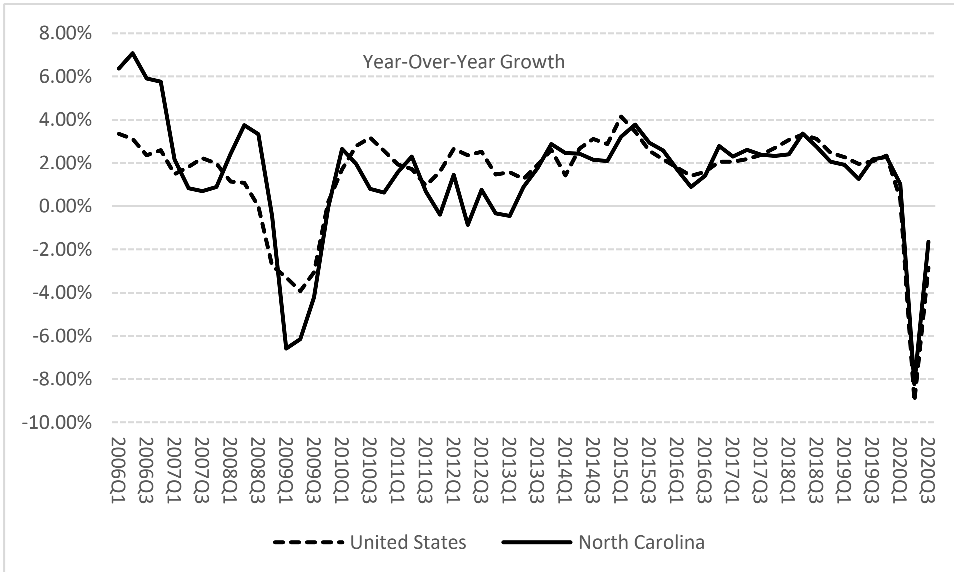
**Chart 2: Seasonally Unadjusted Unemployment Rates[60]**




Looking to real Gross Domestic Product growth, there also has been a relatively strong correlation between North Carolina and the national economy (approximately 81.50%). While the national rate of growth at times outpaced North Carolina between 2010 and 2014, since the first quarter of 2015, North Carolina's economic growth has been relatively consistent with U.S. economic growth. Moreover, North Carolina's real GDP growth fared better than the overall U.S. in 2020; North Carolina's real GDP grew faster than the overall U.S. in the first quarter, and did not decline as much as the U.S. economy declined in the second and third quarters.

60 Source: Bureau of Labor Statistics, St. Louis Federal Reserve.

**Chart 3: Real Gross Domestic Product Growth Rate (Year over Year)[61]**




As to median household income, the correlation between North Carolina and the U.S. is relatively strong (94.00% from 2005 through 2019). Since 2009 (that is, the years subsequent to the financial crisis), nominal median household income in North Carolina has grown at a slightly faster pace than the national median income (3.85% vs. 3.27%, respectively; *see* Chart 4, below). To put household income in perspective, the Missouri Economic Research and Information Center reports that in the second quarter of 2019, North Carolina had the 22nd lowest cost of living index among the 50 states, the District of Columbia, and Puerto Rico.[62]

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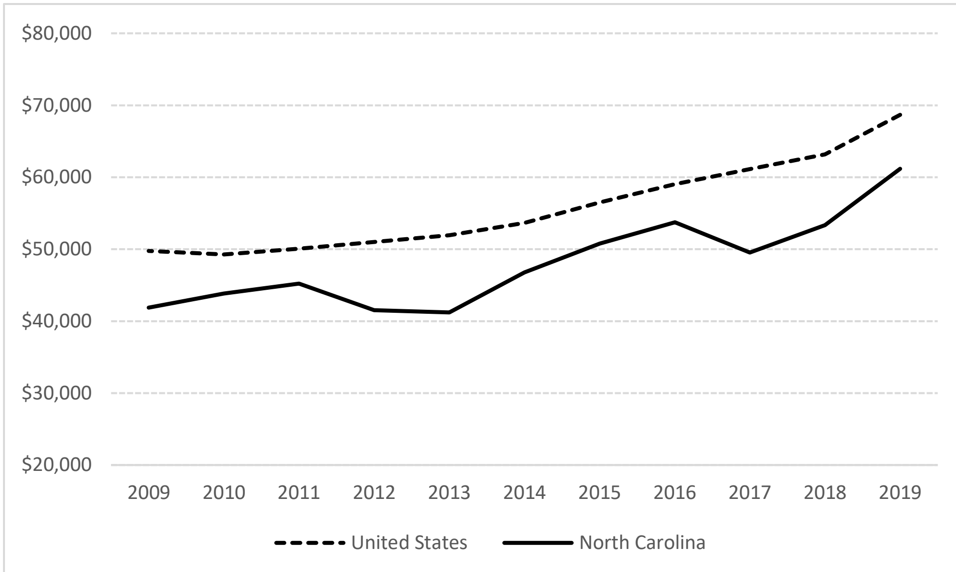
61 Source: Bureau of Economic Analysis.
62 Source: meric.mo.gov/data/cost-living-data-series accessed January 27, 2021.

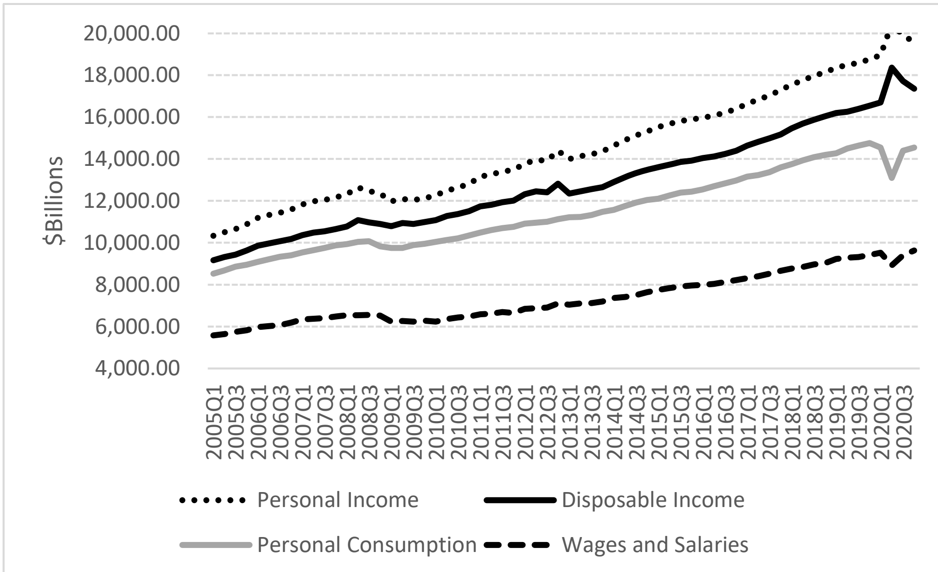
**Chart 4: Median Household Income[63]**




Similarly, as shown in Chart 5, below, since 2009 total personal income, disposable income, personal consumption, and wages and salaries have generally been on an increasing trend at the national level. Although wages and salaries dipped in the second quarter of 2020, they rebounded in the third and fourth quarter to end the year higher than the first quarter of 2020.

63 Source: U.S. Census Bureau, Current Population Survey.

**Chart 5: United States Income and Consumption**[64]




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

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

- Unemployment at both the state and county level remains highly correlated with national rates of unemployment. North Carolina's unemployment rate and the rate in the counties served by Piedmont have fallen significantly since spiking in April 2020.
- The state's real Gross Domestic Product remains highly correlated with national GDP.
- Similarly, since 2005, median household income has grown in North

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64 Source: Bureau of Economic Analysis.

Carolina and has grown at a rate slightly faster than the national average. Additionally, the overall cost of living in North Carolina also is below the national average. Furthermore, at the national level, income has generally been increasing since the financial crisis.

The U.S. and North Carolina economies both experienced an historically difficult and challenging year as a result of the COVID-19 pandemic; yet the data show that economic conditions have improved significantly. Moreover, although economic conditions remain uncertain, North Carolina and the counties contained within Piedmont's service area have fared better than the rest of the U.S. during the COVID-19 pandemic.

**Q. IN YOUR OPINION, IS AN ROE OF 10.25% FAIR AND REASONABLE TO PIEDMONT, ITS SHAREHOLDERS, AND ITS CUSTOMERS, AND NOT UNDULY BURDENSOME TO PIEDMONT'S CUSTOMERS CONSIDERING THE CHANGING ECONOMIC CONDITIONS?**

A. Yes. Based on the factors I have discussed here, I believe that an ROE of 10.25% is fair and reasonable to Piedmont, its shareholders, and its customers in light of the uncertainty surrounding the COVID-19 recovery.

## IX. <u>CONCLUSION</u>

**Q. WHAT IS YOUR RECOMMENDED OVERALL ROE FOR PIEDMONT?**

A. Given the indicated ROE range applicable to the Utility Proxy Group of 9.46% to 12.18% and the Company-specific ROE range of 9.58% to 12.30%, I conclude that an appropriate ROE for the Company is 10.25%.

**Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.25% FAIR AND REASONABLE TO PIEDMONT AND ITS CUSTOMERS?**

A. Yes, it is.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

Piedmont Natural Gas Company, Inc.
General Rate Case
Docket No. G-9, Sub 781





# APPENDIX A

scottmadden
MANAGEMENT CONSULTANTS

Appendix A - Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director

## Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). He has served as a consultant for investor-owned and municipal utilities and authorities for 12 years. Dylan has extensive experience in rate of return analyses, class cost of service, rate design, and valuation for regulated public utilities. He has testified as an expert witness in the subjects of rate of return, cost of service, rate design, and valuation before 30 regulatory commissions in the U.S., one Canadian province, and an American Arbitration Association panel.

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

## Areas of Specialization

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

## Recent Expert Testimony Submission/Appearances

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

## Recent Assignments

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

## Recent Publications and Speeches

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

scottmadden
MANAGEMENT CONSULTANTS

Appendix A - Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Director



| SPONSOR | DATE | CASE/APPLICANT | DOCKET NO. | SUBJECT |
|---|---|---|---|---|
| **Regulatory Commission of Alaska** | | | | |
| Alaska Power Company | 09/20 | Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc. | Tariff Nos. TA886-2; TA6-521; TA4-573 | Capital Structure |
| Alaska Power Company | 07/16 | Alaska Power Company | Docket No. TA857-2 | Rate of Return |
| **Alberta Utilities Commission** | | | | |
| AltaLink, L.P., and EPCOR Distribution & Transmission, Inc. | 01/20 | AltaLink, L.P., and EPCOR Distribution & Transmission, Inc. | 2021 Generic Cost of Capital, Proceeding ID. 24110 | Rate of Return |
| **Arizona Corporation Commission** | | | | |
| EPCOR Water Arizona, Inc. | 06/20 | EPCOR Water Arizona, Inc. | Docket No. WS-01303A-20-0177 | Rate of Return |
| Arizona Water Company | 12/19 | Arizona Water Company – Western Group | Docket No. W-01445A-19-0278 | Rate of Return |
| Arizona Water Company | 08/18 | Arizona Water Company – Northern Group | Docket No. W-01445A-18-0164 | Rate of Return |
| **Colorado Public Utilities Commission** | | | | |
| Summit Utilities, Inc. | 04/18 | Colorado Natural Gas Company | Docket No. 18AL-0305G | Rate of Return |
| Atmos Energy Corporation | 06/17 | Atmos Energy Corporation | Docket No. 17AL-0429G | Rate of Return |
| **Delaware Public Service Commission** | | | | |
| Delmarva Power & Light Co. | 11/20 | Delmarva Power & Light Co. | Docket No. 20-0149 (Electric) | Return on Equity |
| Delmarva Power & Light Co. | 10/20 | Delmarva Power & Light Co. | Docket No. 20-0150 (Gas) | Return on Equity |
| Tidewater Utilities, Inc. | 11/13 | Tidewater Utilities, Inc. | Docket No. 13-466 | Capital Structure |
| **Public Service Commission of the District of Columbia** | | | | |
| Washington Gas Light Company | 09/20 | Washington Gas Light Company | Formal Case No. 1162 | Rate of Return |
| **Federal Energy Regulatory Commission** | | | | |
| LS Power Grid California, LLC | 10/20 | LS Power Grid California, LLC | Docket No. ER21-195-000 | Rate of Return |
| **Florida Public Service Commission** | | | | |
| Peoples Gas System | 09/20 | Peoples Gas System | Docket No. 20200051-GU | Rate of Return |
| Utilities, Inc. of Florida | 06/20 | Utilities, Inc. of Florida | Docket No. 20200139-WS | Rate of Return |
| **Hawaii Public Utilities Commission** | | | | |
| Launiupoko Irrigation Company, Inc. | 12/20 | Launiupoko Irrigation Company, Inc. | Docket No. 2020-0217 / Transferred to 2020-0089 | Capital Structure |
| Lanai Water Company, Inc. | 12/19 | Lanai Water Company, Inc. | Docket No. 2019-0386 | Cost of Service / Rate Design |
| Manele Water Resources, LLC | 08/19 | Manele Water Resources, LLC | Docket No. 2019-0311 | Cost of Service / Rate Design |
| Kaupulehu Water Company | 02/18 | Kaupulehu Water Company | Docket No. 2016-0363 | Rate of Return |
| Aqua Engineers, LLC | 05/17 | Puhi Sewer & Water Company | Docket No. 2017-0118 | Cost of Service / Rate Design |
| Hawaii Resources, Inc. | 09/16 | Laie Water Company | Docket No. 2016-0229 | Cost of Service / Rate Design |
| **Illinois Commerce Commission** | | | | |
| Ameren Illinois Company d/b/a Ameren Illinois | 07/20 | Ameren Illinois Company d/b/a Ameren Illinois | Docket No. 20-0308 | Return on Equity |
| Utility Services of Illinois, Inc. | 11/17 | Utility Services of Illinois, Inc. | Docket No. 17-1106 | Cost of Service / Rate Design |

| SPONSOR | DATE | CASE/APPLICANT | DOCKET NO. | SUBJECT |
|---|---|---|---|---|
| Aqua Illinois, Inc. | 04/17 | Aqua Illinois, Inc. | Docket No. 17-0259 | Rate of Return |
| Utility Services of Illinois, Inc. | 04/15 | Utility Services of Illinois, Inc. | Docket No. 14-0741 | Rate of Return |
| **Indiana Utility Regulatory Commission** | | | | |
| Aqua Indiana, Inc. | 03/16 | Aqua Indiana, Inc. Aboite Wastewater Division | Docket No. 44752 | Rate of Return |
| Twin Lakes, Utilities, Inc. | 08/13 | Twin Lakes, Utilities, Inc. | Docket No. 44388 | Rate of Return |
| **Kansas Corporation Commission** | | | | |
| Atmos Energy | 07/19 | Atmos Energy | 19-ATMG-525-RTS | Rate of Return |
| **Kentucky Public Service Commission** | | | | |
| Bluegrass Water Utility Operating Company | 10/20 | Bluegrass Water Utility Operating Company | 2020-00290 | Return on Equity |
| **Louisiana Public Service Commission** | | | | |
| Southwestern Electric Power Company | 12/20 | Southwestern Electric Power Company | Docket No. U-35441 | Return on Equity |
| Atmos Energy | 04/20 | Atmos Energy | Docket No. U-35535 | Rate of Return |
| Louisiana Water Service, Inc. | 06/13 | Louisiana Water Service, Inc. | Docket No. U-32848 | Rate of Return |
| **Maryland Public Service Commission** | | | | |
| Washington Gas Light Company | 08/20 | Washington Gas Light Company | Case No. 9651 | Rate of Return |
| FirstEnergy, Inc. | 08/18 | Potomac Edison Company | Case No. 9490 | Rate of Return |
| **Massachusetts Department of Public Utilities** | | | | |
| Unitil Corporation | 12/19 | Fitchburg Gas & Electric Co. (Elec.) | D.P.U. 19-130 | Rate of Return |
| Unitil Corporation | 12/19 | Fitchburg Gas & Electric Co. (Gas) | D.P.U. 19-131 | Rate of Return |
| Liberty Utilities | 07/15 | Liberty Utilities d/b/a New England Natural Gas Company | Docket No. 15-75 | Rate of Return |
| **Minnesota Public Utilities Commission** | | | | |
| Northern States Power Company | 11/20 | Northern States Power Company | Docket No. E002/GR-20-723 | Rate of Return |
| **Mississippi Public Service Commission** | | | | |
| Atmos Energy | 03/19 | Atmos Energy | Docket No. 2015-UN-049 | Capital Structure |
| Atmos Energy | 07/18 | Atmos Energy | Docket No. 2015-UN-049 | Capital Structure |
| **Missouri Public Service Commission** | | | | |
| Spire Missouri, Inc. | 12/20 | Spire Missouri, Inc. | Case No. GR-2021-0108 | Return on Equity |
| Indian Hills Utility Operating Company, Inc. | 10/17 | Indian Hills Utility Operating Company, Inc. | Case No. SR-2017-0259 | Rate of Return |
| Raccoon Creek Utility Operating Company, Inc. | 09/16 | Raccoon Creek Utility Operating Company, Inc. | Docket No. SR-2016-0202 | Rate of Return |
| **Public Utilities Commission of Nevada** | | | | |
| Southwest Gas Corporation | 08/20 | Southwest Gas Corporation | Docket No. 20-02023 | Return on Equity |
| **New Hampshire Public Utilities Commission** | | | | |
| Aquarion Water Company of New Hampshire, Inc. | 12/20 | Aquarion Water Company of New Hampshire, Inc. | Docket No. DW 20-184 | Rate of Return |
| **New Jersey Board of Public Utilities** | | | | |
| Atlantic City Electric Company | 12/20 | Atlantic City Electric Company | Docket No. ER20120746 | Return on Equity |

| SPONSOR | DATE | CASE/APPLICANT | DOCKET NO. | SUBJECT |
|---|---|---|---|---|
| FirstEnergy | 02/20 | Jersey Central Power & Light Co. | Docket No. ER20020146 | Rate of Return |
| Aqua New Jersey, Inc. | 12/18 | Aqua New Jersey, Inc. | Docket No. WR18121351 | Rate of Return |
| Middlesex Water Company | 10/17 | Middlesex Water Company | Docket No. WR17101049 | Rate of Return |
| Middlesex Water Company | 03/15 | Middlesex Water Company | Docket No. WR15030391 | Rate of Return |
| The Atlantic City Sewerage Company | 10/14 | The Atlantic City Sewerage Company | Docket No. WR14101263 | Cost of Service / Rate Design |
| Middlesex Water Company | 11/13 | Middlesex Water Company | Docket No. WR1311059 | Capital Structure |
| **New Mexico Public Regulation Commission** | | | | |
| Southwestern Public Service Company | 01/21 | Southwestern Public Service Company | Case No. 20-00238-UT | Return on Equity |
| **North Carolina Utilities Commission** | | | | |
| Duke Energy Carolinas, LLC | 07/20 | Duke Energy Carolinas, LLC | Docket No. E-7, Sub 1214 | Return on Equity |
| Duke Energy Progress, LLC | 07/20 | Duke Energy Progress, LLC | Docket No. E-2, Sub 1219 | Return on Equity |
| Aqua North Carolina, Inc. | 12/19 | Aqua North Carolina, Inc. | Docket No. W-218 Sub 526 | Rate of Return |
| Carolina Water Service, Inc. | 06/19 | Carolina Water Service, Inc. | Docket No. W-354 Sub 364 | Rate of Return |
| Carolina Water Service, Inc. | 09/18 | Carolina Water Service, Inc. | Docket No. W-354 Sub 360 | Rate of Return |
| Aqua North Carolina, Inc. | 07/18 | Aqua North Carolina, Inc. | Docket No. W-218 Sub 497 | Rate of Return |
| **North Dakota Public Service Commission** | | | | |
| Northern States Power Company | 11/20 | Northern States Power Company | Case No. PU-20-441 | Rate of Return |
| **Public Utilities Commission of Ohio** | | | | |
| Aqua Ohio, Inc. | 05/16 | Aqua Ohio, Inc. | Docket No. 16-0907-WW-AIR | Rate of Return |
| **Pennsylvania Public Utility Commission** | | | | |
| Valley Energy, Inc. | 07/19 | C&T Enterprises | Docket No. R-2019-3008209 | Rate of Return |
| Wellsboro Electric Company | 07/19 | C&T Enterprises | Docket No. R-2019-3008208 | Rate of Return |
| Citizens' Electric Company of Lewisburg | 07/19 | C&T Enterprises | Docket No. R-2019-3008212 | Rate of Return |
| Steelton Borough Authority | 01/19 | Steelton Borough Authority | Docket No. A-2019-3006880 | Valuation |
| Mahoning Township, PA | 08/18 | Mahoning Township, PA | Docket No. A-2018-3003519 | Valuation |
| SUEZ Water Pennsylvania Inc. | 04/18 | SUEZ Water Pennsylvania Inc. | Docket No. R-2018-000834 | Rate of Return |
| Columbia Water Company | 09/17 | Columbia Water Company | Docket No. R-2017-2598203 | Rate of Return |
| Veolia Energy Philadelphia, Inc. | 06/17 | Veolia Energy Philadelphia, Inc. | Docket No. R-2017-2593142 | Rate of Return |
| Emporium Water Company | 07/14 | Emporium Water Company | Docket No. R-2014-2402324 | Rate of Return |
| Columbia Water Company | 07/13 | Columbia Water Company | Docket No. R-2013-2360798 | Rate of Return |
| Penn Estates Utilities, Inc. | 12/11 | Penn Estates, Utilities, Inc. | Docket No. R-2011-2255159 | Capital Structure / Long-Term Debt Cost Rate |
| **South Carolina Public Service Commission** | | | | |
| Blue Granite Water Co. | 12/19 | Blue Granite Water Company | Docket No. 2019-292-WS | Rate of Return |
| Carolina Water Service, Inc. | 02/18 | Carolina Water Service, Inc. | Docket No. 2017-292-WS | Rate of Return |
| Carolina Water Service, Inc. | 06/15 | Carolina Water Service, Inc. | Docket No. 2015-199-WS | Rate of Return |
| Carolina Water Service, Inc. | 11/13 | Carolina Water Service, Inc. | Docket No. 2013-275-WS | Rate of Return |
| United Utility Companies, Inc. | 09/13 | United Utility Companies, Inc. | Docket No. 2013-199-WS | Rate of Return |

| SPONSOR | DATE | CASE/APPLICANT | DOCKET NO. | SUBJECT |
|---|---|---|---|---|
| Utility Services of South Carolina, Inc. | 09/13 | Utility Services of South Carolina, Inc. | Docket No. 2013-201-WS | Rate of Return |
| Tega Cay Water Services, Inc. | 11/12 | Tega Cay Water Services, Inc. | Docket No. 2012-177-WS | Capital Structure |
| **Tennessee Public Utility Commission** | | | | |
| Piedmont Natural Gas Company | 07/20 | Piedmont Natural Gas Company | Docket No. 20-00086 | Return on Equity |
| **Public Utility Commission of Texas** | | | | |
| Southwestern Public Service Company | 02/21 | Southwestern Public Service Company | Docket No. 51802 | Return on Equity |
| Southwestern Electric Power Company | 10/20 | Southwestern Electric Power Company | Docket No. 51415 | Rate of Return |
| **Virginia State Corporation Commission** | | | | |
| Massanutten Public Service Corporation | 12/20 | Massanutten Public Service Corporation | Case No. PUE-2020-00039 | Return on Equity |
| Aqua Virginia, Inc. | 07/20 | Aqua Virginia, Inc. | PUR-2020-00106 | Rate of Return |
| WGL Holdings, Inc. | 07/18 | Washington Gas Light Company | PUR-2018-00080 | Rate of Return |
| Atmos Energy Corporation | 05/18 | Atmos Energy Corporation | PUR-2018-00014 | Rate of Return |
| Aqua Virginia, Inc. | 07/17 | Aqua Virginia, Inc. | PUR-2017-00082 | Rate of Return |
| Massanutten Public Service Corp. | 08/14 | Massanutten Public Service Corp. | PUE-2014-00035 | Rate of Return / Rate Design |

**BEFORE THE**

**NORTH CAROLINA UTILITIES COMMISSION**

**REBUTTAL TESTIMONY**

**OF**

**DYLAN W. D'ASCENDIS, CRRA, CVA**

**ON BEHALF OF**

**PIEDMONT NATURAL GAS COMPANY, INC.**

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

August 25, 2021

**TABLE OF CONTENTS**

## I. INTRODUCTION, PURPOSE, AND SUMMARY

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

A. My name is Dylan W. D'Ascendis. I am employed by ScottMadden, Inc. as Partner. My business address is 3000 Atrium Way, Suite 241, Mount Laurel, NJ 08054.

**Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?**

A. I am submitting this rebuttal testimony (referred to throughout as my "Rebuttal Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company").

**Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Yes, I did.

**Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. The purpose of my Rebuttal Testimony is two-fold. First, given the passage of time since my Direct Testimony,[1] I update my cost of common equity ("ROE") analyses to reflect current data. Second, I respond to the direct testimonies of Mr. John R. Hinton, who testifies on behalf of the Public Staff – North Carolina Utilities Commission ("Public Staff"), Mr. Kevin W. O'Donnell, who testifies on behalf of Carolina Utility Customers Association ("CUCA"), and Mr. Nicholas Phillips, Jr., who testifies on behalf of Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR") (collectively, "the Opposing Witnesses") as they relate to the Company's ROE on its North Carolina jurisdictional rate base.

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[1] My Direct Testimony used market data as of January 29, 2021.

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.**

A. Due to the passage of time since the analysis in my Direct Testimony, I have updated my ROE analyses as of July 30, 2021. Based on these updated analyses, my range of reasonable ROEs attributable to Piedmont is between 9.59% and 12.72% (unadjusted) and 9.70% to 12.83% (adjusted). Therefore, my specific ROE recommendation of 10.25% for Piedmont in this case continues to be reasonable, if not conservative. In view of current markets and the updated results of my ROE models, ROEs of 9.42% (Staff) and 9.00% (CUCA) are insufficient at this time.[2]

**Q. DO YOU HAVE GENERAL COMMENTS REGARDING MR. HINTON'S AND MR. O'DONNELL'S RECOMMENDATED ROES?**

A. Yes, I do. Mr. Hinton's and Mr. O'Donnell's recommended ROEs are insufficient, in part, due to their substantial[3] (Hinton) and exclusive (O'Donnell) reliance on the discounted cash flow ("DCF") model results which tend to understate Piedmont's return requirement in the current market. There is both academic and practical support for the use of multiple models in an ROE analysis, which will be explained in detail below.

**Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR RECOMMENDATION?**

A. Yes. I have prepared Exhibit DWD-1R through DWD-14R, which were prepared by me or under my direction.

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2 While Mr. Phillips recommends that the Commission should not approve an ROE greater than 9.56% in this proceeding, he does not provide an independent analysis of the Company's cost of common equity. Given the evidence in this proceeding, Mr. Phillips' recommendation of an ROE no higher than 9.56% is also insufficient at this time.

3 Mr. Hinton gives three-quarters weight to his DCF model results and one-quarter weight to his RPM results as will be discussed below.

**Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?**

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

- Section II – Provides my updated analyses;
- Section III – Discusses the undue weighting of DCF model results by Mr. Hinton and Mr. O'Donnell;
- Section IV – Contains my response to Mr. Hinton;
- Section V – Contains my response to Mr. O'Donnell;
- Section VI – Contains my response to Mr. Phillips; and
- Section VII – Summarizes my conclusions and recommendations.

**Q. PLEASE SUMMARIZE THE KEY ISSUES AND RECOMMENDATIONS OFFERED BY OPPOSING WITNESSES THAT YOU ADDRESS IN YOUR REBUTTAL TESTIMONY.**

A. My Rebuttal Testimony responds to substantive recommendations offered by the Opposing Witnesses in their direct testimonies. I will address the following issues common to Mr. Hinton's and Mr. O'Donnell's direct testimonies:

- Their selection of their proxy group companies;
- Their undue weighting of DCF model results in their ROE recommendations;
- Their choice of growth rates in their DCF models;
- Their application of the comparable earnings model ("CEM"); and
- Their failure to reflect flotation costs.

Specific to Mr. Hinton's direct testimony, I will address the following:

- His application of the risk premium model ("RPM");
- His opinion that mechanisms in place for the Company reduce risk; and
- His use of interest coverage ratios to justify his recommended ROE.

Specific to Mr. O'Donnell's direct testimony, I will address the following:

- His interpretation of capital market conditions;
- His use of the plowback ratio in his DCF model; and
- His application of the Capital Asset Pricing Model ("CAPM").

These factors serve to bias Mr. Hinton's and Mr. O'Donnell's ROE recommendations downward. My Rebuttal Testimony addresses these factors in detail, as well as other issues specific to each witness, and addresses the unfounded critiques of my Direct Testimony by the Opposing Witnesses.

## II. UPDATED ANALYSES

**Q. HAVE YOU UPDATED YOUR COST OF COMMON EQUITY ANALYSES FOR YOUR REBUTTAL TESTIMONY?**

A. Yes, I have. Due to the passage of time since my Direct Testimony analysis (data as of January 29, 2021), I have updated my analysis using data as of July 30, 2021.

**Q. HAVE YOU UPDATED YOUR UTILITY PROXY GROUP FOR YOUR UPDATED ANALYSES?**

A. Yes, I have. Using fiscal year 2020 data, NiSource Inc. fails the criteria of having at least 60% of net operating income and assets attributable to natural gas distribution operations. As such, I have eliminated them from my updated Utility Proxy Group.

**Q. HAVE YOU APPLIED ANY OF YOUR ROE MODELS DIFFERENTLY IN YOUR UPDATED ANALYSES?**

A. No, I have not.

**Q. WHAT ARE THE RESULTS OF YOUR UPDATED ANALYSES?**

A. Using data available as of July 30, 2021, my updated results are presented in page 1 of Exhibit DWD-1R and in Table 1, below.

**<u>Table 1: Updated Cost of Common Equity Results</u>**

| | |
|---|---|
| Discounted Cash Flow Model | 9.59% |
| Risk Premium Model | 10.71% |
| Capital Asset Pricing Model | 12.02% |
| Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies | <u>12.72%</u> |
| | |
| Indicated Range | 9.59% - 12.72% |
| Size Adjustment | 0.00% |
| Flotation Cost Adjustment | <u>0.11%</u> |
| | |
| Recommended Range | 9.70% - 12.83% |
| Recommended Cost of Common Equity | <u>10.25%</u> |

In view of the unadjusted and adjusted ranges of ROE, I maintain my original ROE recommendation of 10.25%. Upon reviewing my updated results, two items became apparent: (1) the indicated results of my ROE models have generally increased from my analyses presented in my Direct Testimony, which is a directional indicator that the investor-required return has increased since my Direct Testimony, and (2) since my recommended ROE of 10.25% is in the bottom half of my ranges of ROEs, it is a conservative measure of the Company's ROE at this time.

## III. UNDUE WEIGHTING OF DCF MODEL RESULTS

**Q. DO YOU HAVE A GENERAL COMMENT REGARDING MR. HINTON'S AND MR. O'DONNELL'S ROE RECOMMENDATIONS?**

A. Yes, I do. As mentioned previously, Mr. Hinton's and Mr. O'Donnell's recommended ROEs of 9.42% and 9.00% are inadequate, in part, because they place undue weight on their DCF model results, which tend to mis-specify the investor-required return when market-to-book ("M/B") ratios are not at unity (*i.e.,* 1.0).

**Q. DO THE OPPOSING WITNESSES RELY PRIMARILY ON THE DCF MODEL TO ARRIVE AT THEIR ROE RECOMMENDATION FOR THE COMPANY?**

A. Yes, they do. Mr. Hinton's ROE recommendation of 9.42% is based on the average of four model results, three of which are his DCF results.[4] Mr. O'Donnell's ROE recommendation of 9.00%[5] is based on the upper end of his DCF model results as he believes that the DCF model is superior to all other ROE models.[6] As discussed in my Direct Testimony,[7] the use of multiple models adds reliability to the estimation of the common equity cost rate, and the prudence of using multiple cost of common equity models is supported in both the financial literature and regulatory precedent.

**Q. CAN YOU PLEASE PROVIDE SOME EXAMPLES FROM THE FINANCIAL LITERATURE WHICH SUPPORT THE USE OF MULTIPLE COST OF**

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4 Hinton Direct Testimony, at 38.
5 O'Donnell Direct Testimony, at 4.
6 *Ibid.*, at 41.
7 D'Ascendis Direct Testimony, at 17.

**COMMON EQUITY MODELS IN DETERMINING THE INVESTOR-REQUIRED RETURN?**

A. Yes. In one example, Morin states:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate a theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.
>
> **No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment.** Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. (emphasis added)
>
> * * *
>
> The financial literature supports the use of multiple methods. Professor Eugene Brigham, a widely respected scholar and finance academician, asserts (footnote omitted):
>
> Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach. **These methods are not mutually exclusive – no method dominates the others**, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand. (emphasis added)

Another prominent finance scholar, Professor Stewart Myers, in an early pioneering article on regulatory finance, stated(footnote omitted):

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

> in parallel with DCF models or other techniques for interpreting capital market data. (emphasis added)
>
> Reliance on multiple tests recognizes that no single methodology produces a precise definitive estimate of the cost of equity. As stated in Bonbright, Danielsen, and Kamerschen (1988), 'no single or group test or technique is conclusive.' Only a fool discards relevant evidence. (italics in original) (emphasis added)
>
> * * *
>
> While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. **The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity.** It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM methodologies. (emphasis added) [8]

Finally, Brigham and Gapenski note:

> In practical work, *it is often best to use all three methods* – CAPM, bond yield plus risk premium, and DCF – and then apply judgment when the methods produce different results. People experienced in estimating equity capital costs recognize that both careful analysis and some very fine judgments are required. It would be nice to pretend that these judgments are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible. Finance is in large part a matter of judgment, and we simply must face this fact. (italics in original) [9]

In the academic literature cited above, three methods are consistently mentioned: the DCF, CAPM, and the RPM, all of which I used in my analyses.

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[8] Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 428-431. ("Morin")

[9] Eugene F. Brigham and Louis C. Gapenski, Financial Management – Theory and Practice, 4th Ed. (The Dryden Press, 1985) at 256.

**Q. CAN YOU ALSO PROVIDE SPECIFIC EXAMPLES WHERE THIS COMMISSION HAS CONSIDERED MULTIPLE COST OF COMMON EQUITY MODELS?**

A. Yes. The Commission in Docket W-354, Sub 360, concerning Carolina Water Service of North Carolina, stated:

> The average of witness D'Ascendis' utility proxy group DCF result of 9.15%, traditional CAPM result of 10.67%, total market RPM of 10.56%, witness Hinton's DCF result of 8.70% and RPM of 9.70% is 9.75%. The Commission approved return on equity of 9.75% is thus supported by the average of the results of the above listed cost of equity models which the Commission finds are entitled to substantial weight based on the record in this proceeding.

Also, in Docket E-2, Sub 1142, concerning Duke Energy Progress, LLC, the Commission stated:

> Thus, the Commission finds and concludes that the Stipulation, along with the expert testimony of witnesses Hevert (risk premium analysis), O'Donnell (comparable earnings), and Parcell (comparable earnings), are credible and substantial evidence of the appropriate rate of return on equity and are entitled to substantial weight in the Commission's determination of this issue.

In the Commission Orders cited above, there is clear language that the Commission considers multiple models in its determination of ROE. It is also my interpretation of these Orders that the Commission correctly observes capital market conditions and their effect on the model results in determining a ROE for utility companies. This, in addition to the academic literature cited above, justifies the use of the DCF, CAPM, RPM, and CEM in this proceeding.

**Q. WHY IS IT YOUR OPINION THAT THE DCF MODEL MIS-SPECIFIES INVESTOR-REQUIRED RETURN WHEN M/B RATIOS ARE NOT AT UNITY?**

A. Traditional rate base/rate of return regulation, where a market-based common equity cost rate is applied to a book value rate base, presumes that M/B ratios are at unity or 1.00. However, that is rarely the case. Morin states:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the market-to-book (M/B) ratio of a given stock exceeds unity. This was particularly relevant in the capital market environment of the 1990s and 2000s where utility stocks were trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates that investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.[10]

As Morin explains, a "simplified" DCF model, like that used by Mr. Hinton and Mr. O'Donnell, assumes an M/B ratio of 1.0 and therefore under- or over-states investors' required return when market value exceeds or is less than book value, respectively. It does so because equity investors evaluate and receive their returns on the market value of a utility's common equity, whereas regulators authorize returns on the book value of that common equity. This means that the market-based DCF will produce the total annual dollar return expected by investors only when market and book values of common equity are equal, a very rare and unlikely situation.

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10 Morin, at 434.

**Q. WHY DO MARKET AND BOOK VALUES DIVERGE?**

A. Market values can diverge from book values for a myriad of reasons including, but not limited to, EPS and DPS expectations, merger/acquisition expectations, interest rates, etc. As noted by Phillips:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.[11]

In addition, Bonbright states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market*. In short, market prices are beyond the control, though not beyond the influence of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels. (italics added)[12]

**Q. CAN THE UNDER- OR OVER-STATEMENT OF INVESTORS' REQUIRED RETURN BY THE DCF MODEL BE DEMONSTRATED MATHEMATICALLY?**

A. Yes, it can. Schedule DWD-2R demonstrates how market-based DCF cost rates of 9.39%[13] and 9.00%[14], when applied to a book value substantially below market value, will understate the investors' required return on market value. In this situation, there is no realistic opportunity for the utility to earn the expected market-based rate of return on book value. In Column [A], investors expect a 9.39% return on an average market price of $62.90 for Mr.

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11 Charles F. Phillips, The Regulation of Public Utilities, Public Utilities Reports, Inc., 1993, p. 395.

12 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates (Public Utilities Reports, Inc., 1988), p. 334.

13 The average of Mr. Hinton's three DCF cost rates, calculated from Public Staff Hinton Exhibit 9.

14 O'Donnell Direct Testimony, at 55.

Hinton's proxy group companies. Column [B] shows that when Mr. Hinton's 9.39% return rate is applied to a book value of $31.70,[15] the total annual return opportunity is $2.977. After subtracting dividends of $2.013, the investor only has the opportunity for $0.964 in market appreciation, or 1.53%. The magnitude of the understatement of investors' required return on market value using Mr. Hinton's 9.39% cost rate is 4.66%, which is calculated by subtracting the market appreciation based on book value of 1.53% from Mr. Hinton's expected growth rate of 6.19%. Schedule DWD-2R also shows that the understatement of investors' required return on market value using Mr. O'Donnell's 9.00% cost rate is 4.36%. In order to synchronize investor expectations with a book value return calculation, premiums of 466 and 436 basis points would need to be added to the results of Mr. Hinton's and Mr. O'Donnell's DCF analyses, as is discussed below.

**Q. HOW DO THE M/B RATIOS OF THE COMBINED PROXY GROUP COMPARE TO THEIR TEN-YEAR AVERAGE?**

A. The M/B ratio of the combined proxy group (*i.e.,* all companies used by all witnesses) is currently close to its ten-year average of approximately 1.97 times.

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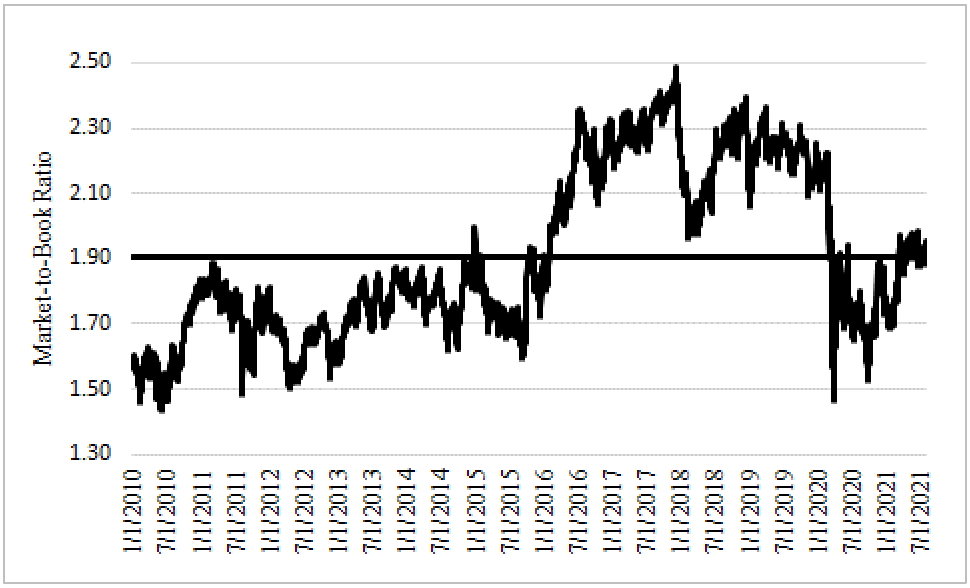
15 Representing a market-to-book ratio of 198.27%.

**Chart 1: M/B Ratios Compared with Ten-Year Average[16]**




The significance of this is that the ten-year average M/B ratio of the combined proxy group has always been greater than 1.0x, which means that DCF model results have consistently understated the investor-required return during that period.

**Q. HOW CAN THE INACCURACY OR MIS-SPECIFICATION OF THE DCF MODEL BE QUANTIFIED WHEN THE M/B RATIOS ARE DIFFERENT THAN UNITY?**

A. The inaccuracy of the DCF model, when market values diverge from book values, can be measured by first calculating the market value of each proxy company's capital structure, which consists of the market value of the company's common equity (shares outstanding multiplied by price) and the fair value of the company's long-term debt and preferred stock. All of these measures, except for price, are available in each company's SEC Form 10-K.

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16 Source: Bloomberg Financial Services.

Second, one must de-leverage the implied cost of common equity based on the DCF. This is accomplished using the Modigliani / Miller equation[17] as illustrated in Schedule DWD-3R and shown below:

$$ku = ke - (((ku - i)(1 - t)) D/E) - (ku - d) P/E \text{ [Equation 1]}$$

Where:

| | | |
|---|---|---|
| ku | = | Unlevered (i.e., 100% equity) cost of common equity; |
| ke | = | Market determined cost of common equity; |
| i | = | Cost of debt; |
| t | = | Income tax rate; |
| D | = | Debt ratio; |
| E | = | Equity ratio; |
| d | = | Cost of preferred stock; and |
| P | = | Preferred equity ratio. |

Using Mr. Hinton's proxy group-specific data, the equation becomes:

$$ku = 9.39\% - (((ku – 4.08\%)(1 - 21\%))\ 41.91\% / 57.72\%) - (ku – 5.90\%)\ 0.37\% / 57.72\%$$

Solving for ku results in an unlevered cost of common equity of 7.45%.

Next, one must re-leverage those costs of common equity by relating them to each proxy group's average book capital structure as shown below:

$$ke = ku + (((ku – i)(1 – t)) D/E) + (ku – d) P/E \text{ [Equation 2]}$$

Once again, using average proxy group-specific data, the equation becomes:

$$ke=7.45\%+(((7.45\% - 4.08\%)(1 - 21\%))50.39\%/ 49.17\%)+(7.45\% - 5.90\%)\ 0.44\%/49.17\%$$

Solving for ke results in a 10.19% indicated cost of common equity relative to the book capital structure of the proxy group, which is an increase of 80 basis points over Mr.

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17 The Modigliani / Miller theorem is an influential element of economic theory and forms the basis for modern theory on capital structure. *See*, F. Modigliani and M. Miller, *The Cost of Capital, Corporation Finance and the Theory of Investment*, The American Economic Review, Vol. 48, No. 3, (June 1958), at 261-297.

Hinton's average indicated DCF result of 9.39%. Schedule DWD-3R also shows that for Mr. O'Donnell's proxy group, solving for ke results in a 9.72% indicated cost of common equity relative to the book capital structure of his proxy group, an increase of 72 basis points over his average indicated DCF result of 9.00%

**Q. ARE YOU ADVOCATING A SPECIFIC ADJUSTMENT TO THE DCF RESULTS TO CORRECT FOR ITS MIS-SPECIFICATION OF THE INVESTOR-REQUIRED RETURN?**

A. No. The purpose of this discussion is to demonstrate that, like all cost of common equity models, the DCF has its limitations. The use of multiple cost of common equity models, in conjunction with informed expert judgment, provides a clearer picture of the investor-required ROE.

## IV. RESPONSE TO PUBLIC STAFF WITNESS HINTON

**Q. PLEASE SUMMARIZE MR. HINTON'S RECOMMENDATIONS.**

A. Mr. Hinton recommends that the Commission establish an overall rate of return of 6.75%, based on a capital structure consisting of 48.80% long-term debt at an embedded cost rate of 4.08%, 0.67% short-term debt at an embedded cost rate of 0.20%, and 50.53% common equity at his recommended cost of common equity of 9.42%.[18] Mr. Hinton's ROE recommendation of 9.42% is based on the average of his three DCF results (ranging from 9.10% to 9.73%) and RPM (9.50%) result.[19]

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18 Hinton Direct Testimony, at 49.
19 *Ibid.*, at 38.

**Q. DO YOU HAVE ANY GENERAL COMMENTS ON MR. HINTON'S RECOMMENDED ROE?**

A. Yes. Mr. Hinton relies exclusively on two models, the DCF and the RPM, in his ROE analysis, using the CEM only as a check on his recommended ROE.[20] In Docket Nos. W-354, Subs 363, 364, and 365, Mr. Hinton also employed the CAPM, albeit as a check, in his ROE analysis.[21] As discussed previously, the use of multiple models adds reliability to the estimation of the common equity cost rate.

**Q. WHAT ARE THE AREAS OF DISAGREEMENT BETWEEN YOU AND MR. HINTON?**

A. While both Mr. Hinton and I rely on the DCF model and RPM in our analyses, there are several areas in which we disagree. As will be discussed below, in addition to disagreeing with the weight given to his DCF model results, I also do not agree with (1) his proxy group; (2) his use of growth rates other than projected growth in earnings per share ("EPS") in his application of the DCF model; (3) certain inputs used in his RPM; (4) certain assumptions and inputs in his CEM; and (5) his failure to reflect flotation costs.

**A. <u>Proxy Group Selection</u>**

**Q. PLEASE DESCRIBE THE SCREENING CRITERIA BY WHICH MR. HINTON DEVELOPED HIS PROXY GROUP.**

A. Mr. Hinton started with the ten companies in the *Value Line* Natural Gas Company group. From that group Mr. Hinton eliminates NiSource Inc. because it cut its dividend in 2015. Mr. Hinton then identified two additional companies covered by *Value Line* that have

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[20] Hinton Direct Testimony, at 28.

[21] Docket Nos. W-354, Subs 363, 364, and 365, Hinton Direct Testimony, at 33-34.

natural gas distribution operations, MDU Resources Group, Inc. and National Fuel Gas Company.[22]

**Q. DO YOU AGREE WITH MR. HINTON'S PROXY GROUP?**

A. No. Several of the companies Mr. Hinton decides to include in his proxy groups have operations in other areas than natural gas distribution services. This is illustrated in Table 2, below:

**Table 2: Percent of 2019 Net Operating Income and Assets Attributable to Gas Distribution Operations of Mr. Hinton's Proxy Group[23]**

| | **Net Oper. Income** | **Total Assets** |
|---|---|---|
| Atmos Energy Corporation | 63.02% | 79.32% |
| **Chesapeake Utilities Corporation** | **38.57%** | **39.82%** |
| **MDU Resources Group, Inc.** | **14.38%** | **33.51%** |
| **National Fuel Gas Company** | **20.00%** | **30.82%** |
| New Jersey Resources Corporation | 87.58% | 70.07% |
| Northwest Natural Holding Company | 94.73% | 95.91% |
| ONE Gas, Inc. | 100.00% | 100.00% |
| South Jersey Industries | 98.14% | 87.03% |
| Southwest Gas Holdings, Inc. | 79.90% | 83.22% |
| Spire, Inc. | 97.06% | 67.72% |
| **UGI Corporation** | **34.57%** | **25.98%** |

This table shows that the four companies included in Mr. Hinton's proxy group, Chesapeake Utilities, MDU Resources Group, Inc., National Fuel Gas Company and UGI Corp. are not valid comparators to Piedmont at this time and should be eliminated.

22 Hinton Direct Testimony, at 30.
23 SEC Form 10-K.

**B. Discounted Cash Flow Model**

**Q. PLEASE SUMMARIZE MR. HINTON'S DCF ANALYSIS.**

A. Mr. Hinton calculated his dividend yield by using the *Value Line* estimate of the 12-month projected dividend yield for each of his proxy companies as reported in the *Value Line* Summary and Index for 13 weeks ended July 23, 2021.[24] He then added the average expected dividend yield of 3.2% to a range of growth rates from 4.8% to 7.8% to arrive at indicated DCF cost rates from 8.0% to 11.0%.[25] From these indicated DCF cost rates, he averaged all of them together for his historical & forecasted growth rate DCF cost rate of 9.35%, averaged all of his indicated DCF cost rates using projected measures of growth for his predicted growth rate DCF cost rate of 9.73%, and then averaged all of his indicated DCF cost rates using historical measures of growth for his historical growth rate DCF cost rate of 9.10%.[26]

**Q. PLEASE COMMENT ON MR. HINTON'S GROWTH RATE ANALYSIS IN HIS APPLICATION OF THE DCF MODEL.**

A. Mr. Hinton states on pages 32-33 of his direct testimony that he employed EPS, dividends per share ("DPS"), and book value of equity per share ("BVPS") growth rates as reported in *Value Line*, both five- and ten-year historical and forecasted, and the five-year projected EPS growth rate as reported by Yahoo! Finance. He includes both historical and forecasted growth rates, "because it is reasonable to expect that investors consider both sets of data in determining their expectations".

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[24] Hinton Direct Testimony, at 32.
[25] *Ibid*., Hinton Exhibit 6.
[26] *Ibid*., Hinton Exhibit 9.

As will be discussed below, there is a significant body of empirical evidence supporting the superiority of analysts' EPS growth rates in a DCF analysis, indicating that analysts' forecasts of earnings remain the best predictor of growth to use in the DCF model. Such ample evidence of the proven reliability and superiority of analysts' forecasts of EPS should not be dismissed by Mr. Hinton.

**Q. PLEASE DESCRIBE SOME OF THE EVIDENCE SUPPORTING THE RELIABILITY AND SUPERIORITY OF ANALYSTS' EPS GROWTH RATES IN A DCF ANALYSIS.**

A. As discussed in my Direct Testimony,[27] over the long run there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant, but not the only, influence on market prices than dividend expectations. Thus, the use of projected EPS growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF, because they have a significant influence on market prices and the appreciation or "growth" experienced by investors.[28] This should be evident even to relatively unsophisticated investors by listening to financial news reports on radio, TV, or reading newspapers.

In addition, Myron Gordon, the "father" of the standard regulatory version of the DCF model widely utilized throughout the United States in rate base/rate of return regulation, recognized the significance of analysts' forecasts of growth in EPS in a speech

27 D'Ascendis Direct Testimony, at 20.
28 Morin, at 298-303.

he gave in March 1990 before the Institute for Quantitative Research and Finance[29], stating on page 12:

> We have seen that earnings and growth estimates by security analysts were found by Malkiel and Cragg to be superior to data obtained from financial statements for the explanation of variation in price among common stocks… estimates by security analysts available from sources such as IBES are far superior to the data available to Malkiel and Cragg.
>
> * * *
>
> Eq (7) is not as elegant as Eq (4), but it has a good deal more intuitive appeal. It says that investors buy earnings, but what they will pay for a dollar of earnings increases with the extent to which the earnings are reflected in the dividend or in appreciation through growth.

Professor Gordon recognized that the total return is largely affected by the terminal price, which is mostly affected by earnings (hence price/earnings ("P/E") multiples).

Studies performed by Cragg and Malkiel[30] demonstrate that analysts' forecasts are superior to historical growth rate extrapolations. While some question the accuracy of analysts' forecasts of EPS growth, the level of accuracy of those analysts' forecasts well after the fact does not really matter. What is important is the forecasts reflect widely held expectations influencing investors at the time they make their pricing decisions, and hence, the market prices they pay.

In addition, Jeremy J. Siegel also supports the use of security analysts' EPS growth forecasts when he states:

> For the equity holder, the source of future cash flows is the earnings of firms. (p. 90)

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29 Myron J. Gordon, *The Pricing of Common Stock*, Presented before the Spring 1990 Seminar, March 27, 1990 of the Institute for Quantitative Research in Finance, Palm Beach, FL.

30 John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices (University of Chicago Press, 1982) Chapter 4.

* * *

> Some people argue that shareholders most value stocks' cash dividends. But this is not necessarily true. (p. 91)

* * *

> Since the price of a stock depends primarily on the present discounted value of all expected future dividends, it appears that dividend policy is crucial to determining the value of the stock. However, this is not generally true. (p. 92)

* * *

> Since stock prices are the present value of future dividends, it would seem natural to assume that economic growth would be an important factor influencing future dividends and hence stock prices. However, this is not necessarily so. The determinants of stock prices are earnings and dividends on a per-share basis. Although economic growth may influence aggregate earnings and dividends favorably, economic growth does not necessarily increase the growth of per-share earnings of dividends. It is earnings per share (EPS) that is important to Wall Street because per-share data, not aggregate earnings or dividends, are the basis of investor returns. (italics in original) (pp. 93-94)[31]

**Q. HAVE YOU CONSIDERED WHETHER ANALYSTS' EPS GROWTH RATE PROJECTIONS ARE CONSISTENT WITH MANAGEMENT GUIDANCE?**

A. Yes, I have. Based on data from Company investor presentations, ten of twelve of the combined proxy group companies currently issue long-term earnings growth guidance. Looking at the sources of growth rates used by Mr. Hinton and Mr. O'Donnell, of the 36 growth rate estimates for companies that also issue earnings guidance, only seven exceeded the upper bound of management guidance. On the other hand, eight were below the

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31 Jeremy J. Siegel, Stocks for the Long Run – The Definitive Guide to Financial Market Returns and Long-Term Investment Strategies, McGraw-Hill 2002, pp. 90-94.

guidance range; the remaining observations were within the range. Put another way, the majority of analysts' projections were within or below management guidance.

**Table 3: EPS Growth Rates and Management Guidance**

| **Company** | | **Guidance Range**[32] | | **Projected EPS Growth Rate**[33] | | | |
|---|---|---|---|---|---|---|---|
| | | Lower | Upper | Yahoo! | Value Line | CFRA | Schwab |
| Atmos Energy | ATO | 6.00 | 8.00 | 7.20 | 7.00 | 8.00 | 7.20 |
| Chesapeake Utilities | CPK | 7.75 | 9.50 | 4.70 | 8.50 | 3.60 | - |
| MDU Resources Group Inc. | MDU | 5.00 | 8.00 | 7.20 | 10.50 | - | - |
| National Fuel Gas Company | NFG | - | - | 8.50 | 19.00 | - | - |
| New Jersey Resources | NJR | 6.00 | 10.00 | 6.00 | 2.00 | 8.00 | 6.00 |
| NiSource Inc | NI | 7.00 | 9.00 | - | 9.50 | 5.00 | 3.50 |
| Northwest Natural | NWN | 3.00 | 5.00 | 3.80 | 5.50 | 4.00 | 3.80 |
| ONE Gas Inc | OGS | 5.00 | 7.00 | 5.00 | 6.50 | 5.00 | 5.00 |
| South Jersey Ind | SJI | 5.00 | 8.00 | 4.80 | 11.50 | 6.00 | 4.80 |
| Southwest Gas | SWX | - | - | 4.00 | 9.00 | 6.00 | 4.00 |
| Spire Inc | SR | 5.00 | 7.00 | 7.30 | 10.00 | 4.00 | 7.30 |
| UGI Corp | UGI | 6.00 | 10.00 | 7.70 | 6.00 | 8.00 | 7.70 |

I understand twelve companies constitute a relatively small sample for such an analysis. Nonetheless, the consistency between management guidance and analysts' projections suggests analysts' projected EPS growth rates are proper inputs to the DCF model.

32 Source: Company investor presentations and Annual Reports.
33 Source: Hinton Exhibit 6, Exhibit KWO-2.

**Q. IS THERE EMPIRICAL EVIDENCE THAT INVESTORS WOULD DISREGARD ANALYST ESTIMATES IN EPS GROWTH?**

A. No, there is not. The article, "Do Analyst Conflicts Matter? Evidence from Stock Recommendations," examines whether conflicts of interest with investment banking [IB] and brokerage businesses induced sell-side analysts to issue optimistic stock recommendations and whether investors were misled by such biases. The authors conclude, "Overall, our findings do not support the view that conflicted analysts are able to systematically mislead investors with optimistic stock recommendations."

Agrawal and Chen further state:

> Overall, our empirical findings suggest that while analysts do respond to IB and brokerage conflicts by inflating their stock recommendations, the market discounts these recommendations after taking analysts' conflicts into account. These findings are reminiscent of the story of the nail soup told by Brealey and Myers (1991), except that here analysts (rather than accountants) are the ones who put the nail in the soup and investors (rather than analysts) are the ones to take it out. Our finding that the market is not fooled by biases stemming from conflicts of interest echoes similar findings in the literature on conflicts of interest in universal banking (for example, Kroszner and Rajan, 1994, 1997; Gompers and Lerner 1999) and on bias in the financial media (for examples, Bhattacharya et al. forthcoming; Reuter and Zitzewitz 2006). Finally, while we cannot rule out the possibility that some investors may have been naïve, our findings do not support the notion that the marginal investor was systematically misled over the last decade by analysts' recommendations.[34]

Finally, while Easton and Sommers' article, "Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts" does state that on average, the difference between the estimate of the expected rate of return based on analysts' earnings forecasts and the estimates based on current earnings realizations is 2.84

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[34] Anup Agrawal and Mark A. Chen, *Do Analysts' Conflicts Matter? Evidence from Stock Recommendations*, Journal of Law and Economics, August 2008, Vol. 51.

percent, they also state that analysts' accuracy[35] and optimism[36] in the implied estimates of the expected rate of return differs with firm size:

> …the mean scaled absolute forecast error, a measure of the accuracy of the forecasts, declines monotonically from 0.102 for the decile of smallest firms to 0.012 for the decile of largest firms. Similarly, the median absolute scaled forecast error declines monotonically from 0.042 to 0.006.
>
> Analysts' optimism, measured as the mean (median) scaled forecast error, declines monotonically from -0.075 (-0.023) for the decile of the smallest firms to -0.005 (-0.002) for the decile of the largest firms.[37]

In plain language, as firm size increases, analyst accuracy increases and analyst optimism diminishes. Since the combined proxy group consists of large and mid-cap companies, analyst accuracy should not be a concern.

In view of the above, given the overwhelming academic and empirical support regarding the superiority of security analysts' EPS growth rate forecasts, such EPS growth rate projections should have been relied on by Mr. Hinton in his DCF analysis.

**Q. IN REVIEWING THE FINANCIAL LITERATURE, DID YOU DISCOVER ANY PUBLICATIONS THAT SUPPORTED THE USE OF PROJECTED DPS OR BVPS GROWTH RATES FOR USE IN A DCF MODEL?**

A. No, I did not.

**Q. LIKEWISE, ARE YOU AWARE OF ANY SOURCES OF DATA WHICH PROVIDE PROJECTED DPS OR BVPS GROWTH RATES TO INVESTORS?**

A. *Value Line* is the only widespread, readily available source of which I am aware that

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35 As measured by the mean (median) absolute forecast error.

36 As measured by the mean (median) forecast error.

37 Peter D. Easton and Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, Journal of Accounting Research, Vol. 45 No. 5 (December 2007), at 1007.

publishes projected DPS and BVPS growth rates. If investors indeed valued projected DPS and BVPS growth rates, there would be a market for those data. As they are not relied on by investors to determine their required returns on investments, there is not. Conversely, projected EPS growth rates are widely available to investors.

**Q. WHAT WOULD MR. HINTON'S DCF RESULT BE HAD HE ONLY RELIED ON EPS GROWTH FORECASTS?**

A. As shown on Schedule DWD-4R, the mean DCF derived cost rate based on EPS growth forecasts is 10.1%. This result should be viewed with caution, however, as the DCF model tends to mis-specify the investor-required return, as previously discussed.

**C. <u>Application of the Risk Premium Model</u>**

**Q. PLEASE SUMMARIZE MR. HINTON'S RPM.**

A. Mr. Hinton's RPM estimates the relationship between average allowed equity returns for natural gas utility companies published by Regulatory Research Associates, Inc. ("RRA") and annual average Moody's Investor Service ("Moody's") A-rated utility bond yields. Using data from the years 2007 through 2021, Mr. Hinton conducts a regression analysis, which he then combines with recent monthly yields on Moody's A-rated public utility bonds, to develop his risk premium estimate of 5.29% and a corresponding ROE of 9.50%.

**Q. DO YOU HAVE ANY CONCERNS REGARDING MR. HINTON'S APPLICATION OF THE RPM?**

A. Yes, I do. While I agree with Mr. Hinton's methodology (*i.e.,* regression analysis of historical equity risk premiums), I disagree with his exclusive use of current interest rates and his use of annual average return data instead of individual rate case data.

**Q. DO YOU BELIEVE THAT MR. HINTON SHOULD RELY EXCLUSIVELY ON CURRENT INTEREST RATES IN THE APPLICATION OF HIS RPM?**

A. No. Because both cost of capital and ratemaking are prospective in nature, Mr. Hinton should also consider using projected interest rates in his RPM. The cost of capital, including the cost rate of common equity, is expectational in that it reflects investors' expectations of future capital markets, including an expectation of interest rate levels, as well as future risks. Ratemaking is prospective in that the rates set in this proceeding will be in effect for a period in the future.

Even though Mr. Hinton relies, in part, on projected growth rates in his DCF analyses, noting that growth in the DCF is expected,[38] he fails to apply that logic to selecting an appropriate interest rate in his RPM.

**Q. MR. HINTON STATES THAT HE DOES NOT BELIEVE INTEREST RATE FORECASTS ARE RELIABLE IN DETERMINING THE ROE BECAUSE THEY DO NOT MATERIALIZE AS EXPECTED. PLEASE RESPOND.**

A. Whether Mr. Hinton believes those forecasts will prove to be accurate is irrelevant to estimating the market-required cost of common equity. Published industry forecasts, such as *Blue Chip Financial Forecasts*' ("*Blue Chip")* consensus interest rate projections, reflect industry expectations. Additionally, investors' expectations are not improper inputs to cost of common equity estimation models simply because prior projections were not proven correct in hindsight. As the Federal Energy Regulatory Commission ("FERC") noted in Opinion No. 531, "the cost of common equity to a regulated enterprise depends

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[38] Hinton Direct Testimony, at 29.

upon what the market expects, not upon what ultimately happens."[39] Because our analyses are predicated on market expectations, the expected increase in bond yields is a measurable, observable, and relevant data point that should be reflected in Mr. Hinton's analysis. Therefore, Mr. Hinton should have used forecasted interest rates in his analysis.

**Q. ARE CURRENT INTEREST RATES ACCURATE PREDICTORS OF FUTURE INTEREST RATES?**

A. No, they are not. Current interest rates are not proven to be a better predictor of future interest rates. In Chart 2 (below) I compare actual monthly yields to the three-month yield average from 12 months prior. This chart demonstrates that current Treasury yields have not been accurate predictors of future yields. Those results make intuitive sense. With the recent market dislocation, Treasury yields have decreased significantly and have been volatile. As interest rates decreased, historical Treasury yields over-projected current yields. As interest rates subsequently increased, the opposite was true.

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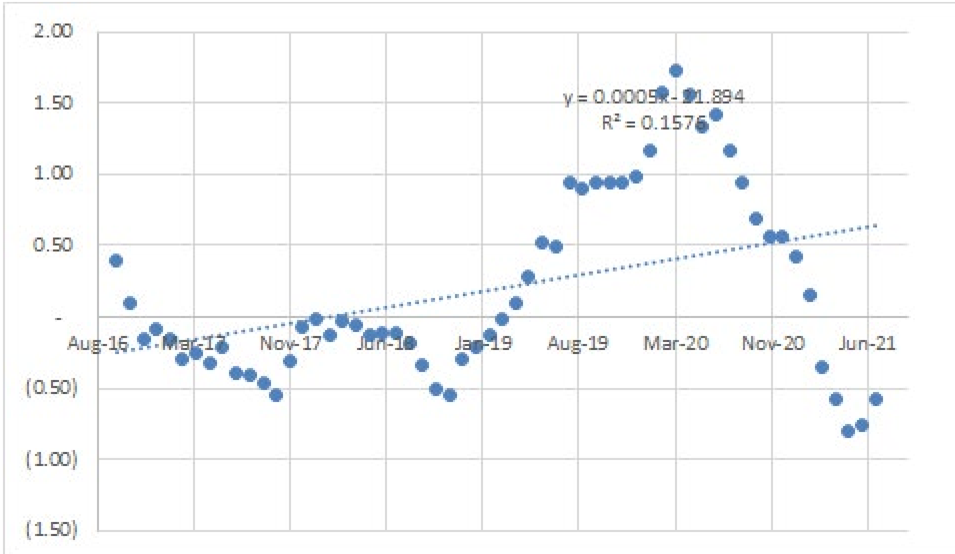
[39] Opinion No. 531, 150 FERC ¶ 61,165 at P 88.

**<u>Chart 2: Forecast Error of Three-Month Average Treasury Yields</u>**[40]




**Q. DO YOU AGREE WITH MR. HINTON'S USE OF ANNUAL AUTHORIZED RETURNS AND INTEREST RATE DATA IN HIS RPM?**

A. No, I do not. Instead of using yearly average authorized returns and Moody's A-rated public utility bond yields, it is preferable to use the authorized returns and Moody's A-rated public utility bond yields on a case-by-case basis. One reason why one should use individual cases instead of an annual average is that some years have more rate case decisions than others, and years with less rate case decisions will garner unnecessary weight. Another reason to use individual cases over an annual average is that interest rates and market conditions change during the year (*e.g.* the beginning and end of 2008), if one uses annual average authorized returns and annual average interest rates, the fluctuation between the interest rates and equity risk premiums during the year are lost.

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40 Source: Federal Reserve Schedule H.15.

**Q. WHAT IS THE RESULT OF THE REGRESSION ANALYSIS AFTER REFLECTING A PROSPECTIVE MOODY'S A-RATED PUBLIC UTILITY BOND YIELD AND USING INDIVIDUAL RATE CASE DATA IN PLACE OF ANNUAL RATE CASE DATA?**

A. As shown on page 1 of Schedule DWD-5R, the analysis is based on a regression of 188 rate cases for natural gas utility companies from January 5, 2007 through July 30, 2021. It shows the implicit equity risk premium relative to the yields on Moody's A-rated public utility bonds immediately prior to the issuance of each regulatory decision.[41]

I determined the appropriate prospective Moody's A-rated public utility yield by relying on a consensus forecast of about 50 economists of the expected yield on Moody's Aaa-rated corporate bonds for the six calendar quarters ending with the third calendar quarter of 2022, and *Blue Chip's* long-term projections for 2023 to 2027, and 2028 to 2032.[42] As described on page 12 of Schedule DWD-1R, the average expected yield on Moody's Aaa-rated corporate bonds is 3.48%. I then derived an expected yield on Moody's A2-rated public utility bonds, by making an upward adjustment of 0.38%, which represents a recent spread between Moody's Aaa-rated corporate bonds and Moody's A2-rated public utility bonds.[43] Adding the recent 0.38% spread to the expected Moody's Aaa-rated corporate bond yield of 3.48% results in an expected Moody's A2-rated public utility bond yield of 3.86%.

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[41] If the Order was in the first half of the month, the Moody's A-rated utility bond from two months prior would be used. If the Order was in the second half of the month, the Moody's A-rated public utility bond from the last prior month was used.

[42] *Blue Chip Financial Forecasts*, August 3, 2021, at 2, June 1, 2021, at 14.

[43] As explained on page 12 of Schedule DWD-1R.

I then used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds of 3.86%. Given the expected Moody's A-rated utility bond yield of 3.86%, the indicated equity risk premium is 5.86%, which results in an indicated ROE of 9.72%, as shown on Schedule DWD-5R. Also shown on Schedule DWD-5R, using Mr. Hinton's current bond yield, the indicated ROE using the RPM is 9.60%.

**D. Application of the Comparable Earnings Model**

**Q. PLEASE DESCRIBE MR. HINTON'S CEM ANALYSIS**

A. Mr. Hinton examined five years of historical earned returns on equity for his natural gas proxy groups and arrived at a 10.0% average and 9.5% median indicated equity return.[44] Mr. Hinton did not rely on the results of this data for his recommended ROE, but only as a check on his DCF and RPM.[45] I would note that his average ROE using his CEM is in excess of 50 basis points over his recommended ROE of 9.42%.

**Q. DO YOU HAVE ANY COMMENT ON THE PROXY GROUPS MR. HINTON USED IN HIS CEM ANALYSIS?**

A. Yes. Mr. Hinton used his natural gas proxy group in his CEM analysis.[46] Any proxy group selected for a CEM analysis should be broad-based in order to obviate company-specific aberrations and should exclude utilities to avoid circularity. Since the achieved returns on book common equity of utilities is a function of the regulatory process itself, they are substantially influenced by regulatory return on common equity awards. Therefore, the

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44 Hinton Direct Testimony, at Public Staff Hinton Exhibit 8.
45 *Ibid*., at 38.
46 *Ibid*.

achieved ROEs of utilities are not representative of the returns that could be earned in a truly competitive market. Hence, Mr. Hinton's use of his gas proxy group utilities in his CEM analysis is a circular exercise. Additionally, as previously discussed, the cost of capital and ratemaking are expectational in nature and, as such, need to use projected data. As shown in Schedule DWD-6R, average and median projected earned returns for Mr. Hinton's proxy group are 10.35% and 10.50%, respectively.

**E. <u>Conclusion of Hinton Adjusted Results</u>**

**Q. WHAT ARE THE RESULTS OF MR. HINTON'S ROE MODELS AFTER MAKING THE ADJUSTMENTS DESCRIBED TO HIS DCF, RPM, AND CEM?**

A. As shown in Table 4, below, Mr. Hinton's adjusted results are as follows:

**<u>Table 4: Mr. Hinton's Adjusted ROE Model Results</u>**

| Model | **Range** | **Midpoint** |
|---|---|---|
| Discounted Cash Flow | 10.10% | 10.10% |
| Risk Premium Model | 9.60% - 9.72% | 9.66% |
| Comparable Earnings Model | 10.35% - 10.50% | 10.43% |
| Average | 9.60% - 10.50% | 10.06% |

Using the midpoints of Mr. Hinton's adjusted RPM and CEM, the average of his adjusted results is 10.06%, which does not reflect flotation costs.

**Q. DOES MR. HINTON INCLUDE FLOTATION COSTS IN HIS RECOMMENDED ROE?**

A. It does not appear so. As stated in my Direct Testimony, flotation costs should be included in an ROE recommendation because they are not reflected in any of the ROE model results.[47] Adding my flotation cost adjustment of 0.11% to Mr. Hinton's adjusted average model result of 10.06% results in a Company-specific ROE of 10.17%, which is within my recommended range of ROEs and similar to my ultimate ROE recommendation of 10.25%.

**Q. MR. HINTON JUSTIFIES HIS RECOMMENDED ROE OF 9.42% BY REVIEWING THE INTEREST COVERAGE RATIO AND CONFIRMING THAT HIS ROE WOULD ALLOW THE COMPANY A SINGLE "A" RATING.[48] DOES ONE MEASURE OF FINANCIAL RISK SUCH AS PRE-TAX INTEREST COVERAGE INDICATE A SPECIFIC CREDIT RATING?**

A. No. While I do not take issue with Mr. Hinton's inputs or calculations in determining Piedmont's pre-tax interest coverage ratio, I note that the ratios of pre-tax coverage needed to qualify for a single "A" rating range from 3.0 to 6.0. As can be seen in Schedule DWD-7R, ROE's ranging from as low as 5.76% to as high as 14.55% all allow Piedmont to qualify for a single "A" rating based on its pre-tax coverage ratio. Clearly a significantly large range of results indicates that simply relying on a single measure, out of a multitude of measures reviewed by the bond/credit ratings agencies, to determine a company's bond rating is without significance.

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[47] D'Ascendis Direct Testimony, at 50-51.
[48] Hinton Direct Testimony, at 39.

**F. <u>Consideration of Mechanisms in Place for Piedmont</u>**

**Q. MR. HINTON DISCUSSES THE COMPANY'S INTEGRITY MANAGEMENT RIDER AND MARGIN DECOUPLING TRACKER MECHANISMS THAT HE CLAIMS IMPACT RISK FOR PIEDMONT.[49] IS HIS CLAIM VALID?**

A. No. The cost of capital is a comparative exercise, so if the mechanism is common throughout the companies that one bases their analyses on, the comparative risk is zero, because any impact of the perceived reduced risk of the mechanism(s) by investors would be reflected in the market data of the proxy group. To that point, as shown on Schedule DWD-8R, ten of the eleven companies in Mr. Hinton's proxy group have a capital investment rider and ten of his eleven proxy group companies have a decoupling mechanism in at least one of their jurisdictions.

**Q. DOES MR. HINTON DISCUSS THE COMMONALITY OF DECOUPLING MECHANISMS FOR GAS UTILITIES IN OTHER CASES?**

A. Yes, he does. In Docket No. W-2018, Sub 526 concerning Aqua North Carolina, Inc., Mr. Hinton states:

> In North Carolina, Piedmont Natural Gas Company, Inc.'s Consumption Utilization Tracker program was first approved in Docket G-9, Sub 499, and later renamed Margin Decoupling Tracker (MDT), and Public Service of North Carolina, Inc. has a similar program which has worked to help stabilize its earnings.
>
> However, in those rate proceedings where the trackers were approved, there was no explicit recognition of the decrease in the Company's business risk in those proceedings or subsequent proceedings, indicating that any direct benefit to customers was lost. This was, in part, due to the face that similar trackers were in operation with various other LDCs, and an argument could

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49 *Ibid.*, at 40.

> be made the risk reduction was somewhat captured in the market prices of the Company's common stock.[50]

This statement echoes my response in the previous question. Our agreement on the issue should lead the Commission to the conclusion that any risk reduction due to Piedmont's mechanisms are already reflected in the market data of the proxy group.

### G. Response to Staff Witness Hinton's Criticisms of Company Analysis

**Q. DOES MR. HINTON HAVE ANY CRITICISMS OF YOUR DIRECT TESTIMONY?**

A. Yes. Mr. Hinton has concerns regarding my exclusive use of projected EPS growth rates in my DCF model analysis and that one of the expected returns used in my CAPM calculation was "unsustainable".[51] I have already discussed the superiority of using projected EPS growth rates in the DCF model and will not repeat that discussion here.

**Q. MR. HINTON STATES THAT YOUR EXPECTED MARKET RETURN ESTIMATE DERIVED FROM BLOOMBERG FINANCIAL SERVICES ("BLOOMBERG") INFLATES YOUR MARKET RISK PREMIUM. PLEASE RESPOND.**

A. I disagree with Mr. Hinton's statement. The implied expected market returns using Bloomberg data is only one out of six measures. The average implied market return for my Direct (12.73%) and Rebuttal (12.62%) Testimonies represent the approximately 48th percentile of actual returns observed from 1926 to 2020, as shown on Exhibit DWD-9R. As discussed previously, multiple measures gives greater insight into the investor-required

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50 Docket No. W-218, Sub 526, Hinton Direct Testimony, at 32-33.
51 Hinton Direct Testimony, at 48.

return than a limited number of measures. The average implied market return for my Direct and Rebuttal Testimonies of 12.73% and 12.62%, respectively, are comparable to the average historical market return of approximately 12.20%.

**Q. DOES MR. HINTON RELY ON ANY EXTERNAL SOURCES TO SUPPORT HIS ASSERTION THAT YOUR BLOOMBERG EXPECTED MARKET RETURN IS UNSUSTAINABLE?**

Yes, he does. Mr. Hinton refers to a Morningstar survey of professional investment advisors that expect "lower future market returns on equity of 5% to 8%."[52] My review of that survey revealed that many of the estimates are "more immediate term than they are long".[53] As stated in my Direct Testimony, the holding period returns used in calculating equity risk premiums for estimating the ROE should be as long as possible to be commensurate with an investment in a company expected to operate in perpetuity.[54] As a result, I do not agree that the expected returns by investment houses referred to by Mr. Hinton are applicable in estimating the Company's ROE.

**Q. WHAT IS THE RELATIONSHIP BETWEEN EXPECTED RETURNS BY INVESTMENT FUNDS AND REQUIRED/ALLOWED ROE?**

A. Expected returns from pension funds or investment houses are not the same as the ROE (otherwise known as required returns). Expected returns from pension funds or investment houses are expecting what the particular utility's earned return will be. Because utilities generally do not earn their authorized returns, investor-expected returns are less than

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52 *Ibid.*, at 48-49.
53 Public Staff Hinton Exhibit 10, at 2.
54 D'Ascendis Direct Testimony at 27.

investor-required returns. For example, a benefit plan asset manager will match the **expected returns** available from various asset classes to the expected liabilities that must be funded. An investor seeking to maximize their risk-adjusted return will only invest in a security if the expected return is equal to or greater than the **required return**. Because expected returns may or may not equal required returns, we should not assume pension funding assumptions (that is, expected returns) may be viewed as a measure of investors' required returns.

Benefit plan managers develop asset allocation and investment decisions based on expected risks and returns for various asset classes and are subject to the investment objective or expected timing and nature of the liabilities being funded by those investments. In the U.S., they must consider: (1) the diversification of the portfolio; (2) the liquidity and current return of the portfolio relative to the expected cash flow requirements under the plan; (3) the portfolio's projected return relative to the plan's funding objective; and (4) the return expected on alternative investments with similar risks.[55] Pension asset managers, therefore, are concerned with investing funds at an expected return to meet expected liabilities.

Widely used finance texts recommend the use of multiple models in estimating the cost of equity, in particular the DCF, CAPM, and RPM. To determine whether the use of broad market expected returns for the purposes of pension asset management also is an approach recommended by finance texts, I reviewed articles published in financial journals, as well as additional texts that speak to the methods used by analysts to estimate the cost

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55 29 CFR 2509.908-1, Interpretive Bulletin Relating to Investing in Economically Targeted Investments, October 17, 2008.

of equity. An article published in Financial Analysts Journal surveyed financial analysts to determine the analytical techniques that are used in practice.[56] Regarding stock price valuation and cost of capital estimation, the author asked respondents to comment only on the DCF, CAPM, and Economic Value-Added models. Nowhere in that article did the author consider asking whether surveys of expected returns or pension fund assumptions are relevant to the determination of the ROE, the subject of this proceeding.

Additionally, I note that the 8% to 10% expected long-term market returns referenced on page 2 of Mr. Hinton's Exhibit 10 can be assumed to be geometric mean returns, as geometric means are generally used by investment houses to discuss past performances. As shown on page 6-17 of Duff & Phelps 2021 SBBI® Yearbook Stocks, Bonds, Bills and Inflation ("SBBI–2021"), the long-term geometric mean return of approximately 10.00% converts to an approximate 12.00% long-term arithmetic mean return.

## V. RESPONSE TO CUCA WITNESS O'DONNELL

**Q. PLEASE PROVIDE A SUMMARY OF MR. O'DONNELL'S TESTIMONY AND RECOMMENDATION.**

A. Mr. O'Donnell recommends an ROE of 9.00%,[57] which is based on the upper end of his DCF model results, which range from 7.50% to 9.50%.[58] Mr. O'Donnell also calculates a CEM and CAPM as checks on his DCF model results, which produced ROE estimates

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

[57] O'Donnell Direct Testimony, at 4.

[58] *Ibid.*, at 69.

ranging from 9.00% to 10.00% for his CEM and 6.00% to 8.00% for his CAPM.[59] Mr. O'Donnell exclusively relies on his DCF model results based on his opinion that the DCF model is superior to all other ROE models.[60]

**Q. PLEASE SUMMARIZE THE REMAINING AREAS IN WHICH YOU DISAGREE WITH MR. O'DONNELL'S ROE ANALYSES, METHODS, AND CONCLUSIONS?**

A. My remaining areas of disagreement with Mr. O'Donnell's analysis are as follows: (1) the interpretation of capital market conditions; (2) his proxy group selection; (3) his consideration of growth rates other than the expected EPS growth rate for his DCF model analysis; (4) his use and miscalculation of the sustainable growth rate; (5) the applicability of the CEM; (6) his application of the CAPM; and (7) his failure to reflect flotation costs.

**A. <u>Capital Market Conditions</u>**

**Q. DO YOU AGREE WITH MR. O'DONNELL THAT UTILITIES ARE "A SAFE HARBOR" DURING PERIODS OF MARKET UNCERTAINTY?[61]**

A. No, I do not. I have studied the relative performance and annualized volatilities of groups of utilities and market indices to gauge whether utilities weathered the COVID-19 pandemic better than the overall market. As shown on Schedule DWD-10R and Table 5, below, from February 1, 2020 to July 30, 2021, contrary to Mr. O'Donnell's opinion, the combined proxy group (including all companies considered by the witnesses in this proceeding) and other groups of utilities were more volatile (i.e. riskier) than the market

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[59] *Ibid.*
[60] *Ibid.,* at 41.
[61] *Ibid*., at 9.

indices and underperformed both the Dow Jones Industrial Average and Standard & Poor's ("S&P") 500.

**Table 5: Annualized Volatility and Returns of Utility Groups and Market Indices February 2020 – July 2021[62]**

| | Proxy Group | Dow Jones Utility Average (DJU) | Utilities Select SPDR (XLU) | Dow Jones Industrial Average | S&P 500 |
|---|---|---|---|---|---|
| **Price Change** | -6.44% | -3.54% | -4.67% | 23.01% | 35.28% |
| **Annualized Volatility** | 44.80% | 33.12% | 33.13% | 30.95% | 29.28% |

Table 5, above, shows that while markets in general have recovered from the market downturn, utilities have not.

**Q. MR. O'DONNELL REFERS TO SEVERAL RECENT REPORTS BY S&P CONCLUDING THAT THE CURRENT OUTLOOK FOR REGULATED UTILITIES IS STABLE.[63] DO YOU AGREE?**

A. No, I do not. Although Mr. O'Donnell's review of recent articles from S&P seems to suggest that the outlook for regulated utilities is stable, a closer look reveals that not to be the case. For example, in January of this year S&P noted:

> Many rate case filings were delayed, rate case orders often took longer than expected, and many orders were below expectations.
>
> ***
>
> During the year, the utility industry performed poorly from a credit quality perspective. The negative outlooks or CreditWatch negative listings doubled and downgrades outpaced upgrades for the first time in a decade

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62 Source: S&P Global Market Intelligence.

63 O'Donnell Direct Testimony, at 11-12.

by about 7 to 1.[64]

Clearly, the outlook for regulated utilities is less stable than Mr. O'Donnell assumes.

**Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S REVIEW OF UNEMPLOYMENT RATES?**

A. Regarding the unemployment rate, Mr. O'Donnell's cited unemployment rate of 6.77% in Q4 2020 dropping to 5.93% in Q2 2021 is accurate, but he is comparing that unemployment rate with the pre-pandemic unemployment rate of 3.67%, which was the lowest unemployment rate for 50 years.[65] The average American unemployment rate is 5.80% over the period 1948-present,[66] which is comparable to the unemployment rate of 5.93% in Q2 2021.

**Q. MR. O'DONNELL DISCUSSES INFLATION STATING THAT IT "IS TOO EARLY TO PREDICT WHETHER THE UNITED STATES ECONOMY WILL SERIOUSLY SUFFER PERMANENTLY IN THE LONG TERM DUE TO RISING PRICES."[67] PLEASE RESPOND.**

A. On August 27, 2020, Federal Chairman Powell released a statement noting that the Federal Open Market Committee will adopt an approach towards inflation that "could be viewed as a flexible form of average inflation targeting"; meaning that following periods in which

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64 S&P Global Ratings, RatingsDirect, *North American Regulated Utilities' Negative Outlook Could See Modest Improvement*, January 20, 2021, at 1.

65 Source: Bureau of Labor Statistics.

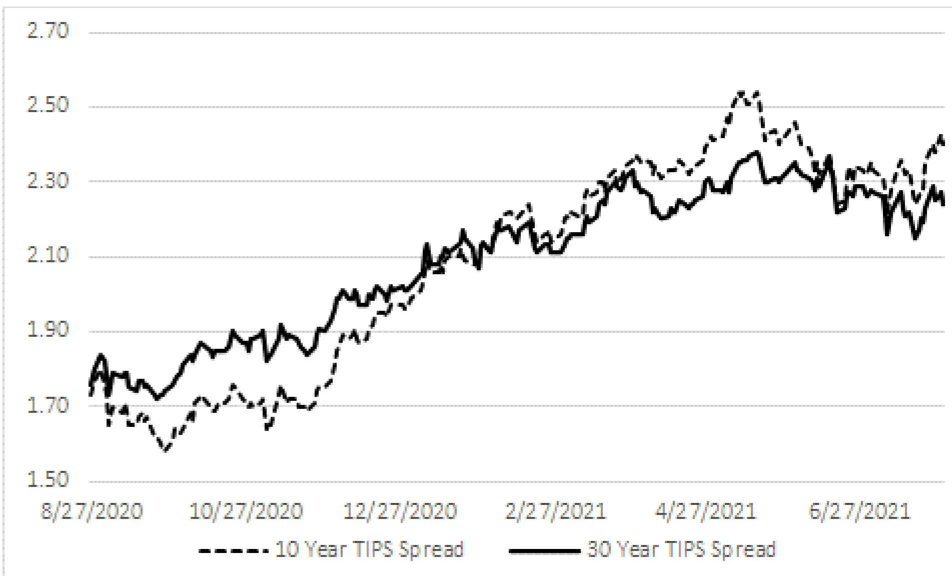
66 Source: Bureau of Labor Statistics dating back to January 1948.

67 O'Donnell Direct Testimony, at 18-19.

inflation has run below 2.00%, "appropriate monetary policy will likely aim to achieve inflation moderately above 2 percent for some time."[68]

Since Mr. Powell's remarks, the breakeven inflation rate, represented as the ten-year and 30-year Treasury Inflation-Protected Securities spread, has increased from 1.73% and 1.76%, respectively, to 2.33% and 2.19% respectively, as of July 30, 2021. Further, as shown in Chart 3 below, breakeven inflation has trended upward since the Federal Reserve's policy change at a relatively consistent pace.

**Chart 3: Breakeven Inflation Since August 27, 2020[69]**




Further, the Consumer Price Index ("CPI") June 2021 monthly increase (0.9%) was the largest monthly increase since June 2008 (1.0%), and the year-over-year increase (5.4%) was the highest it has been since August 2008 (also 5.4%).[70] There is little proof

68 *New Economic Challenges and the Fed's Monetary Policy Review*, Remarks by Jerome H. Powell, Chair Board of Governors of the Federal Reserve System, August 27, 2020.

69 Source: Federal Reserve (https://www.federalreserve.gov/datadownload/)

70 U.S. Bureau of Labor Statistics, Economic News Release, Consumer Price Index Summary – June 2021.

that the current inflationary environment is indeed transitory (one could only judge the period as transitory after it is concluded) so it should be considered at face value.

**Q. IS INFLATION STRONGLY RELATED TO INTEREST RATES?**

A. Yes, it is. Generally, when inflation is increasing, central banks will attempt to raise interest rates by reducing bond buying programs or increasing their interbank offered rates in an attempt to keep inflation at target levels (a long-term average of 2.00%, as noted above). Over the period 1947-2020, the relationship between inflation, as measured by the year-over-year change in the CPI and interest rates had a 0.63 correlation coefficient, showing a strong positive relationship, which is statistically significant.

**Q. IS THERE A LINK BETWEEN INFLATION AND AUTHORIZED ROES?**

A. Yes, there is. Looking at the yearly growth in the CPI and the corresponding authorized ROEs for natural gas utilities, I calculated a correlation of 0.73. In addition, I found the relationship between the two variables to be statistically significant.

## B. Proxy Group Selection

**Q. PLEASE DESCRIBE THE SCREENING CRITERIA BY WHICH MR. O'DONNELL DEVELOPED HIS PROXY GROUP.**

A. Mr. O'Donnell does not screen for comparability of the *Value Line* gas utility group and includes all ten gas distribution utilities covered by *Value Line* in his proxy group.[71]

**Q. DO YOU AGREE WITH MR. O'DONNELL'S PROXY GROUP?**

A. No. Chesapeake Utilities and UGI Corporation have significant operations in activities other than natural gas distribution services. This is illustrated in Table 6, below:

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[71] O'Donnell Direct Testimony, at 23.

**Table 6: Percent of 2019 Net Operating Income and Assets Attributable to Gas Distribution Operations of the Combined Proxy Group**[72]

| | Net Oper. Income | Total Assets |
|---|---|---|
| Atmos Energy Corporation | 63.02% | 79.32% |
| **Chesapeake Utilities Corporation** | **38.57%** | **39.82%** |
| New Jersey Resources Corporation | 87.58% | 70.07% |
| NiSource Inc. | 75.83% | 62.77% |
| Northwest Natural Holding Company | 94.73% | 95.91% |
| ONE Gas, Inc. | 100.00% | 100.00% |
| South Jersey Industries | 98.14% | 87.03% |
| Southwest Gas Holdings, Inc. | 79.90% | 83.22% |
| Spire, Inc. | 97.06% | 67.72% |
| **UGI Corporation** | **34.57%** | **25.98%** |

This table shows that Chesapeake Utilities and UGI Corp. are not valid comparators to Piedmont at this time and should be eliminated.

**Q. HAS MR. O'DONNELL CONSIDERED THE ANALYTICAL RESULTS OF ANY OTHER COMPANIES TO SET HIS RECOMMENDED ROE?**

A. Yes. In addition to his proxy group comprised of natural gas utilities, Mr. O'Donnell also estimates his analytical models based on market data for Duke Energy, Piedmont's ultimate parent.

**Q. IS IT REASONABLE TO ESTIMATE THE ROE FOR PIEDMONT BASED ON THE ANALYTICAL RESULTS OF DUKE ENERGY?**

A. No, it is not. Although Mr. O'Donnell states Duke Energy, "provides the most directly observable link between any company within the comparable proxy group and Piedmont,"

72 SEC Form 10-K.

there are several issues with that conclusion. First, Piedmont represents only 5% of Duke Energy based on assets. Second, although Duke Energy has natural gas distribution operations, a majority of its operating income and assets are related to its electric operations. In 2020, approximately 87.5% of Duke Energy's operating income came from its electric operations, and approximately 85.1% of its assets were related to its electric operations. It is for that reason that *Value Line* includes Duke Energy in its Electric Utility group. As such, it is inappropriate to assume that Duke Energy faces comparable risk to Piedmont based solely on the fact that Piedmont is a subsidiary of Duke Energy. To that point, none of the witnesses in this proceeding have included electric utilities in their proxy groups. Because Duke Energy fails the comparable risk standard, the results of Mr. O'Donnell's analyses using Duke Energy-specific data should be given no weight.

**C. <u>DCF Analysis</u>**

**Q. PLEASE SUMMARIZE MR. O'DONNELL'S APPLICATION OF THE CONSTANT GROWTH DCF MODEL.**

A. Mr. O'Donnell calculates his dividend yield based on the one-week, four-week and 13-week expected dividend yield as provided by *Value Line Summary & Index* for the period April 16, 2021 through July 9, 2021.[73] For the growth component of his Constant Growth DCF model, Mr. O'Donnell reviews a number of growth rates, including historical and projected DPS, BVPS, and EPS growth rates as reported by *Value Line*; analysts' consensus EPS growth rate projections from the Center for Financial Research ("CFRA") and Charles Schwab & Co.[74]; and an estimate of the "plowback" growth rate also known

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73 O'Donnell Direct Testimony, at 45.
74 *Ibid.*, at 49.

as the "Sustainable Growth" or "Retention Growth" derived from data provided by *Value Line*.[75] Mr. O'Donnell concludes that his DCF model produces an ROE in the range of 7.5% to 9.5%.[76]

**Q. DO YOU AGREE WITH MR. O'DONNELL THAT HISTORICAL GROWTH RATES, OR DIVIDEND AND BOOK VALUE GROWTH RATES, ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?**[77]

A. No, I do not. As discussed in my response to Mr. Hinton, there is a significant body of empirical evidence supporting the superiority of analysts' EPS growth rates in a DCF analysis, indicating that analysts' forecasts of EPS remain the best predictor of growth to use in the DCF model.

**Q. DO YOU AGREE WITH MR. O'DONNELL'S CONSIDERATION OF SUSTAINABLE GROWTH RATES IN HIS CONSTANT GROWTH DCF ANALYSIS?**

A. No. As Morin explains, there are inherent weaknesses in using sustainable growth rates in the DCF model.[78] Specifically, Mr. O'Donnell's methodology is inherently circular because: (1) it relies on an expected ROE on book common equity; (2) that expected ROE on book common equity is then used in a DCF analysis to establish an ROE cost rate related to the market value of the common stock; and (3) that market-related ROE, if authorized

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75 *Ibid*.
76 *Ibid*., at 55.
77 *Ibid*., at 52-53.
78 *Ibid*., at 306-307.

as the allowed ROE in this proceeding, becomes the expected ROE on book common equity.

Put simply, the estimated ROEs Mr. O'Donnell used to derive his sustainable growth rate become the regulatory outcome of this proceeding, even as those ROEs are themselves based on regulatory outcomes.

**Q. HAVE YOU REVIEWED INDEPENDENT SOURCES FOR DISCUSSION OF THE USE OF SUSTAINABLE GROWTH FOR ROE ESTIMATION?**

A. Yes. Morin discusses the sustainable growth model and shows that it relies on knowledge of several factors, including:

- "b": the fraction of earnings per share retained;
- "r": the rate of return on equity (ROE);
- "s": the growth rate in common equity due to the sale of stock; and
- "v": the fraction of a stock sale that increases existing book value.

Specifically, Morin states the following:

> There are three problems in the practical application of the sustainable growth method. The first is that it may be even more difficult to estimate what b, r, s and v investors have in mind than it is to estimate what g they envisage. It would appear far more economical and expeditious to use available growth forecasts and obtain g directly instead of relying on four individual forecasts of the determinants of such growth. *It seems only logical that the measurement and forecasting errors inherent in using four different variables to predict growth far exceed the forecasting error inherent in the direct forecast of growth itself.*
>
> Second, there is a potential element of circularity in estimating g by a forecast of b and ROE for the utility being regulated, since ROE is determined in large part by regulation. To estimate what ROE resides in the minds of investors is equivalent to estimating the market's assessment of the outcome of regulatory hearings. Expected ROE is exactly what regulatory commissions set in determining an allowed rate of return. In other words, the method requires an estimate of return on equity before it

> can even be implemented. Common sense would dictate the inconsistency of a return on equity recommendation that is different than the expected ROE that the method assumes the utility will earn forever. For example, using an expected return on equity of 11% to determine the growth rate and using the growth rate to recommend a return on equity of 9% is inconsistent. It is not reasonable to assume that this regulatory utility company is expected to earn 11% forever, but recommend a 9% return on equity. The only way this utility can earn 11% is that rates be set by the regulator so that the utility will, in fact, earn 11%....
>
> Third, the empirical finance literature discussed earlier demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock price and price/earnings ratios, as other historical measures or analysts' growth forecasts. *Other proxies for growth such as historical growth rates and analysts' growth forecasts outperform retention growth estimates*. (emphasis added)[79]

**Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE USE OF THE SUSTAINABLE GROWTH RATE AS A MEASURE OF LONG-TERM GROWTH?**

A. Yes. The sustainable growth rate assumes increasing retention ratios necessarily are associated with increasing future growth. The underlying premise is that future earnings will increase as the retention ratio increases. That is, if future growth is modeled as "b x r" (where "b" is the retention ratio and "r" is the earned return on book equity), growth will increase as "b" increases. There are several reasons, however, why that may not be the case. Consequently, it is appropriate to determine whether the data supports the assumption that higher earnings retention ratios necessarily are associated with higher future earnings growth rates.

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[79] Morin, at 306-307.

**Q. DOES INDEPENDENT RESEARCH SUPPORT THE FINDING THAT FUTURE EARNINGS AND THE RETENTION RATIO ARE NOT POSITIVELY RELATED?**

A. Yes. In 2006, for example, two articles in Financial Analysts Journal addressed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[80] Both articles cite a 2003 study by Arnott and Asness,[81] who found that over the course of 130 years of data, future earnings growth is associated with high, rather than low, payout ratios.[82] In essence, the findings of all three studies found that there is a negative, not a positive, relationship between the two.

**Q. DO YOU AGREE WITH MR. O'DONNELL'S SPECIFICATION OF THE SUSTAINABLE GROWTH RATE?**

A. No, I do not. Not only do I disagree with Mr. O'Donnell's use of the Sustainable Growth Rate, I also do not agree with his form of the model. The full form of the model assumes growth is a function of its expected earnings, and the extent to which it retains earnings to invest in the enterprise. The form of the model on which Mr. O'Donnell relies is its simplest form, which defines growth solely as a function of internally generated funds.

If Mr. O'Donnell is going to consider a form of Sustainable Growth, he should use the "br + sv" form of the model, which reflects growth both from internally generated funds

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80 *See,* Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See also,* Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 7, 2006.

81 *See,* Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

82 Because the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

(*i.e.*, the "br" term) and from issuances of equity (*i.e.*, the "sv" term). As noted above, the first term is the product of the retention ratio (*i.e.*, "b", or the portion of net income not paid in dividends) and the expected ROE (*i.e.*, "r"), which represents the portion of net income that is "plowed back" into the company as a means of funding growth. The "sv" term is represented as:

$$\left(\frac{m}{b} - 1\right) x \text{ Common shares growth rate}$$

where $\frac{m}{b}$ is the M/B ratio. In that form, the "sv" term reflects an element of growth as the product of: (1) the growth in shares outstanding, and (2) that portion of the M/B ratio that exceeds unity.

**Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE GROWTH RATES FOR THE CONSTANT GROWTH DCF MODEL?**

A. Based on the analyses and research noted above and in my response to Mr. Hinton, I conclude projected EPS growth rates are the appropriate measure of growth in the Constant Growth DCF model.

**Q. WHAT ARE MR. O'DONNELL'S GROWTH RATE RANGE AND INDICATED DCF MODEL RESULTS USING PROJECTED EPS GROWTH RATES?**

A. As shown in Schedule DWD-11R, I calculated the individual DCF results of each of Mr. O'Donnell's proxy companies using his three measures of the dividend yield and the average of his three EPS projected growth rates from *Value Line*, CFRA, and Charles Schwab. That analysis indicates average DCF results of 9.51% to 9.57%.

**D. Comparable Earnings Model**

**Q. PLEASE SUMMARIZE MR. O'DONNELL'S CEM.**

A. Mr. O'Donnell performs two forms of the CEM. His first method reviews the historical and forecast earned returns om book value from *Value Line* for his proxy group for the years 2019 through 2021 and the three- to five-year forecast. The results of Mr. O'Donnell's first CEM range from 9.20% to 9.70%.[83] For Mr. O'Donnell's second CEM he calculates the annual average authorized returns for natural gas utilities since 2006. Based on those analyses he estimates a range of results from 9.00% to 10.00%.[84]

**Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S FIRST METHOD?**

A. While I appreciate that Mr. O'Donnell used projected data in calculating his CEM, as discussed in my response to Mr. Hinton, the CEM analysis should be based on a broad group of comparable companies, and not utilities as Mr. O'Donnell has done. As such, I do not agree with Mr. O'Donnell's application of the CEM.

**Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S SECOND METHOD?**

A. Although Mr. O'Donnell suggests that "regulated ROE's have trended down over the past 15 years,"[85] he fails to note that, as shown on his Chart 5, since 2013 authorized returns for natural gas utilities have been relatively stable. In fact, authorized returns through July 30, 2021 averaged 9.60%, which is similar to the average authorized returns in 2013 through 2019, and 14 basis points above the 2020 average.

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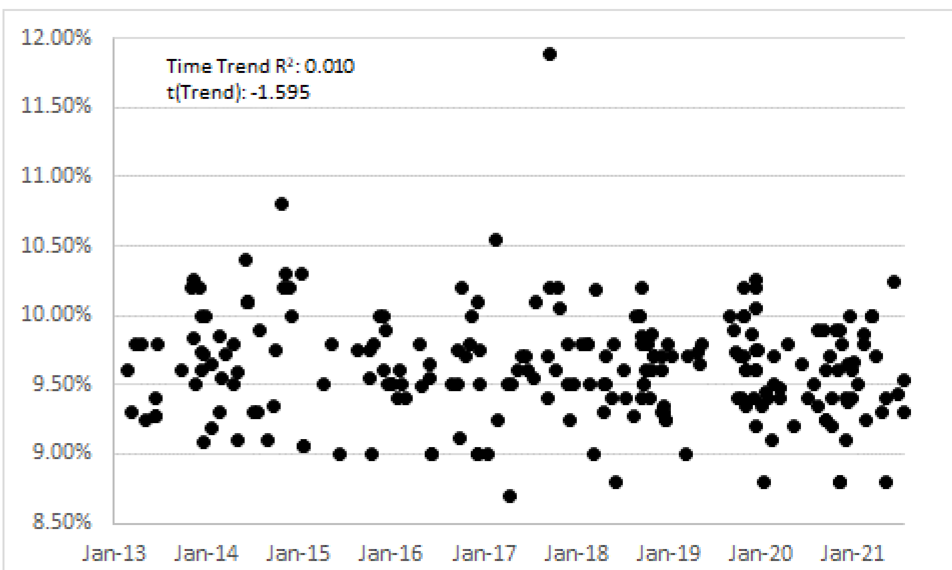
83 O'Donnell Direct Testimony, at 56.
84 *Ibid.*, at 58.
85 *Ibid.*, at 57.

More importantly though, average annual data obscures variations in returns and does not address the number of cases nor the jurisdictions issuing orders within a given year. For example, one year may have fewer cases decided, and a relatively large portion of those cases decided by a single jurisdiction. As shown in Chart 4, below, if all individual authorized ROEs are charted, rather than annual averages, there is no meaningful trend since 2013. Rather, time explains approximately 1% of the change in ROEs, and the trend variable is statistically insignificant. Mr. O'Donnell's reference to the trend in annual averages inaccurately suggests authorized returns have trended downward recently, when they have not.

**Chart 4: Natural Gas Authorized Returns (2013-2021)**[86]

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86 Source: Regulatory Research Associates. Excludes limited issue rate riders. Based on data through July 30, 2021.

From a slightly different perspective, the recent fluctuations around the annual average authorized return data are well within the standard deviation of authorized ROEs, as shown in Table 7, below.

**Table 7: Mean, Median, and Standard Deviation of Authorized Returns (2013-2021)[87]**

| Year | Average | Median | Standard Deviation |
|---|---|---|---|
| 2013 | 9.68% | 9.72% | 0.33% |
| 2014 | 9.78% | 9.78% | 0.44% |
| 2015 | 9.60% | 9.68% | 0.39% |
| 2016 | 9.53% | 9.50% | 0.32% |
| 2017 | 9.73% | 9.60% | 0.61% |
| 2018 | 9.59% | 9.60% | 0.30% |
| 2019 | 9.72% | 9.72% | 0.29% |
| 2020 | 9.46% | 9.42% | 0.31% |
| 2021 | 9.60% | 9.57% | 0.34% |

From that perspective as well, there is no reason to conclude authorized returns have fallen since 2013.

**Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?**

A. Yes, there are. The regulatory environment is one of the most important factors debt and equity investors factor in their assessment of risk. Further, utility credit ratings and outlooks depend substantially on the extent to which rating agencies view the regulatory environment credit supportive, or not. For example, Moody's finds the regulatory environment to be so important that 50.00% of the factors that weigh in its ratings

87 Source: Regulatory Research Associates. Excludes limited issue rate riders. Based on data through July 30, 2021.

determination are determined by the nature of regulation.[88] Given Piedmont's need to access external capital, and the weight rating agencies place on the nature of the regulatory environment, it is important to consider the extent to which the jurisdictions that recently have authorized ROEs for natural gas utilities are viewed as having constructive regulatory environments.

As shown in Table 8 (below; *see also* Schedule DWD-12R), I analyzed the authorized ROE for natural gas utilities based on the jurisdiction's ranking by RRA, which provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint and Below Average indicating a less constructive, higher-risk regulatory climate. Within each principal rating categories, the numbers 1, 2 and 3 indicate relative position. The designation 1 indicates a stronger or more constructive rating from an investor viewpoint; 2, a midrange rating; and 3, a less constructive rating. Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."[89]

The Commission currently is ranked "Average/1", which falls in the top-third of the 53 jurisdictions ranked by RRA.

Across the 232 vertically integrated rate cases for which RRA reports an authorized ROE since 2013, there was a 36-basis point difference between the median return for

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

[89] Regulatory Research Associates, *RRA Regulatory Focus: State Regulatory Evaluations*, May 25, 2021, at 7.

jurisdictions ranked in the top third of all jurisdictions, and jurisdictions ranked in the middle third of all jurisdictions (the higher-ranked jurisdictions providing the higher authorized returns; *see* Table 8, below). As Table 8 indicates, authorized ROEs for natural gas utilities in jurisdictions rated in the top third of all jurisdictions, including North Carolina, range from 9.20% to 10.55%, with an average of 9.83%, and a median of 9.85%.

**Table 8: Natural Gas Authorized ROE by RRA Ranking**[90]

| Authorized ROE (%) Natural Gas Utilities | | | |
|---|---|---|---|
| **RRA Ranking** | **Top Third** | **Middle Third** | **Bottom Third** |
| Mean | 9.83% | 9.45% | 9.62% |
| Median | 9.85% | 9.49% | 9.60% |
| Maximum | 10.55% | 10.20% | 11.88% |
| Minimum | 9.20% | 8.70% | 9.10% |

In view of the above, my recommended ROE, 10.25%, is consistent with the returns authorized in more constructive jurisdictions, such as North Carolina.

**E. CAPM Analysis**

**Q. PLEASE SUMMARIZE MR. O'DONNELL'S CAPM ANALYSIS.**

A. Mr. O'Donnell uses the range of 30-year Treasury yields between April 1, 2019 and July 2, 2021 for the risk-free rate component. He uses *Value Line* Beta coefficients and Market Risk Premiums ("MRP") of 4.25% and 6.25%, based on historical and investment professionals' forecasts, to derive CAPM estimates of 4.60% to 8.60% for his proxy group

90 Source: Regulatory Research Associates. "Top Third" includes Above Average/1,2,3 and Average/1; "Middle Third" includes Average/2; "Bottom Third" includes Average/3 and Below Average/1,2,3. Of the 53 total jurisdictions, the "Top Third" group includes 17 jurisdictions, the "Middle Third" group includes 16 jurisdictions, and the "Bottom Third" group includes 20 jurisdictions. . *See also*, Schedule DWD-12R. Excludes limited issue riders.

and Duke Energy, which he believes indicates a "proper" CAPM result of 6.00% to 8.00%.[91] Mr. O'Donnell's CAPM results are used as a check on his DCF results.[92]

**Q. WHAT ISSUES DO YOU TAKE WITH MR. O'DONNELL'S CAPM ANALYSIS?**

A. I take several issues with Mr. O'Donnell's CAPM analysis, including: (1) his failure to include projected Treasury yields in his analysis; (2) his use of a subset of historical data instead of the long-term historical average MRP in his analysis; (3) his use of geometric returns in the calculation of the historical MRP; (4) his use of the total return on Long-Term Government bonds as a proxy for the risk-free rate in the historical MRP; (5) his consideration of professional investor forecasts and market surveys for his MRP analysis; and (6) his analysis did not include an Empirical CAPM ("ECAPM"). I have discussed the use of projected interest rates in my response to Mr. Hinton. The remaining issues are discussed in turn below.

**Q. DO YOU AGREE WITH MR. O'DONNELL'S USE OF A 1972-2019 HISTORICAL TIME PERIOD FOR HIS HISTORICAL MRP CALCULATION?**

A. No, I don't. SBBI – 2021 makes it clear that the arbitrary selection of short historical periods is highly suspect and unlikely to be representative of long-term trends in market data. For example, SBBI - 2021 states:

> The estimate of the equity risk premium depends on the length of the data series studied. A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influences by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable. Furthermore, because an average of the realized equity risk premium, is quite volatile when calculated using a short history, using a long

[91] O'Donnell Direct Testimony, at 67-68.
[92] *Ibid*., at 40.

> series makes it less likely that the analyst can justify any number he or she wants.[93]

The academic literature demonstrates and confirms that a subset of data could be subject to data manipulation. Because of this, Mr. O'Donnell's historical MRPs should be viewed with considerable caution.

**Q. DO YOU AGREE WITH MR. O'DONNELL'S ESTIMATE OF THE HISTORICAL MARKET RISK PREMIUM?**

A. No. Mr. O'Donnell presents the geometric and arithmetic mean market return estimates based on the Ibbotson historical average from 1972-2019.[94] In addition to using an inappropriate time period, his use of the geometric mean for cost of capital purposes is also inappropriate. Only arithmetic mean return rates, equity risk premiums, and yields are appropriate for cost of capital purposes because *ex-post* (historical) total returns and equity risk premiums differ in size and direction over time, indicating volatility, *i.e.,* variance or risk. The arithmetic mean captures the prospect for variance in returns and equity risk premiums, providing the valuable insight needed by investors in estimating risk in the *future* when making a *current* investment. Absent such valuable insight into the potential variance of returns, investors cannot meaningfully evaluate prospective risk. The geometric mean of ex-post equity risk premiums provides no insight into the potential variance of future returns because the geometric mean relates the change over many time periods to a constant rate of change, rather than the year-to-year fluctuations, or variance, *critical to risk analysis.* Therefore, the geometric mean is of little to no value to investors

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93 Duff & Phelps 2021 SBBI® Yearbook Stocks, Bonds, Bills and Inflation at 10-23 ("SBBI–2021").
94 O'Donnell Direct Testimony, at 64.

seeking to measure risk. Moreover, from a statistical perspective, since stock returns and equity risk premiums are randomly generated, the arithmetic mean is expectational and consistent with the prospective nature of the cost of capital and ratemaking noted above.

The financial literature is quite clear that risk is measured by the variability of expected returns, *i.e.,* the probability distribution of returns.[95] SBBI-2021[96] explains in detail why the arithmetic mean is the correct mean to use when estimating the cost of capital.

In addition, Weston and Brigham provide the standard financial textbook definition of the riskiness of an asset when they state:

> The riskiness of an asset is defined in terms of the likely variability of future returns from the asset. (emphasis added)[97]

Furthermore, Morin states:

> The geometric mean answers the question of what constant return you would have had to achieve in each year to have your investment growth match the return achieved by the stock market. The arithmetic mean answers the question of what growth rate is the best estimate of the future amount of money that will be produced by continually reinvesting in the stock market. It is the rate of return which, compounded over multiple periods, gives the mean of the probability distribution of ending wealth. (emphasis added)[98]

In addition, Brealey and Myers note:

> The proper uses of arithmetic and compound rates of return from past investments are often misunderstood... Thus the arithmetic average of the returns correctly measures the opportunity cost of capital for investments... *Moral*: If the cost of capital is estimated from historical returns or risk

[95] Eugene F. Brigham, Fundamentals of Financial Management, (The Dryden Press, 1989), at 639.
[96] SBBI-2021, at p. 10-22.
[97] J. Fred Weston and Eugene F. Brigham, Essentials of Managerial Finance, 3rd Edition (The Dryden Press, 1974), at 272.
[98] Morin, at 133.

premiums, use arithmetic averages, not compound annual rates of return. (italics in original)[99]

As previously discussed, investors gain insight into relative riskiness by analyzing expected *future* variability. This is accomplished using the arithmetic mean of a random distribution of returns/premiums. Only the arithmetic mean considers all the returns/premiums over a period of time, hence, providing meaningful insight into the variance and standard deviation of those returns/premiums.

**Q. CAN IT BE DEMONSTRATED THAT THE ARITHMETIC MEAN TAKES INTO ACCOUNT ALL OF THE RETURNS AND, THEREFORE, IS THE ONLY APPROPRIATE MEAN TO USE WHEN ESTIMATING THE COST OF CAPITAL?**

A. Yes. Schedules DWD-9R and DWD-13R graphically demonstrate this. Schedule DWD-13R charts the SBBI-2021 returns on large company stocks for each and every year from 1926 through 2020. It is clear from looking at the year-to-year variation of these returns that stock market returns and, hence, MRPs vary (see Chart 5, below).

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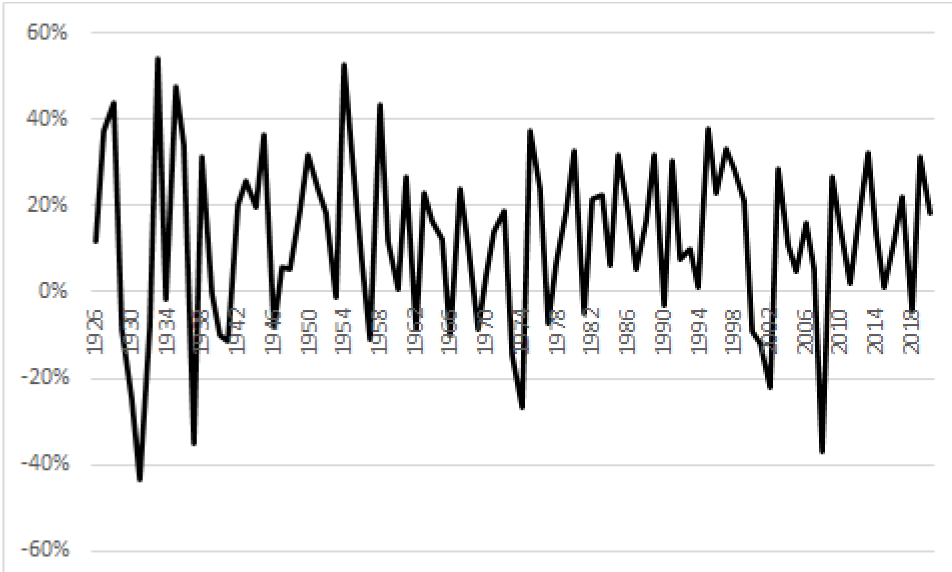
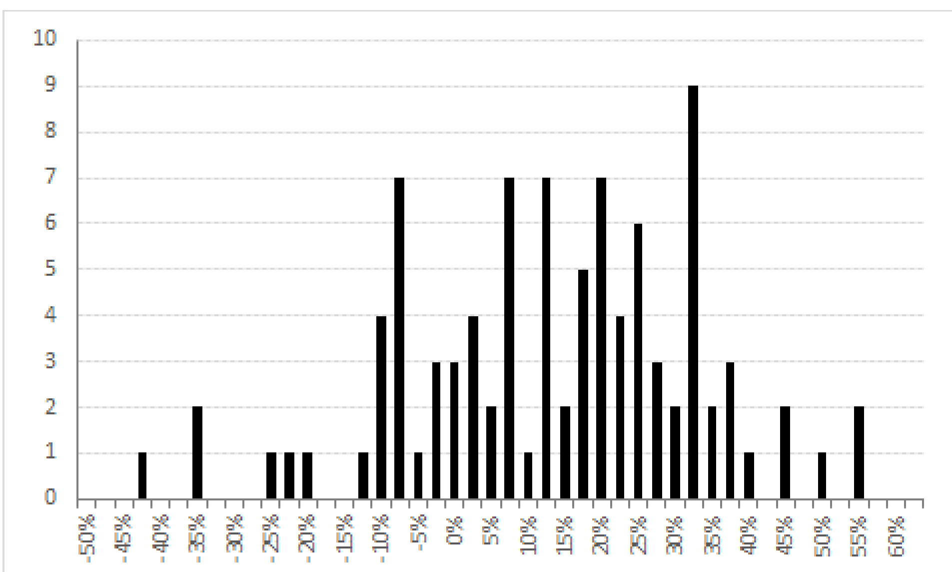
99 Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance, Fifth Edition (The McGraw-Hill Companies, Inc., 1996), at 146 – 147.

**<u>Chart 5: U.S. Large Company Stock Returns 1926-2020[100]</u>**




The distribution of each of those returns for the period from 1926 through 2020 is shown on Schedule DWD-9R and Chart 6, below.

**<u>Chart 6: Frequency Distribution of Observed Market Returns, 1926 - 2020[101]</u>**

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100 <u>SBBI-2021</u> at Appendix A-1.
101 Schedule DWD-9R.

There is a clear bell-shaped pattern to the probability distribution of returns, an indication that they are randomly generated and not serially correlated. The arithmetic mean of this distribution of returns considers each and every return in the distribution. In doing so, the arithmetic mean takes into account the standard deviation or likely variance which may be experienced in the future when estimating the rate of return based on such historical returns.

In contrast, the geometric mean considers only two of the returns, the initial and terminal years, which, in this case, are 1926 and 2020. Based on only those two years, a constant rate of return is calculated by the geometric average. That constant return is graphically represented by a flat line, showing no year-to-year variation for the entire 1926 to 2020 time period. This is obviously unrealistic, based on the histogram shown in Chart 6 above. In view of the foregoing, Mr. O'Donnell should have exclusively relied on the long-term arithmetic average return on the market in calculating his historical risk premium using SBBI-2021 data.

**Q. PLEASE COMMENT ON MR. O'DONNELL'S USE OF TOTAL RETURNS ON LONG-TERM GOVERNMENT BONDS IN THE CALCULATION OF HIS MRP.**

A. Although Mr. O'Donnell relies on Duff & Phelps' historical returns in his CAPM analysis, he has ignored their recommendation to rely on the income return and not the total return on U.S. Treasury securities in deriving an MRP. As indicated in SBBI-2021:

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation.
>
> The total return comprises three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash

> flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[102]

Also, as shown in SBBI-2021 on page 6-17, the standard deviation for the income return on long-term government bonds is 2.6%, which is the lowest (i.e., least risky) measure of all bond returns followed by SBBI. Mr. O'Donnell's recommended measure of the risk-free rate, the total return on long-term government bonds, has a standard deviation of 9.8%, which is the highest (i.e., most risky) measure of all bond returns followed by SBBI. These measures alone warrant the use of the income return on long-term government bonds as the appropriate proxy of the risk-free rate for use in the calculation of the MRP in a CAPM analysis.

In view of the above, the correct derivation of the historical MRP is the difference between the arithmetic mean total return on large company common stocks of 12.20%, and the arithmetic mean 1926-2020 income return on long-term government bonds of 4.90%, which results in an MRP of 7.30%.[103]

**Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S REFERENCE TO PROFESSIONAL INVESTOR FORECASTS AND MARKET SURVEYS THAT**

102 SBBI-2021, at 10-22.
103 *Ibid.*, at 6-17.

**INDICATE EXPECTED MARKET RETURNS RANGE FROM NEGATIVE 5.80% (REAL) TO 5.70% (NOMINAL)?[104]**

A. I have several concerns with his reference. First, Mr. O'Donnell's 9.00% ROE recommendation is at odds with the data he presents. Mr. O'Donnell refers to the market forecasts summarized in Table 9, below.

**Table 9: Summary of Mr. O'Donnell's Market Return Forecast References[105]**

| Institution | Market Return Forecast |
|---|---|
| BlackRock Investment Institute | 5.00% nominal return for US large caps over the next decade |
| Grantham, Mayo, & van Otterloo (GMO) | -5.80% real returns for US large caps over the next 7 years |
| JP Morgan Asset Management | 4.10% nominal return for US equities over a 10-15-year horizon |
| Morningstar Investment Management | -0.10% 10-year nominal returns for US stocks |
| Research Affiliates | 2.00% nominal and -0.20% real (inflation adjusted) returns for US large caps during the next 10 years |
| Vanguard | Nominal equity market returns of 3.70% to 5.70% during the next decade |

As Table 9 indicates, the expected market returns (on a nominal basis) range from negative 0.10% to 5.70% for U.S. equities. Mr. O'Donnell, however, estimates an ROE of 9.00% for a utility that is generally less risky than the overall market. If Mr. O'Donnell believes these expected returns are meaningful measures of investor-required returns, which is the subject of his testimony, his recommendation would be no higher than 5.70%.

In addition to the short-term nature of these forecasts and the difference between expected and required returns as discussed in response to Mr. Hinton's testimony, Mr. O'Donnell does not consider the limiting language often contained in documents providing

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104 O'Donnell Direct Testimony, at 65.

105 *Ibid*., at 65.

expected market returns. For example, JP Morgan Asset Management's *2021 Long-Term Capital Market Assumptions* (the source document for the 4.10% expected market return noted in Table 9, above) states:

> Please note that all information shown is based on qualitative analysis. Exclusive reliance on the above is not advised. This information is not intended as a recommendation to invest in any particular asset class or strategy or as a promise of future performance. Note that these asset class and strategy assumptions are passive only – they do not consider the impact of active management. References to future returns are not promises or even estimates of actual returns a client portfolio may achieve. Assumptions, opinions and estimates are provided for illustrative purposes only.[106]

Regarding the Duke University CFO Survey (Duke CFO Survey),[107] Mr. O'Donnell's 9.00% recommendation is 221 basis points above the 6.79% expected market return suggested by the survey.[108] If the survey were a reasonable method of determining the expected market return, Mr. O'Donnell's ROE recommendation would be no higher than 6.79%. Further, over time the survey results have rather significantly underestimated actual market performance (*see,* Table 10).

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[106] JP Morgan Asset Management, *2021 Long-Term Capital Market Assumptions,* at PDF 130.

[107] O'Donnell Direct Testimony, at 66.

[108] *Ibid*., at 67.

**Table 10: S&P 500 Market Return: Accuracy of Duke CFO Survey Estimates**[109]

| | Actual | Survey Estimate |
|---|---|---|
| 2020 | 18.40% | 5.23% |
| 2019 | 31.49% | 4.59% |
| 2018 | -4.38% | 6.57% |
| 2017 | 21.83% | 5.00% |
| 2016 | 11.96% | 4.32% |
| 2015 | 1.38% | 6.07% |
| 2014 | 13.69% | 5.00% |
| 2013 | 32.39% | 3.40% |
| 2012 | 16.00% | 4.00% |
| 2011 | 2.11% | 5.30% |
| 2010 | 15.06% | 6.28% |
| Average | 14.54% | 5.07% |

The Duke CFO Survey authors also have noted a distinction between the expected market return on one hand, and the "hurdle rate" on the other. In the Third Quarter 2017 survey, the authors reported an average hurdle rate, which is the return required for capital investments, of 13.50%. The authors further reported the average Weighted Average Cost of Capital, which includes the cost of debt, was 9.20% even though the expected market return was 6.50%.[110]

**Q. DO YOU HAVE ANY ADDITIONAL CONCERNS WITH MR. O'DONNELL'S CAPM ANALYSIS?**

A. Yes. Mr. O'Donnell reviews several data points, but he does not explain how he derives his range of MRPs of 4.25% to 6.25%. For example, it appears Mr. O'Donnell gives

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109 Source: SBBI-2021, Appendix A-1; http://www.cfosurvey.org (one-year return estimates as of fourth quarter of the previous year). Note, Graham and Harvey publish the Duke CFO survey.

110 Duke/CFO Magazine Global Business Outlook Survey – U.S., Third Quarter 2017.

significant weight to the May 3, 2021, Charles Schwab report, *Why Market Returns May Be Lower and Global Diversification More Important in the Future*, because that report includes the only MRP estimates at or above the 6.25% upper end of his range.[111] None of the other eight sources presented by Mr. O'Donnell include MRP estimates above 5.70%.[112] Given the subjective nature of Mr. O'Donnell's range of MRP estimates, it is impossible to recreate his analysis.

**Q. DOES MR. O'DONNELL PERFORM AN ECAPM?**

A. No, he does not. Mr. O'Donnell fails to consider the ECAPM, despite the fact that numerous tests of the CAPM have confirmed that the empirical Security Market Line ("SML") described by the traditional CAPM is not as steeply sloped as the predicted SML. Because of the empirical findings presented in my Direct Testimony, and below, Mr. O'Donnell should have considered the ECAPM in his CAPM analysis.

As discussed in my Direct Testimony, numerous tests of the CAPM have measured the extent to which security returns and betas are related as predicted by the CAPM. Fama and French found that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[113]

Similarly, Morin states:[114]

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.
>
> * * *
>
> For an alpha in the range of 1%-2% and for reasonable values of the market

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111 O'Donnell Direct Testimony, at 64-66.

112 *Ibid.*

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

114 Morin, at 175 and 190.

> risk premium and the risk-free rate, Equation 6-5 reduces to the following more pragmatic form:
>
> $$K = R_F + 0.25\,(R_M - R_F) + 0.75\ \beta(R_M - R_F) \quad (6\text{-}6)$$
>
> Over reasonable values of the risk-free rate and the market risk premium, Equation 6-6 produces results that are indistinguishable from the ECAPM of Equation 6-5.[12]
>
> [12] . . . Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\ \beta(R_M - R_F) + (1\text{-}x)\ \beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$

In addition to the above academic evidence, the New York Public Service Commission has been using this form of the CAPM, with factors of 0.25 and 0.75, since the mid-1990s. As such, the ECAPM is a well-established model that has been relied on in both academic and regulatory settings. I continue to believe it is an appropriate model to estimate Piedmont's ROE.

## F. <u>Response to Mr. O'Donnell's Criticisms</u>

**Q. DOES MR. O'DONNELL HAVE ANY CRITIQUES OF YOUR ANALYSIS?**

A. Yes, he does. Critiques of my analysis include: (1) my exclusive reliance on projected EPS growth rates in the DCF model; (2) that my estimate of the MRP is too high; (3) my use of the ECAPM; (4) that my RPM is "overly complex" compared to the DCF model; and (5) a flotation cost adjustment is not appropriate.

I have addressed critiques 1, 2, and 3 previously in this testimony and will not address them again here. I respond to the remaining critiques in turn below.

**Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S CONCERN THAT YOUR RPM IS "OVERLY COMPLEX"?[115]**

A. Although Mr. O'Donnell suggests that finance is simple, and his analysis is simple, my testimony demonstrates that the question of equity financing of a regulated utility is anything but simple. If finance and determining the ROE were simple, investors would rely on the DCF model and not consider the results of any other analysis. In fact, other models would not be necessary. As discussed previously in my Rebuttal Testimony, that is not the case. No model is appropriate under all market conditions. Because of that, the use of multiple models is supported in both the financial literature and regulatory precedent. If determining the appropriate ROE for utilities was as simple as performing a DCF analysis, none of the expert witnesses in this proceeding, or any other, would be necessary. As Mr. O'Donnell notes, that is not the case:

> 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.[116]

Furthermore, the simplicity of the DCF model does not imply that other models, such as the RPM are invalid. The DCF model, CAPM, and RPM are based on varying assumptions and inputs, but are all valid approaches to estimating the ROE and are supported in both the financial literature and regulatory precedent, as discussed previously.

Lastly, my RPM analysis is based on multiple estimates of the Risk Premium, both historical and forward-looking. Mr. O'Donnell similarly relies on several estimates of the

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115 O'Donnell Direct Testimony, at 40.

116 *Ibid*.

MRP in his CAPM analysis. Although Mr. O'Donnell finds my RPM to be "overly complex", I have relied on multiple estimates of the Risk Premium to ensure that my estimate is not biased by any single approach or data source.

Because Mr. O'Donnell finds the RPM complicated does not mean that the model produces an unreasonable estimate of the ROE for Piedmont. As such, I strongly disagree with Mr. O'Donnell's implication that my RPM is "convoluted" because he finds it to be "overly complex."

**Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S CONCERN WITH YOUR FLOTATION COST ADJUSTMENT?**

A. Flotation costs are reflected on the balance sheet under "paid in capital" and incurred over time. As a result, flotation costs remain part of a company's cost structure during the test year and beyond even if the costs were incurred prior to the test year.[117]

As noted by Morin:

> Unlike the case of bonds, common stock has no finite life so that flotation costs cannot be amortized and therefore must be recovered by way of an upward adjustment to the allowed return on equity.[118]

Morin further notes that the equity capital raised in a given offering remains on the balance sheet, and as such, it "would be unfair to burden the current generation of ratepayers with the full costs of raising capital when the benefits of that capital extend indefinitely."[119]

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117 D'Ascendis Direct Testimony, at 83-84.
118 Morin, at 327.
119 *Ibid*. In this quote, Morin is speaking to the issue of recovering flotation costs through rates as they are incurred.

Whether paid directly or indirectly through an underwriting discount, the cost results in net proceeds that are less than the gross proceeds. Under federal law, the underwriters' compensation must be disclosed in the offering prospectus. In fact, those prospectuses are the source of the issuance costs included in Schedule DWD-8 to my Direct Testimony. Because those costs were incurred, the net proceeds to the issuing company were less than the gross proceeds. Whether the issuer wrote a check or received the proceeds at a discount does not matter. What does matter is that issuance costs are a permanent reduction to common equity, and absent a recovery of those costs, the issuing company will not be able to earn its required return.

As further discussed in my Direct Testimony, wholly owned subsidiaries such as Piedmont receive capital from their parents, and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based on the returns of those subsidiaries.[120] As such, denying recovery of issuance costs would penalize the investors that fund the utility operations. As shown in Schedule DWD-14R, because of flotation costs, an authorized return of 10.85% would be required to realize an ROE of 10.75% (i.e., a 10-basis point flotation cost adjustment). If flotation costs are not recovered, the growth rate falls and the ROE decreases to 10.65% (i.e., below the required return).[121]

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[120] D'Ascendis Direct Testimony, at 7-8.

[121] Schedule DWD-14R is provided for illustrative purposes only. Please note that I have not relied on the results of the analysis in determining my recommended ROE or range.

## VI. RESPONSE TO CIGFUR WITNESS PHILLIPS

**Q. PLEASE SUMMARIZE MR. PHILLIPS' DIRECT TESTIMONY AS IT RELATES TO THE COMPANY'S RETURN ON EQUITY.**

A. Mr. Phillips states that the Company's requested ROE is inconsistent with recently authorized returns, which he notes are 9.56% over the 12-month period ending March 31, 2021. He also suggests that the Commission consider Piedmont's cost recovery mechanisms in setting the authorized ROE.

**Q. WHAT IS YOUR RESPONSE TO MR. PHILLIPS?**

A. As discussed in my response to Mr. O'Donnell, average authorized return data obscures the variations in returns and does not address the number of cases nor the jurisdictions issuing orders within a given year. Pointing solely to a 12-month average of authorized returns provides little value in providing context to the appropriate ROE for Piedmont. As further discussed in my response to Mr. O'Donnell, the regulatory environment is one of the most important factors debt and equity investors factor in their assessment of risk. As shown in Table 8, more constructive jurisdictions from an investor standpoint tend to have higher authorized returns.

In addition, as discussed in my response to Mr. Hinton, the cost of capital is a comparative exercise, so if a cost recovery mechanism is common throughout the proxy companies, the comparative risk is zero because any impact of the perceived reduced risk of the mechanism(s) by investors would be reflected in the market data of the proxy group. To that point, as shown on Schedule DWD-8R, ten of the eleven companies in Mr. Hinton's proxy group have a capital investment rider and ten of his eleven proxy group companies have a decoupling mechanism in at least one of their jurisdictions.

## VII. CONCLUSION

**Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

A. In this Rebuttal Testimony I updated my ROE models with market data as of July 30, 2021. The results of the ROE models produced indicated ranges of ROEs from 9.59% to 12.72% (unadjusted) and from 9.70% to 12.83% (adjusted).[122] Given these ranges, I maintain my initial recommendation of 10.25%, which, in light of the current capital markets, is reasonable, if not conservative.

Regarding the Opposing Witnesses' direct testimonies, I discussed my disagreements with their analyses, which I supported with citations to the academic literature and empirical analyses. I also responded to any critiques to my Direct Testimony, again, supporting my responses with citations to the academic literature and empirical analyses.

**Q. SHOULD ANY OR ALL OF THE ARGUMENTS MADE BY THE OPPOSING WITNESSES PERSUADE THE COMMISSION TO LOWER THE RETURN ON COMMON EQUITY IT APPROVES FOR PIEDMONT BELOW YOUR RECOMMENDATION?**

A. No, they should not. My recommended cost of common equity of 10.25% is both reasonable and conservative. It will provide the Company with sufficient earnings to

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122 D'Ascendis Rebuttal Testimony, Exhibit DWD-1R, at 2.

enable it to attract necessary new capital efficiently and at a reasonable cost, to the benefit of both customers and investors.

**Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes, it does.

**BEFORE THE**

**NORTH CAROLINA UTILITIES COMMISSION**

**SETTLEMENT TESTIMONY**

**OF**

**DYLAN W. D'ASCENDIS, CRRA, CVA**

**ON BEHALF OF**

**PIEDMONT NATURAL GAS COMPANY, INC.**

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

## I. INTRODUCTION

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

A. My name is Dylan W. D'Ascendis. I am a Partner at ScottMadden, Inc. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, New Jersey 08054.

**Q. ARE YOU THE SAME DYLAN W. D'ASCENDIS WHO SUBMITTED DIRECT, AND REBUTTAL TESTIMONIES IN THIS PROCEEDING?**

A. Yes, I filed direct testimony ("Direct Testimony") and rebuttal testimony ("Rebuttal Testimony") on behalf of Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company"). In my Direct and Rebuttal testimonies, I recommended an ROE of 10.25%, within ranges of 9.58% to 12.30% (Direct Testimony) and 9.70% to 12.83% (Rebuttal Testimony).

**Q. WHAT IS THE PURPOSE OF YOUR SETTLEMENT SUPPORT TESTIMONY?**

A. The purpose of my testimony is to explain my support for the Stipulation of Partial Settlement, dated September 7, 2021 (the "Partial Settlement") among the Company and the Public Staff – North Carolina Utilities Commission ("Public Staff"), Carolina Utility Customers Association, Inc. ("CUCA"), and Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR") (collectively, the "Settling Parties"). My testimony addresses the agreed-upon return on common equity

("ROE"), capital structure, and overall rate of return contained in the Partial Settlement.[1]

**Q. HAVE YOU PREPARED ANY EXHIBITS IN CONJUNCTION WITH YOUR TESTIMONY?**

**A.** Yes. Settlement Exhibit No. DWD-1 has been prepared by me, or under my direct supervision.

## II. <u>STIPULATED ROE, EQUITY RATIO, AND OVERALL RATE OF RETURN</u>

**Q. ARE YOU FAMILIAR WITH THE TERMS OF THE PARTIAL SETTLEMENT AS IT RELATES TO THE COMPANY'S ROE?**

**A.** Yes. I understand the Settling Parties have agreed to an overall rate of return of 6.90%, based on a capital structure consisting of 47.75% long-term debt at a cost rate of 4.08%, short term debt of 0.65% at a cost rate of 0.20%, and 51.60% common equity at an ROE of 9.60%.[2]

**Q. IN GENERAL, DO YOU SUPPORT THE COMPANY'S DECISION TO AGREE TO THE STIPULATED ROE?**

**A.** Yes, I do. Although the Stipulated ROE is somewhat below the lower bound of my recommended range (*i.e.*, 9.70%), I recognize the Partial Settlement represents negotiations among the Settling Parties regarding several otherwise-contested

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[1] *See*, Docket No. G-9, Sub 781, Stipulation of Partial Settlement, September 7, 2021. I refer to the 9.60% ROE as the "Stipulated ROE", the 51.60% equity ratio as the "Stipulated Equity Ratio", and the 6.90% overall rate of Return as the "Stipulated Rate of Return".

[2] *See*, Docket No. G-9, Sub 781, Stipulation of Partial Settlement, September 7, 2021.

issues. I understand the Company has determined that the terms of the Partial Settlement, in particular the Stipulated ROE and Equity Ratio, would be viewed by the rating agencies as constructive and equitable. I understand and respect that determination.

**Q. PLEASE NOW SUMMARIZE YOUR POSITION REGARDING THE STIPULATED ROE.**

A. Although the Stipulated ROE falls below my recommended range (the low end of which is 9.70%), it is within the range of the analytical results presented in my Direct and Rebuttal Testimonies. As discussed throughout my Direct and Rebuttal Testimonies, the models used to estimate the ROE produce a wide range of estimates. It therefore remains my position that in a fully-litigated proceeding, a range of common equity cost rates between 9.70% and 12.83% is reasonable based on market data. Nonetheless, I recognize the benefits associated with the decision to enter into the Partial Settlement and as such, it is my view that the 9.60% Stipulated ROE is a reasonable resolution of an otherwise contentious issue.

**Q. HAVE YOU ALSO CONSIDERED THE STIPULATED ROE IN THE CONTEXT OF AUTHORIZED RETURNS FOR OTHER NATURAL GAS DISTRIBUTION UTILITIES?**

A. Yes, I have. From January 2017 through July 2021, the average and median authorized ROEs for natural gas distribution utilities were 9.61% and 9.60%, respectively. Of the 144 cases decided during that period, 80 included authorized ROEs of 9.60% or higher.[3]

**Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?**

**A.** Yes, there are. As noted in my Rebuttal Testimony, the Company's credit rating and outlook depend substantially on the extent to which rating agencies view the regulatory environment credit supportive, or not.[4] I noted, for example, that Moody's finds the regulatory environment to be so important that 50.00% of the factors that weigh in its ratings determination are determined by the nature of regulation.[5]

Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, I believe it is important to consider the extent to which the jurisdictions that recently have authorized ROEs for natural gas distribution utilities are viewed as having constructive regulatory environments.

**Q. IS NORTH CAROLINA GENERALLY CONSIDERED TO HAVE A CONSTRUCTIVE REGULATORY ENVIRONMENT?**

**A.** Yes, it is. As discussed in my Rebuttal Testimony, Regulatory Research Associates ("RRA"), which is a widely referenced source of rate case data, provides an

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3 *See* Settlement Exhibit DWD-1.

4 D'Ascendis Rebuttal Testimony, at 53-55.

5 *Ibid.*

assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not.[6] As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid range rating; and, 3, a weaker (less constructive) rating. We endeavor to maintain an approximately equal number of ratings above the average and below the average.[7]

Within RRA's ranking system, North Carolina is rated "Average/1", which falls in the top one-third of the 53 regulatory commissions ranked by RRA.[8]

**Q. DID YOU CONSIDER THOSE DISTINCTIONS IN YOUR REVIEW OF AUTHORIZED RETURNS RELATIVE TO THE STIPULATED ROE?**

A. Yes. Across the 144 cases noted above, there was a 20-basis point difference between the median return for the Top Third and Bottom Third of jurisdictions (the higher-ranked jurisdictions providing the higher authorized returns, see Table 1, below). As Table 1 indicates, authorized ROEs for natural gas distribution utilities

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6 D'Ascendis Rebuttal Testimony, at 54.

7 Source: Regulatory Research Associates, accessed July 31, 2021. *See*, D'Ascendis Rebuttal Testimony, at 54.

8 Source: Regulatory Research Associates, accessed July 31, 2021.

in jurisdictions that, like North Carolina, are rated at least Average/1 range from 9.20% to 10.55%, with a median of 9.80%.

**Table 1: Average Authorized ROE by RRA Ranking[9]**

| | Authorized ROE Natural Gas Distribution Utilities | | |
|---|---|---|---|
| RRA Ranking | Top Third | Middle Third | Bottom Third |
| Average | 9.78% | 9.46% | 9.60% |
| Median | 9.80% | 9.40% | 9.60% |
| Maximum | 10.55% | 10.20% | 11.88% |
| Minimum | 9.20% | 8.70% | 9.10% |

**Q. WHAT CONCLUSIONS DO YOU DRAW FROM THAT DATA?**

A. The Stipulated ROE falls 20 to 18 basis points below the median and mean authorized ROE, respectively, for jurisdictions that are comparable to North Carolina's constructive regulatory environment, and 20 basis points above the median return authorized in less supportive jurisdictions. Taken from that perspective, the Stipulation ROE is a reasonable, if not somewhat conservative measure of the Company's ROE.

9 Source: Regulatory Research Associates. "Top Third" includes Above Average/1,2,3 and Average/1; "Average" includes Average/2 and Average/3; "Bottom Third" includes Below Average/1,2,3. The "Top Third" group includes 18 of 53 jurisdictions, or about one-third of the total. *See* Settlement Exhibit DWD-1

**Q. DO YOU BELIEVE THE STIPULATED CAPITAL STRUCTURE ALSO IS REASONABLE?**

**A.** Yes, I do. As demonstrated in Table 2 (below) the Stipulated Equity Ratio is slightly below the median authorized equity ratio in supportive regulatory jurisdictions (*i.e.*, 51.98%), and is well within the range of equity ratios authorized in those jurisdictions (38.30% to 59.64%).

**Table 2: Average Authorized Equity Ratio by RRA Ranking**[10]

| | **Authorized Equity Ratio Natural Gas Distribution Utilities** | | |
|---|---|---|---|
| RRA Ranking | Top Third | Middle Third | Bottom Third |
| Average | 51.02% | 50.77% | 52.07% |
| Median | 51.98% | 50.23% | 52.00% |
| Maximum | 59.64% | 55.00% | 60.18% |
| Minimum | 38.30% | 42.90% | 46.00% |

Because no two companies are identical, we should not view the average (or median) equity ratio (whether authorized or observed) as a strict measure of industry practice. Nonetheless, the Stipulated Equity Ratio falls well within the range of authorized equity ratios and is slightly below the median for constructive regulatory jurisdictions. In my view, that finding provides additional support for its acceptance.

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10 Source: Regulatory Research Associates. Excludes capital structure decisions from Arkansas, Florida, Indiana, and Michigan, all of which include some form of non-investor supplied capital in the ratemaking capital structure.

**Q. HOW DOES THE 6.90% OVERALL RATE OF RETURN CONTAINED IN THE PARTIAL SETTLEMENT COMPARE TO RECENTLY AUTHORIZED RETURNS?**

A. It is quite low. Since January 2017, there have been 134 cases reported by RRA (for natural gas distribution utilities) in which an overall rate of return was specified. Over those 134 cases, the median rate of return was 7.15%, 25 basis points above the 6.90% rate of return contained in the Partial Settlement. From a slightly different perspective, 103 of the 134 cases had overall rates of return greater than 6.90%. In fact, the Partial Settlement's overall rate of return falls in the bottom 24th percentile of the 134 cases decided since 2017.

The low overall rate of return contained in the Partial Settlement is brought about by the Company's rather low cost of debt. That low cost of debt is supported by reasonable regulatory outcomes, including constructive decisions regarding the ROE and capital structure. In my view, the Partial Settlement continues that support, and produces the low overall rate of return on which customer rates would be set. From that important perspective, the Stipulated ROE and capital structure strike the necessary balance between customer and investor interests.

**Q. LASTLY HAS YOUR TESTIMONY CONSIDERED ECONOMIC CONDITIONS IN NORTH CAROLINA?**

A. Yes, it has. I understand and appreciate the Commission's need to balance the interests of investors and ratepayers, and to consider economic conditions in the State, as it sets rates. As explained in my Direct Testimony, I recognize that economic conditions are recovering in North Carolina and across the U.S as the COVID-19 crisis subsides.[11] Because North Carolina's economic conditions remain highly correlated to the overall conditions in the U.S., my review of North Carolina's economic conditions do not alter my conclusion that the Stipulated ROE, Equity Ratio, and Rate of Return are reasonable resolutions to otherwise contentious issues.

**Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?**

A. Yes, it does.

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11 D'Ascendis Direct Testimony, at 51-61.

MR. JEFFRIES: And we would also move that Mr. D'Ascendis' prefiled exhibits consisting of prefiled Direct Exhibits DWD-1 through DWD-8, prefiled Rebuttal Exhibit DWD-1 consisting of Schedules DWD-1R through DWD-14R, and Mr. D'Ascendis' Settlement Exhibit DWD-1 be identified as marked.

CHAIR MITCHELL: All right. Mr. Jeffries, the exhibits to Mr. D'Ascendis' testimony will be marked for identification as they were when prefiled.

(Exhibits DWD-1 through DWD-8, Rebuttal Exhibit DWD-1 consisting of Schedules DWD-1R through DWD-14R, and Settlement Exhibit DWD-1, were identified as they were marked when prefiled.)

MR. JEFFRIES: Thank you, Chair Mitchell.

Q. Mr. D'Ascendis, have you prepared a summary of your prefiled testimony?

A. I have. It may be a little different -- slightly different, just adding the summary of my settlement testimony, but I will send that over.

Q. Could you provide that to the Commission?

MR. JEFFRIES: And we will provide the court reporter with the modified version of Mr. D'Ascendis' summary.

THE WITNESS: Okay.

My name is Dylan D'Ascendis and I am a partner at ScottMadden, Inc. I offer testimony on issues involving rate of return. I have testified in over 90 proceedings before 32 regulatory jurisdictions. I'm a graduate of the University of Pennsylvania where I received a bachelor of arts degree in economic history. I also hold an MBA from Rutgers University with concentrations in finance and international business. I am a certified rate of return analyst and a certified valuation analyst.

My prefiled direct testimony recommends a return on common equity, or ROE, in the range of 9.58 percent to 12.30 percent with a point estimate of 10.25 percent. I derived my 10.25 ROE recommendation by applying market-based common equity models, such as the discounted cash flow model, or DCF; the capital asset pricing model, or CAPM; and the risk premium model, or RPM, to a proxy group of risk comparable publicly traded gas distribution utilities and a proxy group of nonregulated companies similar in total risk to the utility proxy group. Applying multiple market-based models to the companies comparable in risk to the regulated utilities consistent with the principals of fair rate of return established in the Hope and Bluefield Supreme Court cases; especially the corresponding risk standard, which mandates that an authorized return on common equity for utilities shall be commensurate with the returns on investments and other enterprises having corresponding risks.

Cost of capital testimony tends to be technical, focusing on the financial models used to estimate the ROE, the inputs to those models, and the results they produce. We must apply those models because, unlike interest rates or the cost of debt, we cannot directly observe ROE. And because no individual model by itself provides the best measure of investor behavior at all times and under all market conditions, it is important to provide -- or apply a variety of methods to estimate the cost of equity.

My prefiled rebuttal testimony updates

my analysis using market data as of July 30, 2021. Those data supported the slightly increased range of ROEs between 9.70 percent and 12.83 percent. I maintain my initial recommendation of 10.25 percent. My prefiled rebuttal testimony also responds to the substantive recommendations offered by Mr. John R. Hinton, who testifies on behalf of Public Staff, and Mr. Kevin O'Donnell, who testifies on behalf of the Carolina Utilities Customers Association in their direct testimonies.

Mr. Hinton's recommended ROE of 9.42 and Mr. O'Donnell's recommended ROE of 9.00 percent are insufficient because of their substantial and exclusive reliance on their DCF model results respectfully, which tends to understate the investor-required return when market-to-book ratios are in excess of 1.0 percent -- or 1.0.

In addition to the above, I address the following issues common to Mr. Hinton's and Mr. O'Donnell's direct testimonies: their selection of their proxy group companies; their choice of growth rates in their DCF models; their application of the comparable earnings model, or CEM; and their failure to reflect flotation costs.

Specific to Mr. Hinton's direct testimony, I address the following: his application of the RPM; his opinion that mechanisms in place for the Company reduce risk; and the use of interest coverage ratios to justify his recommended ROE.

Specific to Mr. O'Donnell's testimony, I address the following: His interpretation of capital market conditions; his use of the plowback ratio in his DCF model; and his application of his CAPM.

In addition to addressing Mr. Hinton and Mr. O'Donnell's direct testimonies, I address Mr. Nicholas Phillip, Jr.'s direct testimony on behalf of Carolina Industrial Group for Fair Utility Rates IV regarding the use of authorized ROEs as relevant benchmarks for the authorized ROE in this case.

My prefiled settlement testimony explains my support for the partial settlement as it relates to ROE and capital structure. I explain that the stipulated ROE of 9.60 percent is slightly below the lower bound of my recommended range. And while it still remains my position that, in a fully litigated proceeding, a range from 9.70 percent to 12.83 percent would represent a reasonable and appropriate measure of the Company's cost of equity. I also recognize that the partial settlements represent the give-and-take among parties regarding multiple otherwise-contested issues.

If it is the Company's determination that the partial settlement is a constructive resolution of the ROE and capital structure, I appreciate and respect that decision.

My prefiled select -- settlement testimony also explains the importance to rating agencies of the regulatory environment support of credit, and notes that North Carolina is generally considered to have a constructive regulatory environment. Since 2017, the average ROE for natural gas distribution utilities across the country has been 9.61, nearly identical to the settlement ROE. Among jurisdictions that, like North Carolina, is seen as having constructive regulatory environments, the average ROE was 9.78 percent, 18 basis points above the settlement ROE.

In view of returns authorized in regulatory jurisdictions in general, and in constructive regulatory jurisdictions such as North Carolina, the settlement ROE is a somewhat conservative measure of the Company's cost of equity. Similarly, the 51.60 percent equity ratio falls well within the range of those approved in more constructive regulatory jurisdictions.

Lastly, I understand and appreciate the Commission must apply its informed judgment at arriving at its ROE determination in this and all proceedings. I also appreciate, in the setting of the Company's rates, the Commission must balance the interest of the Company, customers, and investors. And I appreciate that, in doing so, the Commission considers the effect of changing economic conditions on the Company's customers.

In my settlement testimony, I discuss economic conditions in North Carolina and the United States, which continues to support my conclusion as presented in my prefiled direct testimony, that the regional economic conditions in North Carolina are substantially similar to those in the rest of the country, such that the market results of the nationwide proxy group remain applicable to the Company.

That concludes the summary of my testimonies.

Q. Thank you, Mr. D'Ascendis.

MR. JEFFRIES: Chair Mitchell, Mr. D'Ascendis is available for cross and Commission questions.

CHAIR MITCHELL: All right. Attorney General's Office?

MS. FORCE: No questions.

CHAIR MITCHELL: Okay. All right. My notes indicate that no other party has questions for the witness, but I will just make sure before we move on to Commission questions.

(No response.)

CHAIR MITCHELL: All right. I'm not hearing any. So questions from Commissioners?

(No response.)

CHAIR MITCHELL: All right. Mr. D'Ascendis, you are off the hook this morning. All right, sir, you may step down.

Mr. Jeffries, do you intend to recall the witness?

MR. JEFFRIES: We do not, Chair Mitchell.

CHAIR MITCHELL: All right. Mr. D'Ascendis, you may step down and be excused as well. Thank you, sir.

THE WITNESS: Thank you. Have a good day, everybody.

CHAIR MITCHELL: All right. Mr. Jeffries, I'll take a motion from you.

MR. JEFFRIES: Thank you, Chair Mitchell. We would move that Mr. D'Ascendis' prefiled exhibits to his direct, rebuttal, and settlement testimony be entered into evidence in the docket.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Mr. Jeffries, it will be allowed, and the exhibits to the direct, rebuttal, and settlement testimony of Mr. D'Ascendis will be accepted into the record.

(Exhibits DWD-1 through DWD-8, Rebuttal Exhibit DWD-1 consisting of Schedules DWD-1R through DWD-14R, and Settlement Exhibit DWD-1, were admitted into evidence.)

MR. JEFFRIES: Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. Piedmont, you may call your next witness.

MR. JEFFRIES: Chair Mitchell, Piedmont would call Ms. Pia Powers to the stand.

CHAIR MITCHELL: All right. Ms. Powers, good morning, there you are. Raise your right hand, please, ma'am.

Whereupon,

PIA K. POWERS,

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

CHAIR MITCHELL: All right, Mr. Jeffries.

MR. JEFFRIES: Thank you.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Good morning, Ms. Powers.

A. Good morning.

Q. Could you state your name and business address for the record, please.

A. Sure. My name is Pia Katherina Powers. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. And where do you work, Ms. Powers?
A. Piedmont Natural Gas.
Q. And what's your position at Piedmont?
A. My position is managing director of gas rates and regulatory.
Q. All right. Are you the same Pia Powers that prefiled direct testimony in this proceeding on March 22, 2021, consisting of 24 pages and Exhibits PKP-1 and PKP-2?
A. I am.
Q. And you're also the same Ms. Powers that prefiled settlement testimony in this proceeding on September 7, 2021, consisting of 15 pages, and Settlement Exhibits PKP-1 and PKP-2, correct?
A. Correct.
Q. Do have you any corrections to your prefiled testimony or exhibits?
A. I do not.
Q. If I asked you the same questions that are set forth in your prefiled testimony while you were on the stand today, would your answers be the same as are reflected in your prefiled testimony?
A. Yes, they would.
Q. Thank you.

MR. JEFFRIES: Chair Mitchell, we'd move that Ms. Powers' prefiled direct and prefiled settlement testimony be entered into the record as if given orally from the stand.

CHAIR MITCHELL: Hearing no objection, Mr. Jeffries, to your motion, the prefiled direct -- the testimony -- direct testimony of Piedmont witness Powers prefiled in this docket on March 22nd shall be copied into the record as if delivered orally from the stand. In addition, the settlement testimony of Piedmont witness Powers prefiled in this docket on September 7th shall be copied into the record as if delivered orally from the stand.

(Whereupon, the prefiled direct testimony and prefiled settlement testimony of Pia K. Powers was 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

## Direct Testimony and Exhibits
## of
## Pia K. Powers

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**March 22, 2021**

**Q. Please state your name and business address.**

A. My name is Pia K. Powers. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

**A.** I am the Managing Director – Gas Rates & Regulatory for Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company"). In this capacity, I am responsible for a variety of regulatory matters including the development and execution of all rate requests, financial report filings and other filings and requests by Piedmont to its state economic regulators.

**Q. Please describe your educational and professional background.**

A. I have a Bachelor of Arts degree in economics from Fairfield University and a Master of Science degree in environmental and resource economics from the University College London. Between earning my degrees, I undertook a year of research and study in Malta on economic development under a grant awarded by the Fulbright U.S. Student Program. From 1999 through 2003, I was employed as an Economist with the Energy Information Administration, the statistical agency of the U.S. Department of Energy, where I focused on international energy forecasting and environmental issues. I was hired by Piedmont as a Regulatory Analyst in 2003. In the time thereafter, I took on several roles of increasing responsibility within the Company. In 2019, I assumed my current position as Managing Director of Gas Rates & Regulatory.

**Q. Have you previously testified before this Commission or any other regulatory authority?**

**A.** Yes. I have presented testimony before the North Carolina Utilities Commission ("Commission" or "NCUC"), the Public Service Commission of South Carolina, the Tennessee Public Utility Commission and its predecessor the Tennessee Regulatory Authority on a number of occasions.

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

A. The purpose of my testimony in this proceeding is to support Piedmont's petition and the rate relief sought therein. Specifically, my testimony addresses the following subjects: (1) the nature and scope of Piedmont's revenue request in this proceeding; (2) the impact of the revenue request on customers; (3) customer-supportive actions that the Company has and continues to offer during this unprecedented pandemic; (4) the public benefits inherent in the continued operation of our Integrity Management Rider ("IMR") mechanism; (5) a proposed rider mechanism for the Company's ongoing recovery of expenditures for its customer Energy Efficiency Programs; and (6) other proposed changes to Piedmont's Tariff, which consists of its various Rate Schedules and Service Regulations.

**Q. Do any exhibits accompany your testimony?**

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

Exhibit__(PKP-1) Tariff Changes in red-line format

Exhibit__(PKP-2) Tariff Changes in clean format

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

A. Yes.

**Piedmont's Revenue Request**

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

A. Piedmont is requesting approval of revised rates in support of an annual cost of service increase of approximately $109 million in this proceeding.

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

A. Yes. Our filed revenue request in this proceeding represents a 10.4% increase to operating revenues needed to cover the Company's current level of cost for the continued provision of safe, adequate and reliable natural gas service to the Company's customers in North Carolina. Absent the proposed rate adjustment, the Company would yield an insufficient overall rate of return of 5.54% and a return on equity of 6.92%. These returns are significantly lower than the respective returns of 7.14% and 9.70% upon which rates were established in Piedmont's last general rate case.

These low returns, which drive the Company's need for the

10.4% increase in operating revenues, are predominantly a result of the Company's incremental utility gas plant investment that has not been eligible for recovery through the IMR mechanism since the Company's last general rate case. Such incremental plant investment amounts to approximately $1.2 billion, and was required to provide for the ongoing provision of reliable and safe natural gas service to Piedmont's customers throughout North Carolina. In other words, $1.2 billion of the $7.2 billion of Piedmont's pro forma North Carolina plant in service in this proceeding is currently not being recovered through current customer rates and charges, and now needs to be incorporated into Piedmont's base rates.

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

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

A. Piedmont's revenue request in this docket, if granted without modification, would increase Piedmont's annual revenue by approximately $95 per residential customer (or an average monthly increase of just under $8).[1] The Company recognizes that this is a

[1] Table 3 within the direct testimony of Piedmont witness Kally Couzens demonstrates that Piedmont is seeking to increase the annual revenue from the residential class of customers by approximately $65.82 million. Piedmont has approximately 693,000 residential customers in North Carolina. Therefore, the requested revenue increase per residential customer is $95 ( = $65.82 million ÷ 693,000 customers).

meaningful increase for our residential customers only two years after our last rate case but it is necessary in order to allow the Company to earn a reasonable return on invested capital. In evaluating this increase, I think it is important to put the Company's proposed revenue increase in context.

The costs to customers of natural gas service on Piedmont's system previously peaked in 2008 when the commodity cost of natural gas was regularly above $10.00 per dekatherm. In the Fall of 2008, the impact of dramatically lower natural gas costs began to be felt as a result of natural gas production from shale being delivered into the eastern United States. Since 2008, the price of natural gas has been dramatically lower than it was prior to that time – mostly in the $2.00 to $4.00 per dekatherm range. In the interim period, this has allowed Piedmont to provide service to customers at total costs below what they experienced in 2008 even after billions of dollars of additional plant investment by the Company. We are now approaching total annual costs for gas service that approximate those that were incurred roughly 13 years ago. Thus, while the revenue increase requested in this docket is meaningful, by historic standards, the overall cost of natural gas service has been and continues to be reasonable and remains at levels approximating service provided more than a decade ago. I am not familiar with any other essential utility service that can make a comparable claim.

I would also note that Piedmont has achieved significant efficiencies in its annual operations and maintenance expenditures since its merger with Duke Energy, which Piedmont's customers benefit from through the ratemaking process in proceedings such as this one.

**Q. How will Piedmont address any negative impacts of the requested rate increase on its customers?**

A. Some of our customers struggle to pay our bills. We are aware that any increase in rates will make that struggle more difficult. With rate relief properly aligned to the Company's actual cost of service, Piedmont is able to maintain the flexibility and wherewithal to continue to offer and provide extended deferred payment options for customers who are experiencing difficulty in meeting their payment obligations. Piedmont also scrupulously abides by the Commission's billing requirements, as well as its disconnection procedures in the small number of cases where termination of service for non-payment becomes necessary as a last resort measure.

**Q. What is the overall economic context to Piedmont's revenue request and requested rate of return on common equity?**

A. Our requested rate of return on common equity is relatively low by long-term historical standards and at the lower end of the indicated range of common equity cost rates as shown in the direct testimony of Piedmont witness Dylan D'Ascendis. As explained in his testimony, although economic conditions in North Carolina declined significantly in the second quarter of 2020 as a result of the COVID-19 pandemic, they improved considerably in the third and fourth quarters. North Carolina's unemployment rate and the rate in the counties served by Piedmont have fallen significantly since spiking in April 2020. While economic conditions remain uncertain, North Carolina and the counties contained within Piedmont's service area appeared to have fared better than the rest of the U.S. during the COVID-19 pandemic.

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

A. Yes. Piedmont witness D'Ascendis reached the same conclusion in Section VIII of his direct testimony. Having said that, I would also emphasize that Piedmont's return on equity request in this docket is at the lowest rate it has requested from the Commission in the last 30 years and, as I previously noted, is at the lower end of Piedmont witness D'Ascendis' range based on uncertainty about the strength and pace of recovery coming out of the pandemic.

**<u>Increased Customer Support During this Pandemic</u>**

**Q. Is the Company providing any additional support to its customers in light of the financial challenges that some are facing during the coronavirus pandemic?**

A. Yes. Piedmont responded at the start of the pandemic by voluntarily instituting many of the measures that the Commission subsequently mandated in terms of customer disconnection policy and the assessment of late payment and other fees. The Company continues to engage in proactive communications with its customers, using multiple communication channels to advise them of the various options they may pursue to alleviate the burden of the past due balance on their account (not just their past due balance as of August 31, 2020, which was required to be accommodated by extended payment arrangements per the Commission's July 29, 2020 Order in Docket No. G-9, Sub 767) and opportunities to seek financial assistance from agencies. The Company continues to offer all customers a no-interest extended payment arrangement on their present past due balance, and restructure payment arrangements that some customers previously elected but now desire to lengthen to the maximum offering and/or roll-in further past due amounts that have accrued. For residential customers whose household is eligible to receive assistance from the Low-Income Energy Assistance Program ("LIEAP"), the Crisis Intervention Program ("CIP") or the North Carolina Housing Opportunities and Prevention of Evictions Program ("NC HOPE"), Piedmont voluntarily suspended disconnections through March 31, 2021, offering new 12-month extended payment arrangements for these customers for their past due balance; Piedmont subsequently modified the arrangements for these customers to 18-month extended repayment plans in compliance with the Commission's February 23, 2021 Order in Docket No. G-9, Sub 767.

In Fall 2020, after the Commission's lifting of the moratorium on utilities for disconnection of service to customers for non-payment of their bills, the Company approached the resumption of service disconnections to customers for non-payment with significant caution, care and as a measure of last resort for any customer. The Company continues to approach it in this matter. For example, in mid-November 2020, the Company recognized that it did not have access to information that would comprehensively identify which of its .7 million residential customers in North Carolina applied for financial assistance from the NC HOPE Program, which had recently been established to provide utility bill assistance. Piedmont immediately and voluntarily suspended its actions to disconnect service for non-payment to its North Carolina residential customers until such time that Piedmont could identify every residential customer account that was associated with a request for assistance from the NC Hope Program. Completion of that process took approximately four weeks, based upon applicant information shared directly with the Company upon its request to the NC HOPE Program. Whereas it was not known at that time which of the customer applicants would ultimately be granted assistance from the NC Hope Program, the Company chose to forgo disconnecting any such customer until the NC HOPE Program fully processed their application. As of March 15, 2021, Piedmont has received NC Hope Program funds on behalf of 1,145 recipient residential customers accounts amounting to a total of $280,233.

It is the Company's desire for any customer who is eligible for disconnection of their natural gas service due to non-payment, to either make payment on their past due amount or enter into one of the multiple extended payment arrangement offerings by the Company. Either of these actions by the customer will avoid disconnection of their natural gas service for non-payment. The Company takes every reasonable communication measure to ensure the customer is aware of and has the opportunity to request an extended payment arrangement from the Company and to obtain financial assistance from agencies prior to disconnecting service for non-payment. Since the Company resumed disconnection of non-payment to customers at the beginning of November 2020, Piedmont has disconnected natural gas service to 1,994 residential customer accounts for non-payment, compared to 3,843 during that same period of time the year before.[2]

[2] Counts reflect the number of residential accounts that were disconnected for non-payment during the period of time covering November through February.

**Continuation of Piedmont's IMR Mechanism**

**Q. What is the status of Piedmont's IMR mechanism?**

A. Piedmont's IMR mechanism in its original form took effect on January 1, 2014 pursuant to the Commission's Order in Piedmont's 2013 general rate case.[3] It was modified in 2015.[4] In its Order issued October 30, 2019 in Docket No. G-9, Sub 743 ("2019 Rate Case Order"), the Commission approved a stipulation that provided for the continuation of Piedmont's IMR mechanism, including certain additional modifications to the computation of the net IMR revenue requirement, effective November 1, 2019.[5] The IMR mechanism, which is set within Piedmont's Tariff in Appendix E of Piedmont's North Carolina Service Regulations, states in paragraph 11 that the terms and conditions of the IMR mechanism shall be reviewed, and prospective modifications considered by the Commission the earlier of four years or the Company's next general rate case. Piedmont is requesting as part of this general rate case that it be allowed to continue operation of the IMR mechanism for an additional four-year term.

**Q. Can you provide an overview of why you believe that a**

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[3] See the Commission's December 17, 2013 *Order Approving Partial Rate Increase and Allowing Integrity Management Rider* in Docket No. G-9, Sub 631.
[4] See the Commission's November 23, 2015 *Order Approving Stipulation* in Docket Nos. G-9, Sub 631 and Sub 642.
[5] See paragraph 9 of the Stipulation filed in Docket No. G-9, Sub 743 on August 13, 2019. The Stipulation was approved by the Commission in their October 31, 2019 *Order Approving Stipulation, Granting Partial Rate Increase, Line 434 Revenue Rider, EDIT Riders, Provisional Revenue Rider, and Requiring Customer Notice* in Docket No. G-9, Sub 743.

**continuation of the IMR mechanism is in the public interest?**

A. Yes. As the Commission is well aware and as is supported in the testimony of Piedmont witness Brian Weisker, Piedmont has made capital investments in its system of more than a $365.9 million[6] since its last general rate case (from 6/30/2019 to 12/31/2020) in its efforts to comply with the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") Transportation Integrity Management Plan ("TIMP") and Distribution Integrity Management Plan ("DIMP") requirements. Piedmont has also needed to make extraordinary system strengthening and growth-driven capital investments in its system over this same period of time, which are investments other than those driven by compliance with PHMSA's federal safety and system integrity requirements. These other capital investments, which were not eligible for recovery through the IMR mechanism, ultimately gave rise to the Company's need to request rate relief two years after the Company's last general rate case. Nevertheless, the Company's PHMSA compliance-related capital investment were necessary and significant, and will continue to be so over the next several years. The continued operation of the IMR mechanism permits Piedmont an opportunity to begin recovering and earning a return on most of

[6] Amount reported in Schedule 1 of the Company's IMR Monthly Report for December 2020 filed in Docket No. G-9, Sub 642 on February 15, 2021.

its PHMSA compliance-related capital investment, and will mitigate the financial pressure on the Company to file for general rate relief with frequency going forward. General rate cases come at a significant cost, typically in excess of a million dollars each, in rate case expense – not to mention the time and administrative burden on all parties (including the Commission) associated with preparing, prosecuting, and resolving each such case. I believe that the public interest inherent in the reduced frequency of general rate cases is compelling.

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

A. Yes. As is reflected in Exhibit_(BRW-2) accompanying Piedmont witness Weisker's testimony, the ongoing level of integrity management capital investment is expected to vary between approximately $188 million and $417 million per year over the next three years. Based upon these projections, we believe that the same factors that supported the operation of the IMR over the last seven years continue to support its operation over the next four years and we respectfully request that the Commission approve such continuation in this docket.

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

A. Yes. In order to update our existing IMR mechanism, we have proposed certain necessary updates for the IMR to properly function prospectively. These updates are discussed later in my testimony along with other proposed changes to Piedmont's Tariff.

**Rider Mechanism for Energy Efficiency Program Cost Recovery**

**(Proposed Appendix H to Piedmont's Tariff)**

**Q. Is Piedmont proposing in this proceeding to change the method by which it recovers costs for the operation of its Energy Efficiency Programs for customers?**

A. Yes. At present, the cost associated with Piedmont's operation of its Energy Efficiency Programs for its North Carolina customers is recovered through its base rates. Piedmont has been operating three customer Energy Efficiency Programs in North Carolina for over 10 years. Piedmont's current base rates were established in the Company's last general rate proceeding, where the approved cost of service included $1.275 million of expense for the operation of its Energy Efficiency Programs for its North Carolina customers. The Company proposes in this proceeding to modify the method by which it recovers Energy Efficiency Program expenses. In lieu of base rate recovery, Piedmont requests that effective November 1, 2021 this operating expense be recovered through a separate rider mechanism. A description of this new rider mechanism is shown in proposed Appendix H of Piedmont's North Carolina Service

Regulations, which is included in the proposed Tariff changes shown in Exhibit_(PKP-1) and Exhibit_(PKP-2).

**Q. Why is Piedmont proposing to recover the ongoing expense for operation of its Energy Efficiency Programs for customers through a separate rider instead of through base rates going forward?**

A. Going forward, there will likely be more variability to the annual expense that Piedmont incurs to operate its NC Energy Efficiency Programs. Piedmont has recently requested approval from the Commission, in Docket No. G-9, Sub 786, to amend one of its existing Energy Efficiency Programs and to operate three additional Energy Efficiency Programs ("EE Program Request").[7] Should the Company's EE Program Request be approved by the Commission, the annual expense of operating its suite of six Energy Efficiency Programs is expected to range from $2.8 million to $4.5 million per year during the next five years.[8] Variability in the expected total annual expense is inherent to the process of ramping up new, incremental programs, setting up an evaluation, measurement and verification plan for the programs, and considering uncertain customer demand for program incentives that is often experienced

[7] See the Request for Modifications to Existing Energy Efficiency Program and for Approval of New Energy Efficiency Program ("EE Program Request") filed with the Commission on March 19, 2021 in Docket No. G-9, Sub 786.
[8] See Exhibit A of Piedmont's EE Program Request.

without a regular, predictable cadence.

Base rate recovery makes sense when there is a reasonable degree of certainty about the going level expense amount, which is often talked about in terms of being a known and measurable amount. With respect to the Company's Energy Efficiency Programs for its customers, there is a reasonable degree of certainty that there will be significant variability in the annual expense year-over-year for the foreseeable future. Recovering the actual Energy Efficiency Program expenses through a rider mechanism in lieu of base rates supports the Company's continued, uninterrupted operation of these customer programs and would ensure that the program expenses are ultimately neither over- nor under-recovered.

In the event that the Commission does not accept the Company's rider proposal in Appendix H, Piedmont requests Commission approval for regulatory asset treatment for its Energy Efficiency Program expenses effective November 1, 2021. Regulatory asset treatment would be an alternative method to ensure that the Energy Efficiency program expenses are ultimately neither over- nor under-recovered, albeit inferior to the rider method because regulatory asset treatment may lead to larger swings in customer bills due to less frequent true-up of the deferred balance compared to the rider mechanism.

**Q. Please describe the operation of the Energy Efficiency Program**

**rider proposed in Appendix H of the Company's North Carolina Service Regulations.**

A. The Company proposes to defer all Energy Efficiency Program expenses starting November 1, 2021. The Energy Efficiency Program rider rates would be set to $0.00000 per therm effective November 1, 2021. On or before May 15, 2022, Piedmont will file with the Commission a report of the Energy Efficiency Program expenses deferred through March 31, 2022. The May 15, 2022 filing will also include proposed customer billing rates (rates per therm) for this rider, designed to recover the March 31, 2022 deferred account balance, including accrued interest, over the twelve-month period beginning June 1, 2022. For computation of such proposed rider rates, the March 31, 2022 deferred account balance will be allocated to each rate schedule in alignment with the allocation of base margin revenues as set by the final Commission order in this proceeding. Annualized throughout for each rate schedule underlying the proposed volumetric rider rates will also be identical to that approved by the Commission for volumetric rates in this general rate proceeding. Each month beginning June 2022, Piedmont will record to the Energy Efficiency Program expense deferred account incremental deferred program expenses net of the rider revenue collections from customers. Each year thereafter on or before May 15, the Company will file to update the rider rates effective the following June 1 based on the prior March 31 deferred account balance. Furthermore, Piedmont proposes to file monthly reports with the Commission detailing the activity in the Energy Efficiency Program deferred account.

**Q. Does Piedmont expect that the Public Staff will review and audit the Company's operation of Appendix H, including the prudence of the deferred Energy Efficiency Program expenses and accuracy of the Company's March 31 deferred account balances used for rate setting?**

A. Yes. I envision that any audit adjustments that the Public Staff may recommend for a review period (an annual period ending March 31) could be documented in their audit report and filed for approval with the Commission. Any such audit adjustments approved by the Commission could then be rolled-into the March 31 balance next used for rate setting under the rider. This recommended process is similar to how the Public Staff currently audits the Company's IMR mechanism, which I believe has been an effective and efficient process for both parties.

**<u>Other Changes to Piedmont's Tariff</u>**

**Q. In addition to proposed Appendix H to the Company's North Carolina Service Regulations discussed above, is Piedmont proposing any other changes to its North Carolina Tariff?**

A. Yes. The Company is proposing a handful of changes to streamline the Tariff, namely for the purpose of removing outdated, duplicative, incorrect or unnecessary terminology and references, updating forms, eliminating dormant Rate Schedules, and clarifying internal procedures. The proposed changes to Piedmont's Tariff are shown in red-line and clean format in Exhibit_(PKP-1) and Exhibit_(PKP-2), respectively. The Tariff changes other than proposed Appendix H, which has been previously explained in my testimony above, are summarized as follows:

1) Rate Schedule 107: The main changes are the elimination of the obsolete reference to Standby Sales Service, which no longer exists as part of Rate Schedule 113, and the update of the Agency Authorization Form including the Company's current contact information.

2) Rate Schedules 113 and 114: The main change is the insertion of the requirement that service under these two Rate Schedules is contingent upon the Company's installation of telemetering equipment that reports daily consumption. This change is simply for transparency of the requirement within the Company's Tariff. Such telemetering equipment continues to be needed by the Company in order to properly operate its system, render accurate bills to the customer and their agent, and enforce other provisions within its existing Tariff. Such telemetering equipment is already in place for all customers currently served

under this Rate Schedule.

3) Rate Schedules 12 and T-12: The Company proposes that these two Rate Schedules be eliminated. No customers will be impacted by this change because no customers were provided or billed for service under either of these two Rate Schedules during the Test Period, in several years prior to the Test Period, or in the period of time since the Test Period. For this reason, I do not find this proposed change to be material. Since there were no costs incurred nor revenues recorded in the Test Period associated with this Rate Schedule, it was not necessary for the Company to include a pro forma adjustment for this change in its cost of service computation in the proceeding.

4) Rate Schedule 143: One proposed change in this Rate Schedule is to remove reference to Rate Schedules 12 and T-12, since the Company intends to eliminate these two Rate Schedules for the previously explained reason. The other proposed change is to remove 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. This Rate Schedule, including the provision for the original two-year review, took effect on March 28, 2014 pursuant to the Commission authorization granted in Docket No. G-9, Sub 631. The Company subsequently requested authorization to continue the

provision of service under this Rate Schedule after the original two-year period, and such relief was ultimately granted by the Commission pursuant to its February 7, 2017 Order ("2017 Order") in Docket No. G-9, Sub 631. In addition to the authorization for the Company's continued provision of service under this Rate Schedule, the 2017 Order required that in Piedmont's next general rate case the rates for all customer classes including natural gas vehicular fuel ("NGV") services, be evaluated based on the results of an allocated cost of service study and other rate design factors. This requirement was met in Docket No. G-9, Sub 743, Piedmont's 2019 general rate case. No changes or additional conditions on Piedmont's provision of service under Rate Schedule 143 occurred as a result of Docket No. G-9, Sub 743. Accordingly, Piedmont now seeks to remove this outdated, obsolete provision from this Rate Schedule.

5) Appendix B of Piedmont's Service Regulations: The proposed changes are administrative in nature – to correct typographical errors related to a defined term in Piedmont's Service Regulations, and to clarify the Company's internal procedures. The latter change was proposed in the Company's 2019 general rate case; no party objected to that proposed change, however due to an oversight it was not captured in the settlement agreement that was ultimately approved by the Commission in that proceeding.

6) Appendix E of Piedmont's Service Regulations: One

proposed change in this Rate Schedule is to remove reference to Rate Schedules 12 and T-12, since the Company intends to eliminate these two Rate Schedules for the previously explained reason. The other proposed changes are to update the Special Contract Credit amounts, the allocation factors and the annual billing determinants, as is necessary for this IMR mechanism with each new general rate case proceeding.

**Q. Does Piedmont's recently filed petition seeking approval for new Appendix G to its North Carolina Service Regulations impact the relief requested by the Company in this general rate case proceeding?**

A. No. Piedmont is requesting approval of Appendix G to its North Carolina Service Regulations in a separate docket (Docket No. G-9 Sub 784) that was filed with the Commission on March 15, 2021. Proposed Appendix G therein describes an elective program offering for Piedmont's residential and small general service customers to mitigate the carbon footprint impact of their natural gas usage. No aspect of the prospective operation of Appendix G contributes to the requested rate increase being sought by the Company in this general rate case, or otherwise impacts the cost of service computation or other matters in this general rate case.

**Q. Are there any other Tariff changes that you are proposing in this proceeding?**

A. No. However, I want to acknowledge and bring closure to one Tariff-related matter, namely the "Line 434 Revenue Rider" that is discussed in paragraph 31 of the Stipulation that was approved by the Commission in Piedmont's 2019 Rate Case (Docket No. G-9, Sub 743).[9] In that Stipulation, it states the following:

> With regard to any demand charges that may begin to be recovered by Piedmont subsequent to the effective date of the rates approved in this case related to Line 434, but before the effective date of the next general rate case, Piedmont agrees that it will begin contemporaneously flowing through such revenues to reduce the rates of its customers through a separate rate rider (Line 434 Revenue Rider). For purposes of the rates made effective as part of this proceeding, the Line 434 Revenue Rider (including all related billing factors) will be initially set to $0.0000 per dt. Piedmont shall make a filing with the Commission setting forth and requesting approval of the Line 434 Revenue Rider it proposed to put in place to flow through such revenues to its customers. These rates shall be based on the rate class margin percentages approved in the IMR mechanism. Piedmont and the Public Staff shall consult with each other regarding the calculation and determination of the Line 434 Revenue Rider billing factors prior to and at the times Piedmont filed for any changes to those factors. The Line 434 Revenue Rider established in this proceeding shall remain in effect until such time as it can be incorporated into base rated in the first general rate case proceeding after beginning of the receipt of demand charges. The appropriateness and necessity of continuing, modifying, replacing, or eliminating the Line 434 Revenue Rider shall be considered in said general rate case.

[9] See the Stipulation filed in Docket No. G-9, Sub 743 on August 13, 2019. The Stipulation was approved by the Commission in their October 31, 2019 *Order Approving Stipulation, Granting Partial Rate Increase, Line 434 Revenue Rider, EDIT Riders, Provisional Revenue Rider, and Requiring Customer Notice* in Docket No. G-9, Sub 743.

To date, Piedmont has not billed nor otherwise recovered any demand charges related to Line 434. For this reason, Piedmont has had no cause to make a subsequent filing with the Commission seeking to amend the Line 434 Revenue Rider from its initial rate of $0.0000 per dekatherm set in Docket No. G-9, Sub 743. The cancellation of the Atlantic Coast Pipeline eliminated the opportunity for Piedmont to recover demand charges related to Line 434. Furthermore, Line 434 continues to be used and useful in the provision of reliable natural gas service to Piedmont's customers. Since there is no longer a practical need to have a Line 434 Revenue Rider, Piedmont requests that the Commission eliminate this Rider, including eliminating the need for any further reference in future reporting to the Commission of the $0.0000 per dekatherm Line 434 Revenue Rider rate.

**Q. Do you have anything further to add to your testimony?**

A. No, not at this time. Thank you.

# Before the North Carolina Utilities Commission

## Docket No. G-9, Sub 781

## General Rate Case

## Settlement Testimony and Exhibits of Pia K. Powers

## On Behalf Of Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

September 7, 2021

**Q. Ms. Powers, please state your name and business address.**

A. My name is Pia K. Powers. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

**Q. Are you the same Pia K. Powers who prefiled direct testimony in this docket on March 22, 2021?**

A. Yes, I am.

**Q. What is the purpose of your Settlement Testimony in this proceeding?**

A. My Settlement Testimony explains the economic adjustments to Piedmont's filed case[1] as reflected in the Stipulation of Partial Settlement ("Stipulation") between Piedmont and the Public Staff - North Carolina Utilities Commission ("Public Staff"), the Carolina Utility Customers Association, Inc. ("CUCA"), and the Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR IV") (together, the "Stipulating Parties"). My Settlement Testimony also addresses certain other components of the Stipulation.

**Q. Do you have any exhibits supporting your testimony?**

A. Yes. I have two. Settlement Exhibit__(PKP-1) is a reconciliation chart identifying the settled adjustments to Piedmont's rate increase request, wholly excluding the estimated amounts for the Company's Robeson LNG and Pender-Onslow projects. Settlement Exhibit__(PKP-2) is a similar reconciliation chart, although it is inclusive of the estimated impact of these projects.

1 Including Piedmont's rate case Update Filing to the NCUC on July 28, 2021.

**Q. Was this exhibit prepared by you or under your direction and supervision?**

A. Yes.

**Q. Can you explain how the Public Staff pursued its investigation in this matter?**

A. Following the filing of our Application and supporting testimony, the Public Staff engaged in substantial discovery regarding our filing. This included more than 840 individual data requests (not counting parts and subparts) in 137 sets of discovery requests. When Piedmont filed its cost-of-service update on July 28, 2021 ("Update Filing"), the Public Staff also engaged in a due diligence review of the Update Filing.

**Q. How did the Public Staff and Piedmont go about pursuing settlement discussions in this case?**

A. We met with the Public Staff via video conference on several occasions to explore and vet mutually agreeable terms for a settlement. Our initial discussions were aimed at making sure we had a common understanding of our respective litigation positions and filed testimony. After we completed these discussions, we moved on to substantive settlement negotiations and we were able to reach agreement on several issues in this case between Piedmont and the Public Staff. This agreement is reflected in the Stipulation filed concurrently with this testimony.

**Q. Has Piedmont attempted to reach a settlement with the other parties to this case?**

A. Yes. We have held discussions with CUCA and CIGFUR IV in an effort to obtain their consent to join in the settlement and we were able to do so after reaching a proposed rate design that is acceptable to all. We did not reach out to the Attorney General, NUCOR or the Fayetteville Public Works Commission as these parties did not file testimony in this proceeding.

**Q. Do you believe the settlement with the Public Staff is in the public interest and otherwise just and reasonable?**

A. Yes. The Stipulation results in substantial economic benefits to our customers through the cost reductions agreed to with the Public Staff. It also avoids the expenditure of assets that would otherwise be necessary to litigate each of the contested issues in this docket and provides greater certainty of outcome to the Stipulating Parties.

**Q. Can you provide a brief overview of the revenue impact associated with the Stipulation?**

A. Yes. The main revenue impact of the Stipulation pertains to the adjustment of Piedmont's base margin revenues. The Stipulation shows that base margin revenue in two ways – excluding the Robeson LNG and Pender-Onslow projects (Settlement Exhibit A1), as well as inclusive of the estimated amounts for the Robeson LNG and Pender-Onslow projects (Settlement Exhibit A2). Settlement Exhibit_(PKP-1) and Settlement Exhibit__(PKP-2) are aligned with Settlement Exhibits A1 and A2, respectively. Exclusive of the Robeson LNG and Pender-Onslow projects, the settled base margin revenue requirement increase is approximately $34.1 million, which is shown on Line 46 of Settlement Exhibit_(PKP-1). Inclusive of the estimated amount of the Robeson LNG and Pender-Onslow projects, the settled base margin revenue requirement increase would be approximately $67.1 million, which is shown on Line 46 of Settlement Exhibit_(PKP-2).

There are two other revenue impacts associated with the Stipulation. The first impact pertains to cost of gas ("COG") revenues. The Stipulation calls for a change to the base COG revenues, which are reflected identically on Lines 47 thru 49 on each of my settlement exhibits. The effect of the settled change to the base COG revenues is an increase of $6,931,287. The base COG revenue adjustment has no direct impact to Piedmont's earnings. Rather, the purpose of the adjustment is to better align Piedmont's going-level COG expense with its base COG revenues, all of which may also be further modified as needed pursuant to the procedures for rate adjustments set forth under G.S. 62-133.4 and Appendix A of Piedmont's North Carolina Service Regulations.

The second impact is a flow-thru update pertaining to the riders established in Piedmont's last general rate case[2] for the refund to customers of excess deferred income taxes ("EDIT"). The amortization period for two of the three EDIT riders established in Piedmont's last general rate case has not yet concluded – specifically, the riders to refund

2 Docket No. G-9, Sub 743

to customers unprotected federal EDIT and state EDIT are set to conclude on October 31, 2024 and October 31, 2022, respectively. The Company's approved overall rate of return was a component used in the calculation of annual revenue requirement impact for each of these two EDIT riders in the Company's last general rate case. Since the outcome of this current general rate case will modify Piedmont's approved overall rate of return, the Stipulation updates these two EDIT riders over their remaining amortization periods for the effect of the stipulated overall rate of return. The total annual refund to customers for unprotected federal EDIT was updated to $(25,562,970) as shown on Line 51 of each of my settlement exhibits, which is a difference of $(2,258,701) from the approved amount in the Company's last rate case. The total annual refund to customers for state EDIT was updated to $(22,201,275) as shown on Line 52 of each of my settlement exhibits, which is a difference of $(1,466,121) from the approved amount in the Company's last rate case.

**Q. What is the expected revenue impact associated with the Stipulation once updated for the actual cost of the Robeson LNG and Pender-Onslow projects as of August 31, 2021?**

A. The Company's accounting books and records for the month of August 2021 will be finalized within a few days. For this timing reason, it was not feasible to incorporate the effect of the August 31, 2021 "actuals" for these two projects into Settlement Exhibit_(PKP-2) nor the exhibits supporting the Stipulation. Nevertheless, the revenue impact of incorporating the actual Robeson LNG and Pender-Onslow costs as of August 31, 2021 is expected to be very close to that shown in Settlement Exhibit__(PKP-2). In other words, it is expected to yield a stipulated margin revenue increase between approximately $67 million and $68 million.

**Q. Please explain the adjustments to Piedmont's cost of service as agreed to in the Stipulation, and the associated impact to the margin revenue requirement.**

A. The individual cost of service adjustments are identified on my settlement exhibits attached hereto and represent, in aggregate, a downward adjustment from Piedmont's proposed annual margin revenues in its Update Filing. The cumulative impact to margin revenues of each of these cost of service adjustments is shown on Line 45 of each of my settlement exhibits. Excluding the Robeson LNG and Pender-Onslow projects, the Stipulation includes approximately ($62.7 million) of cost of service adjustments impacting base margin revenues. Including the Robeson LNG and Pender-Onslow projects, the Stipulation includes approximately ($29.7 million) of cost of service adjustments impacting base margin revenues.

The individual cost of service adjustments in the Stipulation can be categorized as follows:

1. <u>Capital Structure and Cost of Capital</u>. The Stipulating Parties agreed that the appropriate capital structure for use in this

proceeding consists of 51.60% common equity, 47.75% long-term debt, and 0.65% short-term debt. The agreed cost of long-term debt is 4.08% and the agreed cost of short-term debt is 0.20%. The agreed return on common equity appropriate for use in this proceeding is 9.60%. These modifications resulted in a downward adjustment to Piedmont's margin revenue requirement of approximately ($22.7 million), which is represented on both of my settlement exhibits as the sum of Lines 4 thru 7.

2. Other Operating Revenues. The Stipulating Parties agreed to use in the cost of service computation an increased level of pro forma other operating revenues. This settlement modification resulted in a downward adjustment to Piedmont's margin revenue requirement of approximately ($1.9 million), which is represented on both of my settlement exhibits on Line 14.

3. Employee Compensation. The Stipulating Parties agreed to remove certain employee compensation costs for ratemaking, including a portion of executive payroll, and certain incentive pay. Adjustments were also agreed upon regarding the going-level cost of the remaining payroll expense, pension, health insurance expense and other employee benefits. These modifications resulted in a downward adjustment to Piedmont's margin revenue requirement of approximately ($2.4 million), which is represented on both of my settlement exhibits as the sum of Lines 18 thru 20, 23 and 24.

4. Amortization of Certain Regulatory Assets and Rate Case Expense. The Stipulating Parties agreed to amortize all previously authorized regulatory asset end of period balances (comprised of Pipeline Integrity Management-Transmission ("PIM-T") deferred expenses, Pipeline Integrity Management-Distribution ("PIM-D") deferred expenses, Eastern NCNG deferred O&M expenses, environmental compliance assessment and clean-up deferred expenses, and regulatory fee deferred expenses) over a period of four years in each case. The Stipulating Parties also agreed to the Company's estimate of rate case expense for this proceeding, to be amortized over four years along with the removal of the unamortized deferred balance of the rate case expenses from the Company's last general rate case. On these matters, including the level of each deferred balance included in the working capital components of rate base, the Stipulation resulted in a downward adjustment to Piedmont's margin revenue requirement of approximately ($0.2 million). This is represented on both of my settlement exhibits as the sum of Lines 25, and 30 thru 34.

5. Non-Utility Adjustment. The Stipulating Parties agreed to include a non-utility adjustment for ratemaking, comprised of amounts of operating expense and rate base, that was greater than the Company's proposed non-utility adjustment. Accordingly, the Stipulation resulted in a downward adjustment to Piedmont's margin revenue requirement of

approximately ($0.5 million), which is represented on both of my settlement exhibits on Line 29.

6. Other Expenses. The Stipulating Parties agreed to a variety of adjustments to other expenses for ratemaking that encompassed the following categories of expense: sponsorships and donations, inflation, lobbying, uncollectibles, Board of Directors, interest on customer deposits, regulatory fee, non-recurring COVID-related expenses incurred during the test period, and certain aviation and advertising costs. These modifications taken together resulted in a downward adjustment to Piedmont's margin revenue requirement of approximately ($2.7 million), which is represented on both of my settlement exhibits as the sum of Lines 21, 22, 26 thru 28, and 35 thru 40.

7. Plant, Accumulated Depreciation, Accumulated Deferred Income Taxes, Depreciation Expense and other Related Adjustments including those associated with the Robeson LNG and Pender-Onslow projects. The Stipulating Parties agreed to several changes to Piedmont's rate base in the Stipulation, including ratemaking adjustments for the amortization of protected EDIT as updated for the current ARAM rate. Other rate base-related adjustments include an alignment of depreciation expense and accumulated depreciation with the stipulated plant in service balance, and an alignment of property tax with the settled changes to rate base net of non-utility adjustments, and an alignment of lead/lag to with

all other stipulated adjustments. Exclusive of the Robeson LNG and Pender-Onslow projects, these settlement modifications resulted in a downward adjustment to Piedmont's revenue requirement of approximately $(32.2 million), which is represented on Settlement Exhibit__(PKP-1) as the sum of Lines 8, 9, 11, 12, 16, 17 and 41 thru 44. Inclusive of the Robeson LNG and Pender-Onslow projects, these settlement modifications are estimated to result in an upward adjustment to Piedmont's revenue requirement of approximately $0.8 million, which is represented on Settlement Exhibit_(PKP-2) as the sum of Lines 8, 9, 11, 12, 16, 17 and 41 thru 44.[3]

**Q. Did Piedmont expressly agree with each of the component adjustments in the Stipulation?**

A. No. In fact, Piedmont strongly disagreed with many of these adjustments on an individual basis and the Public Staff likewise opposed many of these adjustments in isolation. In order to reach settlement, however, Piedmont and the Public Staff both compromised on a large number of individual issues in order to reach an overall accommodation in this case. The settlement was arrived at as a whole and, as the Stipulation indicates, each

3 The main cost of service effect of the exclusion of the Robeson LNG and Pender-Onslow projects is shown on Lines 8 and 16 of my settlement exhibits. Piedmont's Update Filing requested an approximate $96.9 million annual margin revenue requirement increase, which included the Robeson LNG and Pender-Onslow projects (as estimated) in rate base and operating expense. Showing the Stipulated margin revenue requirement increase inclusive of the Robeson LNG and Pender-Onslow projects (as estimated) comports with the sum of the settlement adjustments shown on Lines 8 and 16 of Settlement Exhibit__(PKP-2).

individual adjustment may not have been agreeable to all parties participating in this settlement. However, when considered as a whole, the totality of the adjustments was acceptable to each of the Stipulating Parties. For this reason, the Stipulating Parties agree that no precedent is intended to be established by the individual adjustments or component provisions of the Stipulation but that each would support the Stipulation as a whole before the Commission as a reasonable resolution of Piedmont's rate case filing.

**Q. Do you believe that the overall settlement reached by the parties and presented to the Commission is just and reasonable and otherwise compliant with the requirements of North Carolina law?**

A. Yes, I do.

**Q. Does the Stipulation address any non-economic issues and/or or economic issues other than the cost of service adjustments underlying the stipulated revenue requirement increase?**

A. Yes, there are several. The Stipulation calls for the continuation of the Integrity Management Rider ("IMR") mechanism. The Stipulation calls for approval of Piedmont's proposed modifications to its Tariff, namely the elimination of Rate Schedules 12 and T-12, and modifications to Rate Schedules 107, 113, 114 and 143. The Stipulation calls for termination of the Line 434 Revenue Rider, since the cancellation of the Atlantic Coast Pipeline eliminated the need for the operation/existence of this rider. The Stipulation also calls for approval of Piedmont's proposed modifications to its Service Regulations, namely modifications to Appendix B (Customer Agent Agreement) and Appendix E (IMR mechanism). Note that several factors in the Appendix E of the Company's Service Regulations need to align to the stipulated revenues and throughput by rate class and will accordingly be updated and filed with the Commission after finalization of the stipulated revenue requirement and rates per the pending updates for the Robeson LNG and Pender-Onslow projects.

The Stipulating Parties agreed to Piedmont's rollout of new and modified Energy Efficiency Programs ("EE Program(s)"), and that the entire EE portfolio - both the existing and new/modified EE Programs - be authorized for a three-year pilot in order to collect operational data, perform evaluation, measurement, and verification ("EM&V"), and assess cost-effectiveness. The Company also proposed, in Appendix H of its Service Regulations, a rider to enable the recovery of all approved EE Program expenses on a going-forward basis starting November 1, 2021. The Company's proposal, as explained in my prefiled Direct Testimony, requested Commission approval for regulatory asset treatment for its EE Program expenses in the absence of approval of Piedmont's proposed Appendix H.[4] The Stipulating Parties agreed with the Company's proposal to remove the EE Program expenses from the base revenue requirement set in this proceeding and that Piedmont should recover these

4 Note that the Commission's approval of regulatory asset treatment on this matter, in lieu of approval of Piedmont's proposed Appendix H, would defer deliberation of EE Program cost recovery by rate class until Piedmont's next general rate case proceeding.

costs through a mechanism other than base rates set in this proceeding. However the Stipulating Parties have not yet reached agreement on the details of how that cost recovery should precisely work.

The Stipulating Parties agreed that the Commission should allow Piedmont to join and participate in the affordability stakeholder collaborative currently being conducted around electric service provided by Piedmont's affiliates, Duke Energy Progress and Duke Energy Carolinas. The Stipulating Parties also agree to certain customer-supportive revisions to Piedmont's model used to calculate the feasibility of extending natural gas service to its residential and commercial customers. The Stipulation also supports the undertaking of two studies proposed in the direct testimony of Public Staff witness Dustin Metz, which pertain to the breakdown of costs and customer usage between Piedmont's North Carolina and South Carolina jurisdictions.

**Q. Are the adjustments to revenues and rates proposed in the Stipulation fair, just and reasonable?**

A. Yes, I believe so. The revenues and rates agreed to as part of the Stipulation were the product of give and take negotiations between the Stipulating Parties. Each party analyzed the settlement terms, revenues and rates and concluded they were reasonable for purposes of settling this proceeding. The settlement rates are also very beneficial to customers, as they are significantly lower in comparison to Piedmont's proposed rates in this docket.

**Q. What will be the impact on customers of the stipulated revenue request?**

A. In my prefiled Direct Testimony explained that Piedmont's revenue request, as filed in the Company's application at a total increase of $109.0 million, would increase Piedmont's annual revenue by approximately $95 per residential customer (or an average monthly increase of just under $8).[5] By comparison, the annual residential customer impact under the Stipulation excluding the Robeson LNG and Pender-Onslow projects, is approximately $37 (or an average monthly increase of approximately $3).[6] By including the Robeson LNG and Pender-Onslow projects as currently estimated, the annual revenue impact per residential customer under the Stipulation is approximately $65 (or an average monthly increase of approximately $5.50).[7]

**Q. Do you believe that the stipulated revenue and rate increase, including the stipulated ROE, is consistent with the statutory factors identified in G.S. 62-133 and is otherwise fair and reasonable to Piedmont and its customers considering changing economic conditions?**

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5 The calculation of this residential bill impact was shown in footnote 1 of my prefiled Direct Testimony.

6 Line 50 of Settlement Exhibit_(PKP-1) shows the total revenue requirement increase of approximately $41.1 million. The Stipulation calls for approximately $25.7 million of this increase to be borne by the residential class of customers, which now represents approximately 702,600 customers. Therefore, the stipulated revenue increase per residential customer is $37 ( = $25.7 million ÷ 702,600 customers).

7 Line 50 of Settlement Exhibit_(PKP-2) shows the total revenue requirement increase of approximately $74.1 million. The Stipulation calls for approximately $46.0 million of this increase to be borne by the residential class of customers, which now represents approximately 702,600 customers. Therefore, the stipulated revenue increase per residential customer is $65 ( = $46.0 million ÷ 702,600 customers).

A. Yes, I do, for all of the reasons I mentioned above.

**Q. What are you requesting the Commission do in this case?**

A. I am requesting that the Commission, on the basis the agreement reached by the Stipulating Parties and its own independent evaluation of all the evidence presented in this case, approve the terms of the Stipulation reached with the Public Staff as just and reasonable and the appropriate resolution of this case.

**Q. Does this conclude your Settlement Testimony?**

A. Yes, thank you.

MR. JEFFRIES: And Piedmont would also request that Ms. Powers' prefiled direct exhibits and prefiled settlement exhibits be identified as marked.

CHAIR MITCHELL: Okay. The exhibits to Ms. Powers' direct testimony shall be marked for identification as they were when prefiled. In addition, the exhibits to Ms. Powers' settlement testimony shall be marked for identification as they were when prefiled.

(Exhibits PKP-1 and PKP-2 and Settlement Exhibits PKP-1 and PKP-2, were identified as they were marked when prefiled.)

MR. JEFFRIES: Thank you, Chair Mitchell.

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

A. Yes. I have a summary of my direct and my settlement testimony ready.

Q. Could you please provide that to the Commission.

A. Yes. My name is Pia Katherina Powers, and I am the managing director of rates and regulatory for

Piedmont Natural Gas. I prefiled direct testimony in this docket on March 22, 2021, in support of Piedmont's application for a general rate increase.

My prefiled direct testimony and two exhibits explain and support; one, Piedmont's revenue request; two, the impact of the revenue request on customers; three, customer support of actions that Piedmont offers in light of the COVID pandemic; four, the public benefits inherent in the continued operation of Piedmont's integrity management rider mechanism; five, a proposed rider mechanism for Piedmont's ongoing recovery of expenditures for its customer energy efficiency programs; and six, other proposed changes to Piedmont's tariff.

My settlement testimony and its two exhibits explain and support the economic and noneconomic adjustments to Piedmont's filed case as reflected in the stipulation of partial settlement between the stipulating parties, which are Piedmont Natural Gas, Public Staff, the Carolina Utility Customers Association, and the Carolina Industrial Group for Fair Utility Rates IV.

This concludes the summary of my prefiled direct and settlement testimony.

Q. Thank you, Ms. Powers.

MR. JEFFRIES: Chair Mitchell, Ms. Powers is available for cross examination and questions by the Commission.

CHAIR MITCHELL: All right. My notes indicate that no party has cross examination for the witness. I will pause here to make sure that is, in fact, the case.

(No response.)

CHAIR MITCHELL: All right. I'm not hearing any cross examination, so I'll move to Commissioners and ask if Commissioners have questions for the witness.

COMMISSIONER HUGHES: Chair Mitchell, I have a few.

CHAIR MITCHELL: All right. And I see Commissioner Duffley has questions as well, so let's start with -- let's start with Commissioner Hughes.

EXAMINATION BY COMMISSIONER HUGHES:

Q. Yes, Ms. Powers, could you briefly describe how revenues from special contracts are factored into Piedmont's revenue requirements in this case?

A. Yes, Commissioner Hughes. In Piedmont's general rate proceedings, such as this one, all of Piedmont's revenues from its customers, tariff customers as well as customers under special contracts, are considered in the computation of revenues absent a rate adjustment. All of Piedmont's expenses and costs face rate regarding all customers, tariffed and non-tariffed, are factored into the computation. And from that, we compute what rate adjustment is needed in order to support the rate of return that we're requesting in this case. And then, accordingly, that was modified in the settlement agreement.

So regarding your question of how special contracts are factored in, their revenues are factored into the computation, as are all the assets and costs that go in support of those contracts. I would note just for specifics here, you know, absent capturing the revenues from those contracts, the Company's computation of the necessary increase to revenue would have appeared larger.

So we capture the revenues and costs so that it's a full representation of what our needs are -- our requested needs are pursuant to the rate increase.

Q. Okay. Thank you for that. And just a follow-up for that.

If on the circumstance that the revenue actually falls short from what you were expecting, how would that typically be recovered?

A. Commissioner Hughes, may I ask, were you referring to if revenues fall short from the special contract? Is that what your question is?

Q. Yes, I'm sorry. If the special contract revenue, and in particular that -- that subcategory of revenue falls short, where would you get that revenue? How would that be covered?

A. It would be covered from the special contract customer. The special contracts, the rates for that, they're established at a point in time using the Commission's rate of -- overall approved rate of return at that point in time, and as you know, presented for approval before this Commission.

And I believe all, if not most -- excuse me for not having the specifics literally on every single one, but it is Piedmont's common practice, and certainly is in most special contracts, that it has a mechanism such that the annual margin is -- well, some contracts there's a flat annual margin. So it's not volumetrics, so there's really no opportunity to fall short from what was needed.

And in other agreements where it might be more volumetric based, there is a mechanism -- an annual true-up mechanism embedded in it such that we do receive the margin that was contemplated pursuant to the agreement. Our return hat, the overall rate of return -- I will note this other factor, because I think it is important. The overall rate of return that those contract rates are established at, based on the overall rate of return approved by this Commission at the point in time that the proceeding is set, and so those -- the overall rate of return has been declining over time. So there is definitely, I would say, no opportunity where the special contracts provide revenue that is insufficient for the Company's return purposes.

Q. Okay. Thank you for that. No further questions.

CHAIR MITCHELL: All right.

Commissioner Duffley?

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good morning, Ms. Powers.

A. Good morning, Commissioner Duffley.

Q. So I have some questions about the energy efficiency rider mechanism.

A. Yes.

Q. On pages 24 through 28 of the stipulation of partial settlement, the parties agreed to an EE rider mechanism to recover costs of the EE programs; is that correct?

A. Yes.

Q. And actually, the Public Staff agreed to the rider and the cost recovery mechanism in its initial testimony; is that correct?

A. Forgive me, I don't have the testimony in front of me.

Q. Subject to check?

A. Subject to check. My recollection is that they did not object to it, but literally did not recommend approval of tariff appendix H as proposed, which laid out the details. And those details would be subject to further supplemental testimony, or in this case, deliberations that we had in the course of settlement discussions.

Q. All right. Thank you for that.

Is the need for the creation of energy efficiency, or EE programs, a reasonable need?

A. I believe it is, yes.

Q. And is the creation of this EE rider mechanism within a general rate case in which all rate schedules are under consideration?

A. Yes.

Q. Is it correct that these EE programs, as a whole, will be considered a pilot program? Or are all of them within the pilot program?

A. Yes. Pursuant to the stipulation, yes.

Q. And are the costs of the different programs within this larger pilot program uncertain and subject to fluctuate?

A. That is correct.

Q. Could any of these EE programs be temporary, for example, not meet the cost effectiveness test and then the Company would terminate the program, potentially?

A. Potentially, yes.

Q. Would you agree that whether or not to create a rider cost recovery mechanism is case specific in terms on the facts and circumstances of each case?

A. Yes, I would agree.

Q. Is the rider mechanism an appropriate and well-recognized method for cost recovery for this type of item?

A. Yes, it is.

Q. Can you cite to other riders or examples of other riders not created by statute that the Commission has approved that Piedmont considers analogous or similar to the proposed EE rider mechanism?

A. Yes. Piedmont's proposed EE rider mechanism is analogous to its integrity management rider which this Commission approved in 2013. I think that's the most compelling example to provide.

Q. Okay. Thank you, Ms. Powers. I have no further questions.

A. Thank you.

CHAIR MITCHELL: All right. Ms. Powers, I have just a few questions for you following on some of the questions asked by Commissioner Duffley just quickly.

EXAMINATION BY CHAIR MITCHELL:

Q. As an alternative to the rider mechanism, Piedmont proposed that the Commission allow the costs associate with the EE programs to be deferred for consideration in the next rate case.

Has Piedmont given any thought to whether or how those costs would satisfy the deferral test that the Commission has articulated in the past, to the extent that you're aware of that test?

A. Yes. I am aware of that test. With respect to the level of cost of Piedmont's application for the EE program articulated that it would achieve, over time, an annual cost of roughly in the five -- order of magnitude of $5 million a year. And I think that the impact on the Company's financial return would depend on how long the Company is out. Would depend, meaning when Piedmont would come in for its next rate case. So the longer that Piedmont is out for its next rate case, the more impactful the -- it is to not recover those costs.

I believe that is one element that the Commission looks at, the financial impact of the costs that the Company seeks deferral treatment as.

Q. Okay. Thank you, Ms. Powers. Last question for you.

Is it possible for Piedmont to design a dollars-per-dekatherm energy efficiency savings program?

A. I think I'd need to give that consideration. I don't have an answer to that at this moment.

Q. Okay. All right. Fair enough.

CHAIR MITCHELL: All right. Any additional questions from Commissioners? Thank you, Ms. Powers. Any additional questions from

Commissioners?

(No response.)

CHAIR MITCHELL: All right. I'm not hearing. All right. I will ask for questions on Commissioner's questions from any of the intervening parties?

(No response.)

CHAIR MITCHELL: Ms. Force, I see you turned on your camera. Okay. All right.

Mr. Jeffries, questions on Commissioners' questions?

MR. JEFFRIES: I have one question, Chair Mitchell.

CHAIR MITCHELL: Go ahead.

REDIRECT EXAMINATION BY MR. JEFFRIES:

Q. Ms. Powers, talking to Commissioner Hughes, he was asking you some questions that I at least interpreted as being directed at the issue of, you know, how does the Company ensure that it's actually going to recover its revenues under the special contracts. And you mentioned a couple of different mechanisms that are baked into the existing special contracts that help with that.

Is it also true that Piedmont -- at least with respect to existing contracts, that Piedmont's practice has been to recover the full cost of the special contract facilities over the initial term of the contract?

A. That is correct.

Q. And is that -- does that result in an -- essentially, an accelerated recovery of what will eventually be the depreciation expense associated with those facilities?

A. Yes, it does.

Q. And does that provide an additional cushion to help ensure that there won't with be a shortfall in revenues under the special contract?

A. Yes, I would say so.

Q. Okay.

MR. JEFFRIES: That's all the questions I have, Chair Mitchell.

CHAIR MITCHELL: All right. Ms. Powers, I think, at this point in time, you are off the hook. You may step down.

Mr. Jeffries, does the Company intend to recall the witness?

MR. JEFFRIES: We do not, Chair Mitchell.

CHAIR MITCHELL: All right. Ms. Powers, then you may be excused.

And, Mr. Jeffries, I will take a motion from you.

MR. JEFFRIES: Thank you. We would move that Ms. Powers' prefiled direct exhibits marked for identification as Exhibit PKP-1 and PKP-2, as well as Ms. Powers' prefiled settlement exhibits marked for identification as Settlement Exhibit PKP-1 and Settlement Exhibit PKP-2 be entered into the evidence in the record on this proceeding.

CHAIR MITCHELL: All right. Hearing no objection to your motion, the exhibits to witness Powers' prefiled testimony will be admitted into the record.

(Exhibits PKP-1 and PKP-2 and Settlement Exhibits PKP-1 and PKP-2, were admitted into evidence.)

CHAIR MITCHELL: All right. At this point in time, let's take a break for our court reporter. We will go off the record now and go back onto the record at 11:00. Please, everyone, just turn off your cameras and mute your line, but otherwise do not leave the meeting. All right.

Thank you.

(At this time, a recess was taken from 10:47 a.m. to 11:01 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record.

Piedmont?

MR. JEFFRIES: Chair Mitchell, before we call our next witness, if I may, I'd like to bring up an administrative issue that's been brought to my attention.

CHAIR MITCHELL: All right.

MR. JEFFRIES: In our page counts -- I know that, for me, in our page counts in reference to the prefiled testimony, I was only counting the actual pages of testimony, and I've been informed that we need to include the pages for -- that include the cover sheet and any appendices. And so I think -- and I will do that going forward, but for the witnesses that have already appeared, Piedmont would move that the Chair clarify on the record that the page references are to the entirety of the testimony, including the cover sheets and appendices.

CHAIR MITCHELL: All right.

Mr. Jeffries, I'm not hearing any objection to your request, so we will clarify for purposes of the record that the testimony that will be admitted into the record for Piedmont will include all pages, including those which are unnumbered.

MR. JEFFRIES: Thank you, Chair Mitchell. With that, we -- Piedmont would call Ms. Kally Couzens to the stand, please.

CHAIR MITCHELL: All right. There you are, Ms. Couzens. I apologize, I mispronounced your name earlier.

THE WITNESS: No problem.

CHAIR MITCHELL: And I will get it right from now on. Okay. Ms. Couzens, raise your right hand please.

Whereupon,

KALLY A. COUZENS,

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

CHAIR MITCHELL: All right. Mr. Jeffries.

MR. JEFFRIES: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Good morning, Ms. Couzens.
A. Good morning.
Q. I should -- in the spirit of fairness, I should inform the Chairman that she's not the only one that's historically mispronounced Ms. Couzens' last name. I did that for a long time before Ms. Couzens corrected me, so I apologize for that.
Could you state your name and business address for the record, please.
A. My name is Kally Couzens, and my business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.
Q. And where do you work, Ms. Couzens?
A. Piedmont Natural Gas.
Q. And what's your position at Piedmont?
A. I am the manager of rates and regulatory strategy.
Q. Okay. Thank you. So I'm gonna go over your prefiled testimony, and I think you win the prize for filing the most prefiled testimony today, at least for Piedmont. So bear with me here. You're the same Ms. Couzens that prefiled direct testimony on March 22, 2021, consisting of 16 pages; is that correct?

A. Yes.
Q. And there were also four exhibits attached to that prefiled direct testimony marked as KAC-1 through KAC-4; is that correct?
A. Yes.
Q. And are you also the same Kally Couzens that prefiled rebuttal testimony in this proceeding on August 25, 2021, consisting of 10 pages?
A. Yes.
Q. And then you also filed supplemental testimony on July 28, 2021, consisting of eight pages and Updated Exhibits KAC-1 through KAC-4, correct?
A. Yes.
Q. And finally, on September 7th, you filed -- September 7, 2021, you filed settlement testimony consisting of five pages; is that correct?
A. Yes.
Q. And were all -- first of all, do you have any corrections to your prefiled testimonies?
A. No corrections.
Q. Okay. If I ask you the same questions that are set forth in your prefiled testimonies while you were on the stand today, would your answers be the same?

A. Yes.

Q. All right. Thank you.

MR. JEFFRIES: Chair Mitchell, Piedmont would move that Ms. Couzens' prefiled direct, rebuttal, supplemental, and settlement testimonies be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. I'm gonna -- hearing no objection, Mr. Jeffries, to your motion, I'm gonna admit them in the following order: the prefiled direct testimony of witness Couzens that was filed in the docket on March 22nd shall be copied into the record as if given orally from the stand; the supplemental testimony of Piedmont witness Couzens filed in the docket on July 28th shall be copied into the record as if given orally from the stand; the rebuttal testimony of Piedmont witness Couzens filed the docket on August 25th shall be copied into the record as if given orally from the stand; and the settlement testimony of the witness Couzens filed on September 7th in this docket shall be copied into the record as if given orally from the stand.

(Whereupon, the prefiled direct

testimony, prefiled supplemental testimony, prefiled rebuttal testimony, and prefiled settlement testimony of Kally A. Couzens 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

## Direct Testimony and Exhibits
## of
## Kally A. Couzens

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**March 22, 2021**

**Q. Ms. Couzens, please state your name and business address.**

A. My name is Kally Couzens. 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 the Manager of Rates & Regulatory Strategy.

**Q. Please describe your educational and professional background.**

A. I graduated from the University of South Florida in May of 2001 with a bachelor's degree in Business Administration. I was employed by TECO Energy Inc. for six years from 2001 to 2007 as an Analyst in the Strategic and Financial Analysis department. I was hired by Piedmont as a Business Development Analyst in December 2007. In 2009 I joined Regulatory Affairs as a Senior Regulatory Affairs Analyst. In 2016 I was promoted to the position of Manager within the Gas Rates & Regulatory Strategy department.

**Q. Have you previously testified before this Commission or any other regulatory authority?**

A. Yes. I have presented testimony before the North Carolina Utilities Commission in Piedmont's prior general rate case proceedings in Docket No. G-9, Sub 631 and Docket No. G-9, Sub 743. I have also presented testimony before the Tennessee Public Utility Commission.

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

A. My testimony supports the Company's computation of pro forma revenues (i) for the sale and transportation of gas based on normalized Test Period throughput, and (ii) for other operating revenues. I also provide updated computational factors for the operation of our Margin Decoupling Tracker ("MDT") mechanism and support the reasonableness of our proposed rate design.

**Q. Do you have any exhibits as part of your testimony?**

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

| | |
|---|---|
| Exhibit__(KAC-1) | Total Pro Forma Revenues for the Sale and Transportation of Gas |
| Exhibit__(KAC-2) | Components of Pro Forma Sales and Transportation Revenues |
| Exhibit__(KAC-3) | Present Rates and Proposed Rates |
| Exhibit__(KAC-4) | Proposed Factors for the Margin Decoupling Tracker Mechanism |

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

A. Yes.

## Test Period

**Q. What Test Period did Piedmont utilize in preparing this case?**

A. Piedmont used the 12 months ended December 31, 2020.

## Pro Forma Revenues

**Q. Please explain the initial pro forma revenue calculations for the sale and transportation of gas.**

A. The starting point for these calculations is actual Test Period customer usage. Column (1) of Exhibit__(KAC-1) shows the actual Test Period bills and sales and transportation volumes by rate schedule. Column (2) shows the adjustment made to normalize the Test Period volumes to reflect the expected throughput levels under normal weather conditions. Column (3) shows the results of the adjustments in Column (2) on the actual volumes shown in Column (1). Column (4) shows the adjustments applied to bills and volumes of certain large volume customers to match updated rate base and plant through June 30, 2021. Column (5) shows the resulting sales and transportation levels after the normalization of Test Period volumes and the large volume customer adjustments. Column (6) reflects the total bills that would be expected for each customer class as a result of the adjustments. Column (7) shows the current approved rates. These "clean" rates[1] were applied to pro forma bills and volumes to compute the pro forma revenues shown in Column (8). The Integrity Management Rider ("IMR") revenues shown in Column (8) reflect the IMR revenue requirements from Piedmont's 2020 Annual IMR report, which was authorized by the Commission in Docket No. G-9, Sub 777. Column (9) shows the adjustments made to revenues to reflect the Margin

1 "Clean" rates, as applied to billing determinates for the computation of pro forma revenues in Exhibit_(KAC-1), is comprised of Piedmont's current base margin rates, gas cost commodity rates, and gas cost demand rates.

Decoupling Tracking mechanism, projected revenue requirement changes from the IMR mechanism and revenue changes to certain customer contracts. These adjustments were used to properly compute the pro forma revenues shown in Column (10).

**Q. Please explain the normalization adjustment shown in Column (2).**

A. This adjustment is necessary to adjust actual volumes to the quantities that would have been delivered had weather conditions been normal during the Test Period. Actual winter weather during the Test Period was 19.3% warmer than the 30-year average used for normal, while the summer period was 5.8% colder than normal. To calculate this adjustment, the Company's standard method of normalizing volumes was utilized, which has been accepted by the Commission in prior rate proceedings. The resulting normalized volumes after the adjustment are shown in Column (3).

**Q. What growth adjustments did the Company apply to customer bills and consumption levels?**

A. The Company applied adjustments to the bills and consumption levels of certain large volume customers based on available information. In some instances, the billing determinants associated with new customers with in-service dates prior to July 1, 2021, were added to align pro forma revenues with the expense and rate base adjustments from ongoing business activity through June 30, 2021. In other instances, adjustments were made to remove a customer due to an account closure or to reflect the activity of certain customers moving from a special contract agreement to a tariff rate schedule or vice versa. Historically, the Company has also compared the actual changes in customer levels in the year prior to the Test Period to the Test Period year and used that information as a guide to grow the individual rate classes to a level more closely aligned with pro forma expense and rate base through June 30, 2021.

Early in the Test Period, Piedmont responded to the coronavirus pandemic by voluntarily instituting certain measures, which would later be mandated by the Commission, to assist its customers including ceasing the disconnection of service for non-payment. Piedmont recognizes that the Test Period customer levels are significantly elevated compared to 2019, some of which is due to the fact that Piedmont did not disconnect service to any customers for non-payment for the majority of the Test Period. Currently, there is uncertainty regarding how these customer levels will change. With the exception of the adjustments made to certain large volume customers based on known and available information as discussed above, the Company has not applied any further growth adjustments to the Test Period bills and consumption for any of the rate classes.

**Q. Please explain the calculations in columns 5, 6, 7 & 8.**

A. The adjustment in Column (4) is applied to the Test Period annual bills from Column (1) and the normalized volumes in Column (3) to derive the pro forma dekatherms shown in Column (5) and the pro forma bills shown in Column (6). These quantities are then priced out at the Company's existing approved rates, which are shown in Column (7). The results are shown in Column (8), labeled Calculated Revenues. The IMR revenues also shown in Column (8) reflect the IMR revenue requirements authorized from Piedmont's 2020 Annual IMR report.

**Q. Please explain what adjustments to revenues were captured in Column (9)**

A. Column (9) incorporates revenue adjustments for the Margin Decoupling Tracker mechanism, the IMR and certain special contracts.

**Q. Please explain the Margin Decoupling Tracker adjustments shown in Column (9).**

A. The Margin Decoupling Tracker adjustments apply to the Residential, Small General and Medium General Service rate schedules. The adjustment to volumetric revenues as shown in Column (9) increases the total pro forma revenues for Residential Service and Small and Medium General Service to properly reflect the impact of the Margin Decoupling Tracker mechanism as defined in Appendix C of the Company's Service Regulations. The calculation is necessary to adjust margin in a manner that reflects the going level of annual margin for the pro forma bills as identified in Column (6).

**Q. Please explain the IMR adjustments shown in Column (9).**

A. The IMR revenue adjustments apply to all rate classes. The IMR revenue adjustment shown in Column (9) reflects Piedmont's projected change in IMR revenue requirements based on projected integrity plant in-service at

March 31, 2021 and its impact on the IMR revenue requirement component of rates effective June 1, 2021.

**Q. Please explain the customer contract adjustments shown in Column (9).**

A. Piedmont has certain non-residential customers that take gas service pursuant to a contract with Piedmont. In order to appropriately reflect the going-level revenues for those customers, adjustments were made based on the terms of those contracts.

**Q. What are the results of these various calculations?**

A. The total pro forma revenues for the sale and transportation of gas is $1,045,885,591 considering all of the adjustments described above. This amount is shown in Line 354, Column (10) of Exhibit__(KAC-1). This total pro forma revenue amount is comprised of three categories of revenues. Those categories are margin revenues, cost of gas ("COG") commodity revenues and COG demand revenues. Exhibit__(KAC-2) provides the breakdown of total pro forma revenues by these three categories by rate schedule. Line 354 of Exhibit__(KAC-2), shows total pro forma revenues by category as follows:

**Table 1**

| **Revenue Category** | **Pro forma Amount** | **Reference** |
|---|---|---|
| Margin Revenues | $742,058,160 | Exhibit_(KAC-2) Line 354, Column 6 |
| COG Commodity Revenues | $187,342,806 | Exhibit_(KAC-2) Line 354, Column 10 |
| COG Demand Revenues | $116,484,625 | Exhibit_(KAC-2) Line 354, Column 8 |
| Total Pro forma Revenues | $1,045,885,591 | Exhibit_(KAC-1) Line 354, Column 10 |

**Q. Do the figures and calculations shown in Exhibit__(KAC-1) and Exhibit__(KAC-2) accurately represent Piedmont's normalized and adjusted pro forma volumes and revenues for gas sales and transportation for ratemaking purposes in this docket?**

A. Yes.

**Q. Please explain your pro forma revenue calculations for other operating revenues.**

A. The starting point for these calculations is actual Test Period per books other operating revenues, which amounted to $3,194,374. This amount largely consists of late payment charge revenue, rental revenue from gas properties, other miscellaneous revenue, and customer cash-outs for gas shortage imbalances. The accounting and pro forma adjustments, which primarily consist of the removal of cost of gas cash-outs for normalization purposes, bring this amount to the appropriate going-level amount of $1,136,144 for rate making in the proceeding.[2]

**Q. Please summarize the total pro forma revenues for rate making in this proceeding.**

A. In summary, the appropriate amount of total pro forma revenues for rate making in this proceeding is $1,047,021,735. This amount is the sum of the computation of total pro forma revenues for the sale and transportation of gas, cited previously in my testimony as $1,045,885,591, and my computation of other pro forma operating revenues of $1,136,144. These pro forma revenue amounts are used in the revenue deficiency computation explained in the testimony of Piedmont witness Quynh Bowman.

**Proposed Rates and Rate Design**

**Q. What are the rates proposed by the Company in this proceeding?**

A. Piedmont's proposed rates are set forth in Schedule 2 of Exhibit__(KAC-3) and on Appendix I to the petition in this proceeding. The Margin Decoupling Tracker Factors aligned with these rates are shown in Exhibit__(KAC-4). These proposed rates yield a total annual revenue amount of $1,154,911,316 for the sale and transportation of gas. In this rate case, Piedmont is not proposing any changes to its other operating revenues. Therefore, the total proposed revenues in this rate case is $1,156,047,460. This is an increase of

2 The workpaper for this adjustment is provided in G-1 Item 4(a).

$109,025,725 from the Company's pro forma revenues in this proceeding. The testimony of Piedmont witness Bowman supports the derivation of the proposed change in revenues.

**Q. What specific component of revenues is the Company proposing to change?**

A. Piedmont is proposing an increase to the margin component of revenues. A change is not being proposed for the COG demand component or the COG commodity component of revenues, as adjustments to these revenues can be administered separately from this proceeding under the procedures for gas cost rate adjustments set forth in Appendix A of the Company's Service Regulations. The total proposed revenue for gas sales and transportation by revenue category is as follows:

**Table 2**

| Revenue Category | Proposed Amount | Increase / (Decrease) |
|---|---|---|
| Margin Revenues | $851,083,885 | $109,025,725 |
| COG Commodity Revenues | $187,342,806 | $0 |
| COG Demand Revenues | $116,484,625 | $0 |
| Total Proposed Sales & Transportation Revenues | $1,154,911,316 | $109,025,725 |

**Q. Is Piedmont proposing any changes to the existing rates reflected in the Excess Deferred Income Taxes ("EDIT") Rider mechanism?**

A. No, the Company is not proposing any changes to the existing EDIT Rider rates. The EDIT Rider mechanism was approved by the Commission in Piedmont's last general rate case proceeding to administer the flowback to customers of deferrals and excess deferred income taxes created by changes to state and federal income tax rates. Pursuant to the Commission's Order in Docket No. G-9, Sub 776, Piedmont removed the EDIT Rider rates for the one-year giveback of deferred revenues on December 1, 2020, with the completion of those refunds. The EDIT Rider rates for the five-year giveback of federal "Unprotected EDIT" and the rates for the three-year giveback of North Carolina state EDIT will continue refunding to customers as previously authorized until the end of the respective amortization periods. The refunds associated with the EDIT Rider mechanism have been excluded from rate making in this proceeding.

**Q. What rate design is Piedmont proposing in this proceeding?**

A. The Company is proposing to use the same basic rate design, including fixed monthly charges, seasonal cost allocations, and step rates. This is the same rate design methodology that was approved by the Commission in Piedmont's last general rate case proceeding in 2019.

**Q. Does this mean that the rates will remain the same?**

A. No. Piedmont is proposing to change the volumetric billing rates (the rates per them) to reflect the revised cost of service and updated throughput. The Company is not proposing to change the monthly fixed charge amount for any rate schedule.

**Q. How did Piedmont determine its approach to rate design in this case?**

A. The main objective was to design rates that fairly price services to all customer classes while also providing a fair return to investors. It was also critical to design rates that are reflective of conditions in the marketplace and which send the correct market signals. The fundamental goal was to remain consistent with the existing rate structure. In looking at this approach, however, the Company had to be mindful of not disproportionately burdening one class of customers versus another class in allocating the proposed rate increase, particularly when considering the various factors historically used to analyze rates.

**Q. Did the Company perform an Allocated Cost of Service Study in this proceeding?**

A. Yes. Piedmont utilized Cynthia Menhorn, an outside consultant with MCR Performance Solutions ("MCR"), to develop a Piedmont in-house allocated cost of service model and to prepare an allocated cost of service study for this proceeding. The results of the study are reflected in Ms. Menhorn's direct testimony in this proceeding. The study shows that class rates of return under existing rates vary. Ms. Menhorn proposes that the revenue increase requested by the

Company in this proceeding be allocated to the various rate classes in a manner which will generally lead to more equalized rates of return across customer classes than under existing rates. This results in some rate classes being allocated the revenue increase at the overall system increase, while other rate classes will receive more or less than the overall system increase.

**Q. How do the Company's proposed rates conform to Ms. Menhorn's recommendations?**

A. Piedmont adopted Ms. Menhorn's recommended rate design for proposed revenues, which is to allocate the proposed increase in a manner which will lead to more equalized rates of return across the customer classes. This proposed rate design is reasonable and consistent with previous rate design proposals approved in prior proceedings before this Commission and does not unduly burden any of the customer classes.

**Q. Can you please summarize the net effects of the rates you propose in this proceeding?**

A. Yes. Table 3 below illustrates the pro forma revenues attributable to each class of customers, the proposed revenue increase for each such class, the resulting proposed revenues by class, and the percentage increase in revenues to be collected from each class under the proposed rates.

**Table 3**

**Proposed Changes to Operating Revenue**

| | Pro Forma Revenue | Proposed Increase | Proposed Revenue | % Change |
|---|---|---|---|---|
| Residential | $552,245,619 | $65,819,939 | $618,065,558 | 11.9% |
| Small General | $250,716,149 | $29,959,367 | $280,675,516 | 11.9% |
| Medium General | $40,884,097 | $4,439,455 | $45,323,552 | 10.9% |
| Natural Gas Vehicle Fuel | $1,036,559 | $122,934 | $1,159,493 | 11.9% |
| Gas Light Service | $102,158 | $12,116 | $114,274 | 11.9% |
| Firm Large General | $44,471,463 | $6,850,930 | $ 51,322,393 | 15.4% |
| Interruptible Large General | $27,572,286 | $1,425,364 | $ 28,997,650 | 5.2% |
| Military Transport | $2,261,796 | $395,620 | $2,657,416 | 17.5% |
| **Tariff Sales & Transportation Revenue** | **$919,290,128** | **$109,025,725** | **$1,028,315,853** | **11.9%** |
| Special Contracts | $126,595,463 | $0 | $126,595,463 | 0.0% |
| **Total Sales & Transportation Revenue** | **$1,045,885,591** | **$109,025,725** | **$1,154,911,316** | **10.4%** |
| Other Revenue | $1,136,144 | $0 | $1,136,144 | 0.0% |
| **Total Operating Revenue** | **$1,047,021,735** | **$109,025,725** | **$1,156,047,460** | **10.4%** |

**Q. In your opinion, are the revenue increases proposed by the Company in this case equitable and fair to all classes of customers?**

A. Yes, the revenue increases proposed are equitable and fair to all rate classes and are consistent with the revenue recovery approach underlying our existing rates approved by this Commission in prior general rate case proceedings. I also note that Ms. Menhorn's prefiled direct testimony provides additional support for the Company's cost of service study and proposed rate design.

**Q. Does this conclude your testimony?**

A. Yes. Thank you.

# Before the
# North Carolina Utilities Commission

## Docket No. G-9, Sub 781

## General Rate Case

## Supplemental Testimony and Exhibits
## of
## Kally A. Couzens

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**July 28, 2021**

**Q. Please state your name and business address.**

A. My name is Kally Couzens. 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 the Manager of Rates & Regulatory Strategy.

**Q. Are you the same Kally Couzens that previously prefiled Direct Testimony in this proceeding.**

A. Yes.

**Q. What is the purpose of your Supplemental Testimony in this proceeding?**

A. N.C. Gen. Stat. § 62-133(c) and Commission Rule R1-17(c) permit Piedmont to update its rate case filing through the date of the hearing of this matter. In the Company's Application in this proceeding filed on March 22, 2021, Piedmont specifically reserved the right to make these updates. As discussed in the Supplemental Testimony of Quynh Bowman, the Company has now made such updates based on available information in lieu of the previously forecasted cost of service calculation as of June 30, 2021. My Supplemental Testimony supports the updated computation of gas sales and transportation pro forma revenues used in Ms. Bowman's updated cost of service calculation. My Supplemental Testimony also supports the derivation of proposed rates as aligned with Ms. Bowman's updated cost of service calculation.

**Q. Do you have any exhibits supporting your Supplemental Testimony?**

A. Yes. The following updated exhibits are part of my Supplemental Testimony and are attached hereto. These updated exhibits are in replacement of the exhibits supporting my Direct Testimony in this proceeding.

- Exhibit_(KAC-1 UPDATED) Pro Forma Revenues for the Sale and Transportation of Gas
- Exhibit_(KAC-2 UPDATED) Components of Pro Forma Revenues
- Exhibit_(KAC-3 UPDATED) Present and Proposed Rates
- Exhibit_(KAC-4 UPDATED) Proposed Factors for the Margin Decoupling Tracker Mechanism

The present and proposed rates shown in Updated Appendix I in the Company's update filing is consistent with the present and proposed rates shown in Exhibit_(KAC-3 UPDATED).

**Q. Were these four exhibits prepared by you or under your direct supervision?**

A. Yes.

**Q. Please explain the rationale for updating the pro forma sales and transportation revenues.**

A. In my Direct Testimony, I explained the computation of pro forma sales and transportation revenues for the purpose of establishing the Company's going-level revenues absent a rate adjustment in this proceeding. In the period of time since then, the Commission has reset certain components of the

Company's customer billing rates. Specifically, per Commission order in Docket No. G-9, Sub 788, Piedmont's Integrity Management Rider ("IMR") margin revenue requirement and billing rates were changed effective June 1, 2021. Also, per Commission order in Docket No. G-9, Sub 790, Piedmont's Commodity Cost of Gas billing rate was changed effective July 1, 2021. Incorporating the combined effect of these rate changes yields a level of pro forma sales and transportation revenues that differs from the amounts shown in the Company's original filed application in this proceeding and my Direct Testimony. Therefore, it was appropriate to update my computation of pro forma sales and transportation revenues for the purpose of re-establishing the going-level revenues under current Commission approved rates. This update is reflected in Exhibit_(KAC-1 UPDATED) and Exhibit_(KAC-2 UPDATED).

**Q. Were there any other changes incorporated into the update of pro forma sales and transportation revenues?**

A. Yes. In addition to updating that computation using current Commission approved rates, an update to the number of customer bills represented on a pro forma basis in this proceeding was warranted. Specifically, an update was made to increase the number of Residential, Small General and Medium General Service customer bills represented on a pro forma basis compared to the pro forma level used in the Company's original filed application in this proceeding and as shown in my Direct Testimony and exhibits. Since pro forma natural gas consumption by rate schedule is a function of the number of pro forma customer bills by rate schedule, the increase in the pro forma customers also increased the pro forma consumption level for the Residential, Small General and Medium General Service rate schedules. The updated pro forma customer bills align with Piedmont's updated pro forma operating expenses and rate base.

**Q. Why did the Company increase the number of pro forma customers billed and consumption levels from the original filed application?**

A. The methodology used by Piedmont in prior rate case proceedings to align customers billed and consumption levels with pro forma rate base consisted of computing the actual changes in customers billed from the year prior to the Test Period to the Test Period. The computed growth rate was applied to the Test Period customers billed, which in turn affected consumptions levels, to establish the pro forma customers billed and consumption levels. As explained in my Direct Testimony, while Piedmont made adjustments to the customers billed and consumption levels of certain large volume customers based on available information, the Company did not apply growth adjustments to its Residential, Small General and Medium General Service Test Period customers billed. This was in recognition of the fact that the Test Period number of customers billed was significantly elevated compared to prior years, partially due to the fact that Piedmont did not disconnect service to any customers for non-payment for the majority of the Test Period as a result of the Commission's moratorium on disconnections. The application of an abnormally high growth rate, computed from a year reflecting disconnections to a Test Period without disconnections, to the elevated Test Period customer count was unreasonable for Piedmont's original filing based on the distortion caused by the moratorium.

Piedmont's updated sales and transportation revenues reflect growth applied to the level of Residential, Small General and Medium General Service Test Period customers billed to reflect new customers that will be added to the system. The Company utilized growth rates computed from actual customers billed from 2018 to 2019 before the impacts of the coronavirus pandemic. The impacts to Piedmont's customer levels due to future disconnections remains uncertain. Piedmont believes utilization of information from the last two years that were unaffected by the moratorium represents the best method of calculating the customer growth rate in this proceeding.

**Q. What are the changes to the pro forma sales and transportation revenues as a result of the updated pro forma customers billed?**

A. As reflected in Column (4) of Exhibit_(KAC-1 UPDATED), the growth applied to Test Period customers billed for Residential Service increased customers billed annually by 115,335, while the consumption volumes increased annually by 537,092 dekatherms. The Test Period customers billed in aggregate for Small and Medium General Service increased annually by

6,944, while the aggregate consumption volumes increased annually by 359,613 dekatherms. In total, the sales and transportation revenues increased $11,270,816 as a result of the growth applied to Test Period customers billed.

**Q. What is the overall impact of all of the updates to the level of pro forma sales and transportation revenues?**

A. At the time of the Company's original filed application, the pro forma sales and transportation revenues were computed as $1,045,885,591. Updated for present rates and customer growth, the pro forma sales and transportation revenues are computed as $1,112,696,326. This amount is shown in Exhibit_(KAC-1 UPDATED).

**Q. Please explain the updates to the proposed rates reflected in Exhibit_(KAC-3 UPDATED).**

A. The proposed rates shown in Exhibit_(KAC-3 UPDATED) are designed to produce annual gas sales and transportation revenues of $1,209,568,431, as aligned with the updated cost of service shown in Ms. Bowman's Exhibit_(QPB-7 UPDATED). Exhibit_(KAC-4 UPDATED) shows the MDT factors associated with the updated cost of service and proposed rates.

**Q. Do the updated proposed rates shown in Exhibit_(KAC-3 UPDATED) incorporate any change to the rate design methodology used in the Company's original filed application?**

A. No. The updated proposed rates incorporate the same methodology applied in the Company's original filing.

**Q. Does this conclude your Supplemental Testimony?**

A. Yes.

# Before the
# North Carolina Utilities Commission

## Docket No. G-9, Sub 781

## General Rate Case

## Rebuttal Testimony
## of
## Kally A. Couzens

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**August 25, 2021**

**Q. Ms. Couzens, please state your name and business address.**

A. My name is Kally Couzens. 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 the Manager of Rates & Regulatory Strategy.

**Q. Have you previously testified in this proceeding?**

A. Yes. I previously submitted prefiled direct testimony in this proceeding on March 22, 2021.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my testimony is to respond to various matters raised in the direct testimony of the Public Staff - North Carolina Utilities Commission ("Public Staff") witnesses and intervenor witnesses.

**Q. What topics does your rebuttal testimony address?**

A. Specifically, I would like to respond to concerns and recommendations related to the following topics raised by Public Staff witnesses Dustin Metz, Julie Perry, and John Hinton, by Carolina Utility Customer Association, Inc. ("CUCA") witness Kevin O'Donnell, and by Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR IV") witness Nicholas Phillips:

(1) Piedmont's design day allocation of system costs;

(2) Rate increases on special contract customers;

(3) Piedmont's computation of certain operating revenues;

(4) Revisions to Piedmont's gas extension feasibility model.

**Q. What is Piedmont's position on the issue of demand allocation reflected in Mr. Metz's prefiled testimony?**

A. I reviewed Mr. Metz's supplemental testimony, which recommends the use of the Company's proposed North Carolina demand allocation of 85.39%. Therefore, I believe that Piedmont and the Public Staff are now aligned on this issue.

**Q. What is your position on Mr. Metz's proposals to study the allocation of transmission assets and the regression analyses utilized to calculate the design day demand allocation factor?**

A. Mr. Metz recommends two studies. First, Mr. Metz recommends that the Commission order the Company, the Public Staff, and any other interested parties, 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 Piedmont's customer classes and its North Carolina and South Carolina jurisdictions. Second, Mr. Metz proposes a similar study of the jurisdictional allocation of transmission costs on Piedmont's system. We are confident that Piedmont's existing allocation methodologies for each of these matters, which have been consistently used and accepted by this Commission and also by the Public Service Commission of South Carolina for many years, continue to be reasonable and appropriate. Nevertheless, Piedmont is not opposed to the concept of either study and will fully participate if one or both studies are ordered by this Commission.

**Q. What concerns have been raised in this proceeding related to Piedmont's Special Contract customers?**

A. CIGFUR IV witness Phillips alleges that Piedmont's proposed distribution of the revenue requirement increase results in an increase provided by non-contract customers to subsidize Special Contract customers. As a result, witness Phillips recommends that the Commission not allow Piedmont to increase the rates of non-contract customers to make-up the revenue requirement. Additionally, witness Phillips raises concerns that Piedmont's proposal is problematic and self-serving because its largest Special Contract class, which represents Special Contracts to Power Generation providers in North Carolina, involves contracts with Piedmont's affiliates.

**Q. What is Piedmont's response to these concerns?**

A. The terms and conditions of each Special Contract are individually reviewed and approved by the Commission. Piedmont performs a project-specific analysis of the incremental costs needed to provide service to any new Special Contract customer. The model Piedmont uses for this analysis accurately analyzes the contributions needed from the customer to fully compensate Piedmont for the costs of serving that specific customer over the life of the Special Contract. As in prior general rate cases for Piedmont, all of the revenue and costs associated with the provision of natural gas service to customers served under Special Contracts is included in the Company's cost of service computation in this rate proceeding. The net effect of including the costs and revenues of these contracts is a reduction of the revenue requirement for Piedmont's other customers. In short, the subsidization concerns that witness Phillips raises in his testimony do not exist in this case.

**Q. Why then does the Allocated Cost of Service Study prepared by Piedmont witness Ms. Cynthia Menhorn show lower than average rates of return for certain classes of Special Contracts as pointed out by witness Phillips?**

A. Ms. Menhorn's Allocated Cost of Service Study results are derived to determine how total revenues and costs are allocated to all rate classes regardless of whether the classes will be allocated any component of a requested increase. The cost model utilized by Piedmont for individual projects performs a project-specific analysis of the incremental costs needed to provide service. That model accurately analyzes the contributions needed from the new customer to fully compensate Piedmont for the costs of serving that customer during the term of the contract. Ms. Menhorn engages in an entirely different analysis. She allocates total North Carolina rate base, expenses and revenues across all customer classes and then uses the resulting return analysis to inform decisions about how to allocate any revenue requirement increases across Piedmont's rate classes. Importantly, this analysis was never intended to inform the design of existing special contract rates because those Commission-approved rates are fixed and will not change as a result of this rate case. Ms. Menhorn could have excluded all rate base, expenses, and revenues associated with fixed price contracts from her cost of service study. However, such exclusion would have likely required multiple reconciliations throughout this proceeding as totals per the cost of service study would not have been in agreement with total North Carolina rate base, expenses and revenues shown in the G-1 data request response and the testimony and exhibits of Piedmont witness Bowman.

**Q. Does Piedmont follow the same process and use the same model to generate proposed revenues regardless of whether the counterparty to these contracts is an affiliate?**

A. Yes.

**Q. Does witness Phillips raise any other concerns related to Piedmont's Special Contract customers?**

A. Yes. In his direct testimony, witness Phillips also alleges that Piedmont has not demonstrated that the Special Contract Credit included in the Company's Integrity Management Rider ("IMR") mechanism is appropriate to cover the level of IMR costs for its Special Contract customers.

**Q. Do you agree with this concern?**

A. No. As Mr. Phillips notes, the Special Contract Credit portion of Piedmont's IMR represents an amount provided by the Special Contract customers towards the integrity management plant investment. This credit has been consistently approved by the Commission since the inception of Piedmont's IMR. The continuation of this credit was included in the Settlement Agreement approved by the Commission in Piedmont's 2019 general rate case proceeding in Docket No. G-9, Sub 743.

**Q. Are there any other recommendations in this proceeding related to Special Contracts that Piedmont disagrees with?**

A. Yes. In this case, CUCA witness O'Donnell recommends rate increases for Piedmont's Municipal and Power Generation Special Contracts. Additionally, because these contract rates are fixed he suggests that if these contracts extend out for two years beyond the implementation of the new rates in this case, the revenue deficiency caused by these Special Contract customers should be spread to remaining non-contract customers for a period not to exceed two-years. After the two-year period, witness O'Donnell suggests Piedmont should absorb the rate increase or re-negotiate the contracts.

**Q. Do you agree with this recommendation?**

A. No, I do not.

**Q. Please explain.**

A. As previously discussed, each special contract is approved by the Commission and the full revenues and costs associated with service provided to customers served under Special Contracts is included in the Company's cost of service computation. The net effect of this is full recovery of the costs incurred to serve Special Contract customers and a reduction of the revenue requirement for Piedmont's other customers.

**Q. Were there any recommendations raised in this proceeding regarding revenues that you disagree with?**

A. Yes. Public Staff witness Perry recommends an ongoing level of Late Payment Revenues, Miscellaneous Service Revenues, and Rent from Gas Properties by utilizing a five-year historical average of these other operating revenues.

**Q. Please explain your concerns with this recommendation.**

A. Piedmont disagrees with witness Perry's methodology of using a five-year historical average to determine the ongoing level for all categories of Other Revenues. Specifically, regarding Late Payment Revenues, the Company continues to be subject to the Commission's requirement in Docket No. M-100, Sub 158 to forgo assessing late payment charges on customer accounts and it is uncertain when this requirement will be lifted. Therefore, it is uncertain when Piedmont will even begin recording late payment charge revenues again. Accordingly, it is inappropriate to use a methodology for these revenues in the rate case that essentially imputes phantom revenues to the Company for late payment charges that we have no basis to believe under the current circumstances will be recovered. Piedmont also disagrees with using a historical five-year average for the on-going level of Rent from Gas Properties. In its filing, Piedmont made a pro forma adjustment to Rent from Gas Properties to reflect the revenue associated with the current rental rates from the rental contracts. Therefore, the use of a historical trend is not an accurate representation of ongoing Rent from Gas Properties revenues, nor is it necessary to estimate such revenues given the known rental contract rates for the term of each contract. Finally, for Miscellaneous Revenues, which consist primarily of reconnection revenues and non-sufficient funds revenues, the Company disagrees with witness Perry's recommendation to use a five-year historical average. The Company did not charge these fees for many months in 2020 due to the COVID-19 pandemic. Although the Company has resumed assessing reconnection charges and non-sufficient fund charges, there is no indication when, or if, such revenues will return to levels reflected in prior years due to the fact that many customers were placed on extended payment arrangements as a result of the pandemic. In short, the five-year average methodology overstates the Company's ability to recover these charges.

**Q. Are there any other topics raised in this proceeding that you would like to address?**

A. Yes. Public Staff witness John Hinton recommends in his testimony three revisions to Piedmont's gas extension feasibility model used to calculate the feasibility of extending natural gas service to its residential and commercial customers. These revisions include the use of an investment horizon of forty years or an appropriate length of time that matches the book lives of the gas plant, the use of the Company's approved net of tax discount rate employed for the net present value analysis, and the adjustment of all future cash flows by a long-term inflation rate of 2%.

**Q. Do you have any concerns with this recommendation?**

A. No. As mentioned in witness Hinton's testimony, the Company has reviewed these proposed changes and supports these adjustments.

**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

## Settlement Testimony
## of
## Kally A. Couzens

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**September 7, 2021**

**Q. Ms. Couzens, please state your name and business address.**

A. My name is Kally Couzens. 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 the Manager of Rates & Regulatory Strategy.

**Q. Have you previously testified in this proceeding?**

A. Yes. I previously submitted prefiled direct testimony on March 22, 2021, supplemental testimony on July 28, 2021, and prefiled rebuttal testimony on August 25, 2021.

**Q. What is the purpose of your Settlement Testimony in this proceeding?**

A. My Settlement Testimony discusses the changes in the Company's revenue allocation and rate design reflected in the Stipulation of Partial Settlement ("Stipulation") between Piedmont and the Public Staff - North Carolina Utilities Commission ("Public Staff"), Carolina Utilities Customer Association, Inc. ("CUCA") and Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR") (collectively the "Stipulating Parties") on September 7, 2021.

**Q. Have you prepared any exhibits to accompany this Settlement Testimony?**

A. Not specifically to accompany this testimony. The exhibits prepared by me or under my direction are included in the Stipulation at Exhibits C1, C2, D, E1, E2, I, J1, J2, K1, K2, L1, and L2.

**Q. Do the revenue allocation changes and modifications to the Company's previously filed rate design recommendations as presented in the Stipulation and associated exhibits meet the parameters of just and reasonable rates?**

A. Yes, even though the Company put forth in its filing on March 22, 2021 what it considered to be a reasonable rate design, in an effort to settle the case and try to accommodate the parties to this case, the stipulated rate design is also considered reasonable and does not unduly burden any of the customer classes and, therefore, should be accepted.

The rates agreed to as part of the Stipulation and reflected in the exhibits thereto were the product of give and take negotiations between the Stipulating Parties. Each party analyzed the settlement rates and concluded they were reasonable for purposes of settling this proceeding. The settlement rates based on the stipulated lower revenue requirement are also beneficial to customers as compared to Piedmont's initially proposed rates in this docket.

**Q. Please explain the stipulated rate design.**

A The rate design portion of the Stipulation reflects considerable compromise between the Stipulating Parties. As stated in Public Staff witness Floyd's testimony, rate design should follow the same cost causation approach underlying a cost of service study, but strict adherence to cost causation may not always be possible and other considerations must be considered. The stipulated revenue allocation included in

Stipulation Exhibits J1 and J2 was not spread across the board, but affords consideration to the varying rates of return as presented in the prefiled direct testimony of Piedmont witness Cynthia Menhorn and as cited by CUCA witness Kevin O'Donnell and CIGFUR witness Nicholas Phillips, Jr.

**Q. Were there any modifications to fixed cost of gas (demand) rates in this proceeding?**

A. Yes. The Stipulation reflects a fixed gas cost revenue increase to better align Piedmont's fixed gas cost revenue to the going-level of fixed gas cost expense. To determine the stipulated rates, the Company performed an analysis to establish the appropriate level of fixed gas costs by rate class based on the load characteristics of each rate class. Based on the results of the analysis, the Company allocated the revenue increase to the Residential, Small General, and Medium General Service rate schedules to better reflect the appropriate level of fixed gas cost revenues from these rate schedules. The rates to collect fixed gas costs for all other rate schedules remain unchanged. The methodology for computing the fixed gas cost allocation to the rate classes and the resulting rates is consistent with the methodology previously accepted by this Commission. The fixed gas cost rates and associated apportionment factors are presented in Exhibit D of the Stipulation.

**Q. What are you requesting the Commission do in this case?**

A. I am requesting that the Commission, on the basis of the agreement reached among the Stipulating Parties and its own independent evaluation of all the evidence presented in this case, approve the rate design included in the Stipulation as just and reasonable.

**Q. Does this conclude your Settlement Testimony?**

A. Yes.

MR. JEFFRIES: Thank you, Chair Mitchell. Piedmont would also request that Ms. Couzens' prefiled direct Exhibits KAC-1 through KAC-4, and her prefiled Supplemental Exhibits KAC-1 Updated through KAC-4 Updated be identified as marked.

CHAIR MITCHELL: The exhibits -- hearing no objection, Mr. Jeffries, to the motion, the exhibits to Ms. Couzens' testimony shall be marked for identification as they were when prefiled.

(Exhibits KAC-1 through KAC-4 and Supplemental Exhibits KAC-1 Updated through KAC-4 Updated, were identified as they were marked when prefiled.)

MR. JEFFRIES: Thank you, Chair Mitchell.

Q. Ms. Couzens, have you prepared a summary of your prefiled testimonies?

A. I have.

Q. Could you please provide that for the Commission.

A. My name is Kally Couzens, and I am the manager of rates and regulatory strategy for Piedmont Natural Gas Company. I prefiled direct testimony in this docket on March 22, 2021, in support of Piedmont's application for a general rate increase. I also filed supplemental testimony on July 28, 2021, in support of Piedmont's updated cost of service calculation as of June 30, 2021.

Further, on August 25, 2021, I submitted prefiled rebuttal testimony in this proceeding. My prefiled direct testimony supports the Company's computation of pro forma revenues for the sale and transportation of gas based on normalized test period throughput and for other operating revenues. I also provide updated computational factors for the operation of the margin decoupling tracker mechanism and support the reasonableness of Piedmont's proposed rate design.

My direct testimony summarizes the net effects of the rates Piedmont is proposing in this proceeding and provides supporting data that demonstrates that the revenue increased proposed by the Company in this case are equitable and fair to all rate classes. I explain how Piedmont is proposing to use the same basic rate design that was approved by the Commission in Piedmont's last general rate case proceeding in 2019, including fixed monthly charges, seasonal cost allocations, and step rates. My testimony explains that Piedmont's proposed rate design is reasonable and consistent with previous rate design proposals approved in prior proceedings before this Commission and does not unduly burden any other customer classes.

My prefiled direct testimony is supported by the following four exhibits: One, total pro forma revenues for the sale and transportation of gas; two, components of pro forma sales and transportation revenues; three, present and proposed rates; and four, proposed factors for the margin decoupling tracker mechanism.

I also filed supplemental testimony in this docket on July 28, 2021, in support of the Company's updated cost of service calculation as of June 30, 2021, which was performed and filed pursuant to North Carolina General Statute 62-33(c) [sic], and Commission Rule R1-17(c). My supplemental testimony supports the update computation of gas sales and transportation pro forma revenues used in Ms. Bowman's updated cost of service calculation as of June 30, 2021.

My supplemental testimony also supports the derivation of proposed rates as aligned with

Ms. Bowman's updated cost of service calculations as of June 30, 2021.

My supplemental testimony is supported by the following four updated exhibits: One, pro forma revenues for the sale and transportation of gas; two, components of pro forma revenues; three, present and proposed rates; and four, proposed factors for the margin decoupling tracker mechanism.

Finally, I submitted prefiled rebuttal testimony in this docket on August 25, 2021, in response to various matters raised by Commission Public Staff witnesses and intervenor witnesses. Specifically, I respond to concerns and recommendations related to the following four topics raised by Public Staff witnesses Dustin Metz, Julie Perry, and John Hinton; by Carolina Utility Customer Association witness Kevin O'Donnell; and by Carolina Industrial Group for Fair Utility Rates IV witness Nicholas Phillips:

One, Piedmont's design day allocation of system costs; two, rate increases on special contract customers; three, Piedmont's computation of certain operating revenues; and four, revisions to Piedmont's gas extension feasibility model.

This concludes the summary of my prefiled direct, supplemental, and rebuttal testimonies. I would also like to add that I filed settlement testimony in this proceeding on September 7, 2021.

Q. Thank you, Ms. Couzens.

MR. JEFFRIES: Chair Mitchell, Ms. Couzens is available for cross examination and questions by the Commission.

CHAIR MITCHELL: All right. My notes indicate that there is no cross examination for the witness, but I'll pause to make sure that is, in fact, the case.

(No response.)

CHAIR MITCHELL: Okay. I'm not hearing any cross examination for the witness.

Questions from Commissioners. Any Commissioners have questions for the witness?

(No response.)

CHAIR MITCHELL: All right. I'm not seeing any questions from Commissioners. So, Ms. Couzens, I believe you are off the hook for the morning. All right. You may step down.

And, Mr. Jeffries, do you intend to recall the witness?

MR. JEFFRIES: We do not, Chair Mitchell.

CHAIR MITCHELL: All right. Ms. Couzens, you are excused.

THE WITNESS: Thank you.

CHAIR MITCHELL: All right. Thank you.

And, Mr. Jeffries, I will take a motion from you.

MR. JEFFRIES: Thank you, Chair Mitchell. Piedmont would move that Ms. Couzens prefiled direct exhibits marked as Exhibits KAC-1 through KAC-4, and her prefiled supplemental exhibits marked as KAC-1 Updated through KAC-4 Updated be entered into evidence.

CHAIR MITCHELL: All right. Hearing no objection, exhibits to the witness' testimony shall be admitted into evidence.

(Exhibits KAC-1 through KAC-4 and Supplemental Exhibits KAC-1 Updated through KAC-4 Updated, were admitted into evidence.)

CHAIR MITCHELL: All right. Mr. Jeffries, or Piedmont, y'all may call your next witness.

MS. DEMOPOULOS: Good morning, Chair Mitchell. Piedmont will now call Cynthia Menhorn.

CHAIR MITCHELL: All right. Ms. Menhorn, there you are. Would you please raise your right hand?

Whereupon,

CYNTHIA A. MENHORN,

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

CHAIR MITCHELL: All right. Thank you. You may proceed, Ms. Demopoulos.

MS. DEMOPOULOS: Thank you.

DIRECT EXAMINATION BY MS. DEMOPOULOS:

Q. Good morning, Ms. Menhorn.

A. Good morning.

Q. Please state your full name and business address for the record, please.

A. My name is Cynthia Menhorn. My business address is 155, and I'm gonna spell Pfingsten, it's P-F-I-N-G-S-T-E-N, Road, Suite 155, Deerfield, Illinois 60015.

Q. Thank you for making that very clear for the record. I'm sure the court reporter appreciates that.

And where do you work?

A. I am the vice president at MCR Performance Solutions.

Q. And are you the same Cynthia Menhorn that prefiled direct testimony in this proceeding on March 22, 2021, consisting of 20 pages and Exhibits CAM-1 through CAM-3, as well as rebuttal testimony filed on August 25, 2021, consisting of eight pages?

A. I am.

Q. Thank you. And was that testimony, and were those exhibits prepared by you or under your direction?

A. They were.

Q. Do you have any corrections to your testimony?

A. I do not.

Q. If I asked you the same questions as set forth in your prefiled testimony while you were on the stand today, would your answers be the same?

A. Yes, they would.

Q. Thank you.

MS. DEMOPOULOS: Chair Mitchell, at this point, I would like to enter the prefiled testimony of Ms. Menhorn, both direct and rebuttal, into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the testimony of witness Menhorn prefiled in this docket on March 22nd shall be copied into the record as if given orally from the stand, and the rebuttal testimony of witness Menhorn filed in this docket on August 25th shall also be copied into the record as if given orally from the stand.

(Whereupon, the prefiled direct testimony and prefiled rebuttal testimony of Cynthia A. Menhorn was copied into the record as if given orally from the stand.)

**BEFORE THE**

**NORTH CAROLINA UTILITIES COMMISSION**

**DOCKET G-9, SUB 781**

**PREPARED DIRECT TESTIMONY**

**OF**

**CYNTHIA A. MENHORN**

**ON BEHALF OF**

**PIEDMONT NATURAL GAS COMPANY, INC.**

## INTRODUCTION

**Q. Please state your name, address, and position.**

A. My name is Cynthia A. Menhorn. I am Vice President for MCR Performance Solutions ("MCR") and my business address is 155 Pfingsten Road, Suite 155 Deerfield, Illinois 60015.

**Q. On whose behalf are you testifying in this proceeding?**

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

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

A. Currently, I head the Regulatory Services Practice at MCR Performance Solutions ("MCR"). I have been employed by MCR since June 2008. Prior to joining MCR, I held various positions at Allegheny Energy, a Mid-Atlantic utility with five state jurisdictions, where I gained deep experience with regulatory commissions in numerous states and the Federal Energy Regulatory Commission ("FERC"), extensive knowledge of the rate case process, and widespread interaction with stakeholders. The various positions I held include Director of Regulation and Rates, Director of State Regulatory Affairs, Director of Energy Efficiency and Conservation at Allegheny Power, and General Manager, Pricing Services. See Exhibit__(CAM-1).

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

A. No, I have not testified before the NCUC; however, I have been involved in the review of rate case orders in preparation for a possible rate case filing in North Carolina. I have testified on numerous occasions before other state commissions and FERC on a variety of rate and regulatory topics. See Exhibit__(CAM-1) for my experience statement including a listing of previous expert testimony.

**<u>PURPOSE OF DIRECT TESTIMONY</u>**

**Q. What is the purpose of your direct testimony?**

A. The purpose of my direct testimony is to provide and sponsor the fully allocated cost of service study including the targets for class revenues with newly designed rates to achieve those targeted revenues.

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

A. Yes. I am sponsoring the following exhibits to accompany my direct testimony:

Exhibit__(CAM-1) Experience Statement

Exhibit__(CAM-2) Allocated Cost of Service Study

Schedule 1 – Class Cost of Service Study by Rate Schedule

Schedule 2 – Class Cost of Service by Function

Schedule 3 – Class Allocation Factors by Rate Schedule

Schedule 4 – Class Allocation Factors by Function

Schedule 5 – Class Allocation and Functionalization/Classification Allocator Descriptions

Exhibit__(CAM-3) -- Summary of Existing and Proposed Rates and Revenues

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

A. Yes.

**<u>COST OF SERVICE STUDY</u>**

**Q. Who prepared the cost of service study that you are sponsoring in this filing?**

A. The cost of service study, as a fundamental tool of ratemaking in this proceeding, was prepared by MCR Performance Solutions utilizing a model called COST$^{TM}$. COST$^{TM}$ is a model that was developed in house by MCR on an excel based platform. COST™ follows standard cost allocation principles to first functionalize rate base, expenses and revenues, and then allocate those components to the rate classes. The design of the model allows visibility into the development of cost of service in that all components can be tied back to their primary inputs and all calculations are visible to the user of the model. Data, provided in the form of supporting spreadsheets, are loaded via import routines to ensure all data are accurate to the original source information. COST™ is based on a standard design and is customized for each client's unique structure and regulatory situation. This model includes a fully functioning rate design module for complete and thorough analysis of different rate design options.

**Q. Why did MCR develop an in house model rather than using something developed by utilities?**

A. I have utilized cost of service models developed by utilities and others throughout my career, and they can be challenging to use, modify and understand. First, some are designed without transparency, making updates difficult to validate; and second, without that transparency and with employee turnover, there are more hurdles to overcome. MCR's COST™ model is designed to be easily customized to each client's unique situation, allowing MCR to develop a cost of service analysis that is accurate, transparent and easily adaptable for scenario analysis.

**Q. Have your prepared any exhibits for the COST™ portion of this filing?**

A. Yes, Exhibit__(CAM-2) Schedules 1 through 5 provide details of the cost of service that are explained below.

**Q. What are the steps in the development of a cost of service study?**

A. There are three necessary steps that need to be performed for every cost of service study. They are functionalization, classification, and allocation. The MCR COST™ model is customized for each client's business to perform these steps. Supporting data is loaded into the model to provide details required for the cost of service study. For the functionalization and classification steps, the model provides results for the per books data, the pro forma adjusted data and the proposed revenue adjusted data.

**Q. Please explain each step in more detail.**

A. Functionalization – First, the investment and operating costs of the Company are separated into specified functional categories set forth by the Federal Energy Regulatory Commission Uniform System of Accounts. For this study, we utilized the following:

- Production and Storage – This function is associated with the procurement, upstream transmission, storage of commodity gas supply and includes any facilities and expenses associated with production of gas.
- Transmission – Transmission function is associated with the large diameter, high-pressure lines and facilities that transmit natural gas to smaller distribution assets.
- Distribution – This function is associated with investment and expenses related to the assets that deliver natural gas in close proximity to natural gas loads. This includes items related to connecting customers, metering, regulating and other services.

For rate base calculations; intangible plant, general plant, other rate base additions and other rate base deductions are allocated to storage, transmission and distribution functions.

Classification – Next, costs are classified by differentiating the costs based upon two primary cost drivers which are demand-related and customer-related. Piedmont's investment and expenses are classified based on the manner in which the costs were incurred. Costs associated with serving peak requirements in the system are classified as demand-related. Costs associated with providing customers access to and active status on the distribution system are classified as customer-related. Customer-related costs are incurred in a manner that is not related to the amount of gas consumed by the customer and include the costs of services, meters, and billing. Some costs are related to both demand and customer and are allocated appropriately. Storage and transmission items are considered to be 100% demand-related while distribution items can be directly assigned to either demand, customer or both based on their attributes.

Examples of classification include the following:

- Distribution Mains – Distribution mains are allocated based on the minimum distribution study. The premise underlying the study is that the size of the main will be such to serve peak load and the length of the main is based on the number of customers on the main. This is the same criteria used by engineers to design the system.
- Distribution Supervision Expenses – These costs are allocated based on the percentages of net plant attributed directly to demand, customer and distribution mains.
- Mains and Services Expense – Account 874 supports both Mains which are customer and demand-related and Services which are 100% customer-related. The expenses are classified into a Mains component and a Services component based

on gross plant. The Mains component is classified into customer and demand using the minimum distribution study.

- A&G Costs – A&G costs are allocated based on the Labor study and are attributed to each function based on their percentage of operating labor costs of accounts 735 through 916.

Allocation – Finally, one or more allocation factors are selected for each functionalized and classified cost component, to distribute costs among rate classes. The allocation factors are chosen on the basis of cost causation, which attempts to spread costs among classes in proportion to their contribution to the factors that caused costs to be incurred.

The Piedmont cost of service study follows a system-utilization method which is consistent with past practice. The demand allocator in the study is based on the Peak and Average method. Through this method, fixed demand costs are allocated to both peak and off-peak loads.

Other allocation factors are grouped into 3 main categories:

- Summary Statistics – These are statistics for each class that include throughput, winter throughput and number of bills.
- Internal Allocators – These are allocators determined within the cost of service study based on investment or expenses. Examples include Total Utility Plant and Total O&M. These factors are calculated in the build-up of the study and applied to various components.

- Special Studies – These studies are developed because of significant capital investment and expenses incurred.

**Q. Which special studies were used in this cost of service study?**

A. There are four special studies that examine investment and expenses that were prepared for this cost of service model:

- Labor Study – Labor costs are functionalized, classified, and then allocated to rate classes based on the same factors utilized to develop the overall cost of service study.
- Meter Investment Study – The Meter Investment study analyzes the replacement cost of meters by class based on current costs of comparable meters plus labor to install them.
- Services Investment Study – The Services Investment Study determines the aggregate investment in services based on the length and cost of services installed to serve each customer class as well as the associated replacement costs.
- Minimum Distribution Study – The Minimum Distribution Study was used from the prior rate case G-9, Sub 743, which was performed in 2019. During 2020, it was assumed that no major changes occurred that would have significantly impacted the results.

**Q. Describe treatment of gas costs as a part of the cost of service study?**

A. Gas costs are a significant portion of Piedmont's overall expense and are recovered through the procedures for gas cost rate adjustments set forth in Appendix A of the Company's Service Regulations. For purposes of the cost of service study, those costs are assigned directly to each rate class as incurred and represented as such in the study. The exception are gas costs associated with Rate Schedule 142, which is Piedmont's public fueling station. These costs are allocated across all classes using the Rate Base allocator as it is available to all customer classes.

**Q. Please summarize the results of COST™.**

A. The results of most significance in the context of a rate case from COST™ are the rate of return by class. The rate of return signifies how each rate schedule compares to the system average return. The is used in the context of the rate design and will be explained in detail later in this testimony. Exhibit__(CAM-2) includes Schedules 1-5 which summarize the study and provides details related to functionalization, classification, and allocation:

Schedule 1 – Class Cost of Service Study by Rate Schedule

Schedule 2 – Class Cost of Service by Function

Schedule 3 – Class Allocation Factors by Rate Schedule

Schedule 4 – Class Allocation Factors by Function

Schedule 5 – Class Allocation and Functionalization/Classification Allocator Definitions

## PIEDMONT RATE DESIGN

**Q. What do utilities wish to accomplish with rate design?**

A. Rate design objectives vary by company. However, they all attempt to follow James Bonbright's fundamental attributes of a sound rate structure. That is, utilities design rates to recover costs incurred to provide services to customers. Customers are typically segmented into different rate classes or rate schedules based on similar usage characteristics. Rates for each rate class or rate schedule should reflect the costs to serve that class of customers. Rate structures should also produce stable revenue for the utility. In addition, rate structures should be simple and easy to understand. For example, historically, most rates consisted of a customer charge and inclining (the rate is higher in higher usage blocks) or declining (the rate is lower in higher usage blocks) block rates. In the case of larger customer classes, a demand charge can be added.

**Q. What do you regard as the more important factors to be considered in designing rate schedules for a utility such as Piedmont Natural Gas?**

A. A reasonable and practical tariff should, first and foremost, produce adequate revenue to meet the requirements of the utility. In addition, I believe the following factors are important considerations in rate design: 1) rates should reflect the conditions of service requirement by the customers, the facilities requirements to provide the service, and the effect on the system load patterns; 2) each rate should have a reasonable relationship to the other rates in the tariff such that, where practical, a customer will have a reasonable price schedule even if his load conditions change and he must switch from one rate schedule to another; 3) rates should be designed to encourage the economical use of facilities installed by the utility and also promote energy conservation; 4) rates offered must be balanced between simple rate structures for like customers to more complicated structures for like customers to develop overall beneficial systems load patterns; and 5) rates should recognize the competitive environment faced by utilities and their customers.

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

A. The Company's existing rate schedules are described as follows:

1. Rate Schedule 101 (Residential Service): The Company's residential class rate schedule includes a customer charge and a seasonal per-therm delivery charge.
2. Rate Schedule 102 (Small General Service): The Company's rate schedule for non-residential customers with average daily use less than 20 dekatherms per day, which includes a customer charge and a seasonal per-therm delivery charge.
3. Rate Schedule 152 (Medium General Service): The Company's rate schedule for non-residential customers with average daily use between 20 and 50 dekatherms per day, which includes a customer charge and a seasonal declining block per-therm delivery charge. The first block is all usage up to 50,000 therms. The second block is all other usage. It is important to note that the base margin rates changing in this rate case are the same for both blocks.
4. Rate Schedule 144 (Experimental Medium General Motor Fuel – Transportation): The Company's experimental motor fuel transportation schedule currently has zero customers and has the exact same customer charge and per-therm delivery charge as Schedule 152.
5. Rate Schedule 142 (Natural Gas Vehicle Service): The Company's natural gas vehicle schedule includes a per-therm delivery charge and a per-therm fuel rider charge for service at Company premises.
6. Rate Schedule T-10 (Military Transportation Service): The Company's military transportation schedule for military bases with use greater than 5,000 dekatherms per day includes a customer charge and a seasonal per-therm delivery charge.

7. Rate Schedule 105 (Outdoor Gas Lighting Service): The Company's outdoor lighting schedule includes a fixture charge.
8. Rate Schedules 103 and 113 (Large General Sales Service and Large General Transportation Service): The Company's firm large volume rate schedules contain a customer charge, demand charge, and seasonal declining block per-therm delivery charges. There are six block rates: up to 15,000 therms, the next 30,000 therms, the next 90,000 therms, the next 165,000 therms, the next 300,000 therms, and all other therms.
9. Rate Schedules 104 and 114 (Interruptible Sales Service and Interruptible Transportation Service): The Company's interruptible large volume rate schedules contain a customer charge and seasonal declining block per-therm delivery charges. There are six block rates: up to 15,000 therms, the next 30,000 therms, the next 90,000 therms, the next 165,000 therms, the next 300,000 therms, and all other therms.

**Q. Does Piedmont have any customers that are served under long term contracts rather than tariffs?**

A. Yes. Long-term contracts with non-tariff rates are approved by the NCUC prior to initiation of service to the customer.

**Q. What types of customers are served by these long-term contracts?**

A. The customers span from large electric generation, municipals and others 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.

**Q. Are the Company's rate schedules currently earning a rate of return close to or equal to the system average?**

A. No, they are not. As shown in the cost-of-service study, at the pro forma level, most classes are not earning a rate of return close to or equal to the system average. In fact, some classes have an indexed rate of return ("IRR") three to five times the system average, while others have a negative rate of return. The Company's allocation of the revenue increase will work to adjust these rates of return and move them closer to the system average.

**CAM Table -1**

| Rate Schedule | Description | Proforma Existing Rates | | Proposed Rates | |
|---|---|---|---|---|---|
| | | ROR | ROR Index | ROR | ROR Index |
| 101 | Residential | 5.24% | 0.95 | 7.56% | 1.04 |
| 102 | Small General | 8.89% | 1.60 | 11.66% | 1.60 |
| 152 | Medium General | 14.99% | 2.70 | 18.44% | 2.54 |
| 103 | Large General Sales | -2.60% | (0.47) | -1.54% | (0.21) |
| 113 | Large General Transportation | -3.02% | (0.55) | -1.62% | (0.22) |
| *103/113* | *Large General Combined* | -2.97% | (0.54) | -1.61% | (0.22) |
| 104 | Large Interruptible Sales | 31.13% | 5.62 | 34.24% | 4.71 |
| 114 | Large Interruptible Transportation | 20.52% | 3.70 | 23.12% | 3.18 |
| *104/114* | *Large Interruptible Combined* | 20.79% | 3.75 | 23.40% | 3.22 |
| T-10 | Military Transportation | -2.76% | (0.50) | -1.78% | (0.25) |
| **Overall Rate of Return** | | 5.54% | 1.00 | 7.27% | 1.00 |

**Q. Please describe the steps taken to allocate the proposed revenue increase to the Company's rate schedules.**

A. The requested total revenue increase to be allocated to the rate schedules is $109,025,725. This represents an 11.9% increase in pro forma sales and transportation tariff system revenue (which are the base margin revenues and the cost of gas revenues). Subsequently, except when further changes (as listed below) are warranted, rate schedules received a revenue increase consistent with the overall system increase of 11.9%. The rate schedules that received an 11.9% revenue increase are Rate Schedules 101, 102, 142, and 105. To further reduce the IRRs of the two most over-earning rate schedules, Rate Schedules 152 and 104/114 were given only a 10.9% and 5.2% revenue increase, respectively. In order to bring the IRRs of Rate Schedules 103/113 and T-10 (which are both negative) even closer to the system average, those classes were given an increase of 15.4% and 17.5%, respectively. Those extremely under-earning classes were limited in their increase so to not increase revenues more than 20.0% to mitigate rate shock to those customers. These changes are depicted in Table CAM-2 below.

**Table CAM-2**

| | | Proposed Changes to Operating Revenue | | | |
|---|---|---|---|---|---|
| **Rate Schedule** | **Description** | **Proforma Revenue** | **Proposed Increase** | **Proposed Revenue** | **% Change** |
| 101 | Residential | 552,245,619 | 65,819,939 | 618,065,558 | 11.9% |
| 102 | Small General | 250,716,149 | 29,959,367 | 280,675,516 | 11.9% |
| 152 | Medium General | 40,884,097 | 4,439,455 | 45,323,552 | 10.9% |
| 142 | Natural Gas Vehicle Fuel | 1,036,559 | 122,934 | 1,159,493 | 11.9% |
| 105 | Gas Light Service | 102,158 | 12,116 | 114,274 | 11.9% |
| 103 | Large General Sales | 12,877,879 | 683,590 | 13,561,470 | 5.3% |
| 113 | Large General Transportation | 31,593,584 | 6,167,340 | 37,760,924 | 19.5% |
| *103/113* | *Large General Combined* | *44,471,463* | *6,850,930* | *51,322,393* | *15.4%* |
| 104 | Large Interruptible Sales | 2,960,467 | 41,469 | 3,001,936 | 1.4% |
| 114 | Large Interruptible Transportation | 24,611,818 | 1,383,895 | 25,995,714 | 5.6% |
| *104/114* | *Large Interruptible Combined* | *27,572,286* | *1,425,364* | *28,997,650* | *5.2%* |
| T-10 | Military Transportation | 2,261,796 | 395,620 | 2,657,416 | 17.5% |
| **Tariff Sales & Transportation Revenue** | | **919,290,128** | **109,025,725** | **1,028,315,853** | **11.9%** |
| | Special Contracts | 126,595,463 | - | 126,595,463 | 0.0% |
| **Total Sales & Transportation Revenue** | | **1,045,885,592** | **109,025,725** | **1,154,911,316** | **10.4%** |
| | Other Revenue | 1,136,144 | - | 1,136,144 | 0.0% |
| **Total Operating Revenue** | | **1,047,021,735** | **109,025,725** | **1,156,047,460** | **10.4%** |

**Q. Please describe how the revenue allocation adjusts the IRRs developed in the cost-of-service study.**

A. 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. See Table CAM-1 for results.

**Q. Please describe the steps taken to perform the rate design to ensure recovery of the proposed revenue.**

A. The revenue allocation was designed to decrease the inter-class subsidies between rate classes. By moving the rate classes closer to system parity, customers are moving closer to rates that recover only the costs that they incur. Just as a proper revenue allocation reduces inter-class subsidies, a proper rate design reduces intra-class subsidies and ensures that the proposed revenue is more likely to be recovered. This is accomplished by making sure that the costs by component (customer, demand, and delivery) are recovered in their respective types of charges (customer, demand, and delivery charges). This is not always possible due to certain classes not containing a demand charge, or the Company's need or intent to keep certain charges low. Nonetheless, in the following rate design, the Company is providing a rate design that is intended to move customer classes closer to parity without customer classes experiencing rate shock.

For example, the extremely under-earning classes have taken a step towards system parity but could have been assigned additional revenues to bring them even closer. However, the Company limited the increase of any given schedule to 20.0%. If the revenue deficiency was to change, these allocations should be adjusted to continue to move the classes closer to system parity while maintaining that percentage cap.

Additionally, to maintain consistency with customer bills in the Company's proposed rate design, no rate schedule received a customer charge increase. Rate Schedules 103 and 113 had their demand rates increased by 10%. The remaining revenue increase was applied to the delivery and fixture charges.

**Q. Why were no customer charges increased?**

A. An increase in the customer charge must be considered very carefully. Traditionally, the majority of a utility's customer costs are recovered in the demand and delivery charges on a customer's bill. As customer costs have increased and customer charges remained static, the amount of customer costs recovered in customer charges has been dwindling. Table CAM-3 shows the percentage of costs recovered in the current customer charge compared to what the fully allocated customer charge would be. This has put modern utilities in a difficult position, having to weigh the amount of fixed costs recovered in a variable rate with the need to make sure that customers are not overwhelmed with a substantial change in the make-up of their bill and to promote energy efficiency. In this proceeding, the Company is not increasing the customer charges for any class, which is consistent with their treatment in the prior rate case. However, the Company recognizes that many of their classes are not recovering even half of their customer costs in customer charges.

**Table CAM-3**

| Rate Schedule | Description | COST Based Customer Charge | Actual Customer Charge | Amount of Costs Recovered |
|---|---|---|---|---|
| 101 | Residential | $19 | $10 | 52% |
| 102 | Small General | $74 | $22 | 30% |
| 152 | Medium General | $1,602 | $75 | 5% |
| 103 | Large General Sales | $739 | $350 | 47% |
| 113 | Large General Transportation | $1,415 | $350 | 25% |
| 104 | Large Interruptible Sales | $903 | $350 | 39% |
| 114 | Large Interruptible Transportation | $1,852 | $350 | 19% |
| T-10 | Military Transportation | $34,098 | $0 | 0% |

**Q. Why were demand charges limited to a 10% increase?**

A. Demand charges have been limited to a 10% increase in an effort to promote energy efficiency and not introduce too much change in a single proceeding. In a perfect rate-making world, all demand costs would be recovered through demand charges. However, realistically, customers should not experience a major shift to demand charges in one proceeding; therefore, changes should occur at a gradual pace. For these reasons, the demand charges, which are included only in Rate Schedules 103 and 113, have been limited to a 10% increase.

**Q. Please describe the steps taken to perform the rate design for Rate Schedules 101, 102, 152, and 144.**

A. The total revenue allocation, as shown on Exhibit__(CAM-3), for these rate schedules was applied to the delivery charge. The customer charge, as mentioned above, received no increase. As Rate Schedule 144 has no billing determinants and, therefore, has no revenue, their customer charge and delivery rates have been set equal to the proposed rates of Rate Schedule 152, consistent with their current treatment.

**Q. Please describe the steps taken to perform the rate design for Rate Schedule 142.**

A. The total revenue allocation, as shown on Exhibit__(CAM-3), for Rate Schedule 142 was applied to the delivery charge. The rate schedule's Fuel Charge Rider has not been assigned any increase, which is the same treatment given in the Company's prior rate case.

**Q. Please describe the steps taken to perform the rate design for Rate Schedule T-10.**

A. The total revenue allocation, as shown on Exhibit__(CAM-3), for Rate Schedule T-10 was applied to the delivery charge. The percent of revenue assigned to the summer and winter delivery charges has been maintained from the proforma revenue at current rates.

**Q. Please describe the steps taken to perform the rate design for Rate Schedule 105.**

A. The total revenue allocation, as shown on Exhibit__(CAM-3), for Rate Schedule 105 was applied to the fixture charge.

**Q. Please describe the steps taken to perform the rate design for Rate Schedules 103, 113, 104, and 114.**

A. The total revenue allocation, as shown on Exhibit__(CAM-3), for these rate schedules was applied to the delivery charges and demand charges. The customer charges, as mentioned above, received no increase. Additionally, the demand charges for the applicable rate schedules received only enough of the revenue allocated to increase their rates by 10%.

Rate Schedules 103 and 113 are the same class of customer, except that Rate Schedule 113 customers receive gas transportation service only. Accordingly, their customer charges, demand charges, and delivery charges are the same. Rate Schedules 104 and 114 are also the same class of customer, except that Rate Schedule 114 customers receive gas transportation service only. Therefore, their base rates are also the same.

Finally, the percentage of revenues assigned to the declining block rates for these rate schedules has been adjusted to accomplish three things. First, the firm customers of Rate Schedules 103 and 113 should have almost equal or higher delivery charges than the interruptible customers on Rate Schedules 104 and 114, as the interruptible customers should have a slight discount in return for the Company's right to interrupt their service. While this was not completely possible for all the step rates given the allocated revenues to the classes, movement has been made towards this goal. Second, the rates should be true declining block rates, in that each subsequent block's rates should be less than the rates of the previous block. This is not always the case in the current rates. Third, the winter rates should be higher than the summer rates, due to the pressure put on the system in the winter being heavier than in the summer.

**Q. Please describe the proposed changes to the demand rates for the cost of gas.**

A. There are no proposed changes to the gas cost demand rates in this proceeding. This will be further explained in Piedmont witness Kally Couzens' testimony.

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

A. The proposed rate changes presented here provide a move to the overall company's return while displaying sound cost causation and gradualism rate design goals.

**Q. Does this conclude your direct testimony?**

A. Yes.

**BEFORE THE**
**NORTH CAROLINA UTILITIES COMMISSION**
**DOCKET G-9, SUB 781**

**PREPARED REBUTTAL TESTIMONY**
**OF**
**CYNTHIA A. MENHORN**

**ON BEHALF OF**
**PIEDMONT NATURAL GAS COMPANY, INC.**

## INTRODUCTION

**Q. Please state your name, address, and position.**

A. My name is Cynthia A. Menhorn. I am Vice President for MCR Performance Solutions ("MCR") and my business address is 155 Pfingsten Road, Suite 155 Deerfield, Illinois 60015.

**Q. Have you previously testified in this proceeding?**

A. Yes, I submitted direct testimony in this proceeding on behalf of Piedmont Natural Gas Company, Inc. ("Piedmont" or "the Company") on March 22, 2021.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Carolina Utility Customer Association, Inc. ("CUCA") witness Kevin O'Donnell, and Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR IV") witness Nicholas Phillips, in particular the appropriate cost of service study allocation method for distribution mains. In addition, I would like to explain witness O'Donnell's misunderstanding of my statement regarding rates of return and movement in my direct testimony.

I will also be responding to the testimony of Nicholas Phillips, Jr. regarding revenue allocation to classes and the Company's block rate design.

In addition, I will also be responding to the direct testimonies of the above witnesses along with the direct testimony of Jack Floyd regarding the appropriateness of moderate changes when allocating the revenue increase to rate classes.

## COST OF SERVICE ALLOCATION METHODOLOGY

**Q. How do witnesses Phillips and O'Donnell propose allocating the costs for distribution mains?**

A. Witness O'Donnell, on pages 87-90 of his direct testimony, advances the use of allocating distribution mains to rate classes solely using the class contribution to the peak demand in any given year, referred to as the Peak methodology. Witness Phillips proposes the same methodology on page 3 of his direct testimony. Under this method, interruptible customers would be allocated little or, in the case of a Peak Design Day methodology, none of the distribution mains costs.

**Q. Should witnesses Phillips and O'Donnell's proposal be accepted by the Commission?**

A. No. Witness O'Donnell correctly states that Piedmont's system is designed on a day where, when gas demand is at its highest, interruptible customers will be interrupted and will not be using the system's distribution mains. However, this contradicts the way that the system is in fact used every day. The simple truth is that, almost every single day of a given year, interruptible customers make use of the distribution mains on Piedmont's system. It is unreasonable to believe that a part of the system used *almost* every day by a certain class should not have a portion of its costs recovered by that class.

In fact, without the distribution mains, interruptible customers would not be able to receive gas from Piedmont's system at all. There are systems that are designed in a way where customers do not use a portion of the system. In certain electric utilities, there are customers that receive electricity directly from a company's transmission lines. In that instance, they do not use the electric company's primary or secondary lines at all. In that example, those transmission customers should not be assigned any of the primary or secondary costs in the cost of service study. However, that is a far different scenario than we are discussing here with Piedmont's system and interruptible customers, who need to use the distribution mains to receive service.

This is not to say that the nature of interruptible customers should be ignored either. It is, of course, true that interruptible customers can be asked to interrupt their use of the system during extreme demand periods. Therefore, it is appropriate that at least part of the allocation for distribution mains should be based on that peak. This is the reason why I have proposed the allocation method outlined in my direct testimony. It recognizes both the design of the system *and* its everyday usage, which is the most reasonable and prudent method of assigning costs in this instance.

**Q. Has your methodology been accepted by the Commission before?**

A. Yes. The Peak and Average allocation methodology for distribution mains has been accepted by the Commission in prior cases. Additionally, as witness O'Donnell says on page 86 of his direct testimony, it is also a methodology that has been used by Public Staff for quite some time. The methodology in my direct testimony has been tried and tested by this Commission and has previously been found to be the most reasonable. It continues to be the most reasonable.

## REVENUE ALLOCATION TO RATE CLASSES

**Q. What does witness Phillips consider to be a reasonable method to allocate revenue increases to rate classes?**

A. On pages 12 and 13 of witness Phillips direct testimony, he references the testimony of Michael Pirro in a prior Duke Energy Carolinas rate case. In that quote, Mr. Pirro defines a range of reasonableness for where an individual class' rate of return should fall compared to the total Company rate of return. Specifically, he defines that range of reasonableness as being within 10 percent of the system average which was the designated desire by the Company in that particular case for the revenue allocation. That range of reasonableness is just that, a range of reasonableness not an absolute.

**Q. Is that range of reasonableness an appropriate goal in revenue allocation?**

A. Yes. One of the primary, if not *the* primary goal of revenue allocation, is to move customer classes towards the system average rate of return. In this case, I accomplish this, and showed this move by comparing the indexed rates of return ("IROR") for each class to a system average of 1.00. In witness Phillips' example, that would place the IROR band of reasonableness between 0.90 and 1.10 for any individual class. It would be inappropriate to, without specific reasons, move a customer class's IROR further from 1.00 than it already is. My proposed revenue allocation moves every class's IROR closer towards that band of reasonableness. My direct testimony shows this movement on CAM Table-1 on page 13.

**Q. Why is your revenue allocation a more reasonable alternative than the proposed revenue allocations of witnesses Phillips and O'Donnell?**

A. Moving rates of return to the band of reasonableness is the goal of revenue allocation, but it must be tempered by other rate design principles as well as other prudent Company goals. One of those principles, gradualism, encourages moderation in shifts to the rates of return so that customers are not overly burdened by a sudden change in rates. I have moved towards that band of reasonableness in my revenue allocation, but in a more moderate and measured approach than that of witnesses Phillips and O'Donnell. This moderated movement towards the system average is the most reasonable proposal as it works to gradually move classes towards the system average without making extreme class revenue changes causing customers to experience rate shock. In addition, my proposed revenue allocation takes into account all customer classes. This approach ensures that the revenue allocation is not overly burdensome for one class of customers while working towards the overall goal of moving customer classes closer to the overall IROR.

**Q. Does witness O'Donnell mention anything else in his testimony that you wish to comment on?**

A. Yes, on pages 91 and 92 of his direct testimony he references my direct testimony as being incorrect based upon his Table 12 on page 91 of his direct testimony.

**Q. Is witness O'Donnell correct?**

A. No, he is looking at the absolute class rate of return value and not the indexed value.

**Q. Please explain.**

A. What witness O'Donnell is misunderstanding is that it is possible to increase a class' revenue while also bringing it closer to the total system rate of return. When a class has an increase less than the average increase across all classes, that class' IROR decreases. This is what occurred in my proposal. Again, upon examining CAM Table-1 on page 13 of my direct testimony, no class has moved further from the system average IROR of 1.00.

**Q. Is there anything else that may be complicating the issue for witness O'Donnell?**

A. Yes, I believe the other factor that he is missing is that the revenues that are put back into the COST$^{TM}$ model to calculate the final rate of return and indexed rate of return are based upon proforma billing determinants. So the original statement in my direct testimony stating that the "IRRS of each rate schedule moves closer to the system average or remains the same" is in fact correct.

## DECLINING BLOCK RATE STRUCTURE DESIGN

**Q. What does witness Phillips recommend regarding the declining block rate structure design in classes 113 and 114?**

A. On page 17 of his direct testimony, witness Phillips recommends that the initial usage blocks in the declining block rate structure of rate classes 113 and 114 should assume the full fixed costs allocated to those classes, with the remaining usage blocks recovering only variable costs.

**Q. Is this a reasonable recommendation?**

A. The concept is reasonable, but witness Phillips does not make a specific proposal that can be evaluated. It is the goal of rate design for the fixed (or customer) costs assigned to a rate class be recovered by all customers in that class. One method to accomplish that is to place these customer costs within the customer charge. In a declining block rate structure, another method to accomplish this is by placing the customer costs remaining (after assigning some to the customer charge) within the initial few low-usage blocks. However, there is no way to say that these customer costs are not recovered in these initial blocks in my proposed rate design. For example, in the rate design for rate classes 103 and 113, the proposed revenue for the initial two blocks for both summer and winter rates is $8,238,819. However, the customer costs not recovered by the customer charges of rate classes 103 and 113 is only $4,315,587, far less than what is recovered in the initial two blocks.

If witness Phillips had proposed a different block proposal, I could offer a recommendation on whether my rate design is more reasonable than his. However, without a proposal to compare, I do not see how his proposal is not already being accomplished in the rate design that I proposed.

**Q. Do you wish to comment on witnesses Phillips and O'Donnell's recommendations for the treatment of Special Contract revenues?**

A. Yes, both witnesses Phillips and O'Donnell disagree with my treatment of Special Contract revenues. It would be difficult to accept those recommendations of witness Phillips and O'Donnell and the reasoning for that is addressed in the rebuttal testimony of Company witness Couzens.

## CONCLUSION

**Q. What is your conclusion regarding this rebuttal testimony?**

A. It is my belief that the revenue allocation and rate design proposed by the Company have taken into consideration all customer classes and provided a revenue allocation and rate design that moves all classes in a manner that is reasonable for both the customers and the Company. My revenue allocation and rate design proposal should be accepted as filed.

**Q. Does this conclude your rebuttal testimony?**

A. Yes.

MS. DEMOPOULOS: Thank you, Chair Mitchell. I would also ask that the Exhibits CAM-1 through CAM-3 also be identified as marked.

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

(Exhibits CAM-1 through CAM-3, were identified as they were marked when prefiled.)

MS. DEMOPOULOS: Thank you.

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

A. Yes, I have.

Q. Could you please share that with the Commission.

A. Sure.

My name is Cynthia Menhorn, and I am vice president of MCR Performance Solution. I prefiled direct testimony in this docket on March 22, 2021, in support of Piedmont's application for a general rate increase. On August 25, 2021, I submitted prefiled rebuttal testimony in this proceeding. My prefiled direct testimony provides and sponsors the fully allocated cost of service study, including targets for class revenues and rates designed to achieve those targeted revenues. I describe and provide the rationale for the functionalization, classification, and allocation factors used in that model.

My direct testimony discusses important factors considered in designing rates for the Company's rate schedules. Rates of return for existing rate schedules at existing rates, and the allocation of the proposed revenue increase to the rate schedules in order to improve the indexed rates of return.

My testimony demonstrates that Piedmont's proposed allocation of revenues and rate design is reasonable, consistent with previous rate design proposals approved in prior proceedings before this Commission, and does not unduly burden any of the customer classes.

My direct testimony is supported by the following three exhibits: one, my experience statement; two, the allocated cost of service study including schedules 1 through 5; and three, summary of existing and proposed rates and revenue.

I submitted prefiled rebuttal testimony in this docket on August 25, 2021, in response to various matters raised by Commission Public Staff witnesses and intervenor witnesses. Specifically, I respond to concerns and recommendations related to the following four topics raised by Public Staff witness Jack Floyd, by Carolina Utility Customer Association witness Kevin O'Donnell, and by Carolina Industrial Group for Fair Utility Rates witness Nicholas Phillips:

Number 1, Piedmont's recommended allocation methodology; number 2, Piedmont's calculation of rates of return and movement towards unity; number 3, Piedmont's revenue allocation to classes; and number 4, Piedmont's declining block rate design.

This concludes the summary of my prefiled direct and rebuttal testimony.

Q. Thank you, Ms. Menhorn.

MS. DEMOPOULOS: At this time, Piedmont will make Ms. Menhorn available for any questions.

CHAIR MITCHELL: All right. My notes indicate that there is no cross for the witness, but I'll pause to make sure that's the case.

(No response.)

CHAIR MITCHELL: All right. I'm not hearing any cross examination.

Questions from the Commission. Commissioners have questions for the witness?

(No response.)

CHAIR MITCHELL: Not seeing any. I do have two for you, Ms. Menhorn. And these are coming from our staff, so bear with me here.

EXAMINATION BY CHAIR MITCHELL:

Q. Referring to your tables that you provided in your direct testimony, Table 1 occurs on page 13 of your direct testimony, and then Table 2 occurs on page 15 of your direct testimony. We'd like a late-filed exhibit providing a similar table to Table 1 depicting the rate of return and rate of return index for Piedmont's stipulated rates for the two -- for the following two scenarios: excluding Robeson LNG and Pender Onslow, and the second scenario would be including LNG and Pender Onslow.

A. That can be prepared and will be provided.

Q. Okay.

A. I'm looking for my attorneys to get that into the record.

Q. All right.

CHAIR MITCHELL: Ms. Demopoulos, just give me the nod to make sure you got that first one. Okay.

Q. Here's the second one. We'd like a second late-filed exhibit, this time similar to the table you provided, Table 2, depicting the proposed increase, proposed revenue, and percent change for Piedmont's operating scenario for the same two scenarios: excluding Robeson and Pender Onslow, and then the second scenario, including Robeson and Pender Onslow.

A. Yes, that will be provided as well.

Q. Okay. All right. And that's all I have for you, Ms. Menhorn.

CHAIR MITCHELL: I'll make sure my fellow Commissioners -- nothing further for the witness?

(No response.)

CHAIR MITCHELL: All right. Ms. Menhorn, thank you for your participation in this case. You may step down.

Ms. Demopoulos, any intent to recall the witness?

MS. DEMOPOULOS: No, no intention.

CHAIR MITCHELL: All right. You are excused from the proceeding, ma'am.

THE WITNESS: Thank you.

CHAIR MITCHELL: All right. And I will take a motion.

MS. DEMOPOULOS: Yes. Chair Mitchell, at this time, we would move to admit Exhibits CAM-1 through CAM-3 into the evidentiary record.

CHAIR MITCHELL: All right. Ms. Demopoulos, is that all of her -- that's not all of her exhibit -- that does not include all of the exhibits to her testimony, does it?

MS. DEMOPOULOS: It does. These are exhibits to the prefiled direct testimony.

CHAIR MITCHELL: Okay. All right. Okay. Hearing no objection to the motion, it will be allowed.

(Exhibits CAM-1 through CAM-3, were admitted into evidence.)

MS. DEMOPOULOS: Thank you.

CHAIR MITCHELL: And the exhibits will be accepted into evidence. Okay. All right.

Ms. Menhorn, thank you. She's already left us. All right.

Piedmont, you may call your next witness.

MR. JEFFRIES: Thank you, Chair Mitchell. Piedmont would call Ms. Quynh Bowman to the stand.

CHAIR MITCHELL: There you are, Ms. Bowman. Good morning.

THE WITNESS: Good morning.

CHAIR MITCHELL: Please raise your right hand.

Whereupon,

QUYNH P. BOWMAN,

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

CHAIR MITCHELL: All right. Thank you. And, Mr. Jeffries, you may proceed.

MR. JEFFRIES: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Good morning, Ms. Bowman.

A. Good morning.

Q. Could you state your name and business address for the record, please.

A. My name is Quynh Bowman. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. And where do you work, Ms. Bowman?

A. At Piedmont Natural Gas.

Q. And what's your position at Piedmont?

A. My position is the director of gas rates and regulatory strategy.

Q. Thank you. And are you the same Quynh Bowman that prefiled direct testimony in this proceeding on March 22, 2021, consisting of 23 pages?

A. I am.

Q. And also attached to that testimony were Exhibits QPB-1 through QPB-8; is that correct?

A. Yes.

Q. And then you also filed supplemental testimony in this proceeding on July 28, 2021, consisting of 15 pages; is that correct?

A. Yes.

Q. And along with that testimony, you also provided exhibits marked QPB-1 Updated through QPB-8 Updated, correct?

A. Yes.

Q. And then finally, on August 25, 2021, you filed rebuttal testimony in this proceeding consisting of 14 pages, correct?

A. Yes.

Q. All right. And was that testimony and were those exhibits prepared by you or under your direction?

A. Yes.

Q. And if I -- I'm sorry.

Do you have any corrections to your prefiled testimony or exhibits?

A. I have no corrections.

Q. Okay. Thank you. If I asked you the same questions that are set forth in your prefiled testimonies while you were on the stand today, would your answers be the same?

A. Yes.

Q. All right. Thank you.

MR. JEFFRIES: Chair Mitchell, we'd ask that Ms. Bowman's prefiled direct, supplement, and rebuttal testimonies be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. The direct testimony of Piedmont witness Bowman filed in the docket on March 22nd shall be copied into the record as if given orally from the stand, the supplemental testimony of Piedmont witness Bowman filed in the docket on July 28th shall be copied into the record as if given orally from the stand; and the rebuttal testimony of Piedmont witness Bowman filed in the docket on August 25th shall be called into the record as if given orally from the stand.

(Whereupon, the prefiled direct testimony, prefiled supplemental testimony, and prefiled rebuttal testimony of Quynh P. Bowman was 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

## Direct Testimony and Exhibits
## of
## Quynh P. Bowman

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**March 22, 2021**

**Q. Ms. Bowman, please state your name and business address.**

A. My name is Quynh Pham Bowman. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am the Director – Gas Rates & Regulatory Strategy for Piedmont Natural Gas Company, Inc. ("Piedmont" or "the Company"). In this capacity, I am responsible for a variety matters including supporting the development and execution of rate requests and financial report filings by Piedmont.

**Q. Please describe your educational and professional background.**

A. I received a Bachelor of Arts degree in Accounting from Furman University and subsequently earned a Master of Accounting from North Carolina State University. I received my Certified Public Accountant license (NC Certificate #34214) in 2009 that remains active. I am currently pursuing a Master of Business Administration with an Energy Concentration from the University of North Carolina Charlotte.

From 2007 through 2010, I was employed at McGladrey & Pullen, LLP (now RSM) to perform external financial audits for various clients. Since 2010, I have worked at Piedmont and Duke Energy in various roles including Internal Audit, SOX Compliance, Enterprise Risk Management, and, now currently, Gas Rates & Regulatory Strategy.

**Q. Have you previously testified before this Commission or any other regulatory authority?**

A. I have not previously testified before the North Carolina Utilities Commission but have presented testimony before the Tennessee Public Utility Commission.

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

A. My testimony is filed in support of Piedmont's application in this case. Specifically, the purpose of my testimony is to explain and support: (1) Piedmont's rate base at December 31, 2020 and the actual results of Piedmont's operations for the twelve month period ending December 31, 2020 (the "Test Period"); (2) the results of Piedmont's Test Period operations under present rates, as adjusted for accounting and pro forma changes to the Company's operating revenue, operating expense, capital structure and rate base; (3) the additional revenue required to appropriately support Piedmont's pro forma cost of service; (4) Piedmont's compliance with NCUC Form G-1 Minimum Filing Requirements for this general rate case application; and (5) the amortization of certain deferred expenses that have been previously granted regulatory asset treatment by the Commission.

**Q. Do you have any exhibits supporting your testimony?**

A. Yes. The following exhibits are included with my testimony:

Exhibit_(QPB-1) Summary of Rate Base

Exhibit_(QPB-2) Original Cost of Property Used and Useful

Exhibit_(QPB-3) Accumulated Depreciation of Property Used and Useful

Exhibit_(QPB-4) Working Capital

Exhibit_(QPB-5) Accumulated Deferred Income Taxes

Exhibit_(QPB-6) Depreciation Policy and Rates

Exhibit_(QPB-7) Net Operating Income and Rates of Return

Exhibit_(QPB-8) Piedmont Balance Sheet and Income Statement

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

A. Yes.

**Q. Are you familiar with the accounting procedures and books of account of Piedmont?**

A. Yes. The books of account of Piedmont follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission. The Test Period amounts shown on all of my exhibits are those represented on Piedmont's books of account, and all of the pro forma adjustments shown on my exhibits conform to the Company's accounting procedures.

**Q. What steps does the Company take to ensure that its books and records are accurate and complete?**

A. Piedmont maintains and relies upon an extensive system of internal accounting controls and audits by both internal and external auditors. The system of internal accounting controls provides reasonable assurance that all transactions are executed in accordance with management's authorization and are recorded properly. The system of internal accounting controls is reviewed annually, tested and documented by the Company to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper. In addition, independent certified public accountants perform an annual audit to provide assurance that internal accounting controls are operating effectively and that the Company's financial statements are materially accurate.

**<u>Piedmont's Rate Base</u>**

**Q. Please explain the computation of rate base reflected in your exhibits.**

A. Exhibit_(QPB-1) is a summary of Piedmont's end of Test Period rate base amount applicable to its utility operations in North Carolina. Piedmont's end of Test Period rate base for its utility operations in North Carolina is approximately $4.22 billion. This amount reflects the December 31, 2020 balances in the Company's accounting records for utility plant in service, less accumulated depreciation and accumulated deferred income taxes, plus an allowance for working capital.

The largest component of Piedmont's North Carolina rate base is utility plant in service, which is approximately $6.49 billion computed at the original cost of such used and useful property. Exhibit_(QPB-2) identifies utility plant in service by asset category at the end of the Test Period, with approximately 90.18% of those assets being transmission and distribution plant (predominantly consisting of pipe in the ground, classified as either mains or service lines).

Exhibit_(QPB-3) identifies accumulated depreciation by asset category at the end of the Test Period, which is a deduction to rate base of approximately $1.59 billion. Exhibit_(QPB-5) identifies accumulated deferred income taxes ("ADIT") at the end of the Test Period, which is a deduction to rate base of approximately $0.88 billion. The Test Period allowance for working capital reflects the combined average per books balance for the 13-months ended December 31, 2020 for the various other book assets and liabilities supporting Piedmont's utility operations in North Carolina, as well as the results of the cash working capital lead/lag study. The various components of the Test Period allowance for working capital are delineated in Exhibit_(QPB-4) totaling approximately $0.21 billion.

**Q. Has the Company presented the results of a depreciation or lead/lag study in this filing?**

A. No. For purposes of our depreciation and cash working capital calculations we have relied on the depreciation rates and lead/lag calculations provided by studies of those components of rate base in our 2019 rate case, the results of which are incorporated into the settlement in that case and which underlie our existing rates. Because those studies are relatively recent, and because we are not aware of any factors that would render them stale, we elected to rely upon them for purposes of this case rather than burden our customers with the costs of conducting new studies.

**Q. How has Piedmont's rate base changed since its last general rate case?**

A. Piedmont's last general rate case reflected a Test Period rate base at December 31, 2018, updated for known and measurable changes through

June 30, 2019. The amount of Piedmont's rate base coming out of that proceeding was $3.45 billion, compared to $4.22 billion at the end of this current Test Period. Utility plant in service, which is the largest component of rate base, grew by more than $0.97 billion over this period, most significantly in the transmission asset category. See Table 1 as follows for such growth by major plant asset category.

**Table 1**
**Summary of Plant Assets by Category**

| Plant Asset Category | As of June 30, 2019 | As of December 31, 2020 | % Change |
|---|---|---|---|
| Storage Plant | $159,098,556 | $141,885,536 | -11% |
| Transmission Plant | $2,688,126,445 | $3,275,495,473 | 22% |
| Distribution Plant | $2,225,238,801 | $2,574,521,551 | 16% |
| General Plant & Intangibles | $443,909,479 | $494,975,328 | 12% |
| Total Utility Plant | $5,516,373,281 | $6,486,877,888 | 18% |

**Q. What factors have contributed to this increase in rate base since 2018?**

A. Piedmont's rate base growth is the result of several factors. First, Piedmont continues to invest in its system in order to ensure compliance with federal pipeline safety and integrity obligations created by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and much of that compliance work has involved capital projects. This work is explained in greater detail in the testimony of Piedmont witness Brian Weisker. Up until the filing of this rate case, a significant portion of this capital investment has been handled under the Integrity Management

Rider ("IMR") mechanism and Piedmont's base rates have not included any component designed to compensate Piedmont for that investment. As part of this general rate case, we are "rolling-in" our cumulative integrity management capital investment for inclusion in base rates. That integrity management investment since the last rate case accounts for approximately 38% of the growth in Piedmont's plant in service shown in Table 1 above.

Another significant driver for the increase in rate base is the capital investments undertaken to support system infrastructure upgrades. These upgrades have been needed to support the continued provision of reliable firm natural gas service in light of increasing system demands largely driven by customer growth and the associated increase in natural gas throughput. Piedmont's service territory covers a significant physical and demographic portion of the state of North Carolina including major, growing metropolitan areas. Accordingly, the demand for firm natural gas service has continued to steadily increase in Piedmont's service territory.

**Piedmont's Per Books Test Period Cost of Service**

**Q. What are the actual financial results of Piedmont's North Carolina operations for the Test Period?**

A. A summary of the Test Period financial results for Piedmont's North Carolina operations is shown on page 1 column 1 of Exhibit_(QPB-7). Amounts in column 1 were taken from Piedmont's books of account as of December 31, 2020. Column 1 Line 14 shows per books net operating income for return for the Test Period of $288 million. Line 20 shows actual end of Test Period rate base of $4.22 billion. Column 1 Line 21 shows that the Test Period per books overall rate of return on rate base before accounting and pro forma adjustments is 6.82%.

**Piedmont's Pro Forma Cost of Service**

**Q. Please describe the results of Piedmont's Test Period operations under present rates, as adjusted for pro forma changes to the Company's operating revenue, operating expense, capital structure and rate base.**

A. Column 3 of Exhibit_(QPB-7) summarizes the results of Piedmont's Test Period operations under present rates, as adjusted for accounting and pro forma changes to the Company's operating revenue, operating expense, capital structure and rate base. The pro forma adjustment workpapers are included in G-1 Item 4, filed with the Company's Application. Each of the accounting and pro forma adjustments shown in Column 2 of Exhibit_(QPB-7) is based on known and measurable information. Overall, the combined effect of the accounting and pro forma adjustments to the Test Period yields a 5.54% overall rate of return on rate base, as shown in Column 3 Line 21 of Exhibit _(QPB-7).

**Q. Please explain the accounting and pro forma adjustments to revenues and operating expenses used to compute Piedmont's pro forma cost of service.**

A. Each accounting and proforma adjustment is numbered and shown alongside Column 2 on page 1 of Exhibit_(QPB-7). A description of each adjustment is also provided on pages 3 and 4 of Exhibit_(QPB-7). Adjustment 1 is performed for the purpose of normalizing annual revenues for the sale and transportation of gas to present billing rates and current customer throughput levels. Adjustment 2 is performed for the purpose of bringing other operating revenues to the going-level annual amount. The specific computation of these pro forma revenue adjustments is discussed in the testimony of Piedmont witness Kally Couzens.

Adjustments 3 through 8 are performed for the purpose of bringing annual operating expenses to the going-level amount. Adjustment 3 specifically aligns the total annual cost of gas to the present billing rates and current customer throughput levels consistent with Adjustment 1 discussed above. Adjustment 4 increases operations and maintenance ("O&M") expense to the going-level amount of $215 million. Page 3 of Exhibit_(QPB-7) lists each O&M expense category and the adjustment amount. Included in adjustment 4 is a refresh of Piedmont's regulatory amortization expense, which includes expenses associated with costs granted regulatory asset treatment by this Commission. Regulatory amortization expense is further discussed in detail later in my testimony.

Adjustment 5 is for the purpose of annualizing depreciation expense to align with the pro forma amount of plant in service per adjustment 9 herein. Adjustment 6 is to annualize general tax expense (which is predominantly comprised of property tax expense, payroll tax expense and NC franchise tax expense) consistent with the other related pro forma adjustments in this proceeding. Adjustments 7 and 8 simply provide an update of annual state and federal income tax expense (at current rates of 2.5% and 21%, respectively) consistent with the other related pro forma adjustments in this proceeding.

**Q. Are there any aspects of accounting and pro forma adjustments that you would like to comment?**

A. Yes. I would like to call attention to the impact from the investment for Robeson County LNG on going level O&M expenses. Specific adjustments related to the additional LNG facility are included in O&M adjustment 4. These adjustments relate to personnel related expenses, risk insurance expense, and general O&M expense.

In addition, the Test Period is undoubtedly marked with effects from the COVID-19 pandemic. However, an attempt to quantify the effects of the pandemic on the Test Period financial results would provide little more than a theoretical exercise that is inherently subjective in nature. Furthermore, Piedmont did not file a COVID-19 deferral because the Company did not believe that the pandemic impacted its financial results in a material way. Because the impact on the financial results are not known and measurable to a high degree of certainty, Test Period adjustments due to COVID-19 are minimal. Only two adjustments were made to O&M expenses as non-recurring. The first adjustment removes an employee stipend provided to eligible employees (based on income) to help with unplanned expenses due to disruptions from the pandemic. The second adjustment removes costs incurred by Piedmont for third-party fees for customer payments at walk-in payment centers. These fees were suspended by the Company for a significant portion of the Test Period as part of our pandemic relief actions. These two adjustments are made in adjustment 4S.

**Q. Please explain in further detail the pro forma adjustments that comprise Adjustment 4 for O&M expenses.**

A. This adjustment was prepared by segregating the Test Period O&M expense into its major categories and analyzing the Test Period transactions and the specific cost drivers for each of these major categories to appropriately develop the going level expense amount for each major category. The following table includes a description of the nature of each adjustment:

**Table 2**
**Adjustment 4 – O&M Adjustments Detail**

| Adj. No. | Adjustment Description (From page 3 of Bowman Exhibit (QPB-7)) |
|---|---|
| **4A** | **To increase salaries & wages expense to the going-level basis.**<br><br>The adjustment proposes to annualize effective pay rates for headcount at December 31, 2020 and update the jurisdictional allocation factor. Also included is an adjustment for current Robeson County LNG employees who capitalized 100% of their payroll to the project during the Test Period. |
| **4B**<br>**4C** | **To increase short-term incentive plan and long-term incentive plan expense to the going-level basis.**<br><br>The adjustment proposes to update STIP and LTIP compensation expense using 2021 budgets at target level and updating the jurisdictional allocation factor. |
| **4D** | **To reduce executive management compensation for ratemaking purposes.**<br><br>The adjustment proposes to remove 50% of the allocated compensation (including benefits) of the five Duke Energy executives with the highest level of compensation. While the Company fully believes these costs are reasonable, prudent, and appropriate to recover from customers, for purposes of streamlining this proceeding, we have made this adjustment. |
| **4E** | **To increase pension, OPEB and long-term disability expense to the going-level basis.**<br><br>The adjustment proposes to update pension and OPEB expense for known and measurable annual expense as well as normalizes long-term disability expense. The jurisdictional allocation factor is also updated. |
| **4F** | **To increase other employee benefits expense to the going-level basis.**<br><br>The adjustment proposes to increase medical and dental expense to the anticipated going level. The updated jurisdictional allocation factor is reflected in this adjustment. Also included is an adjustment for current Robeson County LNG employees who capitalized 100% of their benefits to the project during the Test Period. |

| | |
|---|---|
| **4G** | **To decrease the provision of uncollectibles expense to the going-level basis.**<br><br>The adjustment proposes to update uncollectible expense to reflect actual write-offs by normalizing the Test Period write-offs-to-revenues ratio and applying the updated ratio to pro forma Sales & Transportation revenue. |
| **4H** | **To decrease rents expense to the going-level basis.**<br><br>The adjustment proposes to update rent expense by reflecting the current terms of the rental agreements and update the jurisdictional allocation factors. |
| **4I** | **To increase insurance expense to the going-level basis.**<br><br>The adjustment proposes to reflect insurance rates that were invoiced for January – December 2021 and update jurisdictional allocation factors. Also included is an adjustment for incremental risk insurance expense for the Robeson County LNG facility. |
| **4J** | **To increase customer payment expenses to the going-level basis.**<br><br>The adjustment proposes to include credit card payment fees into base rates. When a customer service representative assists a customer payment using a credit card, a fee is assessed by the credit card payment vendor. Historically, the customer incurs a $3.50 fee for each transaction. In 2020, as part of the Company's COVID-19 response, these fees were waived for a significant portion of the year. By including the fees in base rates, the Company is removing a potential additional burden for customers and improving our customer care. |
| **4K** | **To decrease expenses for allocations to non-utility activities.**<br><br>The adjustment proposes to allocate a portion of select operating expenses using the three-factor Massachusetts Formula which consists of plant, revenues, and payroll costs, equally weighted. |
| **4L** | **To decrease aviation expense for ratemaking purposes.**<br><br>The adjustment proposes to remove 50% of aviation expenses not related to utility patrol. While the Company fully believes these costs are reasonable, prudent, and appropriate to recover from customers, for purposes of streamlining this proceeding, we have made this adjustment. |
| **4M** | **To increase the regulatory amortization expense for deferred NCNG** |

| | |
|---|---|
| | **OPEB costs.**<br><br>The adjustment proposes to synchronize the annual interest rate to the net of tax rate of return as proposed in this proceeding. No further adjustments are proposed. |
| **4N** | **To increase the regulatory amortization expense for deferred environmental cleanup costs.**<br><br>The adjustment proposes to amortize deferred environmental costs related to various state and federal requirements for air emissions, wastewater discharges, and solid, toxic and hazardous waste management. Piedmont was initially granted regulatory asset treatment in Docket No. G-9, Sub 333. The proposed amortization period is 4 years. Further discussion is included in the Amortization of Deferred Expenses section. |
| **4O** | **To increase the regulatory amortization expense for deferred distribution integrity management program costs.**<br><br>The adjustment proposes to amortize deferred O&M costs arising out of activities required to comply with federal DIMP requirement. Piedmont was initially granted regulatory asset treatment in the last rate case (Docket No. G-9, Sub 743). The proposed amortization period is 4 years. Further discussion is included in the Amortization of Deferred Expenses section. |
| **4P** | **To decrease the regulatory amortization expense for deferred transmission integrity management program costs.**<br><br>The adjustment proposes to amortize deferred O&M costs arising out of activities required to comply with TIMP requirements. Piedmont was initially granted regulatory asset treatment in Docket No. G-9, Sub 495. The proposed amortization period is 4 years. Further discussion is included in the Amortization of Deferred Expenses section. |
| **4Q** | **To increase the regulatory amortization expense for deferred rate case costs.**<br><br>This adjustment proposes to amortize the remaining unamortized balance of deferred rate case costs in addition to the incremental rate case costs incurred for this proceeding. The proposed amortization period is 4 years. |
| **4R** | **To increase current regulatory fee expense to the going level.**<br><br>The adjustment proposes to synchronize the regulatory fee expense with pro forma revenues using the current fee rate of 0.13% |

| | |
|---|---|
| 4S | **To increase expenses for inflation and going-level jurisdictional allocations net of other ratemaking adjustments.**<br><br>The adjustment proposes to remove non-recurring, non-jurisdictional, and out-of-period expenses from Test Period expenses. In addition, costs related to customer energy efficiency programs were removed from O&M to be included in a rider as discussed in the testimony of Piedmont witness Pia Powers.<br><br>The remaining O&M expenses not specifically adjusted are updated by applying an inflation factor calculated using data published by Office of Management and Budget (OMB). Also included is an adjustment for general O&M expenses that are associated with operating the Robeson LNG County facility. |

**Q. Please explain the accounting and pro forma adjustments to rate base.**

A. Adjustments 9, 10, 11, and 12 were made to update the per books end of Test Period rate base amounts to June 30, 2021. Adjustment 9 to plant in service anticipates that additional plant assets totaling $684 million will be placed in service between December 31, 2020 and June 30, 2021. Adjustment 10 reflects the change in accumulated depreciation, an increase of $83 million that is anticipated between December 31, 2020 and June 30, 2021 based on adjustment 9. Adjustment 12 reflects the change in the accumulated deferred income tax balance, an increase of $20 million that we anticipate occurring between December 31, 2020 and June 30, 2021. Adjustments 9, 10 and 12 will be amended to replace the estimates with the actual per books amount of plant in service, accumulated depreciation and accumulated deferred income taxes, respectively, as of June 30, 2021. Adjustment 11 reflects anticipated changes for the asset and liability accounts where regulatory asset deferrals are included using end of Test Period balances while other asset and liability balances are determined using a 13-month average balance. Adjustment 11 also includes the results of the cash working capital lead/lag study based on the Company's cost of service after adjustments for proposed rates.

## Piedmont's Revenue Requirement

**Q. Please explain the additional revenue necessary to appropriately support Piedmont's North Carolina utility operations.**

A. Adjustment 13 shown in Column 4 on page 1 of Exhibit_(QPB-7) reflects the adjustment to the Company's base margin revenues needed to produce a 10.25% return on equity as recommended by Piedmont witness Dylan D'Ascendis in his testimony. To develop adjustment 13, Piedmont's rate base was allocated to its capital source components of long-term debt, short-term debt and common equity. This allocation, as shown in Column 4 on page 2 of Exhibit_(QPB-7), is based on the proposed capitalization ratios of 47.45% long-term debt, 0.55% short-term debt and 52.00% common equity. This is the Company's targeted capital structure and is supported in testimony by Company witness Karl Newlin. At present rates and at the targeted capital structure and the pro forma cost of debt, Piedmont's revenues and expenses will yield a 6.92% return on equity, as shown in Column 6 Line 3 on page 2 of Exhibit_(QPB-7).

**Q. Does your proposed increased in the revenue requirement comport with the proposed rates shown in Appendix I to the petition?**

A. Yes, it does. The proposed rates shown in Appendix I will produce a revenue increase of $109,025,725 which is the proposed revenue requirement adjustment shown in Exhibit_(QPB-7) on page 1. The testimony and exhibits of Piedmont witness Kally Couzens support the derivation of proposed rates for this proposed revenue requirement adjustment amount.

**Q. Does this complete the cost of service portion of your testimony?**

A. Yes. Exhibits, working papers, and testimony filed with the petition were prepared with information currently available to us at the time of the filing. New evidence may become available between the filing date and the time of the hearing. As such, as permitted under North Carolina statues and the rules of the Commission, any additional relevant, material, and competent evidence will be provided at the hearing. We reserve the right to file such updated information at or before the hearing of this docket to the extent such information is relevant to a determination of the matters at issue in this proceeding.

**Amortization of Deferred Expenses**

**Q. Is Piedmont proposing to amortize and recover any deferred expenses in this proceeding?**

A. Yes. Piedmont proposes to amortize expenses that have been previously deferred pursuant to Commission Order.

**Q. What are those main categories of deferred expense?**

A. Piedmont has previously deferred and now seeks recovery of certain transmission and distribution pipeline integrity management costs and certain environmental compliance costs. These costs have been deferred in accordance with prior Commission orders.

**Q. Can you please describe these costs and how they came to be deferred?**

A. Yes. On December 2, 2004, the Commission issued its *Order Approving Deferred Accounting Treatment* in which, pursuant to Piedmont's previous request, it ordered that "effective November 1, 2004, Piedmont is authorized to segregate its incremental and extraordinary O&M expenses for PNG-NC and NCNG incurred in compliance with the new Pipeline Integrity Management Regulations issued by the USDOT pursuant to the Pipeline Safety Improvement Act of 2002 into a special deferred account until recovery of such costs can be sought in a general rate case, subject to a determination that the costs have been prudently incurred and properly accounted for and a determination as to the proper method of recovery."

**Q. How has the Commission treated these types of costs since its December 1, 2004 order?**

A. Following that order, Piedmont deferred operating and maintenance expenses of the type authorized by the Commission and then sought amortization and recovery of those costs in its 2005, 2008, 2013, 2019 rate case filings (per Docket Nos. G-9, Sub 499, G-9, Sub 550, G-9, Sub 631, and G-9, Sub 743 respectively). In those cases, in conformance with settlements of those dockets, the Commission authorized Piedmont to amortize the costs it had deferred and approved a continuation of the mechanism in each case.

**Q. Has Piedmont continued to defer pipeline integrity O&M costs since the last rate case?**

A. Yes. In Piedmont's last rate case, deferred Transmission Integrity O&M costs (PIM-T) was granted 4-year amortized recovery of a balance of $54,449,944, which reflected actual deferred expenses through June 30, 2019 net of regulatory amortizations through October 31, 2019. In this case, Piedmont seeks to include amortization of the costs incurred and deferred since that date. Piedmont is proposing a 4-year amortization of unamortized costs previously approved and the incremental deferred costs since the last rate case. The pro forma adjustment decreases this expense by $409,634, bringing the pro forma annual expense to $13,202,852.

**Q. Are there other pipeline integrity O&M costs for which Piedmont is seeking recovery?**

A. Yes, in addition to PIM-T, Piedmont was granted regulatory asset treatment for O&M expenses arising out of activities required to comply with federal DIMP requirements (PIM-D) in the Company's prior rate case. Piedmont seeks to include amortization of cost incurred and deferred since the last rate case. Piedmont is proposing a 4-year amortization period for deferred costs of $4,764,524. This pro forma annual expense is $1,191,131. These amounts are included in Piedmont's cost of service in this case and is reflected in pro forma O&M expense in Exhibit_(QPB-7).

**Q. Were the pipeline integrity costs for PIM-T and PIM-D prudently incurred and have they been properly accounted for?**

A. Yes, these costs were incurred in compliance with federal laws and regulations and in the ordinary conduct of Piedmont's business.

**Q. Is Piedmont proposing continued regulatory asset treatment for these integrity costs going forward?**

A. Yes. The same reasons which supported deferral of these costs previously continue to persist and support continued regulatory asset treatment for these costs.

**Q. What is the basis for Piedmont's proposed amortization and recovery of deferred environmental compliance costs?**

A. On December 16, 1992, Piedmont requested authorization to defer certain environmental assessment and clean-up costs relating to various state and federal environmental control requirements for air emissions, wastewater discharges, and solid, toxic and hazardous waste management. This request was made in Docket No. G-9, Sub 333. On December 23, 1992, the Commission issued its *Order Granting Request* in this Docket in which it ordered that "the request of special accounting for environmental assessment and cleanup costs filed by Piedmont Natural Gas Company is hereby granted, without prejudice to the right of any party to take issue with the special accounting in a regulatory proceeding."

**Q. Has Piedmont utilized this deferral authority for environmental compliance expenses incurred in the years since it was granted by the Commission?**

A. Yes, it has. Piedmont has routinely deferred its environmental assessment and clean-up costs pursuant to the authority granted by the Commission in Docket No. G-9, Sub 333 and has filed for and been granted amortization of such costs in rate case proceedings since 1992.

**Q. Has Piedmont continued to defer environmental compliance expenses since the last rate case?**

A. Yes. In the last rate case, Piedmont was granted a 4-year amortized recovery of a balance of ($55,817), which was the unamortized deferred balance as through June 30, 2019, net of regulatory amortizations through October 31, 2019. In this proceeding, Piedmont is proposing a 4-year amortization of an unamortized balance of $833,314 for an annual amortization expense of $208,329.

**Q. Were these costs prudently incurred and have they been properly accounted for?**

A. Yes, they were incurred in compliance with federal laws and regulations and in the ordinary conduct of Piedmont's business.

**Q. Is Piedmont proposing any change to deferred regulatory fee expenses or EasternNC deferred O&M expenses?**

A. Piedmont is not proposing any change to its deferred regulatory fee amortization schedule approved in the last rate case. In addition, Piedmont is not proposing any change, other than updating the interest rate to reflect the net of tax overall rate of return as proposed, to the amortization and recovery of EasternNC deferred O&M expenses approved in the prior rate case.

## G-1 Compliance

**Q. Has Piedmont complied with Commission Rule R1-17(b)(12)(c) in this proceeding by filing the information required by NCUC Form G-1 in connection with the filing of this general rate case?**

A. Yes. Piedmont's G-1 Minimum Filing Requirements were prepared and are being filed with the Commission concurrent with its Petition and supporting testimony in this proceeding.

**Q. Does this conclude your pre-filed direct testimony?**

A. Yes.

# Before the
# North Carolina Utilities Commission

## Docket No. G-9, Sub 781

## General Rate Case

## Supplemental Testimony and Exhibits
## of
## Quynh P. Bowman

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**July 28, 2021**

**Q. Please state your name and business address.**

A. My name is Quynh Pham Bowman. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am the Director – Gas Rates & Regulatory Strategy for Piedmont Natural Gas Company, Inc. ("Piedmont" or "the Company").

**Q. Are you the same Quynh Bowman that previously filed Direct Testimony in this docket?**

A. Yes.

**Q. What is the purpose of your Supplemental Testimony in this proceeding?**

A. N.C. Gen. Stat. § 62-133(c) and Commission Rule R1-17(c) permit Piedmont to update its rate case filing through the date of the hearing of this matter. In Piedmont's Application in this proceeding filed on March 22, 2021, we specifically reserved our right to make these updates. The Commission's May 17, 2021 Order in this docket, pursuant to ordering paragraph 10, requires such updates to be filed no later than July 28, 2021.

My Supplemental Testimony is filed in support of Piedmont's update filing ("Update Filing"). Specifically, the purpose of my Supplemental Testimony is two-fold: 1) to explain and support Piedmont's updated pro forma adjustments for operating expense and rate base; and 2) to explain and support the results of Piedmont's Test Period operations under present rates, as adjusted for updated pro forma changes to the Company's operating revenue, operating expense, and rate base.

In Piedmont's Application, it was shown that Piedmont's revenue request was based on a number of pro forma adjustments. The pro forma adjustments were developed on the basis of estimated going-levels of operating expense as of June 30, 2021 and estimated utility rate base as of June 30, 2021. We now have available actual June 30, 2021 balances rather than estimates to support those pro forma expense adjustments and rate base. Furthermore, our commission-approved customer billing rates have materially changed since the time of our Application filing, which necessitates an update to the pro forma revenue calculation reflected in our Application and the Direct Testimony of witness Kally Couzens.[1] For these reasons, updates to the schedules required by Commission Rule R1-17(b) ("Updated Schedules") were warranted in order to reflect our updated cost of service calculation and the components thereof relative to our Application.

**Q. Please explain how, if at all, the Update Filing impacts the Test Period amounts shown by Piedmont in its Application.**

A. Nothing about this Update Filing changes or otherwise impacts the per books Test Period amounts shown in Piedmont's Application and in my Direct Testimony. The Test Period for this general rate case proceeding continues to be the 12-months ending December 31, 2020.

[1] As explained in the Supplemental Testimony of witness Kally Couzens, rate changes were approved by the Commission effective June 1, 2021 per order in Docket No. G-9, Sub 788. Additional rate changes were approved by the Commission effective July 1, 2021 per order in Docket No. G-9, Sub 790.

**Q. Please explain how this Update Filing impacts the accounting and pro forma adjustments shown by Piedmont in its Application.**

A. The following items have been updated from the Company's Application:

1) the pro forma utility rate base adjustments in the Company's Application that were developed based on then-estimated June 30, 2021 amounts;

2) certain pro forma expense adjustments in the Company's Application that were developed based on then-estimated June 30, 2021 amounts; and

3) the pro forma adjustment to utility gas sales and transportation revenue in the Company's Application that was developed based on the then-present Commission approved customer billing rates which have since been revised by the Commission and also based on the rate of customer growth expected at the time the Application was filed.

**Q. Does this Update Filing incorporate any changes to the methodology used by the Company in its computation of the pro forma adjustments compared to those used for the Company's Application?**

A. The approach used to compute each pro forma adjustment supporting this Update Filing is the same as used to compute each pro forma adjustment in the Company's Application, with the exception of the growth adjustment for customer bills and dekatherms delivered as discussed in the supplemental testimony of Piedmont witness Kally Couzens

**Q. Do you have any exhibits supporting your Supplemental Testimony?**

A. Yes. Since many of the schedules provided by Piedmont in its Application for fulfillment of Commission Rule R1-17(b) were exhibits to my Direct Testimony, I have updated all eight of the exhibits to my Direct Testimony in support of the Update Filing, as follows:

- Exhibit_(QPB-1 UPDATED) Summary of Rate Base
- Exhibit_(QPB-2 UPDATED) Original Cost of Used and Useful Property
- Exhibit_(QPB-3 UPDATED) Accumulated Depreciation of Property Used and Useful
- Exhibit_(QPB-4 UPDATED) Working Capital
- Exhibit_(QPB-5 UPDATED) Accumulated Deferred Income Taxes
- Exhibit_(QPB-6 UPDATED) Depreciation Policy and Rates
- Exhibit_(QPB-7 UPDATED) Net Operating Income and Rates of Return
- Exhibit_(QPB-8 UPDATED) Piedmont Balance Sheet and Income Statement

**Q. Were your updated exhibits prepared by you or under your direct supervision?**

A. Yes.

**Q. Please explain the updates to pro forma utility rate base reflected in your updated exhibits.**

A. Exhibit_(QPB-1 UPDATED) summarizes the main components of rate base. The first column in this exhibit shows that Piedmont's end of Test Period rate base was approximately $4.22 billion. In our Application, we had anticipated that rate base would grow to $4.82 billion by June 30, 2021; this estimated June 30, 2021 rate base amount was used in the revenue request computation shown in my original Exhibit_(QPB-7). Now in this Update Filing we show Piedmont's pro forma rate base as $4.74 billion, which reflects a difference of less than 2% from the pro forma rate base amount shown in the original exhibits to my Direct Testimony.

**Q. Was each component of pro forma utility rate base updated using actual amounts as of June 30, 2021?**

A. Yes, with an exception related to two large capital investment projects – the construction of a liquefied natural gas storage facility in Robeson County ("Robeson LNG") and a pipeline main expansion project in Pender and Onslow Counties ("Pender-Onslow"). These two projects were not in service as of June 30, 2021. These two projects are, however, expected to be in service before the hearing concludes. Accordingly, this Update Filing reflects actual rate base as of June 30, 2021, as amended for the effect of the current projection of the in-service amount of the Robeson LNG and Pender-Onslow projects. As such, the updated pro forma rate base shown in Exhibit_(QPB-1 UPDATED) reflects actual rate base as of June 30, 2021, as amended for the effect of the current projection of the in service amount of the Robeson LNG and Pender-Onslow projects.

Exhibit_(QPB-2 UPDATED) identifies utility plant in service by major asset category at the end of the Test Period, and the pro forma amounts per the Company's Application and per the Update Filing. Exhibit_(QPB-3 UPDATED) identifies accumulated depreciation by major asset category at the end of the Test Period, and the pro forma amounts per the Company's Application and per the Update Filing. Exhibit_(QPB-4 UPDATED) identifies the components of allowance for working capital on a 13-month average for the Test Period, and the pro forma amounts per the Company's Application and per the Update Filing. Exhibit_(QPB-5 UPDATED) identifies accumulated deferred income taxes at the end of the Test Period, and the pro forma amounts per the Company's Application and per the Update Filing.

**Q. Please explain the updates to pro forma depreciation expense reflected in your updated exhibits.**

A. In the Company's Application, I presented a pro forma adjustment to annual depreciation expense that was aligned with the pro forma amount of utility plant in service as estimated at June 30, 2021. In this Update Filing, the computation of pro forma annualized depreciation expense is aligned with the updated pro forma utility plant in service. Exhibit_(QPB-6 UPDATED) identifies the composite deprecation rates by major asset category.

**Q. Please explain the updates to pro forma revenues reflected in your updated exhibits.**

A. Exhibit_(QPB-7 UPDATED) incorporates an update to the pro forma gas sales and transportation revenue amount. The computation of updated pro forma gas sales and transportation revenue is explained in the Supplemental Testimony of Piedmont witness Kally Couzens.

**Q. Please explain the update to pro forma cost of gas expense reflected in your updated exhibits.**

A. Exhibit_(QPB-7 UPDATED) incorporates an update to the pro forma cost of gas expense in alignment with the cost of gas component of the updated pro forma gas sales and transportation revenue amount.

**Q. Please explain the updates to pro forma operations and maintenance ("O&M") expense reflected in your updated exhibits.**

A. In the Company's Application and as shown in Exhibit_(QPB-7) to my Direct Testimony, there were nineteen discrete pro forma adjustments to the Test Period level of O&M expense, identified as pro forma adjustments 4A through 4S.[2] Changes to eleven of those nineteen pro forma O&M expense adjustments were warranted in this Update Filing. Those changes were necessary in order to align with updates made to pro forma rate base, pro forma revenues and/or other known changes (corrections). The updates to the pro forma O&M adjustments are described in Table 1.

[2] See Table 2 Adjustment 4 – O&M Adjustment Detail as shown on pages 12 - 15 in Direct Testimony of Quynh Pham Bowman.

Table 1
Adjustment 4 – O&M Updated Adjustments Detail

| Adj No. | Adjustment Description<br>From page 3-4 of Exhibit_(QPB-7 UPDATED) |
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| 4A | **To increase salaries & wages expense to the going-level basis.**<br><br>The adjustment proposes to annualize effective pay rates for headcount at December 31, 2020 and update the jurisdictional allocation factor. Also included is an adjustment for Robeson LNG employees who capitalized 100% of their payroll to the project during the Test Period.<br><br>**Per Update Filing:** This adjustment update reflects actual employee salary and wage rates as of June 30, 2021 in lieu of the estimated employee salary and wage rates used in the Application. |
| 4B<br>4C | **To increase short-term incentive plan and long-term incentive plan expense to the going-level basis.**<br><br>The adjustment proposes to update STIP and LTIP compensation expense using 2021 budgets at target level and update the jurisdictional allocation factor.<br><br>**Per Update Filing:** This adjustment update reflects a correction to the computation of incremental payroll expenses related to the new Robeson LNG facility. No other changes were made. |
| 4D | **To reduce executive management compensation for ratemaking purposes.**<br><br>The adjustment proposes to remove 50% of the Piedmont-allocated compensation (including benefits) of the Company's top five highest compensated executives -- Duke Energy Executives supporting Piedmont's operations. While the Company fully believes these costs are reasonable, prudent, and appropriate to recover from customers, for purposes of streamlining this proceeding, we have made this adjustment.<br><br>**Per Update Filing:** No change from the Application was warranted. |
| 4E | **To increase pension, OPEB and long-term disability expense to the going-level basis.** |

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| | The adjustment proposes to update pension and OPEB expense for known and measurable annual expense as well as normalizes long-term disability expense. The jurisdictional allocation factor is also updated.<br><br>**Per Update Filing:** No change from the Application was warranted. |
| **4F** | **To increase other employee benefits expense to the going-level basis.**<br><br>The adjustment proposes to increase medical and dental expense to the anticipated going level. The updated jurisdictional allocation factor is reflected in this adjustment. Also included is an adjustment for current Robeson County LNG employees who capitalized 100% of their benefits to the project during the Test Period.<br><br>**Per Update Filing:** This adjustment update reflects a correction to the computation of incremental employee benefits expenses related to the new Robeson LNG facility. No other changes were made. |
| **4G** | **To decrease the provision of uncollectibles expense to the going-level basis.**<br><br>The adjustment proposes to update uncollectible expense to reflect actual write-offs by normalizing the Test Period write-offs-to-revenues ratio and applying the updated ratio to pro forma Sales & Transportation revenue.<br><br>**Per Update Filing:** This adjustment update aligns uncollectible expense with the updated pro forma gas sales and transportation revenues amount. |
| **4H** | **To decrease rents expense to the going-level basis.**<br><br>The adjustment proposes to update rent expense by reflecting the current terms of the rental agreements and update the jurisdictional allocation factors.<br><br>**Per Update Filing:** No change from the Application was warranted. |
| **4I** | **To increase insurance expense to the going-level basis.**<br><br>The adjustment proposes to reflect insurance rates that were invoiced for January – December 2021 and update jurisdictional allocation |

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| | factors. Also included is an adjustment for incremental risk insurance expense for the new LNG facility and LNG upgrades since the end of the Test Period.<br><br>**<u>Per Update Filing:</u> <u>:</u>** This adjustment update was made to align with the updated plant amounts for LNG since the end of the Test Period. to |
| **4J** | **To increase customer payment expenses to the going-level basis.**<br><br>The adjustment proposes to include residential customer payment fees through the pay by phone channel into base rates. Currently, when a customer makes a payment via contacting the Company by phone, a $3.50 transaction fee is assessed to the customer by a third-party vendor (Speedpay). In 2020, as part of the Company's COVID-19 response, these fees were waived for a significant portion of the year. By including the fees in base rates, the Company is removing a potential additional burden for residential customers and improving our customer care.<br><br>**<u>Per Update Filing:</u>** No change from the Application was warranted. Note that the workpaper for the original adjustment was modified to include additional language/labels to provide clarity of the adjustment intent. |
| **4K** | **To decrease expenses for allocations to non-utility activities.**<br><br>The adjustment proposes to allocate a portion of select operating expenses using the three-factor Massachusetts Formula which consists of plant, revenues, and payroll costs, equally weighted.<br><br>**<u>Per Update Filing:</u>** This adjustment update reflects changes in pro forma expense balances and a correction to the computation of incremental expenses related to the new Robeson LNG facility. |
| **4L** | **To decrease aviation expense for ratemaking purposes.**<br><br>The adjustment proposes to remove 50% of aviation expenses not related to utility patrol. While the Company fully believes these costs are reasonable, prudent, and appropriate to recover from customers, for purposes of streamlining this proceeding, we have made this adjustment.<br><br>**<u>Per Update Filing:</u>** No change from the Application was warranted. |

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| 4M | **To increase the regulatory amortization expense for deferred NCNG OPEB costs.**<br><br>The adjustment proposes to synchronize the annual interest rate to the net of tax rate of return as proposed in this proceeding. No further adjustments are proposed.<br><br>**Per Update Filing:** No change from the Application was warranted. |
| 4N | **To increase the regulatory amortization expense for deferred environmental cleanup costs.**<br><br>The adjustment proposes to amortize deferred environmental costs, as incurred through the end of the Test Period, related to various state and federal requirements for air emissions, wastewater discharges, and solid, toxic and hazardous waste management. Piedmont was initially granted regulatory asset treatment in Docket No. G-9, Sub 333. The proposed amortization period is 4 years.<br><br>**Per Update Filing:** This adjustment update reflects amortization of expense deferrals through June 30, 2021 and includes a correction of an error identified in certain deferred amounts shown in the Application. |
| 4O | **To increase the regulatory amortization expense for deferred distribution integrity management program costs.**<br><br>The adjustment proposes to amortize deferred O&M costs through the end of the Test Period arising out of activities required to comply with federal DIMP requirement. Piedmont was initially granted regulatory asset treatment in the last rate case (Docket No. G-9, Sub 743). The proposed amortization period is 4 years.<br><br>**Per Update Filing:** This adjustment update reflects amortization of expense deferrals through June 30, 2021. |
| 4P | **To decrease the regulatory amortization expense for deferred transmission integrity management program costs.**<br><br>The adjustment proposes to amortize deferred O&M costs through the end of the Test Period arising out of activities required to comply with TIMP requirements. Piedmont was initially granted regulatory asset treatment in Docket No. G-9, Sub 495. The proposed amortization period is 4 years. |

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| | **Per Update Filing:** This adjustment update reflects amortization of expense deferrals through June 30, 2021. |
| **4Q** | **To increase the regulatory amortization expense for deferred rate case costs.**<br><br>This adjustment proposes to amortize the remaining unamortized balance of deferred rate case costs in addition to the incremental rate case costs incurred for this proceeding. The proposed amortization period is 4 years.<br><br>**Per Update Filing:** No change from the Application was warranted. |
| **4R** | **To increase current regulatory fee expense to the going level.**<br><br>The adjustment proposes to synchronize the regulatory fee expense with pro forma revenues using the current fee rate of 0.13%<br><br>**Per Update Filing:** This adjustment update aligns with the updated uncollectible expense and the updated pro forma gas sales and transportation revenues amount. |
| **4S** | **To increase expenses for inflation and going-level jurisdictional allocations net of other ratemaking adjustments.**<br><br>The adjustment proposes to remove non-recurring, non-jurisdictional, and out-of-period expenses from Test Period expenses. In addition, costs related to customer energy efficiency programs were removed from O&M expense to instead be included in a rider as discussed in the testimony of Piedmont witness Pia Powers.<br><br>The remaining O&M expenses not specifically adjusted are updated by applying an inflation factor calculated using data published by Office of Management and Budget (OMB). Also included is an adjustment for general O&M expenses that are associated with operating the new Robeson LNG facility.<br><br>**Per Update Filing:** This adjustment update reflects the correction of the computation of incremental expenses related to the new Robeson LNG facility. No other changes were made. |

**Q. Please explain the updates to pro forma general tax expense reflected in your updated exhibits.**

A. Two updates to pro forma general tax expense were warranted, which were to the pro forma payroll tax and pro forma property tax component. The update to pro forma payroll tax expense was necessary to align with the updated pro forma salaries and wages expense adjustment in 4A. The update to pro forma property tax was necessary to align with the updated amount of pro forma utility plant in service. In addition, it was discovered that the support used to calculate property tax rate in the original application did not reflect a proper allocation to North Carolina. This was corrected in the updated pro forma property tax adjustment.

**Q. Are there any updates to the embedded cost of debt reflected in your updated exhibits?**

A. Yes, there are two updates. First, the embedded cost of long-term debt was updated to incorporate the actual cost of the $350 million long term debt issuance that occurred on March 11, 2021 at 2.50% in lieu of the estimated cost at 2.70% that was included in the computations supporting the Company's Application. Pursuant to this update, the embedded cost of long-term changed from 4.09% to 4.08%. Second, the embedded cost of short-term debt was updated to incorporate the actual cost rates as of June 30, 2021; this update yielded a reduction in the embedded cost of short-term debt from 0.47% to 0.35%.

**Q. Please explain the updates to income tax expense reflected in your updated exhibits.**

A. The updates to federal and state income tax expense were made in alignment with the overall impact of the updates previously described in my Supplemental Testimony.

**Q. In total, how do these updates impact Piedmont's revenue requirement and proposed rates in this proceeding?**

A. The proposed rates shown in the Updated Appendix I to this Update Filing are designed to achieve annual gas sales and transportation revenues of $1,154,911,31. This is the revenue level needed to support the Company's updated cost of service as shown in Exhibit_(QPB-7 UPDATED). The change in Piedmont's proposed revenue request decreased by approximately 11.2%, from $109.0 million to $96.9 million in the Application and Update Filing, respectively.

**Q. What is Piedmont asking the Commission to do with this information?**

A. The Company requests that the Commission accept and consider the Updated Schedules in their consideration of determining a just and reasonable cost of service for Piedmont in this proceeding and in approving new rates for our customers.

**Q. Do you have any further testimony regarding Piedmont's Update Filing?**

A. No, this concludes my Supplemental Testimony.

# Before the
# North Carolina Utilities Commission

## Docket No. G-9, Sub 781

## General Rate Case

## Rebuttal Testimony
## of
## Quynh P. Bowman

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

Piedmont Natural Gas

**August 25, 2021**

**Q. Ms. Bowman, please state your name and business address.**

A. My name is Quynh Pham Bowman. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am the Director – Gas Rates & Regulatory Strategy for Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company"). In this capacity, I am responsible for a variety matters including supporting the development and execution of rate requests and financial report filings by Piedmont.

**Q. Have you previously testified in this proceeding?**

A. Yes. I previously submitted prefiled direct testimony in this proceeding on March 22, 2021 and supplemental testimony on July 28, 2021.

**Q. What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to respond to a number of accounting adjustments proposed by Public Staff – North Carolina Utilities Commission ("Public Staff"). Specifically, I will address the adjustments in the testimony of Public Staff witness Feasel, Public Staff witness Coleman, and in the testimony and exhibits of Public Staff witness Perry.

**Q. In her direct testimony, Public Staff witness Feasel proposes that the Company absorb one full year of carrying costs associated with previously deferred assets under Piedmont's Distribution and Transmission Integrity Management Programs ("PIM-D" and "PIM-**

**T") and environmental compliance. What is your reaction to this proposal?**

A. I disagree with this proposed reduction of working capital. These deferred expenses are currently afforded regulatory asset treatment under the Commission's order in Piedmont's last general rate case in Docket No. G-9, Sub 743. Under its Commission-approved deferral of expenses associated with its transmission integrity program, Piedmont seeks recovery in general rate cases of deferred expenses net of ongoing amortizations. These amortizations reduce Piedmont's regulatory asset on a monthly basis and serve to reduce the regulatory asset to an appropriate amount of working capital upon which Piedmont should be allowed to earn a return without the further reduction proposed by witness Feasel.

**Q. Has Ms. Feasel offered a justification for this proposed absorption of 12 months of carrying costs on these established regulatory assets?**

A. Not that I can see. Her absorption recommendation is simply embedded in her proposed amortization of such costs in this case without explanation or rationale. Ms. Feasel's recommendation would result in a reduction of Piedmont's rate base of $18,093,484.

**Q. What was the Company's approach to this matter?**

A. In the Company's filed case, Piedmont made an end-of-period adjustment to align the proposed annual amortization and the end-of-period balance of the regulatory assets. We accomplished this by removing the difference between the proposed annual amortization expense and the annual amortization expense for the Test Period for each of these regulatory assets, which was the appropriate way to handle this issue.

**Q. In her Direct Testimony, Public Staff witness Coleman proposes to disallow fifty percent (50%) of the total compensation of the top five Duke Energy Executives which consists of total annual salary, Short-Term Incentive Plan, Long-Term Incentive Plan and Benefits. What is your reaction to this proposed adjustment?**

A. First, I would like to acknowledge that the Company included an executive management compensation adjustment to remove 50% of the total compensation allocated to Piedmont for the top five Duke Energy Executives. As stated in my filed testimony on March 22, although we believe these costs are reasonable, prudent, and appropriate to recover from customers, we made this adjustment in good faith for purposes of streamlining this proceeding.

Ms. Coleman has replaced one of the top five Duke Energy executives of the holding company with the Senior Vice President - Natural Gas Business. In my opinion, the rationale for this disallowance – that the specified executives spend half of their time working for shareholders – is much less convincing when applied to an employee who spends the majority of his time managing and directing the operations of Piedmont and, as Ms. Coleman states, is "more closely aligned with Piedmont's efforts to minimize costs and maximize the reliability of Piedmont's service to customers."

My belief is that Ms. Coleman chose to update the Company's adjustment simply to further reduce our filed position by $250,246. This seems like a methodology driven to reduce the revenue requirement rather than one based on the professed concepts by Public Staff.

**Q. In her direct testimony, Ms. Perry proposes to disallow Piedmont the ability to recover the unamortized portion of rate case expense for Piedmont's 2019 rate case and to reduce the projected rate case expense from this case by $237,030. What is your response to these proposals from Public Staff witness Perry?**

A. I do not agree with Ms. Perry's proposals. The rate case expense from the 2019 rate case was agreed to as part of the settlement of that case, as was the four-year amortization of that expense. The settlement in that case was approved by a Commission order that approved the four-year amortization. The expense that will be outstanding as of October 31, 2021 is $654,931. Nothing in the prior settlement or the Commission's Order approving that settlement dictated that the rate case expense would become unrecoverable if Piedmont filed a rate case prior to the end of the four-year amortization period. Piedmont included the unamortized balance for its recovery in its revenue requirement in this case and continues to believe that it is entitled to recover these amounts.

**Q. What is your response to Ms. Perry's reduction in current rate case expense in this case?**

A. I disagree with that adjustment. Our proposed rate case expense in this docket is approximately $73,000 (6%) more than actual rate case expense incurred in our 2019 rate case. Further, Ms. Perry relied on a "run rate" calculation in making her reduction which ignored the fact that the period utilized for calculating that run rate included only preparation of the initial filing and discovery. This calculation does not include review and analysis of intervenor testimony, preparation of rebuttal testimony, settlement negotiations, preparation for hearing, the conduct of the hearing itself, and briefing/drafting of proposed orders.

In short, I find Ms. Perry's adjustment to be arbitrary and not representative of the actual costs of prosecuting this case. Adoption of this adjustment by the Commission will prevent Piedmont from being able to collect its actual rate case expense in this proceeding.

**Q. In her direct testimony, Ms. Perry utilizes a five-year average of uncollectibles expense to reduce the Company's pro forma level of uncollectibles in its revenue requirement. Do you agree with Ms. Perry's adjustment?**

A. No. The rate of uncollectibles experienced by Piedmont over the five-year period used by Public Staff (and in particular the early years of that five-year period) are not representative of the level of uncollectibles Piedmont has experienced during the more recent past. And while we agree with Ms. Perry that 2020 is not a reasonable year to solely rely on for uncollectibles experience, her selection of a five-year average includes outdated data and understates the Company's recent experience with uncollectibles expense. We believe the most accurate measure of future uncollectible expense is an average of the two years prior to 2020 which should be excluded due to the impacts of the pandemic.

**Q. What is your response to the Public Staff's adjustment to remove an additional $821,959 for Pension, OPEB and long-term disability expenses?**

A. I do not agree with the approach used by Public Staff. Ms. Perry proposes to use a 12-month period ending May 31, 2021 as a suitable ongoing level of expense for pension, OPEB, and long-term disability. This methodology uses historical balances and does not reflect an ongoing level. The Company's pension and OPEB adjustments are supported by third-party valuation reports. Of the $821,959 reduction proposed by Public Staff, $552,226 is related to the difference in long-term disability expense. The Company's proposed adjustment is based on a three-year average of participant counts and applies a 6.25% medical inflation rate, again supported by third party valuation reports, to actual costs per participant during 2020. This methodology is consistent with the three-year average employed by the Public Staff in determining the medical and dental expenses in their proposed adjustment.

**Q. In her direct testimony, Ms. Perry removes $28,024,252 of Customer Growth Expenses from the balance of expenses adjusted for inflation. What is your reaction to this adjustment?**

A. I disagree with it because the result of Ms. Perry's adjustment yields an insufficient pro forma level of expense due to its failure to address the fact that some expenses increase because of inflation <u>and</u> an increase in customer count.

**Q. Do you have other disagreements with Ms. Perry's adjustment for inflation?**

A. Yes, I do. To align with Public Staff's adjustments for various items, Ms. Perry removes an additional $4,724,920 from the Test Period basis used to calculate the inflation adjustment. However, the amounts do not reflect the Test Period amounts that the Public Staff excluded from the cost of service. The amounts included in the inflation adjustment should exactly reflect the Test Period amounts that have been excluded by Public Staff. For example, Public Staff witness Coleman proposes to remove $360,740 from the revenue requirement yet in Ms. Perry's adjustment, $721,478 is removed from the basis for inflation. Even if we agreed to Ms. Coleman's adjustment to remove $360,740, the remaining amount is still included in the cost of service and should be included in the inflation adjustment.

Finally, no support was provided for the calculation of an inflation factor of 1.93% used in the Public Staff adjustment, whereas our inflation factor is based on growth during 2021 as applied to 2020 Test Period as supported in electronic workpaper filed with the application on March 22, 2021.

**Q. Ms. Perry proposes to reduce Piedmont's COVID 19 expense by $953,096. What is your response to her proposed adjustment?**

A. First, the Public Staff has acknowledged to Piedmont that $74,446 of their proposed disallowance was not included in Piedmont's proposed revenue requirement and additional removal is unwarranted. Nevertheless, there are several critical flaws in the remainder of the Public Staff's proposed adjustment. The Public Staff removed $878,650 of expenses out of a belief that these costs were not ongoing expenses. That belief is misguided. These costs relate to employee expenses for personal protective equipment such as masks, gloves, coveralls; increased cleaning of shared spaces and equipment; and proactive testing for critical employees that are required to interact with customers and other employees. The Company believes these costs can be reasonably expected to be incurred in the future especially in light of the ongoing pandemic and increasing levels of infections throughout North Carolina. I am not aware of any information that reliably predicts an end to this pandemic or a return to pre-pandemic handling of personal protection and sanitation. It is Piedmont's responsibility to protect our customers, the general public, and our employees from possible infection at any point in the reasonably foreseeable future.

Further, Piedmont has not proposed to include pre-pandemic levels of avoided employee costs in this case for the exactly the same reason that it has proposed to recover these employee costs. Any attempt to normalize incremental expenses due to COVID should reasonably be balanced with normalizing avoided expenses due to COVID. Just as the pandemic dictates certain employee costs like business travel must be curtailed, it also dictates that responsible companies must protect their employees through the types of expenditures that the Public Staff proposes to disallow. By way of illustration, employee expenses decreased from approximately $4.1M in 2019 to $1.8M in 2020. The Public Staff does not appropriately balance these two factors, however, and seeks to disallow recovery of certain prudently incurred costs while simultaneously accepting the benefits of reduced levels of employee expenses experienced during the test period. Piedmont's position is a reasonable middle ground which still reduces employee expenses below pre-pandemic "normal" levels.

**Q. In her direct testimony, Ms. Perry proposes to disallow recovery of per transaction charges under arrangements for customers to pay their bills through Speedpay to the extent they exceed similar charges incurred by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC. What is your reaction to this proposed adjustment?**

A. I do not agree. The Public Staff seeks to limits Piedmont's cost recovery to a lower level than exists in Piedmont's existing contract with Speedpay. Piedmont is bound under its existing contract for an additional two years, and the Public Staff has made no showing that Piedmont was imprudent in entering into the existing contract. As such, we believe that we are entitled to recover the per transaction charges under the Speedpay contract but certainly would hope to reduce those charges when the contract is renegotiated to a level commensurate with the lower transaction fees contained in the Public Staff's proposed adjustment.

**Q. If the Commission does not approve full cost recovery, does that Company have an alternative request?**

A. Yes. The Company requests complete removal of this from its revenue requirement. Under this circumstance, the Company requests it be allowed to continue collecting these fees from specific customers as they are incurred. This will reduce the Company's requested revenue requirement in this proceeding by $1,475,923.

**Q. In her direct testimony, Public Staff witness Perry proposes an adjustment to amortization of protected EDIT. What is your response to Ms. Perry's proposal?**

A. I would like to acknowledge here the Company's recent identification that its application inadvertently represented the amortization of protected EDIT in base rate in a way that does not conform with IRS tax normalization requirements. To comply with such IRS tax normalization requirements, the Company's annual amortization expense of protected EDIT adopted in this proceeding needs to be no greater than $(2,795,775). Since Ms. Perry's proposed amortization to protected EDIT is in excess of this amount, it should be rejected. Further details on this matter pertaining will be included in my forthcoming supplemental testimony to specifically address this issue.

**Q. What is your position on the Public Staff's proposed removal from rate base of the amounts associated with the assets that the Company uses to provide natural gas service to Duke Lincoln?**

A. The Public Staff presented no legitimate evidence to support the net $2,120,901 adjustment to rate base, only citing a reference to a vague footnote indicating the amount came from a prior general rate case. Piedmont does not currently possess granular records of individual additions to utility plant in service for assets of this vintage as requested by the Public Staff during discovery. Given the lack of information, the Public Staff used a number that had a very unclear origin to make an adjustment that does not meet any reasonable standard for support and should be rejected in its entirety.

**Q. Ms. Perry also proposes to remove certain O&M and A&G expenses associated with the Robeson LNG plant on the basis of Mr. Metz's removal of Robeson plant from rate base. Do you agree with that adjustment?**

A. I do not. Piedmont witness Adam Long's rebuttal testimony explains the status of the Robeson LNG facilities and supports Piedmont's expectation that they will qualify for rate base treatment in this proceeding. Mr. Long will provide supplemental testimony to inform the Commission after key milestones have been achieved and the facility has been closed to utility plant on Piedmont's books. Accordingly, the expenses removed by Ms. Perry should not be removed from our proposed revenue requirement in this case subsequent to Mr. Long's pending update.

**Q. Did you discover any mathematical errors in the Public Staff's direct Testimony?**

A. Yes, we discovered such errors and have discussed them with the Public Staff and understand they plan to correct these errors in an updated filing.

**Q. Are there other areas of adjusted expense from the Public Staff testimony that you disagree with?**

A. Yes, but they are fundamentally flow-through impacts of the contested adjustments discussed above and involve the following areas:

- Depreciation and Accumulated Depreciation
- Property Tax Expense
- Payroll Tax Expense
- Deferred Eastern NCNG Amortization Expense
- Regulatory Fee
- All components of rate base

**Q. Do you have any further comments on the Public Staff's accounting adjustments?**

A. Not on their direct testimony, but I understand the Public Staff intends to file supplemental testimony concerning our update filing made July 28, 2021 and the correction of certain errors. I would respectfully reserve the right to respond to any supplemental testimony that may be filed in this proceeding.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

MR. JEFFRIES: Thank you, Chair Mitchell. We'd also request that Ms. Bowman's prefiled direct Exhibits QPB-1 through QPB-8, and her prefiled Supplemental Exhibits QPB-1 Updated through QPB-8 Updated be identified as marked.

CHAIR MITCHELL: All right. The exhibits to the witness' testimony will be marked for identification as they were when prefiled.

(Exhibits QPB-1 through QPB-8 and Supplemental Exhibits QPB-1 Updated through QPB-8 Updated, were identified as they were marked when prefiled.)

MR. JEFFRIES: Thank you.

Q. Ms. Bowman, have you prepared a summary of your prefiled testimonies?

A. I have.

Q. Could you please provide that to the Commission.

A. My name is Quynh Bowman, and I'm the director of gas rates and regulatory strategy for Piedmont Natural Gas. I prefiled direct testimony in this docket on March 22, 2021, in support of Piedmont's application for a general rate increase. I also filed supplemental testimony on July 28, 2021, in support of Piedmont's updated cost of service calculation as of June 30, 2021. Further, on August 25, 2021, I submitted prefiled rebuttal testimony in this proceeding.

My prefiled direct testimony explains and supports: one, Piedmont's rate base at December 31, 2020, and the actual of results of Piedmont's operations for the test period which is the 12 months ending December 31, 2020; two, the results of Piedmont's test period operations under present rates as adjustment for accounting and pro forma changes to the Company's operating revenue, operating expense, capital structure, and rate base; three, the additional revenue required to appropriately support Piedmont's pro forma cost of service; four, Piedmont's compliance with Commission Form G-1 minimum filing requirements for this general rate case application; and five, the amortization of certain deferred expenses that previously have been granted regulatory asset treatment by the Commission.

My prefiled direct testimony is accompanied by eight exhibits which provide support for the five topics I previously mentioned.

I also filed supplemental testimony in this docket on July 28, 2021, in support of the Company's updated cost of service calculation as of June 30, 2021, which was performed and filed pursuant to North Carolina General Statute Section 62-133(c) and Commission Rule R1-17(c).

Finally, I submitted prefiled rebuttal testimony in this docket on August 25, 2021, to respond to a number of accounting adjustments proposed by Commission Public Staff. Specifically, I addressed the adjustments recommended in the testimonies of Public Staff witnesses Feasel, Coleman, and Perry.

This concludes the summary of my prefiled direct, supplemental, and rebuttal testimony.

Q. Thank you, Ms. Bowman.

MR. JEFFRIES: Chair Mitchell, Ms. Bowman is available for cross examination questions by the Commission.

CHAIR MITCHELL: All right. My notes indicate that the Attorney General's Office has cross for the witness.

MS. FORCE: No questions. Thank you.

CHAIR MITCHELL: All right. Questions from Commissioners for the witness?

(No response.)

CHAIR MITCHELL: Any questions from Commissioners?

(No response.)

CHAIR MITCHELL: All right. Ms. Bowman, you are off the hook this morning. Thank you, ma'am, for your participation in this proceeding. You may step down.

And, Mr. Jeffries, intent to recall the witness?

MR. JEFFRIES: No intent to recall Ms. Bowman.

CHAIR MITCHELL: All right. Ms. Bowman, you may be excused from the proceeding.

All right. Mr. Jeffries, I'll take a motion.

MR. JEFFRIES: Thank you, Chair Mitchell. Piedmont would move that Ms. Bowman's prefiled direct Exhibits QPB-1 through QPB-8, and her prefiled Supplemental Exhibits QPB-1 Updated through QPB-8 Updated be entered into evidence in the proceeding.

CHAIR MITCHELL: All right. Hearing no objection to the motion, it will be allowed. And the exhibits to the witness' testimony will be accepted into the record.

(Exhibits QPB-1 through QPB-8 and Supplemental Exhibits QPB-1 Updated through QPB-8 Updated, were admitted into evidence.)

MR. JEFFRIES: Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. You may call your next witness.

MR. JEFFRIES: Thank you. Piedmont would call Mr. Ken Sosnick to the stand.

CHAIR MITCHELL: All right. Mr. Sosnick, would you raise your right hand, please, sir.

Whereupon,

KENNETH A. SOSNICK,

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

CHAIR MITCHELL: All right. You may proceed, Mr. Jeffries.

MR. JEFFRIES: Thank you.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Good morning, Mr. Sosnick.

A. Good morning.
Q. Would you state your name and business address for the record, please.
A. My name is Kenneth Sosnick. My business address is 200 State Street, and we're located on the --

(Reporter interruption due to sound failure.)

CHAIR MITCHELL: All right. Mr. Sosnick -- we've lost him.

THE WITNESS: Can you not hear me?

MR. JEFFRIES: We can now, it's much better than it was.

THE WITNESS: Okay. Sorry about that.

Q. Yeah, I'm not sure what was going on there again, but let's try it again.
Could you state your name and business address for the record, please?
A. My name is Kenneth Sosnick. My business address is 200 State Street, Ninth Floor, Boston, Massachusetts 02109.
Q. And where do you work, Mr. Sosnick?
A. FTI Consulting.
Q. Okay. And what's your position as FTI

Consulting?
A. I'm a managing director.
Q. Thank you. And you're also the same Mr. Sosnick that was moved to substitute for the prior testimony of Mr. DeCourcey in this proceeding; is that correct?
A. I am.
Q. Okay. And you -- after that motion was allowed, you prefiled direct testimony in your name on August 23, 2021, consisting of 29 pages, and along with Exhibit KAS-1, correct?
A. Yes.
Q. Okay. Do you have any corrections to your prefiled testimony or exhibits?
A. I have three corrections. On page 5, line 4, there is a duplicative parentheses after "Transco." On page 6, line 15, it reads "$0.0294," and it should be changed to $0.00294, so an additional zero there. And on page 20, Table 2, the "total" line, the "variable adder" column which reads "412188" should be changed to 364188.
Q. And just for clarity, you said the variable adder column; it's the "no variable adder" column, correct?

A. No variable adder, yes. Sorry.

Q. Thank you. Mr. Sosnick, if I asked you the same questions that are set forth in your prefiled testimony with the corrections you noted while you were on the stand today, would your answers be the same?

A. Yes.

MR. JEFFRIES: Chair Mitchell, we would move that Mr. Sosnick's prefiled direct testimony be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to the motion, the testimony of witness Sosnick will be copied in the record as if delivered orally from the stand.

(Whereupon, the prefiled direct testimony of Kenneth A. Sosnick 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

## General Rate Case

## Direct Testimony and Exhibit
## of
## Kenneth A. Sosnick

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

**PUBLIC VERSION**

**August 23, 2021**

**Q. Please state your name and business address.**

A. My name is Kenneth A. Sosnick. My business address is 200 State Street, Boston, MA, 02109.

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

A. I am a Managing Director in the Power & Utilities practice at FTI Consulting, Inc. ("FTI").

**Q. Please describe FTI and its Power & Utilities practice.**

A. FTI is a worldwide consulting firm dedicated to helping organizations manage change, mitigate risk, and resolve disputes. Our Power & Utilities practice brings these services to firms in regulated and competitive energy industries. The services we provide our utility clients include expert testimony, regulatory advice, support for strategic decision-making, and advice regarding investments and capital allocation. Our team is comprised of former utility executives, regulators, investors, and financial analysts that combine for hundreds of years of experience in the regulated energy space.

**Q. Please describe your educational and professional background.**

A. I have been with FTI since 2019. Previously, I consulted with Concentric Energy Advisors, Inc. in Marlborough, MA, and with MRW & Associates in Oakland, CA. I hold a Bachelor of Science in Accounting from the Indiana University of Pennsylvania. A current copy of my resume is included as Exhibit__(KAS-1).

**Q. Have you previously testified before the North Carolina Utilities Commission ("Commission") or any other regulatory authority?**

A. I have not previously testified before the Commission. I have appeared as an expert before utility regulators in the District of Columbia, Michigan, and New Hampshire and also before the Federal Energy Regulatory Commission and the Florida legislature. Additionally, I have been retained in several instances to advise state regulators and their staff, including assignments I completed on behalf of utility regulators in California, Maryland, and New Jersey.

**Q. On whose behalf are you appearing in this proceeding?**

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

## I. Summary and Overview

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to support the agreement between Piedmont and Duke Energy Carolinas ("DEC") for the construction of new facilities (the "Incremental Facilities") and the delivery of natural gas by Piedmont to DEC's Lincoln County Turbine Facility (the "Lincoln CT"), the most recent version of which was filed with the Commission in November 2018 in Docket No. G-9, Sub 722 (the "Lincoln Agreement"). As I discuss later in my testimony, the Lincoln Agreement is a revision from a previous version that had been filed for the Commission's consideration. The update to the agreement was required because of concerns expressed by the Public Staff ("Public Staff"), which I discuss in detail later in my testimony.

**Q. What have you concluded regarding the Lincoln Agreement?**

A. I have concluded that the terms of the Lincoln Agreement, including, specifically, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] are appropriate and comport with utility industry best practices. I have also concluded that the Lincoln Agreement, as it is currently formulated, creates significant benefits for Piedmont's customers. Finally, I have concluded that a recommendation by the Public Staff to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. How is the rest of your testimony organized?**

A. Below, in Section II, I summarize the Lincoln Agreement and explain why it is consistent with best practices in the utility industry. I also discuss my conclusion that there is no evidence to indicate that DEC has received favorable terms because it is a Piedmont affiliate. In Section III, I discuss Staff's recommended changes to the Lincoln Agreement and explain why those recommendations are inappropriate and would increase costs for electric customers. In Section IV, I describe the benefits that accrue to

Piedmont's customers from the Lincoln Agreement. Finally, in Section V, I summarize my conclusions and their support for my recommendation that the Commission accept the Lincoln Agreement without modification.

## II. The Lincoln Agreement is Consistent with Best Practices in the Utility Industry

**Q. Please summarize this section of your testimony.**

A. In this section of my testimony, I summarize key elements of the Lincoln Agreement, describe how contract rates provide for Piedmont's recovery of the costs of the new facilities, and discuss how the cost assignment and recovery methods described therein align closely with industry best practices. Additionally, I explain why the Commission should not be concerned that this transaction is taking place between affiliate companies since these contracts require Commission approval and full transparency is available to the Commission and the Public Staff.

*Summary of the Lincoln Agreement*

**Q. Have you reviewed the Lincoln Agreement?**

A. Yes. The Company provided me with a copy of the confidential version of the Lincoln Agreement that was filed with the Commission on November 16, 2018.

**Q. Please describe the infrastructure that was built pursuant to the Lincoln Agreement.**

A. Among other things, the Lincoln Agreement requires the Company to build approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] along with a delivery station. The Incremental Facilities expand the capacity of existing infrastructure (the "Existing Facilities") from which the Lincoln CT receives gas from Transco. The total cost of the Incremental Facilities was estimated to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] including the cost of the pipeline, the cost of the delivery station, and other costs.[1]

**Q. Do either the Existing Facilities or the Incremental Facilities interconnect with any other element of the Piedmont distribution system?**

A. No. Both the Existing Facilities and Incremental Facilities run only between Transco and the Lincoln CT. Neither are connected with any portion of Piedmont's system that serves other customers.

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[1] I am aware that the capital costs indicated in the Lincoln Agreement and reflected in the COS Study were based on an estimate and that Piedmont's actual costs of the Incremental Facilities were somewhat higher. For purposes of my testimony, I have focused on the cost estimate pending at the time the Lincoln Agreement was executed since it provides the basis for the rates included in the contract. It is my understanding that the rates under the Lincoln Agreement have been trued up to reflect actual construction costs.

**Q. What quantity of gas is covered under the Lincoln Agreement?**

A. DEC's entitlement, referred to as the Transportation Contract Quantity ("TCQ"), is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] dekatherms per day ("Dth/day"). The TCQ includes capacity from the Existing Facilities and from the Incremental Facilities.

**Q. Are rates that DEC will pay to use the Incremental Facilities fixed or variable?**

A. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Please describe the fixed charges.**

A. As shown in Attachment B of the Lincoln Agreement, Piedmont's [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Can you explain how the COS was derived?**

A. The cost to own and operate the Existing Facilities was known to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Piedmont conducted a COS Study to determine the cost to own and operate the Incremental Facilities, which it determined to be [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]

**Q. Have you reviewed the COS Study?**

A. Yes, Piedmont provided me with a copy. I understand that the same copy was also provided to Public Staff.

**Q. Have you reached any conclusions about Piedmont's costs of owning and operating the Incremental Facilities?**

A. Yes, I conclude that Piedmont's costs are all fixed, or nearly so. Below, in Table 1, I have totaled the COS for the Incremental Facilities for the first three years included in the COS Study for [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] O&M, the only cost element that could plausibly vary as a function of volumes flowed across the Incremental Facilities, was projected by Piedmont to increase at a rate of exactly [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Table 1. Incremental Facilities COS for Years 1-3**

| | Year 1 | Year 2 | Year 3 | Average | % total |
|---|---|---|---|---|---|
| O&M | [BEGIN CONFIDENTIAL]] [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Depreciation | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Taxes | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Return | [redacted] | [redacted] | | [redacted] | [redacted] |
| Total[2] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] [END CONFID-ENTIAL] |

**Q. Is it significant that Piedmont's costs for the Incremental Facilities are all fixed, or nearly so?**

A. Yes. As I discuss later in my testimony, the fact that [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Please describe the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] that are defined by the Lincoln Agreement.**

A. There are two. [BEGIN CONFIDENTIAL] [redacted]

[2] As discussed previously, payments to Piedmont under the Lincoln Agreement are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[redacted] [END CONFIDENTIAL]

**Q. Was the Incremental Facilities [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] designed to recover Piedmont's costs for the Incremental Facilities?**

A. No, it is a rate that Piedmont developed in response to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] As I understand it, the Public Staff requested the inclusion of a volumetric "system support" charge in addition to the charges that had been included in other contracts approved by the Commission. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. [BEGIN CONFIDENTIAL] [redacted]**

A. [redacted]

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[3] [redacted]

**Q.** [redacted]

A. [redacted] [END CONFIDENTIAL]

**Q. Does the Lincoln Agreement require Piedmont to return revenues greater than its COS to DEC?**

A. No.

**Q. Do the revenues Piedmont will collect [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] benefit its shareholders?**

A. No. My understanding is that all the earnings from the Lincoln Agreement are included in the test year revenues the Company reported in this proceeding. Accordingly, any earnings from the Lincoln Agreement that are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] reduce rates for Piedmont's other customers.

**Q. Why does Public Staff believe a volumetric rate component is necessary?**

A. In its comments filed in this proceeding from June 1, 2020 (the "Public Staff Comments"), Public Staff explains its belief that "...the purpose of [a] volumetric rate component included in special and electric generation contracts is to provide recovery of costs related to existing local distribution company (LDC) infrastructure and operations and to prevent subsidization of the contract customer by the LDC's other customers."[4] In other words, Public Staff believes when service to a generation customer creates costs from the use of other elements of the distribution system, a volumetric charge should be applied to prevent such costs from being borne by other customers.

**Q. Do you agree?**

A. Not in this instance. Neither the Existing Facilities nor the Incremental Facilities connect with any other element of Piedmont's system, so it is not possible that deliveries to the Lincoln CT can result in the kinds of cost increases for the Company's other customers [BEGIN CONFIDENTIAL] [redacted]

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4 [redacted]

**Q.** [redacted]

A. [redacted] [END CONFIDENTIAL]

*The Lincoln Agreement Adheres to Industry Best Practices Regarding Cost Recovery and Rate Design*

**Q. How is the cost of infrastructure that is built to serve a new customer typically recovered in the utility industry?**

A. When infrastructure is built to serve either a single customer or an identifiable group of customers, the costs of that infrastructure are generally recovered from that customer or customers. Often, that is accomplished via a special rate that is designed to recover the COS of the new infrastructure.

**Q. Please explain the concept of subsidization, as you used the term earlier in your testimony.**

A. Subsidization occurs when one customer or group of customers is made to pay for costs that were caused by another customer(s). Avoidance of subsidization is an important goal of utility ratemaking.

**Q. How does the concept apply to the Lincoln Agreement?**

A. The current circumstance creates one of the least ambiguous situations of cost causality, recovery, and subsidization imaginable. The Incremental Facilities were built at the request of a single customer, DEC. The cost to build and operate those facilities is known and is clearly distinguishable from the cost to own and operate the rest of Piedmont's system and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Because none of the infrastructure that Piedmont uses to serve the Lincoln CT (neither the Existing Facilities nor the Incremental Facilities) is connected to any other element of its system [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] there is no risk of subsidization by Piedmont's other customers since there is no mechanism by which their costs could increase.

**Q. Does the Lincoln Agreement recover all of the costs to serve the Lincoln CT from DEC?**

A. Yes.

**Q. Do any of Piedmont's other customers subsidize DEC?**

A. No.

**Q. Does DEC subsidize Piedmont's other customers?**

A. Strictly speaking, yes, DEC is subsidizing Piedmont's other customers since the Lincoln Agreement generates more revenue than Piedmont's COS.

**Q. Is the creation of that subsidy problematic?**

A. Not in this case. As I explain in greater detail later in my testimony, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Generally speaking, is the cost of new utility infrastructure best recovered on a fixed or variable basis?**

A. It is a widely held principle of utility ratemaking that costs should be recovered on the same basis as they are incurred. Fixed costs, which include costs such as fixed O&M, depreciation, return on equity, taxes, and others, are the same for a utility regardless of how much gas flows over the system; such costs are best recovered via fixed charges. Volumetric costs, such as variable O&M, increase and decrease as system utilization increases and decreases. These costs are best recovered via variable charges.

**Q. Why?**

A. Aligning cost causation with cost recovery reduces the potential for subsidization between customers and customer classes, and because doing so decreases the likelihood that a utility's revenues will deviate significantly from its costs.

**Q. Please explain.**

A. If one assumes, for example, that some element of a utility's COS is variable in the sense that its costs increase when customer consumption increases, and *vice versa*, then recovering that cost through an appropriate variable rate means costs, revenues and system utilization will all rise and fall together, making it more probable that the utility will recover its costs and authorized return. If, on the other hand, a fixed cost is recovered via a variable rate, changes in consumption levels can result in large mismatches between costs and revenues, which can be problematic from a ratemaking perspective.

**Q. How does this situation apply to the Lincoln Agreement?**

A. All or nearly all of Piedmont's costs to provide service under the Lincoln Agreement are fixed. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

*<u>There is No Affiliate Issue</u>*

**Q. Are Piedmont and DEC affiliates?**

A. Yes, both are wholly owned subsidiaries of Duke Energy.

**Q. Are you therefore concerned that Piedmont is offering DEC favorable terms because it is an affiliate?**

A. No.

**Q. Why not?**

A. Because pricing for service from the Incremental Facilities is based on a transparent COS Study that Piedmont has shared with the Public Staff and the Commission which shows the complete derivation of the rates Piedmont has offered. Simply put, the Company has no opportunity to offer a rate less than its COS in a way that would not be apparent on review.

## III. Public Staff's Recommendation is Without Support and Would Create Rates Inconsistent with Industry Best Practice

**Q. Please summarize this section of your testimony.**

A. In this section of my testimony I summarize a recommendation by Public Staff to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] describe how that recommendation is without any meaningful basis, and explain that the Commission's acceptance would arbitrarily transfer costs between gas and electric ratepayers in North Carolina. I also explain that the inclusion of Public Staff's [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] would result in a rate structure inconsistent with utility best practices since it would disconnect cost causation with revenue recovery and necessarily create subsidies among Piedmont's customer classes.

*Public Staff's Recommendation Has No Basis and Would Increase Costs for Electric Customers*

**Q. Please summarize your understanding of the discussions among Piedmont, DEC, and Public Staff regarding the inclusion of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]**

A. As I understand it, a prior version of the Lincoln Agreement that was filed with the Commission on April 23, 2018 and provided for Piedmont's recovery of the costs of the Incremental Facilities [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] During ensuing discussions between the parties, Public Staff indicated that it believed [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

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5 Public Staff Comments, at 7-8.

6 Other differences between the Lincoln Agreement and the version that was filed in April 2018 include a reduction in Piedmont's capital cost requirements, which I understand to have been caused by the elimination of certain facilities that would be used for system inspections.

**Q. What is the Public Staff's recommendation?**

A. That the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Expressed in percentage terms, how large of an increase would that represent?**

A. Public Staff's recommendation would [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Why does the Public Staff believe a larger rate is required?**

A. As I explain previously, Public Staff is concerned that incremental service to the Lincoln CT will increase costs to Piedmont's customers and that DEC should therefore [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Do you agree?**

A. No.

**Q. Does the Public Staff explain how the Incremental Facilities can increase costs for existing customers despite being physically separate from the rest of the Piedmont system?**

A. No.

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[7] [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. How much would the increase recommended by the Public Staff cost DEC?**

A. In comments it filed in this proceeding, DEC indicated that its costs would [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Would that amount represent a large change in DEC's payments?**

A. Yes. Table 2 compares the annual cost to DEC under the three different sets of payment structures. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Calculating the annual payments that would be made under each structure shows that if Public Staff's recommendation is accepted, DEC's costs [BEGIN CONFIDENTIAL]

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[8] DEC Comments, at 7.

[redacted] [END CONFIDENTIAL]

**Table 2. Annual Contract Costs to DEC for [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to the New Incremental Facilities**

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

**Q. Has Public Staff explained why it believes that DEC's annual payments under the Lincoln Agreement should [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]**

A. No.

**Q. Has Public Staff offered any evidence that providing DEC service under the Lincoln Agreement will increase costs to Piedmont's other customers [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]**

A. No.

**Q. Has Public Staff provided any relevant evidence to show that [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

A. No. The Public Staff Comments include a discussion of analyses of O&M costs for customers served under Piedmont's Rate Schedule 113, but no explanation is made as to whether or how those analyses apply to the Lincoln Agreement nor are any calculations or results actually provided.[9] References to agreements reached between Piedmont and a glass manufacturer are likewise vague and unsupportive, as is a general description of elements of other commercial agreements between gas utilities and other electric generators, neither the specifics nor relevance of which are explained.[10]

**Q. Has Public Staff attempted to reconcile [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

A. No.

**Q. What do you believe would be the result of the Commission's acceptance of Public Staff's recommendation?**

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9 Public Staff Comments, at 12

10 Public Staff Comments, at 12-13

A. If we assume that DEC would continue to participate in the Lincoln Agreement and operate the Lincoln CT in precisely the same manner as it would otherwise, then its costs would [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Who would bear the cost of the subsidy?**

A. In this instance, the cost would be passed on to DEC's electric customers. As Piedmont [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for the Incremental Facilities, its costs to serve its other gas customers would decrease, causing its distribution rates to decline, all else being equal. That benefit would be paid for by DEC's electric ratepayers, who would absorb the added cost of operating the Lincoln CT. As I understand the configuration of the utility service territories in North Carolina, there is significant, but not complete, overlap between the service territories of Piedmont and DEC, which could mean that, in some cases, DEC customers who do not take service from Piedmont would bear the cost of this subsidy but not benefit from offsetting reductions in gas costs.

**Q. Could the Commission's acceptance of Public Staff's recommendation cause DEC to stop taking service under the Lincoln Agreement?**

A. Possibly, but I do not have enough information to reach a conclusion on that question.

*<u>Public Staff's Recommendation is Inconsistent with Industry Best Practices</u>*

**Q. Is Public Staff's recommendation consistent with industry best practices?**

A. No. If Public Staff's recommendation is accepted, the Lincoln Agreement would, by design, create revenues that are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Given the explanations of industry best practices that you have provided, are you concerned that the Lincoln Agreement [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

A. No. Despite those considerations, I find that the Lincoln Agreement is consistent with industry best practices and recommend its approval by the

Commission without modification for several reasons. *First*, the fixed charge included in the Lincoln Agreement provides for recovery of Piedmont's COS in a way that aligns costs and revenues, is transparent, and reduces the risk of large over- or under-recoveries. *Second*, the amount of revenue generated [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] go to Piedmont's other customers, who also realize additional benefits that I explain in the next section of my testimony. In other words, the contract includes terms that are acceptable to both buyer and seller, it creates no costs or risks to other customers, and it will reduce costs for the Company's existing customers, all of which support the Commission's approval.

## IV. <u>The Lincoln Agreement as Currently Formulated Provides Significant Benefits.</u>

**Q. Please summarize this section of your testimony.**

A. In this section of my testimony, I explain that the Lincoln Agreement, as currently formulated, reduces distribution costs for Piedmont's other ratepayers because the [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]

**Q. How much do you expect Piedmont to earn [BEGIN CONFIDENTIAL] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [END CONFIDENTIAL] each year?**

A. As I explain above, if the Lincoln CT's consumption is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Does that amount offset Piedmont's COS?**

A. No. As I explained previously in my testimony, all of the Company's costs [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Would you characterize that as a significant amount of revenue?**

A. Yes. Revenues above COS that total approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Public Staff's recommendation could generate even more revenues for Piedmont's existing customers; would you characterize the extra revenues that could be generated as unreasonable?**

A. Yes, I would. As I explained previously in my testimony, Public Staff's recommendations could [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] COS for providing its service.

**Q. Please summarize the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]**

A. The method that Piedmont used to estimate the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] is recovered, which increase revenues from the contract and benefit

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[11] ($500,000 per year) * (20 years) = $10 million

Piedmont's other customers. This issue is discussed in detail in Mr. Barkley's testimony.[12]

**V. Summary of Conclusions and Recommendations**

**Q. Please summarize your conclusions.**

A. My testimony supports the following conclusions:

1. The Lincoln Agreement comports with best industry practices regarding the alignment of cost causation with cost recovery.
2. The Lincoln Agreement comports with best industry practices regarding rate design.
3. Public Staff's recommended [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] is without basis.
4. Public Staff's recommended [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] would create rates that are inconsistent with industry best practices.
5. Public Staff's recommended [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] among Piedmont's customer classes.

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[12] Barkley testimony at p. 14.

6. Public Staff's [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] would unreasonably increase costs to electric ratepayers.

7. The Lincoln Agreement, as it is currently formulated, creates significant benefits for Piedmont's customers.

**Q. What is your recommendation?**

A. Based on these conclusions, I recommend that the Commission accept the Lincoln Agreement without modification.

**Q. Does this conclude your testimony?**

A. Yes, it does.

MR. JEFFRIES: And we would further move that Mr. Sosnick's exhibit -- direct Exhibit KAS-1 be identified as marked.

CHAIR MITCHELL: Motion is allowed. The exhibit to the witness' testimony shall be marked for identification as was when prefiled.

(Confidential Exhibit KAS-1 was identified as they were marked when prefiled.)

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

A. Yes, I did.

Q. All right. Thank you. Before you give that, and --

MR. JEFFRIES: Madam Chair, I apologize, I probably should have done this at the onset of Mr. Sosnick's appearance. I want to make it clear that Mr. Sosnick is testifying today in Docket 722 and his testimony is limited to the issues in that docket.

Q. Could you please provide your summary for the Commission?

CHAIR MITCHELL: Mr. Sosnick, please -- just one minute, please. Also, I'd like to note for purposes of the record that portions of the witness' testimony are confidential and must be treated as such in the record, and ask counsel to make sure that -- work with the court reporter to ensure confidential treatment of those portions of the witness' testimony.

All right. Mr. Sosnick, you may proceed.

THE WITNESS: Thank you.

My name is Kenneth A. Sosnick. I'm the managing director in the power and utilities practice, FTI Consulting, Inc. On April 19, 2021, Matthew DeCourcey, formerly of FTI, prefiled direct testimony in consolidated Docket Numbers G-9, Sub 722 and the instant docket in support of the Company's November 2018 agreement pertaining to the Lincoln contract. Mr. DeCourcey has since left FTI, and the Commission approved my substitution as a witness on August 21, 2021.

In my prefiled direct testimony, I specifically argued that this agreement, the Lincoln agreement, between Piedmont and Duke Energy for the construction of new facilities and the delivery of natural gas by Piedmont to DEC's

Lincoln facility, aligns with industry best practices for rate design, cost causation, and recovery.

My prefiled direct testimony directly addresses a recommendation made by Public Staff that suggests Piedmont recover costs from building and serving the incremental facilities through a volumetric rate on top of the fixed charge currently in the terms of the Lincoln agreement. The purpose of this charge is to prevent cross subsidization between customers, a tenet of rate design by calculating the cost, mainly fixed, specific to the incremental facility and recovering them over time through a fixed fee solely charged to DEC.

I reviewed the Company's cost of service model and concluded that the cost to own and operate incremental facilities were nearly all fixed, aside from a small O&M expense that was projected to rise steadily at 2 percent per year. The fixed fee in the Lincoln agreement essentially recovers a set sum through a set charge. Public Staff's recommendation of adding a volumetric charge to this fixed charge would instead recover a set sum through a variable fee.

I conclude that the Lincoln agreement, as filed, comports with industry best practices in regard to rate design, cost causation, and recovery. I argue that although the proposed volumetric fee introduced to prevent between cross subsidization between customers is not needed because the incremental facilities are not interconnected to the overall Piedmont system, and therefore do not cause wear and tear to this system, the agreement, as filed with its volumetric rate being lower than Staff's, still meets Staff's wishes, does not inflate DEC's rates inviably, and provides benefits to Piedmont's overall customer base through lower rates.

My final recommendation is to accept the Lincoln agreement filed November 2018 without modification.

Q. Thank you, Mr. Sosnick.

MR. JEFFRIES: Madam Chair, Mr. Sosnick is available for cross examination and questions by the Commission.

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

Ms. Culpepper?

MS. CULPEPPER: Public Staff has no cross.

CHAIR MITCHELL: Okay. Questions for the witness from Commissioners?

(No response.)

CHAIR MITCHELL: Any questions from Commissioners?

(No response.)

CHAIR MITCHELL: Commission Brown-Bland, I see you moving. Do you have questions? Are you thinking about questions for this witness?

COMMISSIONER BROWN-BLAND: Yes. I'll just put one out here.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Sosnick, as I understand your testimony and the position of the Company, all fixed -- all relevant costs here are being recovered through a contract. There are no -- from the Company's position, there are no additional costs to be recovered; is that correct?

A. That is correct. And I do want to point out that there is an adder that is much less than the Public Staff's recommendation that's included. So I would say that all costs are being recovered through the contract -- through the contract rate.

Q. All right. Thank you.

CHAIR MITCHELL: All right. Any additional questions from Commissioners?

(No response.)

CHAIR MITCHELL: Okay. Hearing none, let's take questions on Commissioner Brown-Bland's question. I'll start with the intervenors.

MS. CULPEPPER: No questions.

CHAIR MITCHELL: Okay. Thank you, Ms. Culpepper.

All right. Mr. Jeffries?

MR. JEFFRIES: No questions, Chair Mitchell.

CHAIR MITCHELL: All right. All right, Mr. Sosnick, there is nothing further for you, sir. We appreciate your participation in the proceeding. You may step down.

Mr. Jeffries, intent to recall him?

MR. JEFFRIES: No intent to recall Mr. Sosnick.

CHAIR MITCHELL: So, Mr. Sosnick, you are excused from the hearing today.

And I will take a motion, Mr. Jeffries.

MR. JEFFRIES: Thank you, Chair Mitchell. We would move that Mr. Sosnick's prefiled Exhibit KAS-1 be entered into evidence.

CHAIR MITCHELL: Hearing no objection to that motion, it's allowed.

(Confidential Exhibit KAS-1 was admitted into evidence.)

CHAIR MITCHELL: All right. Piedmont, you may call your next witness.

MR. JEFFRIES: Piedmont calls Bruce Barkley to the stand.

CHAIR MITCHELL: All right. Mr. Barkley, good morning, sir. Would you raise your right hand.

Whereupon,

BRUCE P. BARKLEY,

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

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

MR. JEFFRIES: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Good morning, Mr. Barkley.

A. Good morning.

Q. Could you please state your name and business address for the record, please.

A. Bruce Barkley. 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q. And where do you work, sir?

A. Piedmont Natural Gas.

Q. And what's your position at Piedmont?

A. Vice president of rates and gas supply.

Q. And your testimony today is in the Sub 722 docket; is that correct?

A. Yes.

Q. Okay. And you're the same Bruce Barkley that prefiled direct testimony on April 19, 2021, in docket G-9, Sub 722 consisting of 19 pages, and Exhibits BPB-1 and BPB-2; is that correct?

A. Yes. And I believe there was also a third exhibit, Mr. Jeffries.

Q. I was thinking the same thing, but it's not on my list. Let me just confirm that real quick. Yes, you are correct.

You also prepared BPB-3 with your direct testimony, correct?

A. Yes.

Q. And you also filed rebuttal testimony on August 25, 2021, consisting of four pages; is that correct?

A. Yes.

Q. All right. Do you have any corrections to the prefiled testimony or exhibits?

A. No.

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

A. Yes.

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

CHAIR MITCHELL: All right. Hearing no objection to the motion, the direct testimony filed by Piedmont in the docket on April 19, 2021, shall be copied into the record as if given orally from the stand; the rebuttal testimony filed in the docket on August 25, 2021, shall be copied into the record as if given orally from the stand. I will note for the record, portions of the witness' direct testimony are confidential and should be identified as such in the record.

(Whereupon, the prefiled direct testimony and prefiled rebuttal testimony of Bruce P. Barkley 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

## General Rate Case

## Direct Testimony and Exhibits
## of
## Bruce P. Barkley

## On Behalf Of
## Piedmont Natural Gas Company, Inc.

**PUBLIC VERSION**

Piedmont Natural Gas

**April 19, 2021**

**Q. Please state your name and business address.**

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

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

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

**Q. Please describe your educational and professional background.**

A. I obtained a Bachelor of Science Degree in Business Administration with a concentration in Accounting from the University of North Carolina at Chapel Hill and an MBA Degree from Wake Forest University. From 1988 through 2001, I was employed by Public Service Company of North Carolina, Inc., where I was responsible for regulatory filings and reports submitted to the North Carolina Utilities Commission ("NCUC" or "Commission"). Prior to joining Piedmont, I held various positions with Progress Energy, Inc. and subsequently Duke Energy Corporation ("Duke Energy") in Regulatory Affairs, Fuels, and Regulatory Accounting. I joined Piedmont in 2015 and began serving in my current role in 2019.

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

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

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

A. The purpose of my testimony is to support Piedmont's revised Consolidated Natural Gas Construction and Redelivery Services Agreement filed on November 16, 2018 in Docket No. G-9, Sub 722.

**Q. Are there any other witnesses providing testimony for Piedmont on the issues raised in the Sub 722 Docket?**

A. Yes, Mr. Matthew DeCourcey, an expert on natural gas cost allocation and rate design with FTI Consulting, is also filing testimony in this docket in support of the Company's position.

**Q. Do you have any exhibits to your testimony?**

A. Yes. I have the following three exhibits:

Exhibit __(BPB-1) June 26, 2020 Comments in G-9, Sub 722

Exhibit __(BPB-2) Return Calculation for Lincoln Contract

Exhibit __(BPB-3) Response to Commission Questions

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

A. Yes.

## Background

**Q. Can you explain the context of the issues raised in Docket No. G-9, Sub 722 that have now been consolidated with Piedmont's general rate case proceeding in Docket No. G-9, Sub 781?**

A. Yes. On April 23, 2018, Piedmont filed a Consolidated Natural Gas and Redelivery Services Agreement ("Consolidated Agreement") between Piedmont and Duke Energy Carolinas, LLC ("DEC") for approval by the Commission. This Consolidated Agreement served two purposes: (1) it updated the form of a long-standing service agreement between Piedmont and DEC for service at Duke's Lincoln County turbine facility to Piedmont's current form of agreement (while preserving the rates underlying the service provided under the long-standing agreement approved by the Commission in Docket No. G-9, Sub 491); and (2) provided for an additional level of new service to the Lincoln County facilities needed by DEC as a fuel source for additional gas-fired turbine generation equipment being installed at the Lincoln County facility.

Piedmont estimated that the new incremental facilities it would need to construct to serve the additional load at the Lincoln County plant would cost approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] million to construct and would consist of a 1,000-feet of new transmission main running from the existing Piedmont transmission main to the new Lincoln County facilities, as well as measuring and regulating station equipment. No other party was intended to be served through these facilities. The Consolidated Agreement reflected these terms and, in addition to the charges provided for under the pre-existing service arrangement with DEC, also provided for [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL] to recover the costs of the incremental facilities over the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] term of the Consolidated Agreement.

**Q. How did Piedmont calculate the new incremental facilities demand charge?**

A. We used our standard cost of service model, which is used in every case where we are evaluating the economic feasibility of a system expansion to serve a new large volume customer. This model incorporates standard cost inputs, including capital expenditures, operating and maintenance expenses ("O&M"), property taxes, payroll taxes, income taxes, and interest to arrive at a net present value determination as to whether the expansion of service to a proposed project under our tariff rates is economically feasible. If a project is not economically feasible under the revenues that would be produced under our tariff rates, i.e., it doesn't produce a reasonable return on investment, then Piedmont [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and calculates demand rates necessary to produce those revenues. Occasionally, on the opposite end of the spectrum, our tariff rates generate revenues and returns that are unacceptably high to customers that have the option to locate elsewhere or to use an alternative fuel. Piedmont then [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Piedmont uses this approach consistently with every new proposed large volume customer and does not vary the model or the application of the model for affiliates or any other party. The end result of this process is typically a proposed service agreement filed with the Commission for approval as a special contract if standard tariff rates are either insufficient or excessive. The Company does not bill amounts that vary from its approved tariffs until it receives authorization in the form of an order from the Commission.

**Q. Did Piedmont utilize this approach in arriving at the terms of the Consolidated Agreement with DEC in this case?**

A. Yes.

**Q. Did the application of the model to the incremental Duke Lincoln facilities leave out any costs anticipated to be incurred by Piedmont in providing incremental service to DEC?**

A. No, our model was inclusive of all costs we anticipated incurring in order to serve DEC.

**Q. What happened after Piedmont filed the Consolidated Agreement for approval by the Commission in this case?**

A. The Public Staff engaged in discovery on and reviewed the Consolidated Agreement, following which they expressed some concerns over the fact that, in their view, the Consolidated Agreement did not provide adequate "system support" for Piedmont's other customers. They particularly focused on the idea that the Consolidated Agreement should reflect some sort of volumetric surcharge in order to provide system support.

**Q. Did the Public Staff provide a recommended methodology for calculating such a system support charge?**

A. No. In our discussions with them regarding this subject they did not provide a recommended formula or methodology for calculating a usage-based system support surcharge.

**Q. What happened next?**

A. Based on our conversations with the Public Staff, we went back to DEC and advised them that the Public Staff appeared to be unwilling to support approval of the Consolidated Agreement [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]

**Q. What was the basis for that amount?**

A. No specific ratemaking method underlies the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] approach. There is no standard approach that the Commission has directed Piedmont to use for this purpose nor did Public Staff offer any input as to how the rate should be set. Instead, the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] is the result of a Piedmont's determination of a commercially viable solution that was scalable (and repeatable) that would result in a meaningful contribution above Piedmont's incremental costs, ultimately benefitting Piedmont's other customers. DEC reluctantly agreed to the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and the revised Consolidated Agreement ("Revised Agreement") was refiled with the Commission on November 16, 2018.

**Q. What happened subsequent to the November 16, 2018 filings?**

A. The Public Staff undertook discovery on the Revised Agreement but otherwise took no action to move the Revised Agreement forward for consideration by the Commission. Piedmont and the Public Staff periodically had discussions regarding the status of the Revised

Agreement, but no resolution was reached. For the most part, the Public Staff continued to object to approval of the Revised Agreement because, in their view, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] When Piedmont asked how the Public Staff would [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] that would provide adequate system support (in their view), they had no suggestions. They also had no explanation as to why a contract for incremental service to the new turbine generation equipment at Lincoln, which did not rely on Piedmont's other system assets in any way, should be assessed [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. What other actions did Piedmont undertake while this matter remained pending further action by the Public Staff?**

A. Because the amount of capital for this project was relatively small and because DEC indicated that they needed gas service to test their new gas turbine equipment in the near future, Piedmont proceeded with construction of the new incremental facilities in late 2019 and on January 10, 2020 filed a Request for Authorization to Commence Service to DEC through the new incremental facilities. This service was proposed to be provided on an interim basis subject to the Commission's final disposition of the Revised Agreement in this docket. On January 28, 2020, the Commission issued its Order Granting Interim Authority to Operate Under Second Revised Agreement and Requiring Public Staff Action. This order allowed Piedmont to commence service to DEC through the incremental facilities and required the Public Staff to file recommendations and its proposed order in the docket. After several extensions, the Public Staff filed its recommendations and proposed order on June 1, 2020. On June 26, 2020, Piedmont and DEC filed comments on the Public Staff's recommendations. Piedmont has continued to serve the Lincoln facility under the terms of Revised Agreement pursuant to Commission order issued in this docket on July 20, 2020.

**Matters at Issue in This Proceeding**

**Q. What recommendations did the Public Staff make in their June 1, 2020 filing?**

A. Based on their conclusion that the Revised Agreement was not in compliance with the requirements of N.C.G.S 62-140 and 62-153, the Public Staff recommended that Piedmont be ordered to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. What is Piedmont's position on the Public Staff's recommendations?**

A. We explained our opposition to the Public Staff's position in some detail in comments filed in this docket on June 26, 2020 and I hereby adopt those comments, which are attached hereto as Exhibit __(BPB-1). In short, we disagree with the Public Staff's proposal on multiple grounds but primarily because it is not based on cost or on any other discernible formula or analysis and because the application of [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] As I will explain further in my testimony, Piedmont objects to both [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] As we have stated previously in this docket, we do not oppose the idea of a system support surcharge associated with special contract arrangements that actually utilize portions of our pre-existing system to effectuate deliveries to a special contract customer. One very significant aspect of the Lincoln County service arrangement is that the facilities used to provide that service are 100% dedicated to serving the DEC Lincoln plant and do not serve any other customer. Piedmont does not rely on any other part of its transmission or distribution system to serve DEC at the Lincoln facilities.

**Q. Please explain why you believe the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the Public Staff's recommendation is not appropriate in this circumstance.**

A. Mr. DeCourcy addresses this issue in his testimony and I concur that [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] are appropriate because Piedmont's costs for the new facilities are substantively fixed. The [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] remains acceptable to Piedmont in this proceeding as it was offered in the spirit of compromise, was accepted by the customer, and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for the incremental facilities are based on the Public Staff's conclusions that other electric generation contracts with North Carolina local distribution companies (and other special contract arrangements in some circumstances) "usually" contain a volumetric charge and that customers under these contracts should provide support to the larger LDC system. Because most of the contracts discussed are with other LDCs, the Public Staff has redacted commercial details, which renders Piedmont unable to determine the merits of those contracts. Piedmont also cannot determine the underlying rate design philosophy upon which those contracts were based – which means we cannot know if variable charges were appropriate or to what degree, if any, the variable charges under those agreements provide system support.

For example, Piedmont's tariff rates and charges for Large General Transportation Service are comprised of a fixed monthly charge, a demand charge component and a usage charge component. Together, these billing components are designed to recover the Company's share of revenue requirement allocated to Large General Transportation customers as a class. The fact that some portion of this revenue requirement is being collected volumetrically through usage based rates, says nothing about the underlying "fairness" of the costs allocated to these customers and certainly does not mean that they are providing "system support" in excess of costs. In other words, the form of revenue recovery (fixed versus volumetric) is not indicative of whether costs are being under-recovered or over-recovered, being subsidized or subsidizing others. Applying this logic to the other LDC contracts that the Public Staff relies upon, the mere fact that they contain a volumetric component does not mean those customers are paying more than the cost to provide them with service – it just means that the costs allocated to those customers (whatever they may be and however calculated) are being recovered in both fixed and usage-based rates.

**Q. Please explain why Piedmont is concerned by [BEGIN CONFIDENTIAL]** [redacted]**. [END CONFIDENTIAL]**

A. Piedmont's primary concern [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] DEC would have decided either to not construct this facility, locate it elsewhere or bring a complaint against Piedmont before this Commission. If the project were not completed within Piedmont's service territory, its customers would have been denied the benefits associated with the project. I will subsequently explain and present those potentially forfeited customer benefits. Piedmont continually seeks to resolve customer complaints from all customer classes through collaboration and without the time expenditure and cost associated with litigation such as this ongoing dispute.

**Q. Why, then, did Piedmont and DEC agree to [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

A. We did so because both Piedmont and DEC wanted to be responsive to Public Staff's concerns and because the charge was commercially reasonable. As I explain above, the Public Staff refused to consider supporting this contract [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**Q. Have you quantified these benefits based on the traditional inputs into the ratemaking process as summarized in this proceeding on Piedmont witness Bowman's Exhibit_(QPB-7)?**

A. Yes, as shown on the attached Exhibit_(BPB-2) and summarized in Table 1 below. This exhibit clearly demonstrates a return on equity

("ROE") that [BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] These returns benefit all other customers in general rate case proceedings over the life of the contract. The base case is shown on Page 1 of this exhibit and includes revenues without the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Piedmont does not believe the returns shown on Page 3 to be commercially viable.

**Q. Please explain how Piedmont's NPV based cost of service study for DEC Lincoln yielded the results presented on page 1 of Exhibit_(BPB-2).**

A. When Piedmont reviews a potential expansion project under its cost model, it [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL] from the project which reduces the revenue requirement for Piedmont's other customers in its next rate case (when the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]). Table 1 below shows our calculation of the average returns that would result from the original methodology [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

**TABLE 1**

| | [BEGIN CONFIDENTIAL] [redacted] | [BEGIN CONFIDENTIAL] [redacted] | [BEGIN CONFIDENTIAL] [redacted] |
|---|---|---|---|
| Average Operating Income | [redacted] | [redacted] | [redacted] |
| Average Equity Income | [redacted] | [redacted] | [redacted] |
| Average Return on Rate Base | [redacted] | [redacted] | [redacted] |
| Average Return on Equity | [redacted] [END CONFIDENTIAL] | [redacted] [END CONFIDENTIAL] | [redacted] [END CONFIDENTIAL] |

**Q. Do these results reconcile with the results of the Allocated Cost of Service Study prepared for Piedmont in its current general rate case proceeding?**

A. No. The Allocated Cost of Service Study prepared by Ms. Cynthia Menhorn shows returns for power generation contracts that are lower than Piedmont's overall test year return of 6.82%.

**Q. Can you explain the apparent discrepancy?**

A. Yes, Ms. Menhorn's Allocated Cost of Service Study results are derived to determine how total revenues and costs are allocated to all rate classes regardless of whether or not the classes will be allocated any component of a requested rate increase. Specifically, for purposes of our cost model we do a discrete project specific analysis of the incremental costs needed to provide service as previously described previously in my testimony. That model accurately analyzes the contributions needed from the new customer to fully compensate Piedmont for the costs of serving that specific customer. Ms. Menhorn engages in an entirely different analysis. She allocates total North Carolina rate base, expenses and revenues across all customer classes and then uses the resulting return analysis to inform decisions about how to allocate any revenue requirement increases across Piedmont's rate classes. Significantly, this analysis was never intended to inform the design of existing special contract rates because those rates are fixed and will not change as a result of this rate case. Ms. Menhorn could have excluded all rate base, expenses, and revenues associated with fixed price contracts from her cost of service study. However, such exclusion would have likely required multiple reconciliations throughout this proceeding as totals per the cost of service study would not have been in agreement with total North Carolina rate base, expenses and revenues shown in the G-1 data request response and the testimony and exhibits of Piedmont witness Bowman.

**Q. Have you also prepared responses to the Commission's specific questions set forth in its order consolidating this proceeding with Piedmont' general rate case proceeding?**

A. Yes. Piedmont's responses to the Commission's questions reflected in its March 16, 2021 Order Consolidating Dockets And Requiring Filing Of Testimony are attached hereto as Exhibit__(BPB-3).

**Q. Do you believe the Revised Agreement to be in the public interest?**

A. Yes, I do.

**Q. Does this conclude your testimony?**

A. Yes.

# Before the
# North Carolina Utilities Commission

## Docket No. G-9, Sub 722

## Rebuttal Testimony
## of
## Bruce P. Barkley

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

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

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

**Q. Have you previously testified in this proceeding?**

A. Yes. I previously submitted prefiled direct testimony in Docket No. G-9, Sub 722 on April 19, 2021.

**Q. Have you reviewed the pre-filed direct testimony of North Carolina Utilities Commission – Public Staff ("Public Staff") witness Julie Perry regarding the matters at issue in this docket?**

A. Yes, I have. That testimony relied heavily on prior filings by the Public Staff in Docket No. G-9, Sub 722.

**Q. Does the Company have any response to the testimony of witness Perry in this docket?**

A. No. The Company is satisfied that the issues addressed in the pre-filed direct testimony of Public Staff witness Perry have been fully addressed by Piedmont's pre-filed testimony and related filings in this docket.

**Q. Does the Company have any response to the answers provided by the Public Staff to the questions posed by the Commission at Exhibit A of its order issued in this docket on March 16, 2021?**

A. Yes. The Commission's Public Staff Question 1.b. is as follows: "In the absence of a volumetric rate, provide the calculations and the assumptions used to calculate the subsidy that DEC's New Facilities would receive." The Public Staff's response frames various subsidy scenarios in terms of how the results differ from amounts calculated under Piedmont's Rate Schedule 113, Large General Transportation Service.

**Q. Are variances from amounts that would have been billed under Rate Schedule 113 legitimate subsidies provided by other customers to DEC?**

A. No. I do not believe the Public Staff's response reflects a subsidy received by DEC because the results are divorced from the realities of providing natural gas transportation service to a special contract customer. Under Rate Schedule 113, Piedmont's investment in the incremental facilities would be repaid threefold every year during the life of the contract. That scenario represents a huge subsidy being paid by DEC, not to DEC. Further, DEC would not have agreed to such a pricing option and would have located this incremental investment elsewhere. Piedmont's original agreement with DEC included rates that recovered all incremental costs, therefore, no subsidy existed. Due to the absence of any subsidy, none could be provided to the Commission and the Public Staff simply subtracted three different data points from the amount that would have billed under Rate 113 in response to Question 1.b.

**Q. If there was no subsidy in the original agreement, why did Piedmont and DEC subsequently execute a revised contract with a volumetric adder?**

A. The parties sought to compromise with the Public Staff to avoid protracted litigation, allowing the approval process by the Commission to move forward in an efficient manner.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

MR. JEFFRIES: Thank you, Chair Mitchell. Piedmont would also ask that Mr. Barkley's prefiled direct Exhibits BPB-1 through BPB-3 be identified as marked.

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

(Confidential Exhibits BPB-1 through BPB-3 were identified as they were marked when prefiled.)

MR. JEFFRIES: Thank you, Chair Mitchell.

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

A. Yes.

Q. Could you provide that to the Commission, please.

A. Yes.

My name is Bruce Barkley. I'm vice president of rates and natural gas supply for Piedmont Natural Gas Company. I prefiled direct testimony in consolidated Dockets Number G-9, Sub 722, and the instant Docket G-9, Sub 781 on April 19, 2021. I also submitted prefiled rebuttal testimony on

August 25, 2021, in this proceeding. My prefiled direct testimony supports Piedmont's revised consolidated natural gas construction and redelivery services agreement between itself and Duke Energy Carolinas, LLC filed on November 16, 2018, in Docket Number G-9, Sub 722.

The consolidated agreement serves two purposes. It updates the form of a long-standing agreement between Piedmont and DEC for service at DEC's Lincoln County turbine facility to Piedmont's current form agreement, and provides for an additional level of new service to the Lincoln County facilities needed by DEC as a fuel source for additional gas-fired turbine generation equipment being installed at the Lincoln County facility.

My direct testimony is supported by the following three exhibits: Number 1, Piedmont's June 26, 2020, comments, Docket Number G-9, Sub 722; the return calculations for the Lincoln contract; and Piedmont's responses to Commission questions.

I also prefiled rebuttal testimony to address and respond to the answers provided to the -- by the Public Staff to the questions posed by the Commission in Exhibit A of its March 16, 2021, order consolidating dockets and requiring filing of testimony in the instant docket. Specifically, I responded to the Public Staff's answer to the Commission's Public Staff question 1.b.

This concludes the summary of my prefiled and rebuttal testimony.

Q. Thank you, Mr. Barkley.

MR. JEFFRIES: Chair Mitchell, Mr. Barkley is available for cross examination and questions by the Commissioner.

CHAIR MITCHELL: All right. We'll start with the Public Staff.

MS. CULPEPPER: We have no questions.

CHAIR MITCHELL: All right. Attorney General's Office?

MS. FORCE: No questions.

CHAIR MITCHELL: All right, Mr. Barkley. Questions from the Commission. Start with Commissioner Hughes.

COMMISSIONER HUGHES: Yes, Chair Mitchell. I think most of the questions I have will not cover confidential testimony, although one question, the testimony -- there is a footnote that is marked as confidential to the testimony. So, you know, we can proceed and just defer to Piedmont. I'm not sure how you want to proceed.

CHAIR MITCHELL: Let's do this. Commissioner Hughes, ask your questions. Mr. Jeffries, pay close attention to the questions. And, Mr. Barkley, if you-all feel that you're gonna have to get into confidential information to respond, then we will go into a confidential setting. But for now, let's try proceeding in the open hearing with your questions, Commissioner Hughes.

COMMISSIONER HUGHES: Okay. Thank you.

EXAMINATION BY COMMISSIONER HUGHES:

Q. So I understand from your testimony, which is not marked as confidential, that if the volumetric charge in this special contract is implemented as Public Staff would like, it will lead to an over-earning, essentially, on the part of Piedmont.

So with that said, who will benefit from -- or who should benefit from that over-earning, the ratepayers or shareholders?

A. As we move to the next rate case, Commissioner Hughes, the next rate case after the implementation of the item that you questioned, it would be with ratepayers. Between cases, it would be with shareholders, and it would serve perhaps the function of delayed rate cases. But it can be -- it can and will be provided to shareholders in the context of general rate case, such as the one that we're in today.

Q. Okay. That's clear. Thank you. If, on the other hand, it's not -- you haven't testified to this, but if you were under-earning the rate of a special contract -- I asked this question to Ms. Powers as well, but you can just chime in with your response -- if you were under-earning on this contract, should other ratepayers subsidize the special contract customer, or should shareholders absorb the revenue shortfall? Just the reverse of the last question I asked.

A. I think if there were ever a situation where theoretically one of many contracts were under-earning and the net over-earned, then that would be to the benefit of customers. So I think I would look at the overall impact of these special contracts. If we did not recover these amounts for whatever reason -- and I think, Commissioner Hughes, Ms. Powers shared with you that the structure of these is fixed cost, so I think that we addressed this risk.

These are Commission-approved contracts, so I think that they would flow through rates regardless of the direction, would be my recommendation, whether we were over-earning or under-earning, but I believe that we have covered the risk to our customers by establishing fixed cost collection.

Q. Okay. Okay. That's helpful.

COMMISSIONER HUGHES: There is another staff question that is marked as confidential, Chair Mitchell. It involves an amount that I believe is confidential. So I suppose, if we are going to ask that question, we're going to need to do it on the confidential line.

CHAIR MITCHELL: All right. Let's pause here, Commissioner Hughes, with your questions. I'll check in with other Commissioners to see if they have questions for the witness that won't get into confidential information. Please speak up now if you have questions, Commissioners.

(No response.)

CHAIR MITCHELL: All right. I'm not seeing any.

I do have one for you, Mr. Barkley. I don't think you should have to get into confidential information. I trust that if you do, you can tell me, we can take care of it when we're on the line.

EXAMINATION BY CHAIR MITCHELL:

Q. Mr. Barkley, help me understand the Public Staff's concern here. What is the Public Staff guarding against? Or what risk is the Public Staff mitigating here with the position that it's taking? And I recognize I'm asking you to speak for the Public Staff, but that's what I'm asking you to do, and I recognize what I'm asking you.

A. That is an interesting perspective, Chair Mitchell. But I certainly have had conversations with the Public Staff, and I reviewed the information that they filed in this proceeding. My perspective of their concern is that there would be a subsidy provided to the special contract customer, who in this case is DEC, by all the other ratepayers.

And so that is what they are trying to guard against with the positions that they have taken.

Q. But can you elaborate, Mr. Barkley, a subsidy in terms of -- just what is that subsidy?

A. Sure. I'll, again, certainly try. I think that perhaps all of the costs that should be collected in this contract are not being collected, and as I was just speaking with Commissioner Hughes, if they're not -- if this project is causing certain costs that are not being collected from this counterparty, then they're going to be socialized and collected from everyone else.

So I would agree with the Public Staff, that is not a situation we want. We do not want all of the other rate sets to subsidize this counterparty. And that's why we set up a cost-based analysis, so that all costs are assigned to this customer. And it's even cost plus, because I believe, again, without getting into confidential, that our testimony, both mine and Mr. Sosnick's indicates healthy returns.

So that indicates to me that not only are all the other customers held harmless, which that's sort of the first goal, is to hold them all harmless from Piedmont's perspective, but they're actually benefitting from this.

Q. Okay. Thank you, Mr. Barkley. Just one more follow-up for you.

Has the Public Staff identified a specific cost that this contract might impose on other customers or on the system that other customers would have to subsidize or absorb?

A. I do not believe they have, no.

Q. Okay. All right.

CHAIR MITCHELL: All right.

COMMISSIONER BROWN-BLAND: Chair Mitchell?

CHAIR MITCHELL: Yes, ma'am, do you have questions for the witness?

COMMISSIONER BROWN-BLAND: Yes.

CHAIR MITCHELL: Please proceed, Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Sort of just one, and I've hesitate to ask, because I'm frustrated as I read the various items that are marked confidential, whether we should even be discussing. But it seems to me you just covered what I wanted to ask about, so I'm going to go anyway.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. So just the one follow-up to what Chair Mitchell was asking, Mr. Barkley.

If there is an amount that's not being

recovered pursuant to the agreement, the special contract that leaves the Company's ratepayers vulnerable to have to pick up some addition, is there -- and I know that it's not the Company's position that there is anything that's been left out, but if there were, is there any reason that that amount could not be recovered by a fixed charge, some other additional fixed charge? Is there some reason that it must be, or it's better to be volumetric?

A. I believe fixed is the best way to guard against the risk that we're discussing and that I believe you're asking about, because the very nature of a volumetric charge is such that you can't know how much it's going to be, depending on many things, the weather even perhaps being a prime example. So the risk is best mitigated by collecting -- our costs are fixed, so we now mitigate that risk by recommending a fixed-cost structure in this and other special contracts.

Q. And just generally speaking, in rate recovery, an appropriately assessed fixed charge would come closer to assured recovery of costs than trying to collect fixed costs through volumetric charges; isn't that right?

A. Yes.

COMMISSIONER BROWN-BLAND: All right. No further questions.

CHAIR MITCHELL: All right. While we're still in open session, I'm going to see if there are questions on the Commissioner's questions?

(No response.)

CHAIR MITCHELL: Asked so far. I see Mrs. Culpepper.

CROSS EXAMINATION BY MS. CULPEPPER:

Q. Mr. Barkley, Chair Mitchell asked you a question you responded that you used a cost-based analysis; is that correct?

A. I do believe I said that. And regardless, I do believe this is, yes, cost based for this contract; yes, ma'am.

Q. Have you provided that analysis to the Public Staff?

A. Yes, ma'am.

Q. Can you tell me what it is? I mean, describe how it was provided or the analysis.

A. Sure. It's a net present value analysis based on cash flows. Both for this project and in many projects, all special contracts that -- the support in

Excel sheets are provided to Public Staff accounting as a routine matter of course. I think probably in discovery, as soon as we file one of these, shortly thereafter we receive discovery from Public Staff, generally, on the accounting side, I believe, and we provide the Excel sheets that support the rates that we recommend for approval.

Q. Thank you.

MS. CULPEPPER: That's all I have.

CHAIR MITCHELL: Thank you, Ms. Culpepper.

Any additional questions on the Commissioners' questions?

MR. JEFFRIES: Chair Mitchel, I have one for Mr. Barkley.

CHAIR MITCHELL: Okay.

REDIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. Barkley, you recall a moment ago you were having a discussion with Chair Mitchell where she had asked you to try to express in your words what you understood to be the Public Staff's concerns here, and my recollection is that your testimony was to the effect that you thought they were concerned about subsidies from our general ratepayer base to the special contract customers; is that consistent with your recollection?

A. I do believe that was the gist of my conversation and my response to the Chair; yes, sir.

Q. Yeah. And then you also mentioned that, you know, it was this idea of cost shifting from ratepayers to the special contract customers that was the Public Staff's specific concern. And I just wanted to be clear on the record, it's not your position that that cost shifting is happening, correct?

A. Absolutely not. That is not my position. I believe that, for this contract, there is no cost shift. That our recovery from this counterparty is very sufficient to protect all other customers.

Q. And is it your understanding that the contract provides for an escalation for O&M expense over time to guard against the possibility that there are additional expenses incurred that weren't anticipated?

A. Inflation is built in to the O&M assumption, so yes is the answer to your question; yes, sir.

Q. And if there were to be a need for additional capital expense, that would have to be the subject of a new arrangement, correct?

A. Yes.

Q. Okay.

MR. JEFFRIES: That's all the questions I have, Chair Mitchell.

CHAIR MITCHELL: All right. At this time, we need to go -- I've got some additional questions for the witness. We're going to have to go into confidential session to get those questions -- for me to ask those questions and for the witness to respond to them. So what I would ask of everyone now is to -- those parties that have entered into confidentiality agreements with the Company may join the line. I assume everyone has been provided with a phone number. Commissioners have the phone number and need to join now as well. While we're in confidential session, please turn off your camera and mute your lines. All right. Thank you, everybody.

(Due to the proprietary nature of the testimony found on pages 592 to 618, it was filed under seal.)

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CHAIR MITCHELL: At this point, we are no longer in confidential session, we are in open session.

Any additional questions from the Commissioners for this witness?

(No response.)

CHAIR MITCHELL: All right. I am hearing none. So I believe at this point, there is nothing further for this witness. I'm not hearing anyone object or correct me there. So, Mr. Barkley, you may step down, sir.

And, Mr. Jeffries, I understand that you will not be recalling this witness; is that correct?

MR. JEFFRIES: We will not be recalling this witness to present testimony. He's already presented his prefiled direct and rebuttal. But we would like to reserve the right to recall Mr. Barkley if something needs to be addressed on rebuttal from further testimony to come in Sub 722.

CHAIR MITCHELL: All right. Well, Mr. Barkley, then you may step down, but you are not yet excused, sir.

All right. With that, it is 12:45. We

will --

MR. JEFFRIES: Chair Mitchell, may I move his exhibits into evidence?

CHAIR MITCHELL: Absolutely. Please do.

MR. JEFFRIES: Chair Mitchell, Piedmont would move that Mr. Barkley's direct prefiled exhibits marked BPB-1 through BPB-3 be admitted into evidence.

CHAIR MITCHELL: All right. Hearing no objection to that motion, the exhibits attached to the prefiled testimony of the witness will be accepted into evidence.

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

MR. JEFFRIES: And, Chair Mitchell, we would also -- just a sort of recordkeeping matter, we would move that the stipulation and accompanying exhibits, which were filed in this proceeding on September 7th, be entered into the record as well.

CHAIR MITCHELL: All right. Mr. Jeffries, I'm not hearing -- let's see -- I'm not hearing objection to your motion, so the stipulation of partial settlement and exhibits thereto between Piedmont and Public Staff, Carolina

Utility Customer Association Incorporated and Carolina Industrial Group for Fair Utility Rates IV will be accepted into evidence.

(Stipulation of Partial Settlement and Exhibits were admitted into evidence.)

CHAIR MITCHELL: All right. At this point we will break for lunch. It's 12:45. We will go off the record now. We will be back on the record at 2:00.

(The hearing was adjourned at 12:45 p.m. and set to reconvene at 1:00 p.m. on Thursday, 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.

NDTCA · Signed Electronic Transcript

JOANN BUNZE, RPR
Notary Public #200707300112